INNOVATIVE CLEAN COAL TECHNOLOGY (ICCT)

500 MW DEMONSTRATION OF ADVANCED WALL-FIRED COMBUSTION TECHNIQUES FOR THE REDUCTION OF NITROGEN OXIDE (NOx) EMISSIONS FROM COAL-FIRED BOILERS

Final Report
Phases 1 – 3B

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Prepared by:

Southern Company Services, Inc.
600 North 18 Street
Birmingham, Alabama 35202

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ABSTRACT

This report presents the results of a U.S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) project demonstrating advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The project was conducted at Georgia Power Company's Plant Hammond Unit 4 located near Rome, Georgia. The technologies demonstrated at this site include Foster Wheeler Energy Corporation's advanced overfire air system and Controlled Flow/Split Flame low NOx burner. The DOE Cooperative Agreement Number for this project is DE-FC22-90PC89651.

The Clean Coal Technology Program is a jointly funded effort between government and industry to move the most promising advanced coal-based technologies from the research and development stage to the commercial marketplace. The Clean Coal effort sponsors projects that are different from traditional research and development programs sponsored by the DOE. Traditional projects focus on long-range, high-risk, high-payoff technologies with the DOE providing the majority of the funding. In contrast, the goal of the Clean Coal Program is to demonstrate commercially feasible, advanced coal-based technologies that have already reached the "proof-of-concept" stage.

The primary objective of the demonstration at Hammond Unit 4 was to determine the long-term effects of commercially available wall-fired low NOx combustion technologies on NOx emissions and boiler performance. Short-term tests of each technology were also performed to provide engineering information about emissions and performance trends. A target of achieving fifty percent NOx reduction using combustion modifications was established for the project.

Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low NOx burners were then installed during a seven-week outage starting on March 8, 1991 and continuing to May 5, 1991. Following optimization of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing commenced during July 1991 and continued until January 1992. Testing in the LNB+AOFA configuration was completed during August 1993.

This report provides documentation on the design criteria used in the performance of this project as it pertains to the scope involved with the low NOx burners and advanced overfire systems.

Over the course of the project, several tasks not part of the original project scope were included:

- Chemical Emissions Testing
- Advanced Digital Control / Optimization

These other aspects of the project are reported elsewhere.

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POINT OF CONTACT

Southern Company Services

John N. Sorge
Southern Company Services, Inc.
600 North 18th Street
Birmingham, AL 35202
Tel: 205.257.7426
E-mail: jnsorge@southernco.com

Georgia Power Company

W. E. (Ernie) Padgett
Georgia Power Company / Plant Hammond
5963 Alabama Highway SW
Coosa, Georgia 30129
Tel: 706.290.6223
E-mail: w.e.padgett@gpc.com

U.S. Department of Energy

Scott M. Smouse
U.S. Department of Energy
Pittsburgh Energy Technology Center
P. O. Box 10940
Pittsburgh, PA 15236-0940
Tel: 412.892.5725
E-mail: smouse@fetc.doe.gov

Electric Power Research Institute

Jeffery W. Stallings
Electric Power Research Institute
3412 Hillview Ave.
Palo Alto, CA 94304-1395
Tel: 415.855.2427
E-mail: jstallin@epri.com

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LIST OF ABBREVIATIONS

°C	Degrees Celsius
°F	Degrees Fahrenheit
°K	Degrees Kelvin
(M)Btu	(million) British thermal unit
acfm	actual cubic feet per minute
acm	actual cubic meter
AEL	alternate emission limit
AMIS	All mills in service
AOFA	Advanced Overfire Air
ASME	American Society of Mechanical Engineers
BOOS	Burners out of service
C	carbon
CAA(A)	Clean Air Act (Amendments)
CCT	U.S. Department of Energy's Clean Coal Technology Program
CEM	Continuous emissions monitor
cfm	Cubic feet per minute
CFSF	Controlled Flow/Split Flame
Cl	chlorine
CO	carbon monoxide
DAS	data acquisition system
DCS	digital control system
DOE	U.S. Department of Energy
ECEM	extractive CEM
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
ETEC	Energy Technology Consultants, Inc.
FC	fixed carbon
FGR	flu gas recirculation
Flame	Flame Refractories
ft	feet
FWEC	Foster Wheeler Energy Corporation
GPC	Georgia Power Company
H	hydrogen
HHV	higher heating value
HVT	High velocity thermocouple
I&C	Instruments and Controls
ICCT	Innovative Clean Coal Technology
ID Fan	Induced draft fan
IEEE	Institute Electrical and Electronic Engineers
KPPH	kilo pounds per hour
kw	kilowatt
kWh	kilowatt hour
lb(s)	pound(s)

lb/Mbtu	Pounds per million Btu of fuel burned
LEA	low excess air
LNB	low NO_x burner
LOI	loss on ignition
MOOS	Mills out of service
MW	megawatt
N	nitrogen
NO	nitrogen oxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O, O_2	oxygen
OFA	overfire air
PA fan	primary air fan
ppm	parts per million
psig	pounds per square inch gauge
PTC	Performance Test Codes
RSD	relative standard deviation
S	sulfur
SCA	specific collection area
SCS	Southern Company Services
sec	Second
SO_2	sulfur dioxide
SoRI	Southern Research Institute
Spectrum	Spectrum Systems Inc.
THC	total hydrocarbons
UARG	Utility Air Regulatory Group
UBC	unburned carbon
VM	volatile matter

EXECUTIVE SUMMARY

This report discusses the results of a U.S. Department of Energy Innovative Clean Coal Technology (ICCT) demonstration of advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The project was conducted at Georgia Power Company's Plant Hammond Unit 4 located near Rome, Georgia. Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW. The primary goal of this project was the characterization of the low NOx combustion equipment through the collection and analysis of long-term emissions data. The project was funded by the Electric Power Research Institute, Southern Company, and U.S. Department of Energy. The project provided a stepwise evaluation of FWEC's Advanced Overfire Air (AOFA) and Control Flow / Split Flame low NOx burner (LNB), alone and in combination with the AOFA.

Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low NOx burners were then installed during a seven-week outage starting on March 8, 1991 and continuing to May 5, 1991. Following optimization of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing commenced during July 1991 and continued until January 1992. Testing in the LNB+AOFA configuration was completed during August 1993.

Based on long-term testing, the following full-load NOx emission levels were achieved:

Technology	NOx Emission Rate	Reduction from Baseline
Baseline	1.24 lb/MBtu	--
AOFA	0.94 lb/MBtu	24%
LNB	0.65 lb/MBtu	48%
LNB+AOFA	0.40 lb/Mbtu	68%

Although significant NOx emission reductions were achieved, the low NOx burners and advanced overfire air, alone and in combination, had adverse operational and performance impacts on the unit, including increased carbon-in-ash and decreased boiler efficiencies. These degradations in turn adversely affected stack particulate emissions.

Based on the observed NOx reductions and efficiency impacts, the cost effectiveness of the technologies for Hammond 4 were determined to be:

Technology	Increased O&M Costs $1000/year	Cost Effectiveness $/ton NOx removed
AOFA	$290	$144
LNB	$165	$65
LNB+AOFA	$333	$86

1 INTRODUCTION

1.1 Purpose of this Report

This Final Report presents the results of a U.S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) project demonstrating advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The project was conducted on Unit 4 at Georgia Power Company's Plant Hammond, located near Rome, Georgia. The technologies demonstrated on this unit include Foster Wheeler Energy Corporation's advanced overfire air system and Controlled Flow/Split Flame low NOx burner. The DOE Cooperative Agreement Number for this project is DE-FC22-90PC89651.

The project was managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: Southern Company, U.S. Department of Energy (DOE), and Electric Power Research Institute (EPRI). Southern Company, the largest producer of electricity in the United States is the parent firm of Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Savannah Electric. Based in Atlanta, Southern Company supplies electricity in nine countries on four continents and provides energy-related marketing, trading and technical services and wireless telecommunications. SCS provides engineering, research, and financial services to Southern Company.

The Clean Coal Technology Program is a jointly funded effort between government and industry to move the most promising advanced coal-based technologies from the research and development stage to the commercial marketplace. The Clean Coal effort sponsors projects that are different from traditional research and development programs sponsored by the DOE. Traditional projects focus on long range, high risk, high payoff technologies with the DOE providing the majority of the funding. In contrast, the goal of the Clean Coal Program is to demonstrate commercially feasible, advanced coal-based technologies that have already reached the "proof of concept" stage. As a result, the Clean Coal Projects are jointly funded endeavors between the government and the private sector, conducted as cooperative agreements in which the industrial participant contributes at least fifty percent of the total project cost.

This report provides documentation on the design criteria used in the performance of this project as it pertains to the scope involved with the low NOx burners and advanced overfire systems.

1.2 Overview of Project

1.3 Background of Project

The U.S. Department of Energy's Clean Coal Technology (CCT) Demonstration Program is a $7.1 billion cost-shared industry/government technology effort targeted at demonstrating a new generation of advanced coal-based technologies for both the domestic and international marketplace. DOE's share of the total project cost is approximately $2.4 billion (34 percent). As conceived by DOE, "the CCT Program has a key role in advancing three goals of the DOE Strategic Plan under the Energy Resource business line," the goals being

- Reduce adverse environmental impacts associated with energy production, delivery, and use,

- Ensure reliable energy services with reduced vulnerability to energy price and supply volatility, and
- Enhance energy productivity to strengthen the U.S. economy and improve living standards.

The technologies being demonstrated through the CCT Program primarily target emissions of sulfur oxides, nitrogen oxides, greenhouse gases, hazardous air pollutants, and solid and liquid waste. The CCT Program has been implemented through a series of five solicitations conducted over a period of nine years. The first three solicitations (Rounds I through III) were aimed primarily at acid rain technologies while the latter two (Rounds IV and V) addressed post year 2000 energy supply.

In December 1987, Public Law No. 100-202, as amended by Public Law No. 100-446, provided $575 million to conduct cost-shared CCT Projects to demonstrate emerging clean coal technologies that are capable of retrofitting or repowering existing facilities. To that end a Program Opportunity Notice (PON) for Round II of the CCT Program was issued by DOE in February 1988 soliciting proposals to demonstrate technologies that are: (1) capable of being commercialized in the 1990's, (2) more cost effective than current technologies, and (3) capable of achieving significant reductions in sulfur dioxide (SO_2) and/or nitrogen oxide (NOx) emissions from existing coal burning facilities, particularly those that contribute to transboundary and interstate pollution. In response to the PON, 55 proposals were received by the DOE and eventually 16 selected for funding. As one of the accepted proposals, Southern Company Services was awarded a contract for the project "500 MW Demonstration of Advanced, Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal-Fired Boilers."

1.3.1 Project Objectives

The primary objective of the demonstration at Hammond Unit 4 was to determine the long-term effects of commercially available wall-fired low NOx combustion technologies on NOx emissions and boiler performance. Short-term tests of each technology were also performed to provide engineering information about emissions and performance trends. A target of achieving fifty percent NOx reduction using combustion modifications was established for the project.

Specifically, the original objectives of the project were:

- Demonstrate in a logical stepwise fashion the short-term NOx reduction capabilities of the following advanced low NOx combustion technologies:

  Advanced Overfire Air (AOFA)

  Low NOx burners (LNB)

  LNB with AOFA

- Determine the dynamic, long-term emissions characteristics of each of these combustion NOx reduction methods using statistical techniques.

- Evaluate the progressive cost effectiveness (i.e., dollars per ton NOx removed) of the low NOx combustion techniques tested.

- Determine the effects on other combustion parameters (e.g., CO production, carbon carryover, particulate characteristics) of applying the NOx reduction methods listed above.

To accomplish these evaluations, the project was partitioned into the following test phases:

- Phase 1 - Baseline

- Phase 2 - Advanced Overfire Air

- Phase 3A - Low NOx Burners

- Phase 3B - Low NOx Burners plus Advanced Overfire Air

Each of the phases of the project involved three distinct testing periods: short-term characterization, long-term characterization, and short-term verification. The short-term characterization testing established the trends of NOx versus various parameters and establishes the influence of the operating mode on other combustion parameters. The long-term characterization testing (50 to 80 continuous days of testing) established the dynamic response of the NOx emissions to all of the influencing parameters encountered. The short-term verification testing documented any fundamental changes in NOx emissions characteristics that may have occurred during the long-term test period.

Over the course of the project, several tasks not part of the original project scope were included:

- Chemical Emissions Testing - Chemical emissions testing was conducted during Phases 2 and 3A.

- Advanced Digital Control / Optimization - This task, added as Phase 4 of the project, evaluated advanced digital control and optimization techniques as applied to (1) reduction of NOx emissions, (2) mitigation of adverse impacts of low NOx burners and advanced overfire air system, and (3) improvement of boiler efficiency.

- Demonstration of On-Line Carbon-in-Ash Monitors.

These tasks are reported elsewhere.

1.3.2 Host Site Description

Georgia Power Company's Plant Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW gross, with design steam conditions of 2500 psig and 1000/1000°F superheat/reheat temperatures, respectively. Hammond 4 was placed into commercial operation on December 14, 1970. Prior to the LNB retrofit, six FWEC Planetary Roller and Table type mills provided pulverized eastern bituminous coal (12,900 Btu/lb, 33% VM, 53% FC, 1.7% S, 1.4% N) to 24 pre-NSPS, FWEC Intervane burners. During the LNB outage, the existing burners were replaced with FWEC Control Flow/Split Flame burners. The unit was also retrofitted with six Babcock and Wilcox MPS 75 mills during the course of the demonstration (two each during the spring 1991, spring 1992, and fall 1993 outages). The burners are arranged in a matrix of twelve burners (4 wide x 3 high) on opposing walls with each mill supplying coal to 4 burners per elevation. As part of this demonstration project, Hammond 4 was retrofit with a FWEC-designed Advanced Overfire Air System. The unit is equipped with a coldside ESP and utilizes two regenerative secondary air heaters and two regenerative primary air heaters. Designed for pressurized furnace operation, Hammond 4 was converted to balanced draft operation in 1977. The unit was equipped with a Bailey pneumatic boiler control system during the baseline, AOFA, LNB, and LNB+AOFA phases of the project.

1.3.3 Project Organization

The overall project organization is shown in Figure 1-1 and descriptions of the responsibilities of the team members are discussed below.

Energy Technology Consultants, Inc. (ETEC) During Phases 1 through 3, ETEC had primary responsibility for on-site testing and analysis of the data and served as test coordinator.

Flame Refractories, Inc. (Flame) Flame was responsible for activities related to fuel/air input parameters and furnace output temperature measurements during the performance testing portion of the short-term characterization.

Foster Wheeler Energy Corporation (FWEC) FWEC designed, fabricated, installed, and commissioned the advanced overfire air system and CF/SF low NOx burners.

Georgia Power Company (GPC) GPC provided on-site coordination for the erection of the advanced overfire air, low NOx burners, and digital control systems.

Radian International (Radian) Radian was responsible for the environmental reporting for the project and also conducted the chemical emissions testing performed at this site.

Southern Research Institute (SoRI) During Phases 1 through 3, SoRI was responsible for testing related to flue gas particulate measurements during the performance testing portion of the short-term characterization.

Southern Company Services (SCS) Served as prime contractor to project funders and as such directed subcontracted efforts of the burner manufacturer, installation contractors, and test coordination contractor, supplying the NOx emissions control systems as described below.

Spectrum Systems, Inc. Spectrum provided a full-time, on-site instrument technician who was responsible for operation and maintenance of the project instrumentation.

W. S. Pitts Consulting, Inc. (WSPC) WSPC was responsible for the statistical analysis of the long-term emissions data.

1.3.4 Project Schedule

Figure 1-2 shows the schedule for the project activities. Test instrumentation was originally installed during the third and fourth quarter 1989. Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low NOx burners were then installed during a seven-week outage starting on March 8, 1991 and continuing to May 5, 1991. Following optimization of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing commenced during July 1991 and continued until January 1992. Testing in the LNB+AOFA configuration was completed during August 1993.

1.3.5 Project Cost

The total estimated cost of the project is $15,853,890. The Participants' cash contribution and the Government share in the costs of this project are shown in Table 1-1. The costs quoted are those submitted in the most recent Cooperative Agreement modification. A summary of funding by contributor is shown in Table 1-2.

1.4 Report Organization

The purpose of this report is to provide a technical account of the total work performed under the Cooperative Agreement. The following is a brief description of the information provided in each section:

Section 1 - Introduction - Background and funding information.

Section 2 - Unit Description and Pre-Retrofit Operating Characteristics - Host site description.

Section 3 - Process Description - Overview of NOx formation process and combustion control technologies.

Section 4 - Technology Description - Description of the NOx control technologies tested at this site.

Section 5 - Test Program Description - Description of the sampling methods and test program design.

Section 6 - Baseline Testing

Section 7 - AOFA Testing

Section 8 - LNB Testing

Section 9 - LNB+AOFA Testing

Section 10 - Performance Comparison

Section 11 - Economic Analysis

Section 12 - Conclusions

Testing specifically excluded from this final report includes that from the chemical emissions testing, evaluation of on-line carbon-in-ash analyzers, and on-line optimization methods. These results have been reported elsewhere [Radian 1993; SCS 1997; SCS 1998].

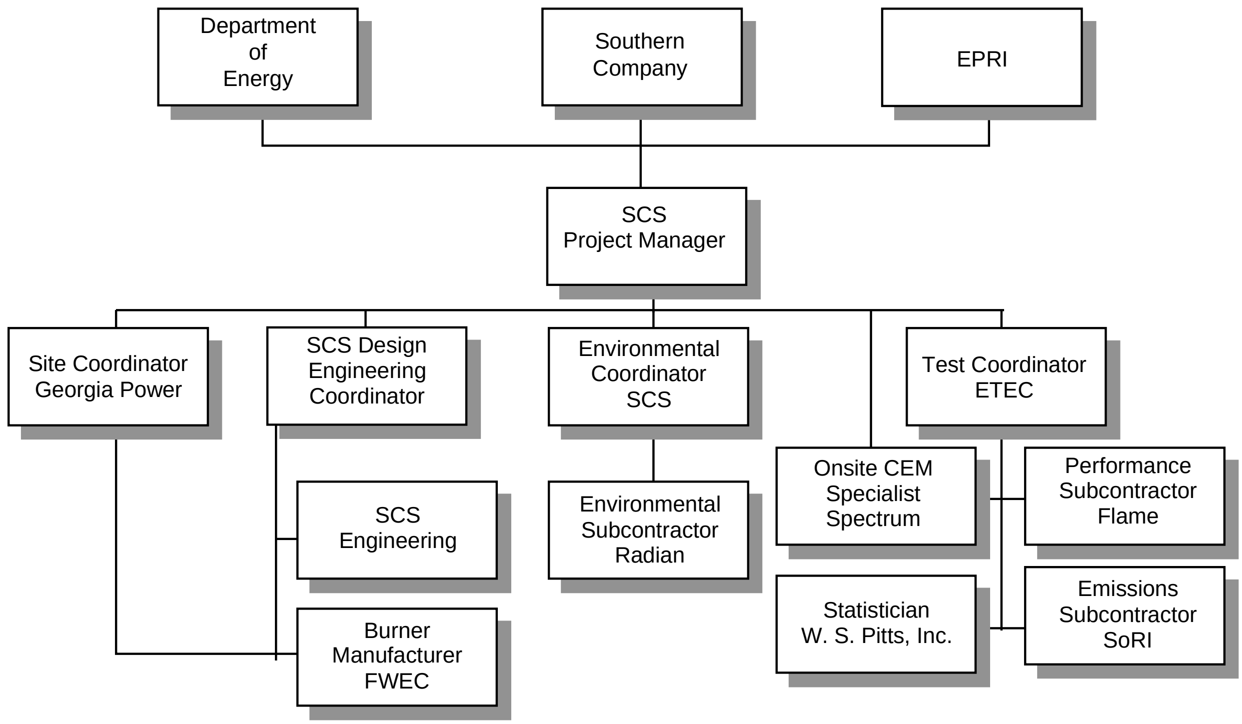


Figure 1-1 Project Organization

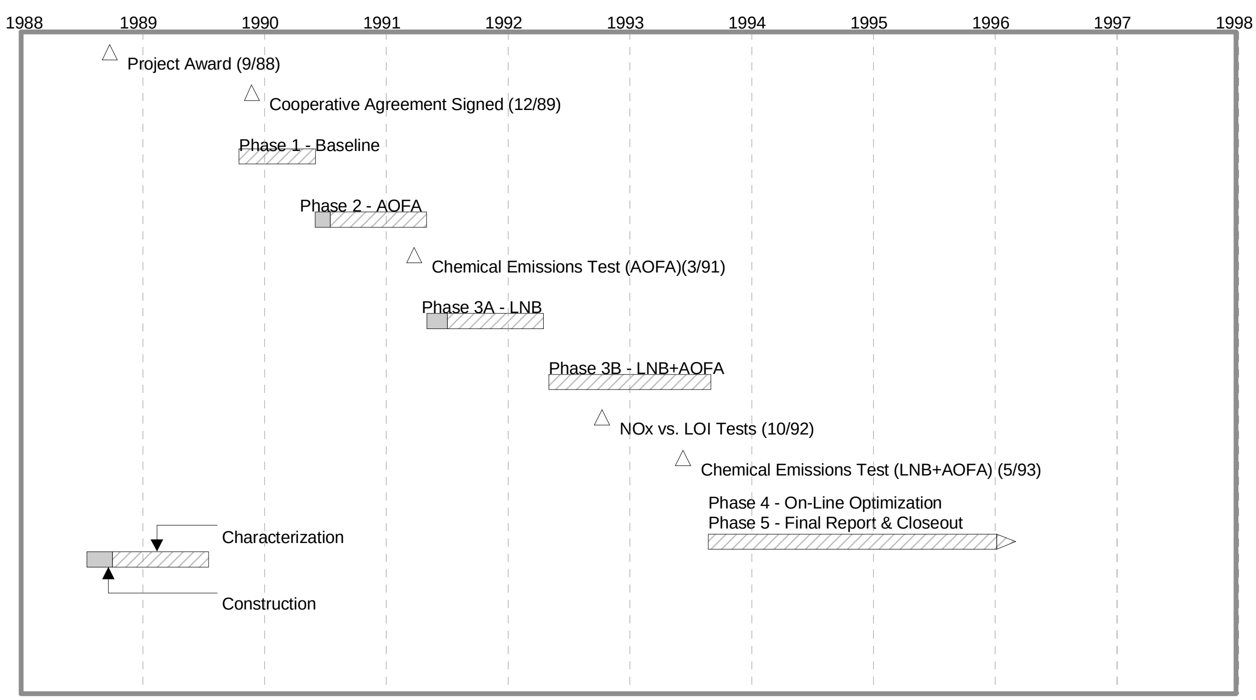


Figure 1-2 Overall Project Schedule

Table 1-1 Project Costs by Phase

Phase	Dollar Share ($)	Percent Share (%)
Phase 0 - Pre-Award		
Government	$122,311	41%
Participant	$179,637	59%
	$301,948	
Phase 1 - Baseline Testing		
Government	$660,426	45%
Participant	$813,739	55%
	$1,474,165	
Phase 2 - AOFA Installation and Characterization		
Government	$1,712,745	45%
Participant	$2,110,346	55%
	$3,823,091	
Phase 3 - LNB Installation and Characterization		
Government	$2,571,446	45%
Participant	$3,168,389	55%
	$5,739,835	
Phase 4 - Digital Control System		
Government	$1,076,000	30%
Participant	$2,522,338	70%
	$3,598,338	
Phase 4 - Project Close-out and Final Reporting		
Government	$410,598	45%
Participant	$505,915	55%
	$916,513	
Total Project Funding	$15,853,890	

Table 1-2 Project Funding by Participant

Participant	Dollar Contribution	Percent
DOE	$6,553,526	41.3
EPRI + Southern Company	$9,300,364	58.7
Total	$15,853,890	100

2 UNIT DESCRIPTION AND PRE-RETROFIT OPERATING CHARACTERISTICS

2.1 Unit Description

Georgia Power Company's Plant Hammond is located near Rome, Georgia, approximately 100 miles northwest of Atlanta (Figure 2-1). The site has four pulverized coal units. Units 1 through 3 are 100 MW Babcock and Wilcox wall-fired units. Unit 4, the host site for the ICCT project, is a Foster Wheeler opposed wall-fired boiler, which started operating in 1970. The unit, shown in Figure 2-2, is rated at 500 MW with design steam conditions of 2500 psig and 1000/1000°F superheat and reheat temperatures, respectively. The boiler was originally designed for pressurized operation, but was converted to balanced draft in 1977. As shown in Figure 2-3, the burners are arranged in a matrix of twelve burners (4 wide x 3 high) on the front and rear walls with each mill supplying coal to the four burners of each elevation. The original design characteristics of the unit are summarized in Table 2-1.

Figure 2-1 Plant Hammond

Table 2-1 Hammond Unit 4 Design Characteristics/Pre-Technology Retrofit

Unit Size	500 MW
Commissioning Year	1970
Firing System/Number of burners	Opposed wall-fired/24 burners
Vendor	Foster Wheeler Energy Corp.
Furnace	
- Configuration	Single Furnace
- Width × Depth (ft × ft)	52.5 × 40
- Burner Zone Liberation Rate (Btu/hr-sqft)	425,000
Windbox Design	
- Coal Elevation Spacing (ft)	8.5
- Top coal elev.-to-furn. outlet (nose) (ft)	55
Number of Mills/Mill Type	6 FWEC Planery Roller & Table Mills
Air/Fuel Ratio	2.1
Mill Transition Points	400 MW: E or B-MOOS 300 MW:BE or EF-MOOS or AE-MOOS
Coal Type	Eastern bituminous
FC/VM	1.57
ESP (cold-side)	
- Specific collection area (ft^2)	161
- Fly ash resistivity (ohm-cm)	low-to-mid 10^{10}

As originally constructed and during baseline testing, six Foster Wheeler Energy Corporation (FWEC) planetary roller and table type mills provided pulverized eastern bituminous coal to 24 FWEC Intervane burners. During the test program, although not part of it, the existing FWEC mills were replaced with B&W MPS 75 mills in phases; two mills (C and F) were replaced in the spring of 1991 and two more (A and E) in the spring of 1992. The last two mills (B and D) were replaced and came online in June 1994.

As shown in Figure 2-4, the unit is equipped with a cold-side electrostatic precipitator (ESP); Ljungstrom air heaters; two secondary and two primary air heaters. The ESP capacity (original design of 161 SCA) was characterized as marginal under the baseline conditions.

In June of 1994, installation of a new electrostatic precipitator was completed for Hammond Unit 4. The new precipitators were furnished by Research Cottrell and are designed with an SCA of 213 ft^2/1000 acfm. The precipitators utilize a rigid discharge electrode design and have a design gas velocity of 5.15 ft/sec and collection efficiency of 99.65 percent.

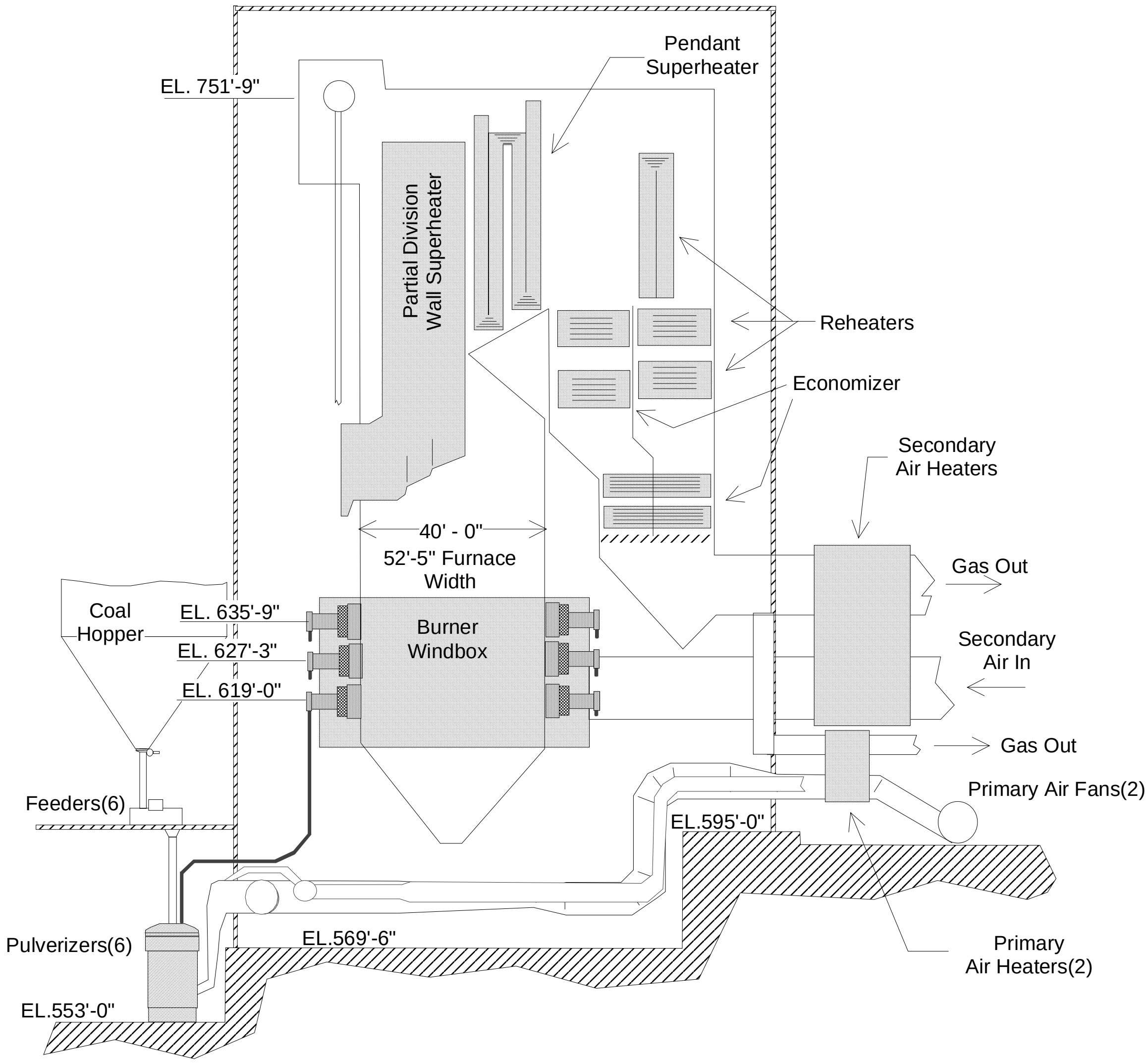


Figure 2-2 Hammond Unit 4 Side View / Pre-Retrofits

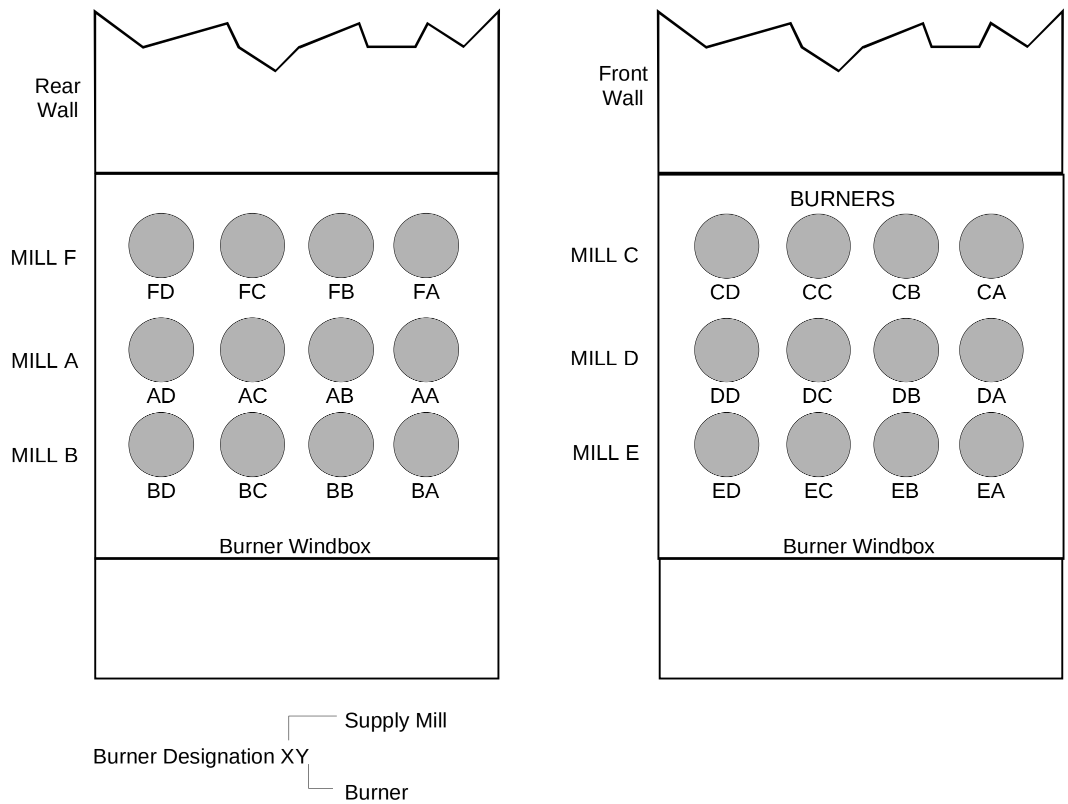


Figure 2-3 Burner Layout

The key features of Hammond Unit 4 which may impact the NOx emission reduction with the low NOx technologies and the applicability of the results to other wall-fired units are:

- High heat release rate
- Relatively small distance between the top burner elevation and the furnace outlet (55 ft)
- Marginal ESP capacity during Phases 1 through 3 of the test program; 9 fps velocity and 161 SCA
- The coal being burned at Hammond Unit 4 is a medium-to-low reactivity Eastern Bituminous coal

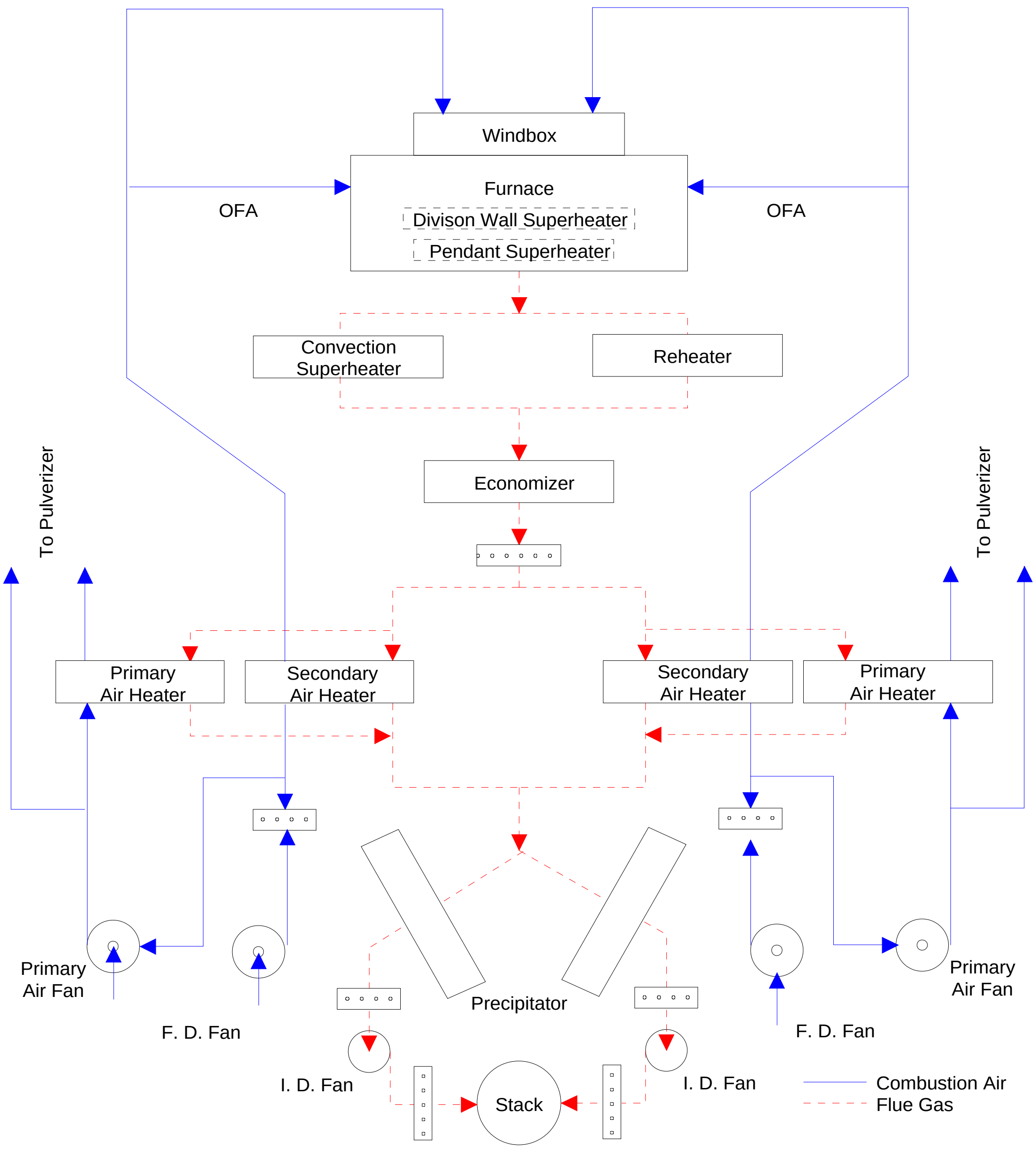


Figure 2-4 Layout of Combustion Air and Flue Gas Paths

The high heat release rate of the unit contributed to the higher than average baseline NOx emissions (1.24 lb/MBtu long-term NOx at full load). The heat release rate[1] for Hammond 4 is 425,000 Btu/hr-sqft as compared to the average heat release rate for opposed Foster Wheeler wall-fired units of 250,000 Btu/hr-sqft. However, it was not clear how the heat release rate impacts the (percentage) NOx emission reduction.

The smaller than average distance from the top burner to the furnace outlet limited the size and the location of the AOFA system, and potentially reduced the NOx emission reduction potential of this technology. Also, owing to the short distance from the top burner to the furnace outlet (furnace nose plane), the residence time of the coal particles is reduced and the unburned carbon (LOI) may increase. However, the Hammond unit is not unique; there are many similar boilers designed in the 1960s, which face the same retrofit issues.

The boiler burns a medium to low volatility eastern bituminous coal with a typical analysis as shown in Table 2-2. As Figure 2-5 shows, the reactivity of the Hammond coal is similar to Illinois Bituminous B-type coals.

Table 2-2 Typical Hammond 4Coal (As Received)

Characteristic	Value
Constituents	
Ultimate	
Carbon	72.40 %
Hydrogen	4.69 %
Nitrogen	1.43 %
Sulfur	1.72 %
Oxygen	5.65 %
Moisture	4.28 %
Ash	9.77 %
Proximate	
Fixed Carbon:	52.70 %
Volatiles	33.50 %
Ash	9.77 %
HHV	12,900 Btu/lb

[1] FWEC uses burner zone liberation rate to indicate heat release. The area is calculated as follows: 2(W x H) + 2(D x H) + 2(D x W) where W = Width, D = Depth, and H = Height from knuckle to 10 feet above centerline of top row of burners. Other boiler manufacturers define heat release in a different manner.

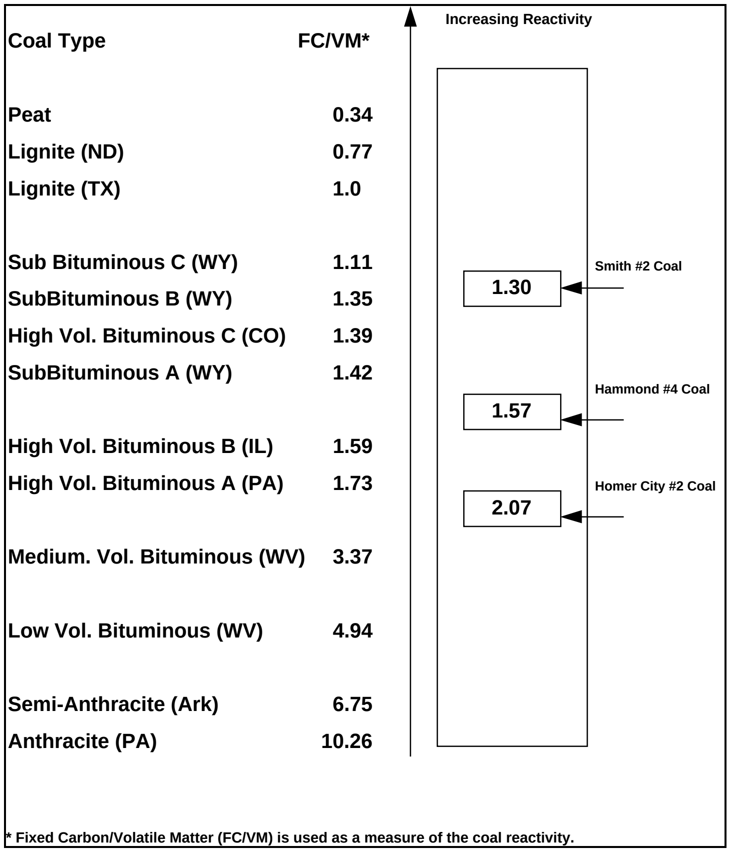


Figure 2-5 Comparison of Hammond Coal Reactivity to Other U.S. Coals

2.2 Pre-Retrofit Operating Characteristics

The main parameters characterizing the unit performance as it relates to this project are NOx and CO emissions, required O_2, LOI, coal fineness, furnace slagging, backpass fouling, and performance of the ESP. The pre-technology values for these important operating characteristics are briefly discussed below. Detailed results from baseline testing are provided in Section 6.

NOx Emissions

Pre-retrofit NOx emissions at 480 MW load ranged from 1.1 to 1.45 lb/MBtu (750 to 1000 ppm) with O_2 of 2 to 5 percent as measured at the economizer outlet. The average full load long-term NOx emissions at full load were 1.24 lb/MBtu at an average O_2 level of 2.6 percent. This emission level represents normal operation with the combustion system not optimized to reduce NOx emissions prior to the commencement of the baseline testing. As shown in Figure 2-5, NOx emissions decreased slightly with decreasing load. At 300 MW (control point), NOx emissions were approximately 1.00 lb/MBtu.

CO Emissions

CO emissions were generally below 100 ppm over the load range. The CO level was adversely impacted by plant staff lowering operation excess O_2 levels in an effort to reduce stack particulate emissions.

Excess Oxygen

Excess O_2 (as measured at the economizer outlet) at full load ranged from 2 to 5 percent with an average of 2.6 percent. The lower limit was set to keep CO emissions from increasing while the upper limit resulted from ESP capacity limitations.

Fly Ash Loss-on-Ignition

LOI at full load was 5 percent with average coal fineness of 63.0 percent through 200 mesh and 2.8 percent left on 50 mesh (Figure 2-6). This coal fineness does not compare favorably with the coal fineness recommended by most low NOx burner manufacturers (higher than 70 percent through 200 mesh and less than 1.5 percent left on 50 mesh), but it established a basis for comparing the post-retrofit coal fineness and LOI. It should be noted also that the baseline testing was performed with all six original FWEC mills.

Air and Fuel Balancing

Significant air and coal flow imbalance was measured; O_2 ranged from 2 to 5 percent from the front to the rear wall of the furnace, respectively. The coal flow rate through each mill varied significantly, as well; even though the mills were set by the control room to approximately equal flow rates, up to 11 percent difference in flow rate was observed between mills.

Furnace Slagging

Prior to the retrofits, the unit could be considered to have moderate-to-high in-furnace slagging. This high slagging contributed to the extremely high furnace temperatures.

Steam Temperatures

Superheater outlet temperature was between 990 and 1000°F, while the reheat outlet was below 1000°F. The reheat temperature was particularly low (950-980°F) in the 250 to 420 MW load range.

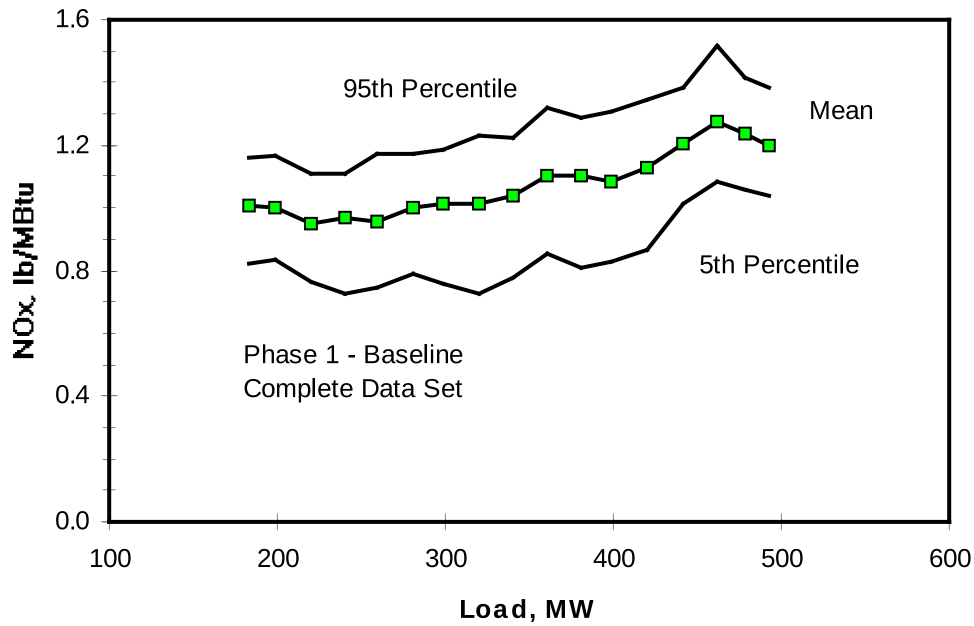


Figure 2-6 Pre-Retrofit NO_x Emissions

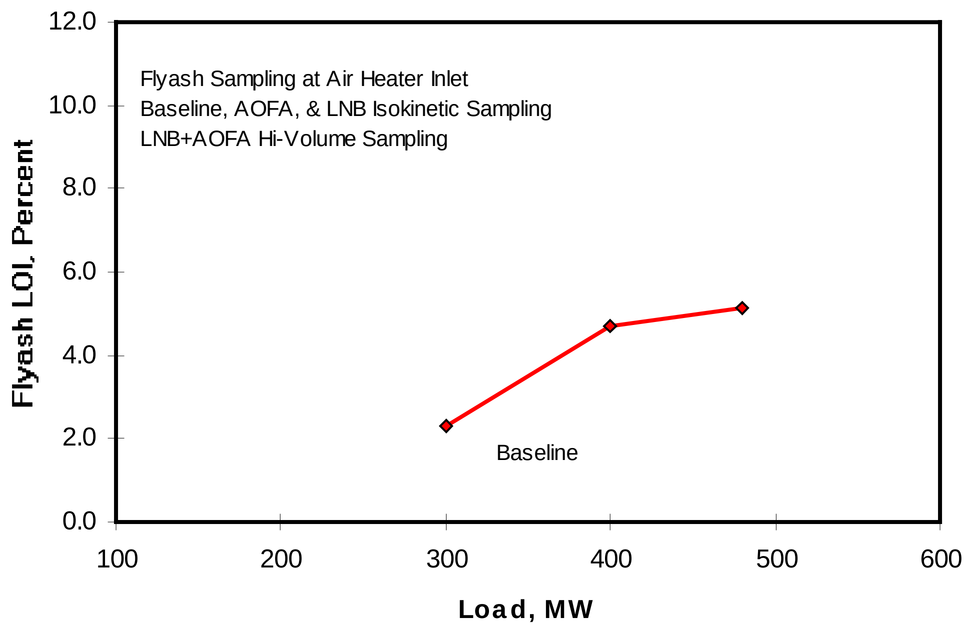


Figure 2-7 Pre-Retrofit Fly Ash Loss-on-Ignition

3 PROCESS DESCRIPTION

The NOx control technologies demonstrated as part of this project rely primarily upon precise control of the combustion process to regulate the formation (and destruction) of NOx within the combustion zone of the furnace. The following sections provide discussions of: (1) the detailed descriptions of the fundamental chemical and physical mechanisms that control NOx formation, and (2) the processes by which each of the technologies controls these mechanisms to minimize NOx formation.

3.1 Process Concept Description

To comprehend the chemical and physical processes governing the operation of the NOx control technologies that were demonstrated, a thorough understanding of the mechanisms by which NOx is formed in combustion processes and the parameters that govern the formation or destruction of NOx is important. Although many readers of this report will already have a comprehensive knowledge of this subject, it is thought to be useful to present in this document a concise overview of NOx formation and control mechanisms for all readers. The discussion presented herein is a compendium of a large volume of public literature dating from 1947 (original Zeldovich equilibrium mechanisms) to present-day papers presented at NOx control symposia. The following discussion represents a widely held consensus on the mechanisms of formation and destruction of nitrogen oxides in fossil fuel combustion processes.

3.1.1 NOx Formation Mechanisms

Nitrogen oxides are formed in combustion processes through the thermal fixation of atmospheric nitrogen in the combustion air producing "thermal NOx," and the conversion of chemically bound nitrogen in the fuel producing "fuel NOx." For natural gas and distillate oil, nearly all NOx emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel-bound nitrogen can be significant and, in many cases, predominant.

Thermal NOx

Nitrogen oxides (NOx) are formed during combustion by the high temperature, thermal fixation of N_2. At high temperature, both N_2 and O_2 molecules in air are dissociated into their respective atomic states, N and O. The subsequent reduction of these atoms is described by the well known Zeldovich mechanism equations:

$$N_2 + O \leftrightarrow NO + N$$
$$N + O_2 \leftrightarrow NO + O$$
$$N + OH \leftrightarrow NO + H$$

Nitric oxide (NO) is the primary reaction product, even though NO_2 is thermodynamically favored at lower temperatures. The residence time in most stationary combustion processes is too short for significant oxidation of NO to NO_2.

In the flame zone itself, the Zeldovich mechanism with the equilibrium oxygen assumption is not adequate to account for experimentally observed NO formation rates. Several investigators have observed the production of significant amounts of "prompt" NO, which is formed very rapidly in the flame front, but there is no general agreement on how it is produced. Prompt NO is believed to stem from the existence of "super-equilibrium" radical concentrations within the flame zone which result from hydrocarbon chemistry and/or nitrogen specie reactions. To date, prompt NO has only been explicitly measured in carefully controlled laminar flames, but the mechanism almost certainly exists in commercial combustor flames as well. In an actual combustor, both the hydrocarbon and NOx kinetics are directly coupled to turbulent mixing in the flame zone.

Experiments indicate that under certain conditions, the amount of NO formed in heated mixtures of N_2 and O_2 can be expressed by the following equation.

$$[NO] = k_l \exp(-k_2/T)\,[N_2]\,[O_2]^{1/2t}$$

where [ ] = mole fraction
k_1, k_2 = constants
T = temperature
t = time.

Although this equation does not adequately describe NOx formation in turbulent flames, it illustrates several points about thermal NOx formation. First, it shows the strong dependence of NO formation on temperature (an inverse exponential function of 1/T, thus increasing with T). Also, NO formation is directly proportional to the square root of oxygen concentration.

Based on the above relations, thermal NOx can theoretically be reduced by decreasing:

- peak temperature
- local nitrogen concentrations at peak temperatures
- local oxygen concentrations at peak temperatures
- residence time at peak temperatures

Because reducing N_2 levels is quite difficult, thermal NOx control efforts have focused on reducing oxygen levels, peak temperatures, and time of exposure in the NOx producing regions of a furnace. Techniques such as lowered excess air and staged combustion have been used to lower local O_2 concentrations in utility boilers. Similarly, flue gas recirculation and reduced air preheat have been used on gas- and oil-fired boilers to control thermal NOx by lowering peak flame temperatures. Flue gas recirculation also reduces combustion gas residence time, but its primary effect on thermal NOx control is through temperature reduction. Neither flue gas recirculation nor air preheat reduction have been very successful in reducing NOx on coal-fired boilers.

It is important to recognize that the above-mentioned techniques for thermal NOx reduction alter combustion conditions. Although these techniques have all been relatively successful in reducing thermal NOx, local combustion conditions ultimately determine the amount of thermal NOx formed. These conditions in turn are intimately related to such variables as local combustion intensity, heat removal rates, and internal mixing effects. Modifying these secondary combustion variables requires fundamental changes in combustion equipment design.

Studies on the formation of thermal NOx in gaseous flames have confirmed that internal mixing can have large effects on the total amount of NO formed. Burner turbulence, combustion air velocity, fuel injection angle and velocity, burner quarl shape, and confinement ratio all affect the mixing between fuel, combustion air, and recirculated products. Mixing, in turn, alters the local temperatures and specie concentrations that control the rate of NOx formation.

Generalizing these effects is difficult because the interactions are complex. Increasing turbulence, for example, may increase entrainment of cooled combustion products (hence lowering peak temperatures) and increase fuel/air mixing (raising local combustion intensity). The net effect of increasing turbulence can be either to raise or lower NOx emissions, depending on other system parameters.

The hierarchy of effects depicted in Table 3-1 describes local combustion conditions that promote thermal NOx formation. Although combustion modification technology seeks to affect the fundamental parameters of combustion, modification must be made by changing the primary equipment and fuel parameters. Control of thermal NOx, which historically began by altering inlet conditions and external mass addition, has moved to more fundamental changes in combustion equipment design.

Table 3-1 Factors Controlling the Formation of Thermal NOx

Primary Equipment and Fuel Parameters	Secondary Combustion Parameters	Fundamental Parameters
Inlet temperature, velocity		
Furnace design	Combustion intensity	
Fuel composition	Heat removal rate	Oxygen level
Injection pattern of fuel and air	Mixing of combustion products into flame	Peak temperature
Size of droplets or particles	Local fuel/air ratio	Exposure time at peak temperature
Burner swirl	Turbulent distortion of flame zone	
External mass addition	Reduction of flame temperatures by dilution	

Fuel NOx

Fuel-bound nitrogen occurs in coal and petroleum fuels. However, the nitrogen-containing compounds in petroleum tend to concentrate in the heavy resin and asphalt fractions upon distillation. Therefore fuel NOx is of importance primarily in residual oil and coal firing. The nitrogen compounds found in petroleum include pyrroles, indoles, isoquinolines, acridines, and prophyrins. Although the structure of coal has not been defined with certainty, it is believed that coal-bound nitrogen also occurs in aromatic ring structures such as pyridine, picoline, quinoline, and nicotine. The nitrogen content of most U.S. coals lies in the 0.5 percent to 2 percent range. Thus, fuel NOx is a primary concern of coal combustion.

Although the precise mechanism by which fuel nitrogen in coal is converted to NOx is not understood, certain aspects are clear. In a large pulverized coal-fired utility boiler, the coal particles are conveyed by an air stream into the hot combustion chamber, where they are heated at a rate in excess of 10,000°F/second. Volatile species containing some of the coal-bound nitrogen vaporize and burn rapidly (on the order of 10 milliseconds). This volatile combustion occurs homogeneously at some distance away from the original coal particle. Combustion of the remaining solid char is heterogeneous and much slower (on the order of 300 milliseconds). Nitrogen oxide can be produced from either the volatile or char fraction of the coal.

Figure 3-1 depicts a possible history of fuel nitrogen during this process. In general, volatile nitrogen evolution parallels evolution of the total volatiles except during the initial 10 to 15 percent volatilization in which little nitrogen is released. Both total mass volatilized and total nitrogen volatilized increase with higher pyrolysis temperature; the nitrogen volatilization increases more rapidly than that of the total mass. Pyrolysis temperatures can influence the ratio between volatile and char NO. However, at temperatures greater than 1800°K (2780°F), the char would be devoid of nitrogen, and char-produced NO would not exist. Coal type and pyrolysis temperature are both important in determining the amount of nitrogen devolatilized. For a given temperature, differences of up to 30 percent in volatile nitrogen yield can be seen. Thus, NOx emissions may be different from coals with the same nitrogen content.

Although there is no absolute agreement on how the volatiles separate into species, it appears that about half the total volatiles and 85 percent of the nitrogenous species evolved react to form other reduced species before being oxidized. Prior to oxidation, the devolatilized nitrogen may be converted to a small number of common, reduced intermediates such as HCN and NH in the fuel-rich regions of the flames. The existence of a set of common reduced intermediates would explain the observation that the form of the original fuel nitrogen compound does not influence its conversion to NO. The reduced intermediates are then either oxidized to NO or converted to N_2 in the post combustion zone. Nitrogen retained in the char may also be oxidized to NO, or reduced to N_2 through heterogeneous reactions occurring in the post-combustion zone. The fraction of nitrogen remaining in the char can be high, although its conversion to NO is low compared to volatile nitrogen conversion to NO. This is probably the result of the mechanism of char combustion. It is believed that char combustion involves internal burning with diffusion at or in the particulate being a controlling parameter. Because of the nature of char combustion, the conversion of nitrogen in the char to NO is not affected by near-burner aerodynamics. Thus, char NO can have significance in terms of the ultimate ability to reduce NO emissions.

Based on experimental and modeling studies, it is believed that 60 to 80 percent of the fuel NOx results from volatile nitrogen oxidation. Conversion of char nitrogen to NO is generally lower, by factors of two to three, than conversion of total coal nitrogen, but is also relatively insensitive to load or overall stoichiometry.

Regardless of the precise mechanism of fuel NOx formation, several general trends are evident. Fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment. Oxidation of the char nitrogen is relatively insensitive to fuel/air changes, but volatile NO formation is strongly affected by fuel/air ratio changes. Thermal nitrogen is also affected by the fuel/air ratio.

In contrast to thermal NOx, fuel NOx production is relatively insensitive to small changes in combustion zone temperature. Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, it is believed to be partially offset by a decrease in percentage conversion. Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current systems.

Fuel NOx emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal volatilization will dramatically increase volatile nitrogen conversion and increase fuel NOx. In contrast, char NO formation is only weakly dependent on initial mixing.

From the above discussions, it appears that, in principle, the best strategy for fuel NOx abatement combines low excess air (LEA) firing, optimum burner design, and staged combustion. Assuming suitable stage separation, LEA may have little effect on fuel NOx, but it may increase boiler efficiency. Before using LEA firing, the need to establish good carbon burnout and low CO emissions must be considered.

Optimum burner design ensures locally fuel-rich conditions during devolatilization, which promotes reduction of devolatilized fuel nitrogen to N_2. Staged combustion produces overall fuel-rich conditions during the first one to two seconds of combustion and promotes the reduction of NO to N_2 through reburning reactions. High secondary air preheat may also be desirable, because it promotes more complete nitrogen devolatilization in the fuel-rich initial combustion stage. This leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage. Unfortunately, it also tends to favor thermal NO formation, and at present there is no general agreement on which effect dominates.

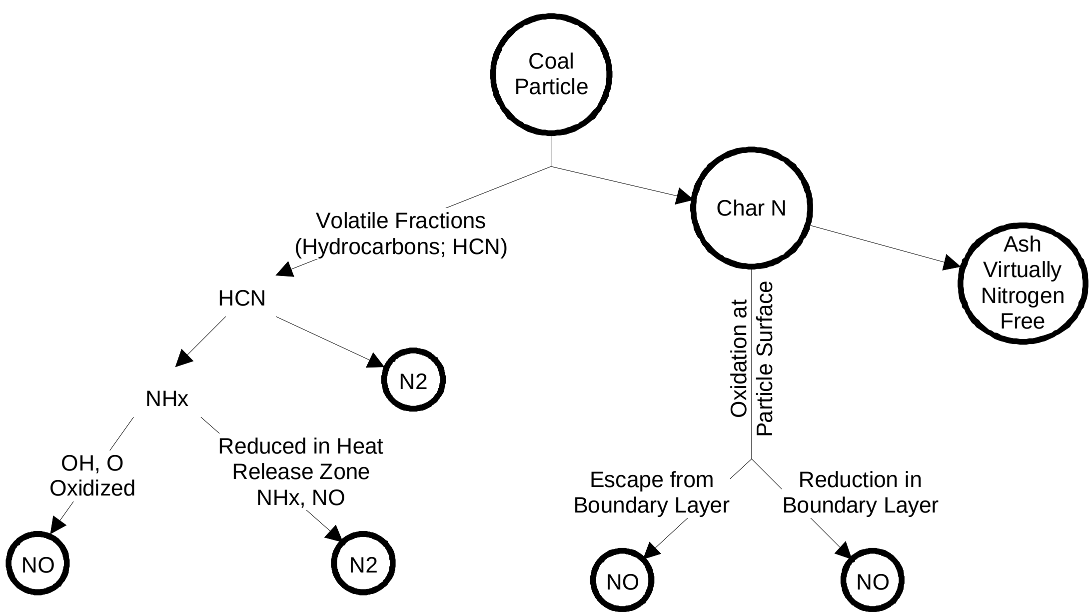


Figure 3-1 Possible History of Fuel Nitrogen

Summary

Both thermal and fuel NOx are kinetically or aerodynamically limited in that their emission rates are far below the levels that would prevail at equilibrium. Thus, the rate of formation of both thermal and fuel NOx is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NOx are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NOx is greatly increased by long residence time at high temperature. The modified combustion conditions and control concepts that have been tried or suggested to combat the formation mechanisms are as follows:

I. Decrease primary flame zone O_2 level by

   A. Decreased overall O_2 level

   B. Controlled mixing of fuel and air

   C. Use of fuel-rich primary flame zone

II. Decrease time of exposure at high temperature by

   A. Decreased peak temperature

   B. Decreased adiabatic flame temperature through

   C. Dilution with furnace gases

III. Decreased combustion intensity

   A. Increased flame cooling

   B. Controlled mixing of fuel and air or use of fuel rich primary flame zone

IV. Decreased primary flame zone residence time

The primary techniques used to reduce primary zone O_2 levels and decrease the residence time at high temperatures, thereby reducing NOx emissions, are low excess air (LEA), burners out-of-service (BOOS), overfire air (OFA), flue gas recirculation (FGR), and low NOx burners (LNB). In many boilers, LEA is already employed to the extent possible for reasons of efficiency; therefore, little improvement in NOx is likely to be possible. BOOS operation poses problems with furnace conditions (staging, corrosion), complicates operation of the coal-fired system by requiring redistribution of coal to the burners, and may limit maximum load on the unit.

The following paragraphs describe the technologies that are applicable to this project. The proposed NOx control technologies will reduce NOx formation from both thermal and fuel nitrogen conversion mechanisms through control of flame stoichiometry, mixing and temperature. This is achieved by careful control of fuel and air injection mechanisms and localized staged combustion.

3.2 NOx Control Technologies

The control technologies at Hammond employ two distinct approaches to NOx reduction through combustion control. Each is capable of achieving substantial NOx reduction if employed alone, but when the technologies are used in concert, even greater NOx reductions are achieved. The following discussions present descriptions of the technologies and some background as to their evolution to the current development status.

3.2.1 Advanced Overfire Air (AOFA)

Because NOx formation is strongly dependent on the flame zone stoichiometry, as discussed above, a process which removes some of the "excess" air (above the stoichiometric quantity) from the burner flame zone and reintroduces it later in the combustion area, away from the high temperature flames, should reduce NOx formation. This process was first documented in full-scale field tests with gas and oil fuels by leaving some upper level burners out of service (no fuel), but with the air flow to these burners unchanged. As a consequence, the stoichiometry at the in-service burners became less air rich, with less oxygen available for combination with nitrogen in the hot flame zone. The result was a reduction of about 50 percent in NOx emissions at the highest degree of combustion staging. Subsequent development led to installation of separate overfire air (OFA) ports above the highest burner level, supplied with air from the windbox. This configuration resulted in similar NOx emissions but allowed operation of all normal burners-in-service and some improvement in control of the staging process. When New Source Performance Standards (NSPS) regulations dictated reductions in NOx emissions for new boilers, OFA technology was applied to coal-fired boilers (both wall-fired and tangential), with NOx reductions on the order of 15-25 percent being typically achieved, depending upon furnace dimensions, burner configurations and location, fuel type, OFA port design, and degree of staging achievable. This process has been used on many boilers up to the present day as one means of NOx control.

The primary limitations to increasing the effectiveness of NOx control with OFA are the degree of staging which can be achieved without adversely affecting boiler operation, and the difficulty in achieving complete combustion by thorough mixing of the OFA with the partially combusted furnace gases from the burner zone.

The degree of staging achievable is potentially limited only by the provision of sufficient air to the burners to sustain stable combustion. However, extremely low stoichiometries can aggravate slag formation and other undesirable conditions in the furnace. A minimum stoichiometry of around 70-80 percent of theoretical is probably feasible. OFA staging has typically been limited to ensure that the overall burner zone stoichiometry is always above theoretical, so that local reducing conditions would not occur in the furnace. Reducing atmospheres, if allowed to persist adjacent to the furnace walls can result in a severe increase in corrosion of the tube metal. To avoid this condition OFA staging has been limited to approximately 10-20 percent of total combustion air and burner zone stoichiometrics in the range of 1.2 to 1.0.

Because OFA operation results in combustion in the flame zone at stoichiometrics lower than would ordinarily occur, some incomplete combustion occurs, with the partially burned gases and carbon particles proceeding upwards from the flame zone. Completion of the combustion of these gases and carbon depends upon mixing with the remaining OFA at temperatures high enough to sustain the combustion within the furnace volume. If any gases or carbon do not encounter oxygen molecules at the proper temperature prior to exiting the furnace, then an increase in combustible losses will occur. It is the function of the OFA design to ensure that mixing is sufficient to complete the combustion within the furnace. The effectiveness of the mixing is limited by the injection pressures (velocities) achievable with the windbox air supply provided. In addition to the concerns for flame zone reducing atmospheres cited above, the degree of staging possible with normal OFA designs has been further restricted by the limitations on achieving thorough mixing of the OFA with the combustion gases.

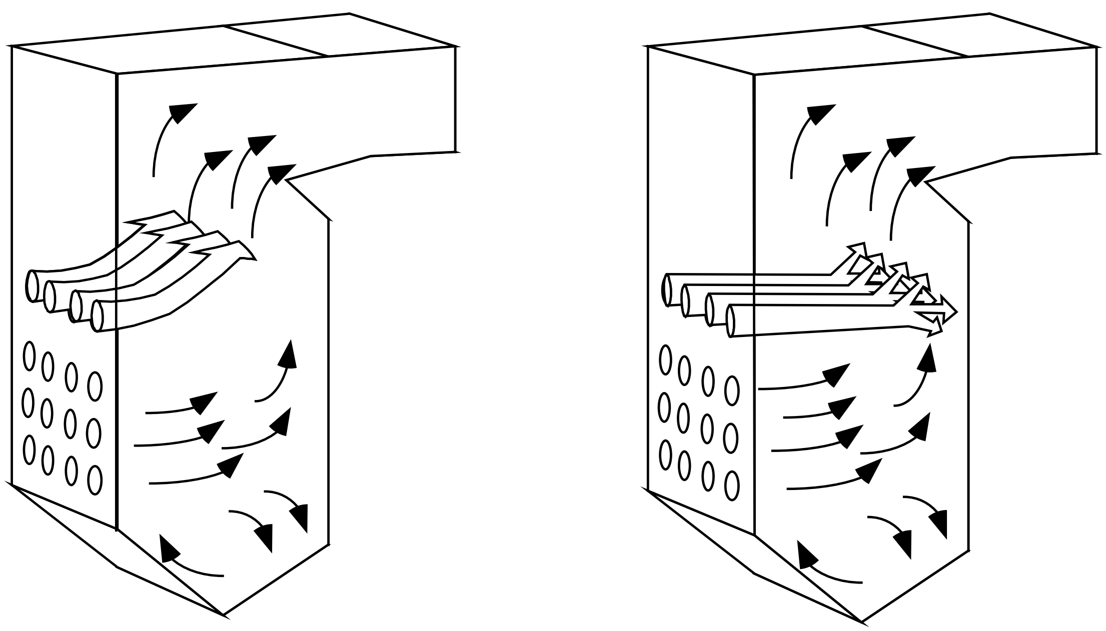
Because of the inherent limitations on OFA effectiveness and the potential for furnace corrosion, staging, etc. associated with OFA operation, in the mid-to-late 1970s, manufacturers concentrated on development of the first generation of low NOx coal burners, both to reduce the need for OFA and to address the more stringent NOx NSPS requirements promulgated in 1979. Therefore, little advancement in OFA technology was made from that time until the late 1980s.

Also, efforts were directed toward increasing OFA effectiveness for use as an additional NOx control technique in conjunction with other advanced control technologies, such as low NOx burners and concentric firing techniques. Efforts have been aimed in two directions; first to permit greater degrees of staging to sub-stoichiometric conditions in the flame zone (called "Deep Staging") and second to improve mixing of the OFA with the sub-stoichiometric combustion gases.

Deep staging involves removing sufficient air from the burner zone so that the overall air/fuel ratio to the burners is sub-stoichiometric, i.e., less than the theoretically required air to complete combustion. Because of the high sensitivity of both thermal and fuel NOx production to the flame zone stoichiometry, substantial reductions in NOx production can be achieved. However, as mentioned above, sub-stoichiometric (reducing) atmospheres can aggravate corrosion and staging on the furnace walls. To counteract this condition and provide protection to the wall tubes, some of the air diverted from the burners is directed along the furnace wall surfaces, providing, in effect, a "boundary" of air which maintains an oxidizing atmosphere close to the tube walls. In wall-fired units, this "boundary air" is provided by tertiary air ports located in the burner zone and close to the side walls. Air flows from the windbox through these ports and into the furnace.

The second technique used in AOFA is to improve the mixing of the overfire air with the furnace gases so as to complete the combustion of the partially burned gases and carbon particles. This is achieved primarily by increasing the velocity of the OFA injection relative to upward furnace gas velocities. Higher injection velocities (and less diffuse air streams) can be achieved both by increasing the pressure of the air above normal windbox levels and by improved OFA port designs. The higher pressures are provided by booster air fans that extract air from either the windbox or its supply ducts. Figure 3-2 illustrates the concept of high velocity OFA mixing compared to normal OFA injection. Alternative methods of achieving high velocity OFA injection, other than providing booster fans, may produce equivalent or better mixing results at a much lower cost. For example, using a very small quantity of high pressure air to aspirate the large OFA volume into the furnace at high velocity may be an attractive alternative to booster fans.

The implications of improved OFA mixing are three-fold. First, at normal staging rates (burner stoichiometry around 1.0 to 1.2), improving OFA mixing means that a lower overall stoichiometry (less total excess air) can be provided while still avoiding high unburned combustibles losses. Second, for a given total stoichiometry (excess air), deeper staging can be achieved without increasing combustible losses. This second feature, along with the protection of "boundary air," permits improved NOx reductions compared to normal OFA operation. Finally, the increased mixing capability allows the AOFA ports to be placed higher in the furnace, away from the upper burners, without increasing combustible losses as depicted in Figure 3-3. Thus, the sub-stoichiometric conditions would persist for a longer time between leaving the flame zone and reaching the AOFA mixing zone. Studies have shown that NOx production diminishes rapidly with time as the combustion products persist in a reducing (sub-stoichiometric) atmosphere. A residence time of one second can cause a reduction in NOx level of 50 percent compared to the NOx at the flame boundary. The combination of the three techniques, improved OFA mixing, deep staging, and boundary air constitutes the complete AOFA concept.



Furnace Flow Patterns with Low OFA Flow   Furnace Flow Patterns with High OFA Flow

Figure 3-2 Effect of OFA Injection Velocity

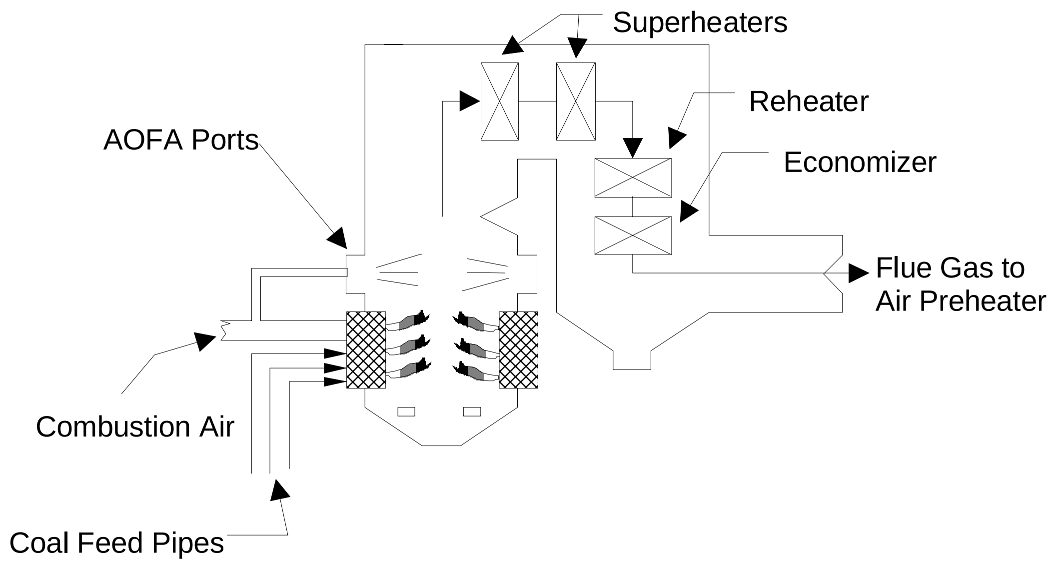


Figure 3-3 Advanced Overfire Air Concept

3.2.2 Low NOx Burner System (LNB)

An alternative to the use of OFA as a means to control NOx production through controlled fuel/air mixing (staged combustion) on a gross, furnace-wide basis, is to design the burner system to achieve the same combustion staging effects for localized, individual burner flames. To achieve this, the burner must regulate the initial fuel/air mixture, velocities, and turbulence to create a fuel-rich flame core, with sufficient air to sustain combustion at a severely sub-stoichiometric air/fuel ratio. The burner must also then control the rate at which the additional air necessary to complete combustion is mixed with the flame solids and gases so as to maintain a deficiency of oxygen until the remaining combustibles fall below the peak NOx producing temperature (around 2800°F). The final excess air can then be allowed to mix with the unburned products so that combustion is completed at a low temperature. The fuel-rich flame gas provides a sustained, oxygen deficient region in which the fuel volatile nitrogen can be evolved and reduced to molecular nitrogen rather than NO. The remaining char nitrogen evolves in the extended flame zone where oxygen becomes available at a controlled mixing rate so as to minimize conversion of char nitrogen to NOx. Thermal NOx is also minimized as the controlled air mixing extends into the cooler regions downstream of the flame. All low NOx burner designs utilize the same basic concepts of controlled fuel/air mixing in similar but unique ways.

4 TECHNOLOGY DESCRIPTION

As mentioned in previous sections of this report, three FWEC low NOx technologies were tested at Hammond: the Advanced Overfire Air (AOFA), the CF/SF Low NOx Burners (LNB), and the LNB+AOFA. These technologies are commercially available and well documented in industry and vendor publications [EPRI 1993; FWEC 1992; VATSKY 1993]. For this reason, only a brief description of the low NOx systems tested at Hammond is provided in this section, emphasizing their unique features relative to the FWEC standard commercial offerings.

4.1 Advanced Overfire Air System (AOFA)

As discussed in Section 3, in general, combustion NOx reduction techniques attempt to stage the introduction of oxygen into the furnace. This staging reduces NOx production by creating a delay in fuel and air mixing which lowers combustion temperatures. This staging also reduces the quantity of oxygen available to the fuel-bound nitrogen. Typical overfire air (OFA) systems accomplish this staging by diverting 10 to 20 percent of the total combustion air to ports located above the primary combustion zone. AOFA improves this concept by introducing the OFA through separate ductwork in greater quantities, with more control, and at higher pressures. The resulting system is capable of providing deep staging of the combustion process with accurate measurement of the AOFA airflow.

The FWEC AOFA system that is offered commercially utilizes a number of high velocity ports located at a higher elevation than the conventional OFA and uses a maximum of 20 percent of the total combustion air. As shown in Figure 4-1, the AOFA system diverts air from the secondary air ducts and introduces it through a number of overfire air ports in the front and rear wall of the furnace. The Hammond Unit 4 boiler design characteristics and project requirements had an impact on the design of the AOFA system. The Hammond AOFA system differs from the standard FWEC AOFA design in the following two features:

- It utilizes four AOFA ports per wall instead of the six proposed originally by FWEC.
- It is located closer to the burners than FWEC would have liked (Hammond distance between the top burner and the bottom of the AOFA = 9' 2").

These two design features of the AOFA system are believed to have impacted the NOx reduction potential, but they should not compromise the applicability of the tests results for other wall-fired units because many units are subject to similar limitations. The AOFA system operation at Hammond was not automated; a separate control panel was provided in the control room through which the operators manually controlled the AOFA dampers.

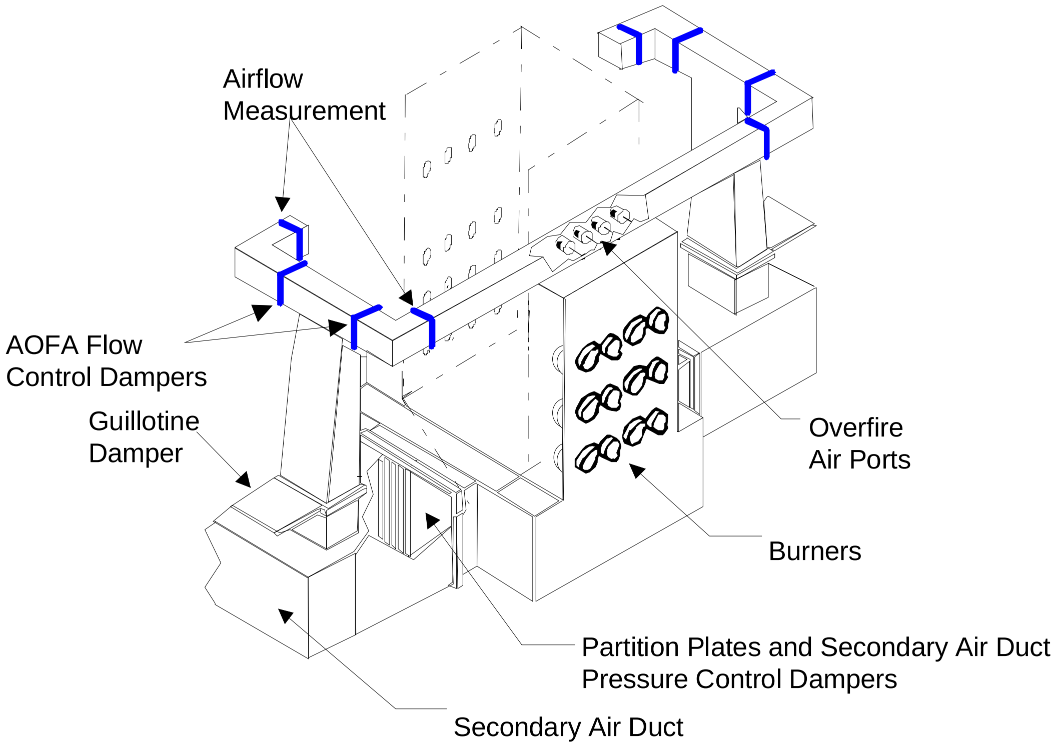


Figure 4-1 Advanced Overfire Air System

To insure optimum AOFA system performance, a burner/windbox air distribution system was also installed at the time of the installation of the AOFA system. The primary purpose of this system is to provide optimum distribution of combustion between the front and rear windboxes and to serve as backpressure dampers to enable sufficient flow to the AOFA system. A sketch of the installed system is shown in Figure 4-2. Figures 4-3 and 4-4 provide a view of the AOFA ductwork and ports, respectively, as installed on Hammond Unit 4.

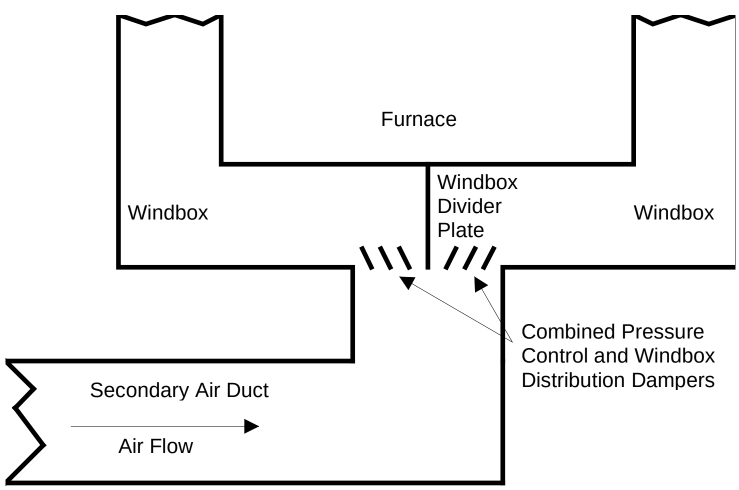


Figure 4-2 Windbox Inlet AOFA Pressure Control Dampers

Figure 4-3 Photo of Inside of Overfire Air System

Figure 4-4 Photo of Inside of Furnace

In conjunction with the installation of the AOFA system, FWEC also installed a furnace boundary air system. The purpose of this system was to provide a passive means of maintaining an oxidizing atmosphere along the furnace sidewalls and in the furnace hopper zone. The boundary air system consists of airports, hopper airslots and sidewall airslots (Figure 4-5) designed to bias a small amount of air from the burners to the lower furnace walls. The boundary air system does not supply additional air to the furnace and it does not increase the excess air requirement of the boiler.

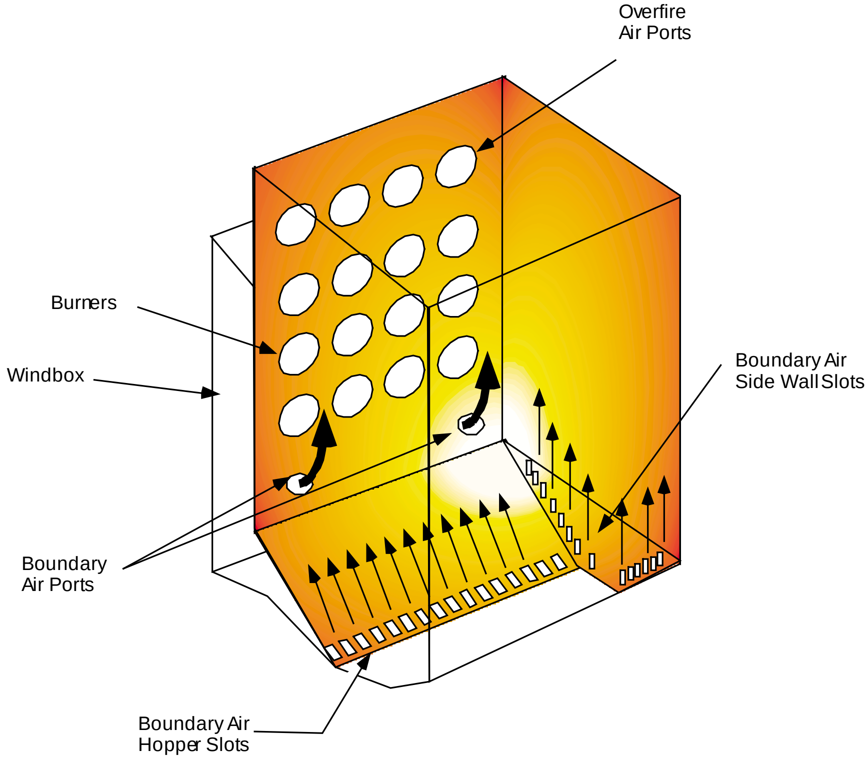


Figure 4-5 Boundary Air System

During the month of April 1990, the AOFA system was installed at the demonstration site. The construction subcontractor worked two, ten-hour shifts per day, six days per week. At peak work levels, the construction subcontractor employed approximately 130 craft personnel. Refer to Figure 4-6 for a schedule of activities.

Prior to the outage, the erection contractors mobilized and did as much work as possible before the unit came off-line. At midnight, on Thursday, April 5, 1990, Hammond Unit 4 was brought off-line. As soon as the boiler cooled down, deslagging was performed and erection of scaffolding inside the furnace began. During the third week of the outage, the average workforce was approximately 70 workers during the day and approximately 60 workers during the night shift. On Tuesday, May 1, 1990, a hydrostatic test was performed on the boiler. With the guillotine dampers in the AOFA system closed, the unit began start-up at 3:30 PM on Saturday, May 5, 1990. More information on the installation can be found in Appendix E.

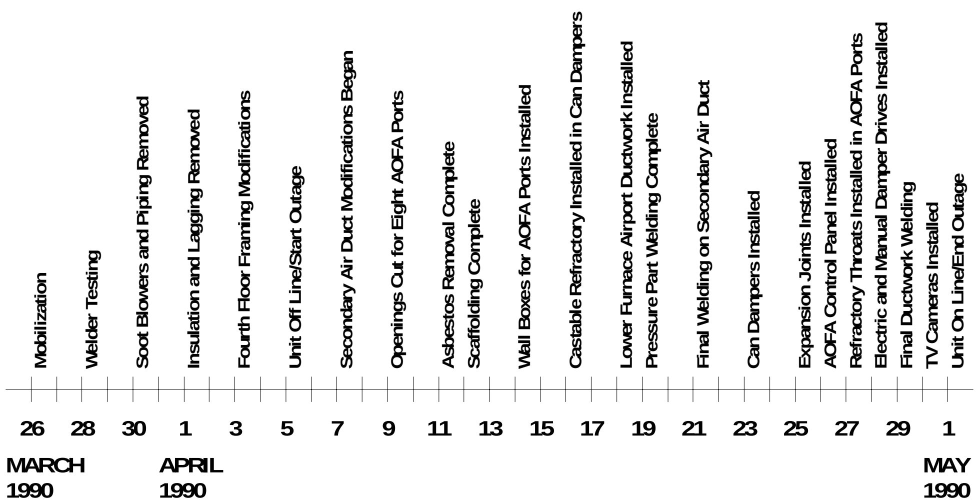


Figure 4-6 AOFA Erection Timeline

4.2 Controlled Flow/Split Flame Burner (LNB)

Low NOx burner systems attempt to stage combustion without the need for the additional ductwork and furnace ports required by OFA and AOFA systems. These commercially available burner systems introduce the air and coal into the furnace in a well-controlled, reduced turbulence manner. To achieve this, the burner must regulate the initial fuel/air mixture, velocities and turbulence to create a fuel-rich core, with sufficient air to sustain combustion at a severely sub-stoichiometric air/fuel ratio. The burner must then control the rate at which additional air, necessary to complete combustion, is mixed with the flame solids and gases to maintain a deficiency of oxygen until the remaining combustibles fall below the peak NOx producing temperature (around 2800°F). The final excess air can then be allowed to mix with the unburned products so that the combustion is completed at lower temperatures. Burners have been developed for single wall and opposed-wall boilers.

Foster Wheeler Energy Corporation (FWEC) was competitively selected to design, fabricate, and erect the opposed-wall, low NOx burner shown in Figures 4-7, 4-8, and 4-9, and the AOFA system described above. In the FWEC Controlled Flow/Split Flame (CFSF) burner, secondary combustion air is divided between inner and outer flow cylinders. A sliding sleeve damper regulates the total secondary airflow entering the burner and is used to balance the burner airflow distribution. An adjustable outer register assembly divides the burners secondary air into two concentric paths and also imparts some swirl to the air streams. The secondary air that traverses the inner path, flows across an adjustable inner register assembly that, by providing a variable pressure drop, apportions the flow between the inner and outer flow paths. The inner register also controls the degree of additional swirl imparted to the coal/air mixture in the near throat region. The outer airflow enters the furnace axially, providing the remaining air necessary to complete combustion. An axially movable inner sleeve tip provides a means for varying the primary air velocity while maintaining a constant primary flow. The split flame nozzle segregates the coal/air mixture into four concentrated streams, each of which forms an individual flame when entering the furnace. This segregation minimizes mixing between the coal and the primary air, assisting in the staged combustion process. The adjustments to the sleeve dampers, inner registers, outer registers, and tip position are made during the burner optimization process and thereafter remain fixed unless changes in plant operation or equipment condition dictate further adjustments. The two low NOx technologies, AOFA and LNBs, were also combined into the LNB+AOFA system.

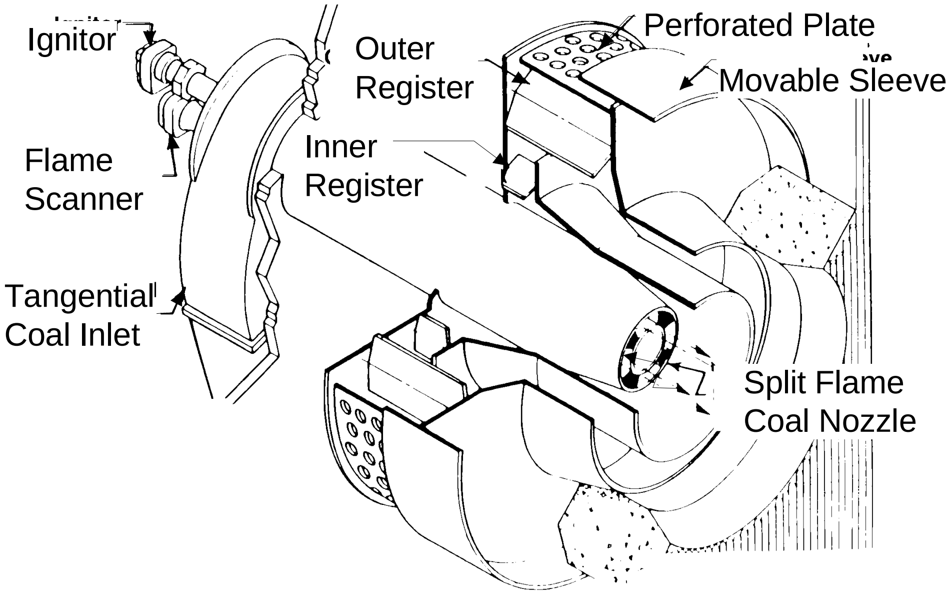


Figure 4-7 Controlled Flow / Split Flame Low NOx Burner

Figure 4-8 Photo of LNB from Tip

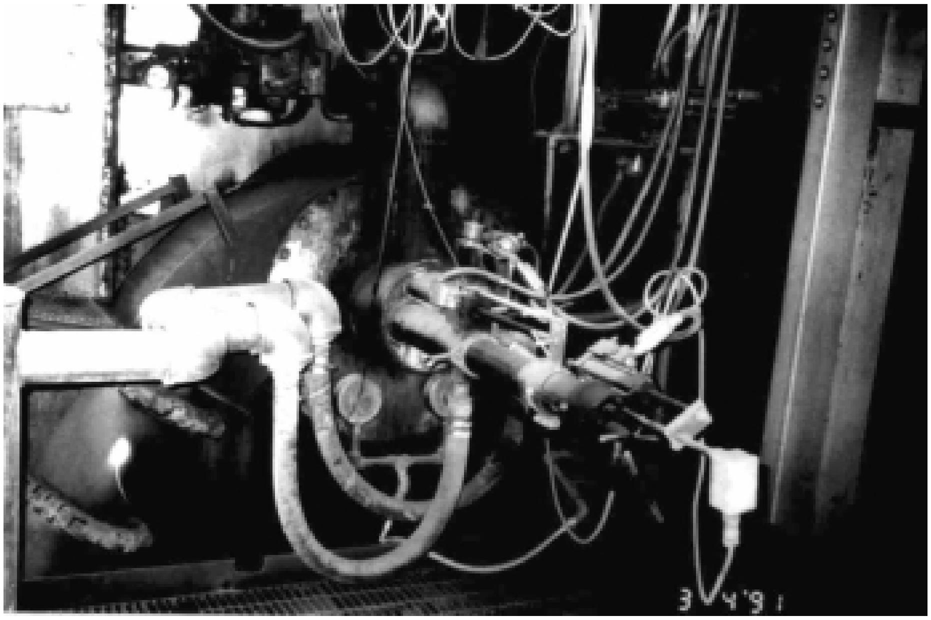


Figure 4-9 Photo of LNB from Back

The new LNBs were installed during a seven-week outage that began March 1991 and continued to April 1991 (Figure 4-10). Approximately thirty craft personnel were involved in the retrofit, working a single ten-hour shift six days per week, for four weeks, and two ten hour shifts, six days per week, for the remaining three weeks. Prior to the outage, equipment was received and unloaded, rigging was installed, access pathways were formed and a great deal of insulation and lagging were removed. Unit 4 came off line at 5:00 p.m. EST on March 8, 1990. The first oil fire was introduced to the boiler at approximately 6:20 p.m. EST on April 28, 1991. The first coal was introduced to the boiler and the turbine was rolled on May 1, 1991. More information on the installation can be found in Appendix F.

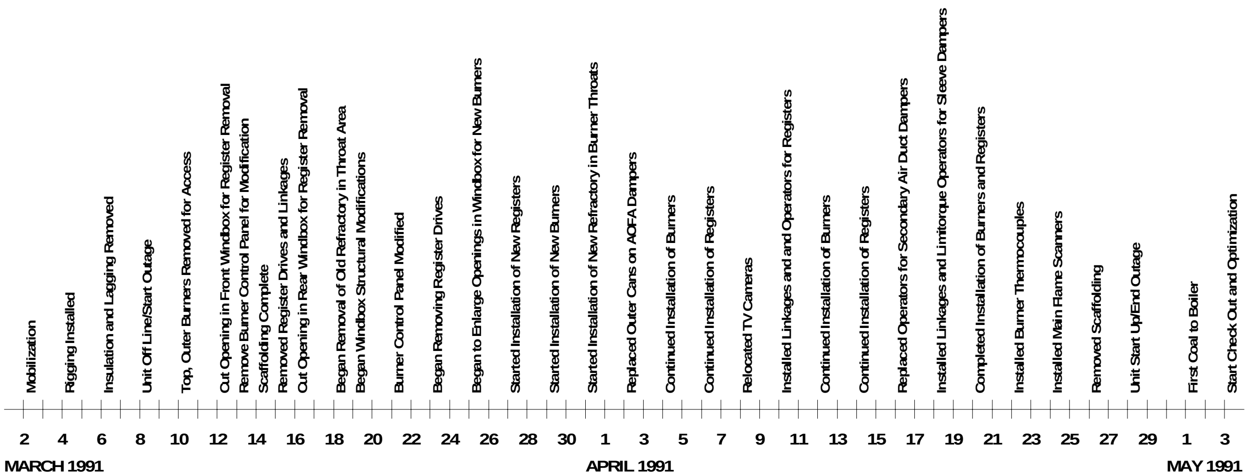


Figure 4-10 LNB Erection Timeline

5 TEST PROGRAM DESCRIPTION

5.1 Program Test Elements

In the past, there have been a number of "demonstration" programs by various burner manufacturers for the purpose of evaluating the NOx reduction potential of their equipment. Without exception, these demonstrations have provided only minimal amounts of information that could be used to extrapolate to the general population of utility boilers. All of these demonstrations provided only small amounts of short-term data (generally less than one day for each data point) in both pre- and post-retrofit configurations. Very few of these demonstrations have provided long-term data (on the order of months of continuous data) in the post-retrofit configuration, and none have provided long-term data in the pre-retrofit configuration. The purpose of this CCT program is to provide detailed short- and long-term pre- and post-retrofit emission data on a number of low NOx combustion technologies applied to a wall-fired utility boiler. The technologies demonstrated include advanced overfire air (AOFA) and low NOx burners (LNB) with and without AOFA.

The project was performed in the following phases:

- Phase 1 - Baseline
- Phase 2 - Advanced Overfire Air (AOFA)
- Phase 3A - Low NOx Burners
- Phase 3B - Low NOx Burners with Advanced Overfire Air

One of the underlying premises for the structure of the testing efforts in all of the phases of this project is that short-term tests cannot adequately characterize the emissions of a utility boiler. As a consequence of this, the focal point of the test efforts during all phases of this project is long-term evaluation. Short-term testing is used only to establish trends that may be used to extrapolate the results of this project to other similar boilers. During this program, the short-term test results are not intended to be used to determine the relative effectiveness of the retrofitted NOx control technologies.

5.1.1 Short-Term Characterization

Initial short-term testing is generally performed to establish the trends of NOx emissions under the most commonly used configurations. In addition, it is used to establish the performance of the boiler in these normal modes of operation. Three types of short-term tests were conducted:

- Diagnostic tests
- Performance tests
- Chemical emissions testing

These tests were conducted under controlled conditions by project test personnel and were conducted with the unit off automatic load dispatch to maintain steady-state boiler conditions.

Diagnostic Testing. Diagnostic testing was used to establish the gaseous emission trends of the unit over the range of operating conditions normally encountered. Reasonable excursions about these normal conditions were also investigated. The primary parameters that are used for characterization are excess oxygen, mill pattern, and mill bias. Testing at each of the selected conditions is accomplished during a one to three hour period with the unit in a fixed condition, with the duration of the test dependent on the specific sampling conducted.

Performance Testing. The goal of the performance tests was to comprehensively evaluate the emissions and performance impacts of the technologies tested. Performance testing was conducted at specified loads in configurations recommended by plant personnel, technology vendor, and the results of the diagnostic tests. These configurations represent one of the normal modes of operation for each load condition. Generally, performance tests were conducted during a ten to twelve hour test periods with the unit off load dispatch. Because of time limitations, performance tests generally spanned a two-day period, with portions of the sampling being conducted on day one and the balance on day two of the test. On the two days, the unit was set up so that operating and test conditions for the two days were the same to the degree possible.

Generally, during each performance test, the following sampling was conducted:

- Gaseous emissions (NOx, SO_2, CO, and excess O_2) at the economizer outlet and stack,
- Flue gas solids emission parameters (resistivity, total particulate emissions, and LOI),
- Combustion airflow (primary, secondary, and overfire) distribution,
- Fuel distribution and characteristics (HHV, NOx content, fineness), and
- Boiler performance parameters (economizer outlet temperatures, steam flows)

Chemical Emissions Testing. Stack chemical emissions testing was conducted in the AOFA configuration and LNB plus AOFA configuration. For these two phases, concentrations of selected inorganic and organic substances were measured in the process and discharge streams. The specific objectives of each test period were:

- To quantify emissions of target substances from the stack,
- To determine the efficiency of the ESPs for removing the target substances, and
- To determine the fate of target substances in the various plant discharge streams.

The unit operated at nearly full load during each of the sampling periods. Operating parameters were monitored to verify the stability of the unit during sampling. The chemical emissions testing conducted at Hammond 4 as part of the project is discussed elsewhere [Radian 1993].

5.1.2 Long-Term Characterization

As stated earlier, one of the underlying premises for the structure of the testing efforts in all of the phases of this project is that, generally, short-term tests cannot adequately characterize the long-term emissions of a utility boiler [Smith 1987]. Long-term testing for each phase was conducted under normal, automatic load dispatch. No intervention with respect to specifying the operating configuration or conditions were imposed by test personnel. The long-term testing provides emission and operational results that include most if not all of the possible influencing parameters that can affect NOx emissions for a boiler over the long run. These parameters include coal variability, mill in-service patterns, mill bias ranges, excess oxygen excursions, equipment conditions as well as many yet undetermined influencing parameters.

5.1.3 Instrumentation and Data Acquisition

The instrumentation and data acquisition package for the project was designed to provide the data necessary to conduct the test program efficiently and to provide the data necessary to determine the performance of the demonstrated technologies. Existing plant instrumentation was used when feasible, however, the nature of the test program required that some specialized instrumentation be installed on the unit. The specialized instrumentation was installed to measure specific parameters related to the combustion and thermal performance of the boiler as well as selected gaseous emissions and included combustion gas analyzer, acoustic pyrometer, heat flux sensors, and continuous ash sampling systems. Also, because the unit was equipped with a pneumatic boiler control system and mainly pneumatic instrumentation at project initiation (1989), it was necessary to install a data acquisition system (DAS) and electronic transmitters to conduct the test program. A summary of the type of data archived is shown in Table 5-1.

Table 5-1 Summary of Data Archived by DAS

Boiler Drum Pressure	Superheater Outlet Pressure
Cold Reheat Pressure	Hot Reheat Pressure
Turbine lst Stg Pressure	Feed Water Pressure
Feed Water Flow	Reheater Spray Flow
Superheater Spray Flow	Secondary Airflow
Primary Airflow	Pri. Tempering Airflows
Coal Flows (Feeder Speeds)	Unit Gross Generation (MW)
Main Steam Temperatures	Economizer Inlet (F.W.)
Heater 8A/B Drain Temps	Pri. Superheater Outlet Temp
Sec. Superheater Outlet Temps	Superheater Spray Water Temp
Cold Reheat Temperature	Reheat Spray Water Temperature
Hot Reheat Temperature	Secondary Air Htr Air Out Temp
FD Fan Outlet Temps	Pulv. Mill Temperatures
Boiler Exit Gas Oxygen	Air Heater Exit Gas Oxygen

The following paragraphs describe the major elements of the instrumentation system.

5.1.4 Extractive Continuous Emissions Monitoring System (ECEM)

A principal objective of this project was to evaluate the long-term effectiveness of the installation of low NOx burners and advanced overfire air with regards to the reduction of NO_x pollutants in the boiler exhaust gas. The ECEM was purchased from KVB to aid in the evaluation of combustion modifications. The system provides the means of extracting gas samples for automatic chemical analysis from sample points at strategic locations in the boiler exhaust ducts. The ECEM (Figure 5-1) is equipped with a manual valving system that permits the extraction of gas samples from any ECEM probe or combination of probes. Flue gas extraction points were located before and after the secondary air heaters, prior to the primary air heaters, and in the ductwork leading from the precipitator to the stack (Figure 5-1). The probe arrangements are shown in Figures 5-2 and 5-3.

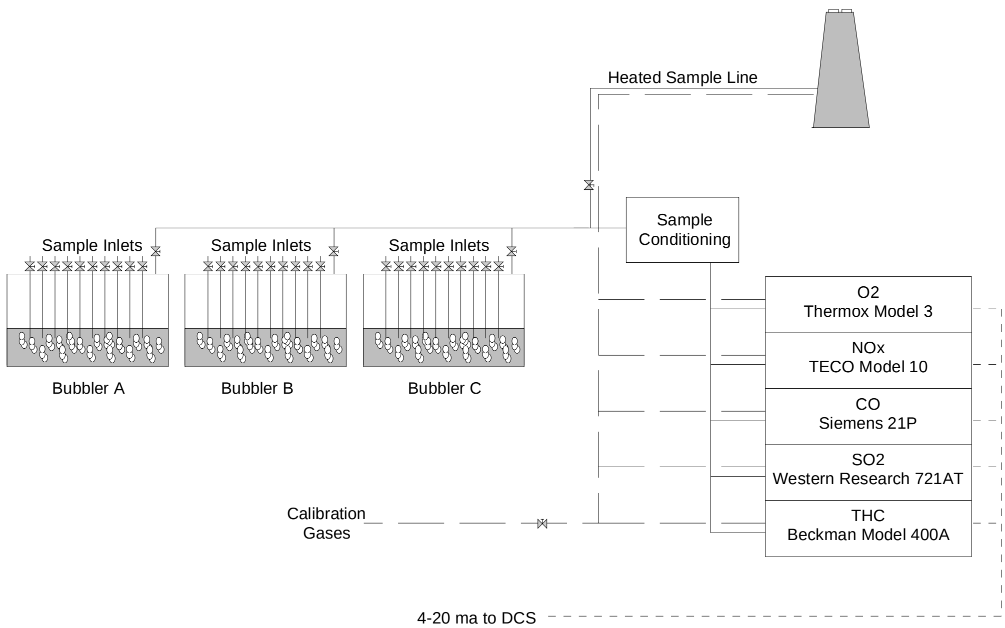


Figure 5-1 Extractive Gas Analysis System

The system quantitatively analyzes gas samples for NOx, O_2, SO_2, CO, and total hydrocarbons (THC). The ECEM comprises sample probes and lines, a sample control system consisting of valves and sample distribution manifolds, pumps, sample conditioning (filters, condenser/dryer, pressure regulation and a moisture detector), flowmeters, gas analyzers and an automatic calibration system. The sample probes consist of l/2" Hastelloy C pipes fitted with sintered stainless steel filters to prevent fly ash from entering the probes. Where appropriate one, two, or three probes penetrate a single port cap, extending vertically down into the duct to various depths. Polyethylene sample lines (3/8" OD) connect the probes to the ECEM sample selection valving. Exterior sample lines are heat traced and insulated for freeze protection. A Teflon sample line connected to a probe in the stack is heated to prevent moisture condensation. This line/probe is called the "continuous stack monitoring line."

With the exception of the continuous stack monitor probe line, all sample lines lead to individual flow control valves that are part of a sample distribution system. This arrangement allows the test personnel to sample selectively from any one probe, or any combination of probes, for analysis of the exhaust gases. The sample distribution bubblers act as simple flowmeters to ensure equal flow from each probe sampled. The use of the bubblers invalidates any SO_2 or THC readings from the duct probes owing to their partial solubility of the two gases in the bubbler water. The valid SO_2 and THC data are acquired only through the heated stack probe/line.

The sample acquisition/conditioning system consists of dual diaphragm type pumps, a refrigerated, water bath moisture condenser, filters, valves and a back pressure regulator. Moisture is removed from the sample gas within the condenser and drained automatically at set intervals. The back pressure regulator assures constant pressure supply to the analyzers to avoid measurement drifts associated with flow variations. The pumps draw roughly l.0 cfm of sampled gas, of which a small portion is delivered to the analyzers and the remainder vented overboard. The high total sample rate is used to minimize the response time between the sample entering the probes and analysis.

Automatic (or manual) calibration is achieved by sequentially introducing certified gases of known zero and span value for each analyzer into the lines. The signal output of each analyzer for its respective zero or span gas is recorded by the control computer and translated into a linear calibration equation in engineering units. All of the analyzers have linear output response.

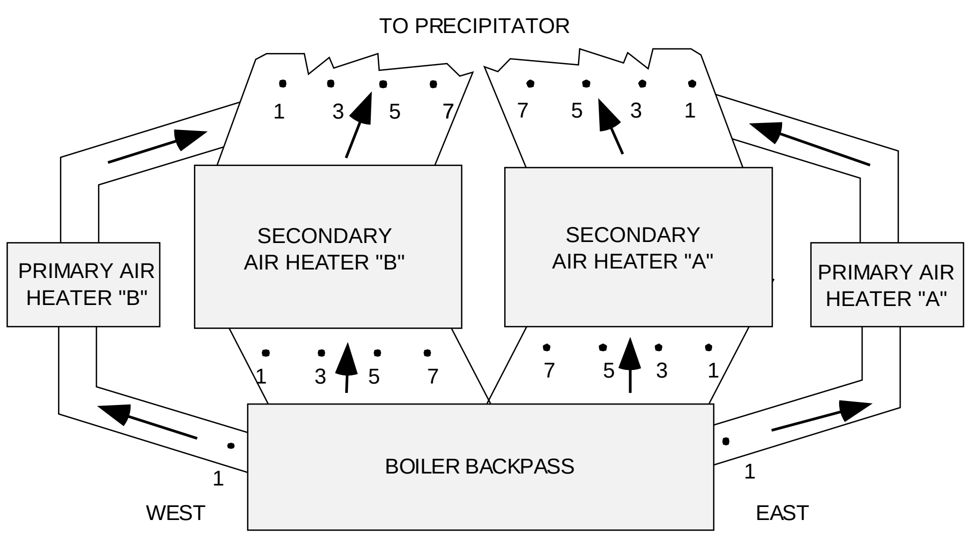


Figure 5-2 Extractive Gas Analysis System Probe Locations

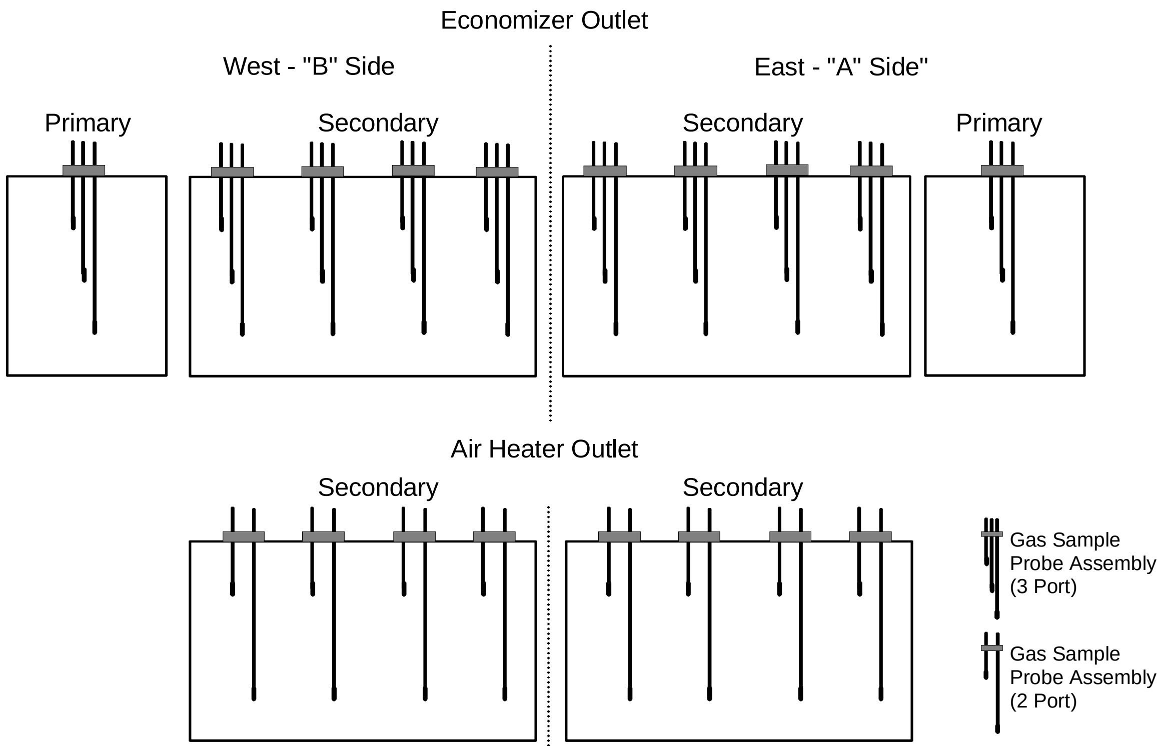


Figure 5-3 Extractive Gas Analysis System Probe Arrangement

5.1.5 Special Flue Gas Instrumentation

Excess O_2 Probes. In situ oxygen monitors were installed at the economizer outlet and the air heater. The purpose of these monitors was to allow detection of air heater leakage through the seals and to provide excess oxygen data for the long-term data collection effort. The excess oxygen monitoring system uses zirconium oxide measuring cells located in the flue gas path. This in-situ method of measurement eliminates many of the maintenance problems associated with extractive systems. The zirconium oxide O_2 monitors used at Hammond are commonly used in power plant applications and provide an accuracy of ± 0.25 percent O_2. The installation includes six monitors at the economizer outlet and six monitors at the air heater outlet (Figure 5-4).

Thermocouple Grids. Multi-point thermocouple grids were installed in the flue gas steam at the economizer outlet and the secondary air heater outlet (Figure 5-5). These instruments supplemented existing plant instrumentation.

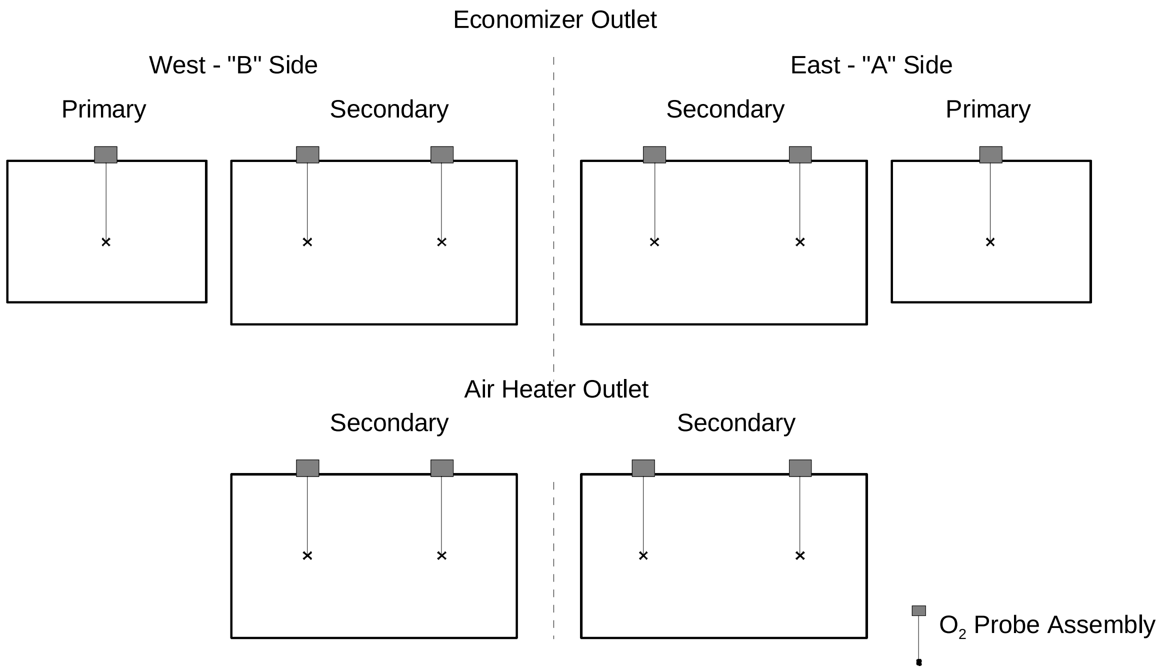


Figure 5-4 Oxygen Probe Arrangement

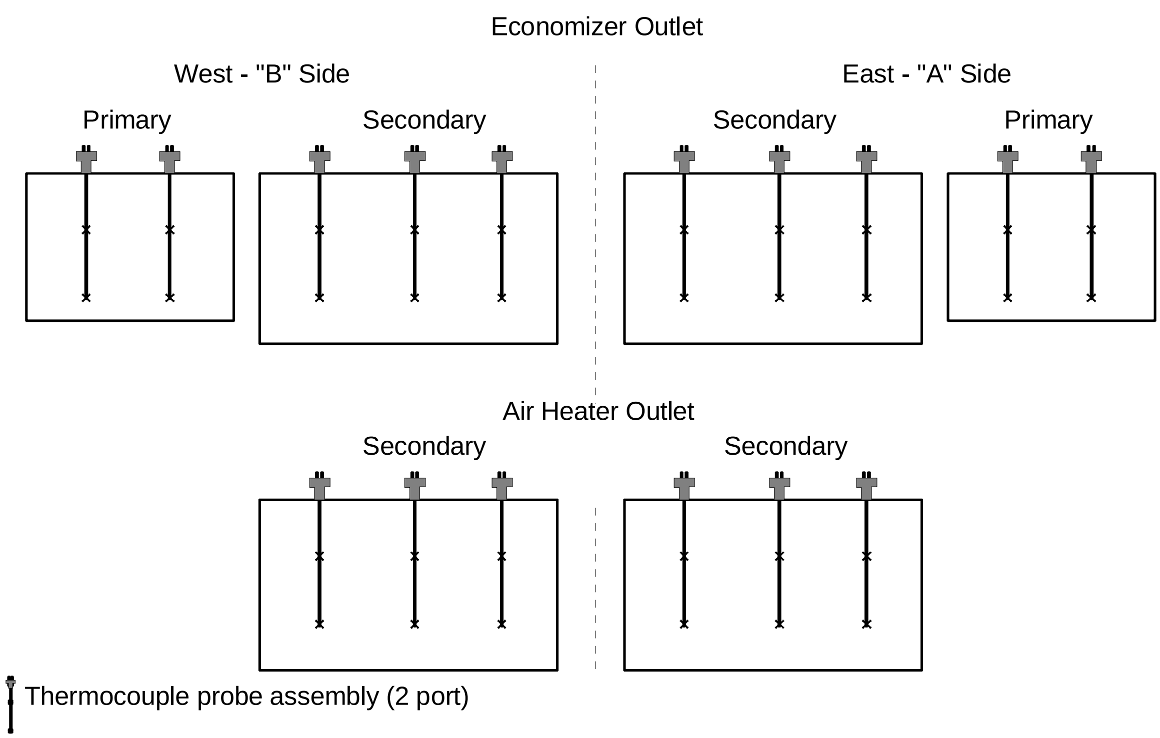


Figure 5-5 Thermocouple Probe Arrangement

5.1.6 Heat Flux Sensors

Heat flux sensors (Land Combustion Fluxdomes) were installed to detect changes in the heat absorption in the furnace combustion zone. The sensors consist of small metal cylinders welded to the fire side surface of a boiler tube. The shape, size and weld specifications of each cylinder are carefully controlled to assure exact dimensions in order to provide a specified heat path from the furnace/tube interface into the boiler tube. Two type-K thermocouples are embedded in each cylinder at prescribed depths. The temperature gradient detected by the thermocouples is proportional to the heat flux at the point of measurement. The arrangement of the sensors is shown in Figure 5-6.

5.1.7 Acoustic Pyrometer

The acoustic pyrometer package (from Scientific Engineering Instruments) provides furnace gas temperature data for the analysis of variations in the combustion process. The acoustic pyrometer is a microcomputer controlled system that transmits and receives sonic signals through the hot furnace gas from multiple locations around the girth of the boiler furnace. The velocity of acoustic pulses along multiple paths across the furnace can be computed and processed to provide an isothermal (contour) map of furnace temperatures at the level where the acoustic pyrometer transceivers are installed around the furnace. At Hammond, the horizontal plane that includes the transceivers is approximately l5 feet above the uppermost elevation of burners. The acoustic pyrometer's six furnace wall transceivers are located as shown in Figure 5-7.

The acoustic pyrometer provides average temperature data for straight-line paths between any two transceivers not located on the same furnace wall (Figure 5-7). For the six-transceiver configuration, a total of 12 paths are provided. The acoustic pyrometer computer provides eight 4-20 ma signals that can be programmed to represent any eight of the twelve temperature paths between transceivers. In addition, the acoustic pyrometer can display, on its color monitor, isothermal maps and three-dimensional surface plots to allow engineers to evaluate heat profiles in the boiler. Print outs of the monitor can be generated on demand at the plant.

5.1.8 Data Acquisition System

Prior to baseline testing, a data acquisition system (DAS) was installed at the site. The DAS was used exclusively for Phases 1 through 3. Approximately 150 inputs were terminated to the DAS including instrumentation installed around the air heaters, the ECEM, flux domes, acoustic pyrometers, and temperatures and pressures relating to the steam and feedwater cycle. The basic scan rate of the system is 5 seconds and the data is compiled into 5 minute averages for archival.

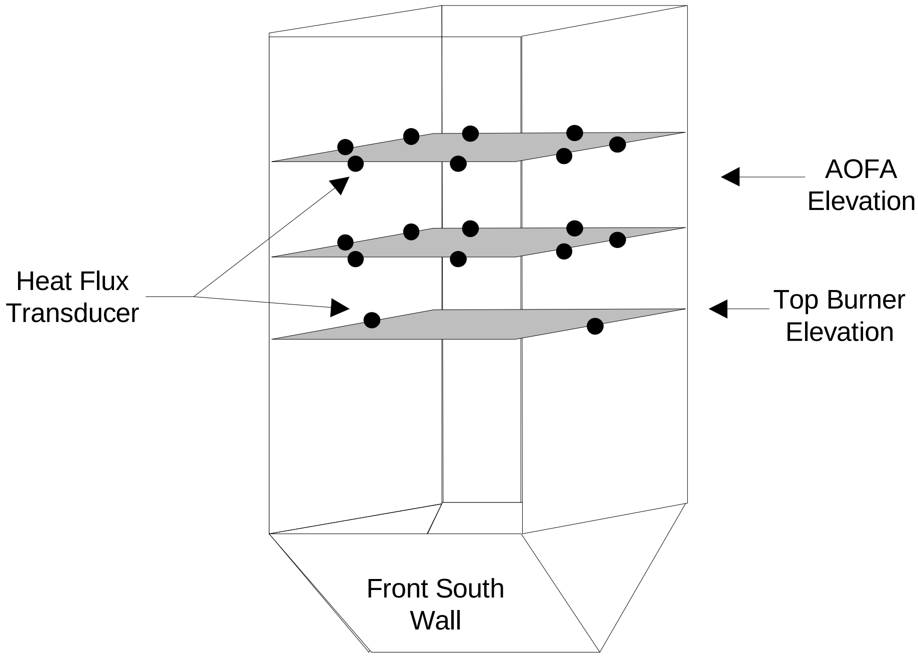


Figure 5-6 Arrangement of Heat Flux Sensors

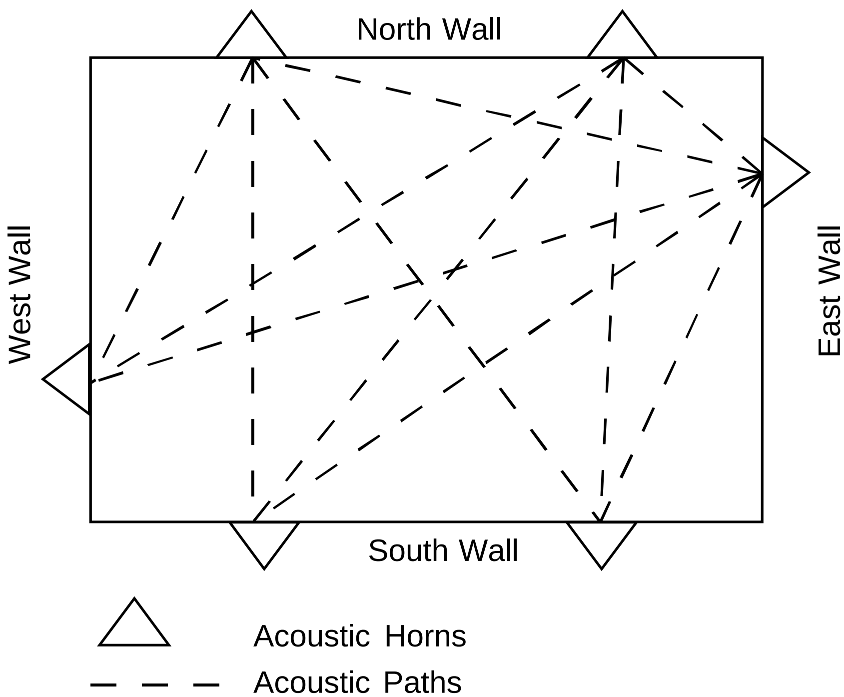


Figure 5-7 Acoustic Pyrometer

5.1.9 Test Methods and Determinations

The acquisition of data can be conveniently grouped into four broad categories relating to the equipment and procedures used [Smith 1991].

Manual Boiler Data Collection. This data was recorded manually onto data forms based on readings from existing plant instruments and controls. The data was subsequently entered manually into a computer data management program. Coal, bottom ash, and ESP hopper ash samples were collected regularly for subsequent laboratory analysis.

Combustion System Tests. At several specific operating conditions, a team of engineers using specialized apparatus performed tests and procedures to measure parameters related to the combustion and thermal performance of the boiler.

Solid/Sulfur Emissions Tests. During the performance tests, measurements were made of particulate and gaseous emissions exiting the boiler, using specialized equipment and procedures.

The manual data collection duplicated some of the operational parameters also measured by the automated boiler data collection system in order to provide backup of important data and to permit assessment of the boiler operation during the test period. A summary of the sampling locations is shown in Figure 5-8 and described in Table 5-2. The following sections describe the equipment and procedures used in each category and the way in which the data were reduced and analyzed.

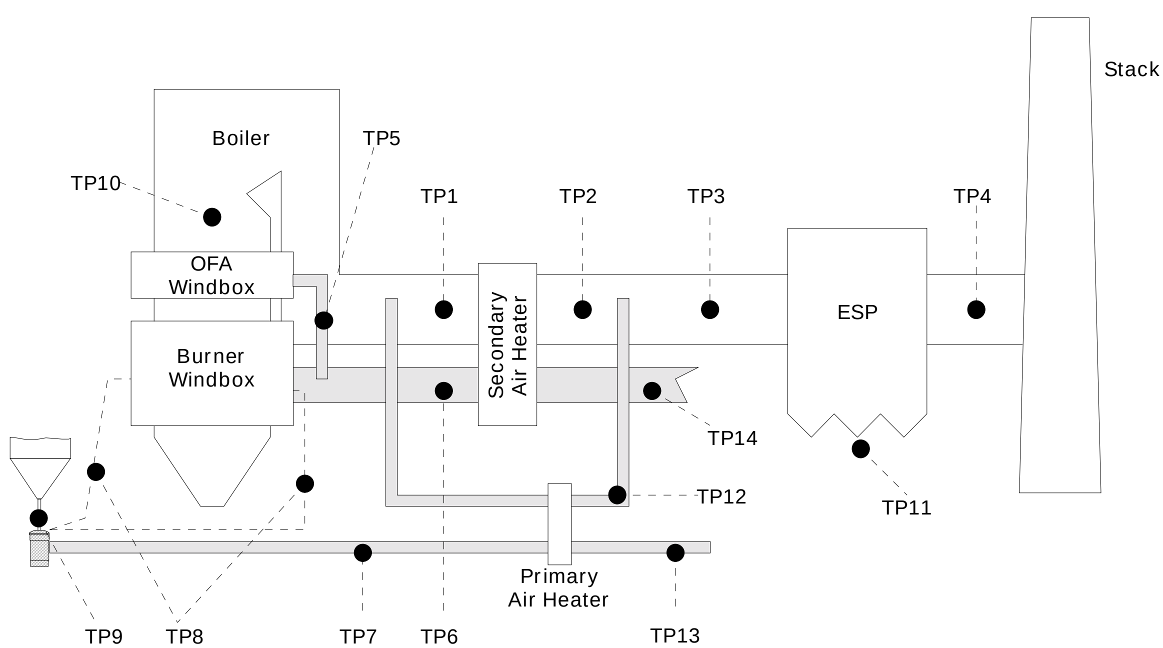


Figure 5-8 Sampling Locations

Table 5-2 Sampling Location Description

Sample Point	Location	Tests Performed
TP1	Flue Gas Leaving Economizer	Gas species (NOx, CO, SO_2, THC, O_2) Excess O_2 Temperature
TP2	Flue Gas Leaving Sec. Air Heater	Gas species (NOx, CO, SO_2, THC, O_2) Excess O_2 Temperature
TP3	Flue Gas Entering Precipitator	Resistivity SO_3 Particle size LOI Total mass loading
TP4	Flue Gas Leaving Precipitator	Gas species (NOx, CO, SO_2, THC, O_2)
TP5	Air Entering OFA Windbox	Flow rate Temperature
TP6	Air Leaving Sec. Air Heater	Flow rate Temperature
TP7	Air Leaving Pri. Air Heater	Flow rate Temperature
TP8	Coal Pipes	Dirty air velocity Particle size Coal flow distribution
TP9	Feeder Inlets	Coal samples
TP10	Furnace Nose	Gas species Temperatures
TP11	Precipitator Ash Hoppers	Resistivity LOI
TP12	Flue Gas Leaving Pri. Air Heater	Temperatures
TP13	Air Entering Pri. Air Heater	Temperatures
TP14	Air Entering Sec. Air Heater	Temperatures
TP15	Stack Gas	Gas species (NOx, CO_2, SO_2)

5.1.10 Boiler Operating Data

Detailed operational data was recorded from plant instrumentation for two principal reasons [Smith 1991]. First, the data was used to establish, maintain, and document critical operating parameters at specified steady state test conditions for comparison to subsequent post retrofit testing. The second reason was to provide a broad range of operational data that might be useful in the analysis and interpretation of vital performance and emissions data related to combustion.

Short-term diagnostic tests were performed to document the relationship of NOx emissions to various boiler operating parameters (load, excess O_2, mill operation, etc.) and to establish baseline NOx emissions and boiler efficiency for later comparison to post-retrofit results. Performance tests were conducted to acquire some of the operational and emissions data that require longer times to complete, such as fuel/air flow distributions and solid/sulfur emission characteristics.

The diagnostic, or parametric, tests were performed over periods of from l to 3 hours, beginning after the desired operating conditions had been established and the unit had been stabilized for up to an hour. Steady operating conditions were maintained to the extent possible during the test. Typically, data was recorded manually at the beginning and end of the total test duration and approximately one-hour intervals in between in the case of longer test duration. A single composite coal sample from all active mill feeders was taken on each day of testing.

Each performance test series was run over a period of 10 to 12 hours on each of two days. After establishing the unit operation at the desired test conditions, the unit was allowed to establish steady state operation for up to one hour prior to the start of the test. During the full duration of each day's tests, slight adjustments were made periodically, as necessary, to maintain combustion conditions. These adjustments were made to maintain fuel and air flows, temperatures, steam conditions, excess O_2, opacity, etc., as constant as possible, notwithstanding uncontrollable variations in ambient temperature and humidity, fuel quality, etc. This was accomplished by setting the boiler fuel and air masters on hand control and making slight adjustments gradually during the day to keep the firing rate, steam conditions, excess air, etc., relatively constant. In general, it was possible to keep these parameters steady within ± 2 percent over the duration of the test period.

The greatest variation experienced during the tests was in excess O_2, as the FD fan output changed as a result of variations in ambient air temperature. For the most part, the excess O_2 varied within ±0.3 percent of the average for individual tests. In order to monitor the stability of the test parameters during the performance tests, readings of the parameters were recorded at the beginning and end of the test period and at roughly 2-hour intervals in between.

5.1.11 Material Samples

Batch samples of coal, bottom ash and ESP hopper fly ash were obtained by plant personnel at various times during the duration of each performance test. Table 5-3 shows the approximate sample times and locations.

Table 5-3 Sampling Location Description

Sample	Source	Point in Test
Coal	Each mill inlet chute (sample mixed and crushed by plant personnel)	Start-mid-end
Bottom Ash	Combination of east and west hopper	Mid
ESP Ash	Separate samples from leading hoppers	Mid

The normal regimen for soot blowing on the unit calls for soot blowing the furnace walls and convective pass tubing as needed to maintain proper steam temperature balances, and air heater (APH) blowing about once per shift to prevent pluggage of the APH baskets. During the performance and emissions sampling periods of each characterization test, no soot blowing was allowed. Air heaters were blown clean at times during midday breaks in the emissions sampling routine. APH blowing was stopped at least ½ hour prior to resumption of emissions testing.

During the performance testing, coal samples were acquired three times daily. The coal samples were obtained directly from the silo outlet chutes supplying each mill feeder. Care was taken to ensure that a representative sample of the coal entering each mill was obtained in approximately equal amounts. All samples taken at a specific time were mixed, quartered and divided, crushed to roughly 50 mesh and sealed in plastic bags of about 3 pound capacity. A tag identifying the date and time of sample was written on each bag. Ultimate and proximate analyses were performed on all samples. Ash fusion temperatures (initial deformation temperature, softening temperature, fluid temperature) were determined for all performance test samples.

Bottom ash samples were obtained once per day near the midpoint of the test. Early in each test the bottom ash was pulled to insure that in the ensuing several hours, only ash deposited under known test conditions would accumulate in the hopper. For the desired sample, approximately 20 to 50 pounds of bottom ash was removed from one hopper and allowed to drain on a clean section of concrete floor. Approximately l0 pounds of moist ash was placed in a plastic bag. The process was repeated for the other bottom hopper, adding about l0 pounds of moist ash to the first sample. The bag of mixed ash was tagged to identify the date and time of sampling. Bottom ash samples from the performance tests were analyzed for loss-on-ignition according to ASTM D3l74 82.

The ESP hoppers are continuously emptied by a pneumatic conveying system. Thus, several hours into a test the ESP hoppers should contain only ash that represents the accumulation during the early test period. For each test day, four bags of ash (approximately 2 pounds each) were obtained; one each from four separate ESP hoppers representing inlet and outlet ESP fields and one from both sides of the boiler exit (east and west). The ESP ash samples were kept separate in the event that it became necessary to assess the variation of ash characteristics spatially within the precipitator. Each ESP ash sample was divided in two parts; one portion was reserved for archive and the other was analyzed.

5.1.12 Primary Air / Fuel Measurements

These tests were performed to characterize the quantity and properties of coal fuel and its transport airflow (primary air), supplied to each burner under several firing rates [Storm 1990; Smith 1991]. The purpose of these tests is to correlate combustion conditions, boiler thermal performance, slagging/fouling characteristics, and emissions (particulates, fly ash properties, NOx, etc.) with the fuel supply. In that way, the effects of the subsequent modifications to the burners and air supply (e.g. OFA) may be discriminated from effects due to any changes in the fuel supply characteristics. The principal fuel supply measurements were of the coal mass distribution to each burner and the particle size distribution within each burner supply pipe. Supporting measurements were made to determine the primary air/coal velocity profile in each supply pipe and the primary airflow provided at each mill inlet.

The initial measurements made for each test condition were of the "dirty air" (PA plus coal) velocity profiles in each burner supply pipe. This was done using a specialized type of pitot tube designed by Flame Refractories for use in particle laden air. The pitot total/static pressure differential was measured using a combination vertical/inclined water manometer. The temperature within the coal pipe was measured with a type K (chromel/alumel) thermocouple and digital thermometer readout with a temperature-compensating junction.

Measurements were made at 12 points along each of two perpendicular axes for each pipe (Figure 5-9). A dustless connection was used to prevent coal leakage around the velocity probe. The connection employs air aspiration to counteract the pipe internal pressure as the cock valve is opened and the velocity probe inserted. During velocity measurement, the aspirating air is turned off to avoid undue influence on the velocity measurements.

Following determination of the dirty air velocity profile in each pipe, a coal-sampling device was inserted through the dustless connection and coal withdrawn over a measured time period. The device used for coal sampling is based upon the recommended ASME design (PTC 4.2) but modified by Flame Refractories to include a filter, a flow measurement orifice, and a sampling aspirator with control valve.

At each sample point (12 points on each of two diameters), the coal was sampled for a timed duration at an isokinetic rate consistent with the previously determined velocity profile for the pipe. Each pipe was sampled for the same duration. Therefore the quantity of air/coal sampled for each pipe should be proportional to the total air flow rate in the pipe. Thus, it is assumed that the coal acquired from each pipe represents a reasonably accurate measure of the total coal distribution to the burners.

Each coal sample and filter was transferred to a plastic bag, sealed, and identified as to test condition, coal pipe, and the date and time of the sample. Each sample was subsequently weighed to determine the relative coal flow per unit time for each pipe.

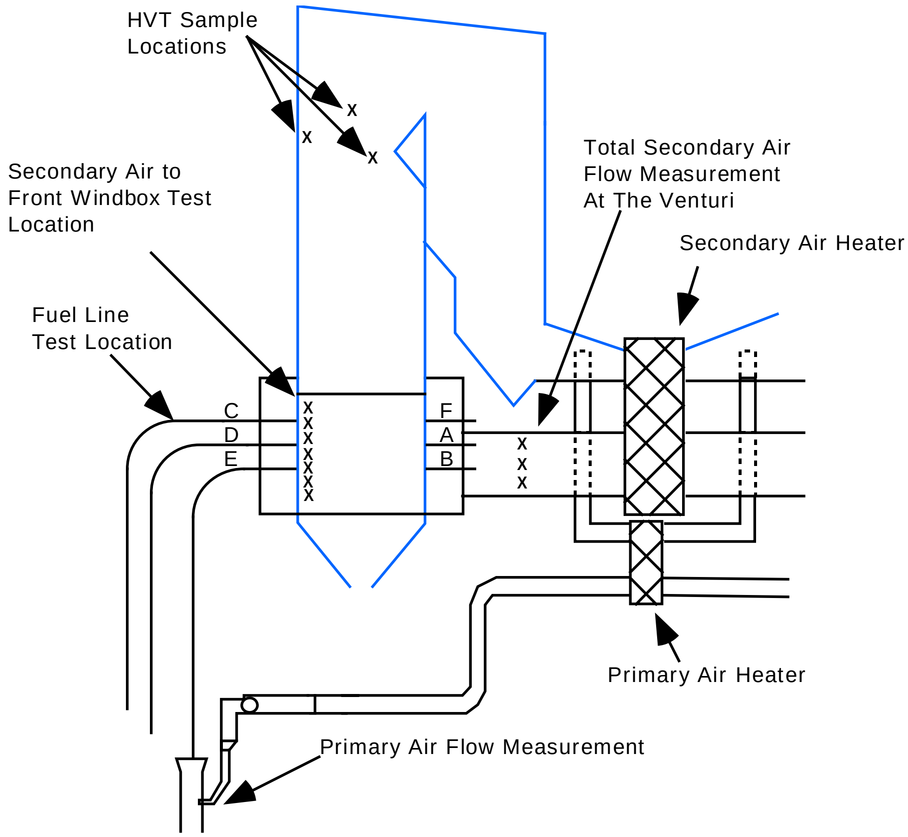


Figure 5-9 Combustion System Test Locations

5.1.13 Secondary Airflow Measurements

Heated combustion air is supplied to the boiler through two ducts, one on either side of the boiler (east and west) (Figure 5-9) [Storm 1990]. Each supply duct contains a two dimensional venturi section with pressure taps to measure airflow. Approximately at the midpoint of the east and west sides of the boiler, the air supply ducts connect to a windbox that encircles the boiler at the level of the burners. During performance tests, secondary airflow rates (velocity) were measured at the east and west venturi throats and also in the east and west sides of the boiler windbox just before the front windbox area. For all locations both modified Type S and Fecheimer pitot probes were used along with a vertical/inclined manometer and a Type K thermocouple with a digital thermometer readout. At the venturi throat location, velocities were measured at three depths at four test ports. Velocities entering the front windbox (east and west) were measured at eight horizontal insertion depths for each of nine vertically aligned ports. The flow to the rear windbox was inferred by subtracting the measured flow to the front windbox from the measured flow at the venturi throats. The modified Type S pitot probe was used on all tests. For selected measurements, the Fecheimer velocity vector probe was also used to corroborate the Type S pitot measurements.

Following installation of the advanced overfire air system, the combustion air supplied through this system was measured at the four corners of the AOFA windbox using the same methods as discussed above.

5.1.14 Furnace Gas Measurements

During performance tests, measurements were made of temperature and gas species within the furnace combustion zone above the burners to assess the potential effects of low NOx retrofits on heat distributions and the completeness of combustion within the furnace [Storm 1990]. A twenty (20) foot long, water-cooled high-velocity thermocouple (HVT) probe was used to measure both the temperature and gaseous species compositions of the combustion gases above the burner zone, near the entrance of the gas flow into the convective tube passages. The probe is a triple tube design with the outer two tubes providing supply and return passages for the water coolant, and the innermost tube providing for aspiration of furnace gases to the boiler exterior. An enclosed thermocouple probe passes through the innermost tube and emerges at the insertion end to expose the measurement tip to the furnace gases. A radiation shield of stainless steel (or ceramic) is provided to prevent a false thermocouple reading as a result from radiation gain or loss from the surroundings. A Type K (chromel/alumel) thermocouple was used along with a Fluke digital thermometer.

Furnace gases are aspirated through the innermost tube of the probe in order to ensure constant exposure of the thermocouple tip to the hot furnace gases and to exhaust the furnace gases for analysis of their species composition. An air-driven aspirator exhausts gases through the probe and expels them to the atmosphere. A portable oxygen/CO analyzer with a self-contained sampling pump withdraws a small amount of the furnace gases from between the probe and the aspirator. The probe was inserted through view ports at the 7^{th} and 8^{th} floor elevations, in the proximity of the furnace nose (Figure 5-10). Figure 5-11 shows the plan view of the measurement locations, representing a total of 80 distinct points at the 8^{th} Floor and 20 additional points at the 7^{th} floor.

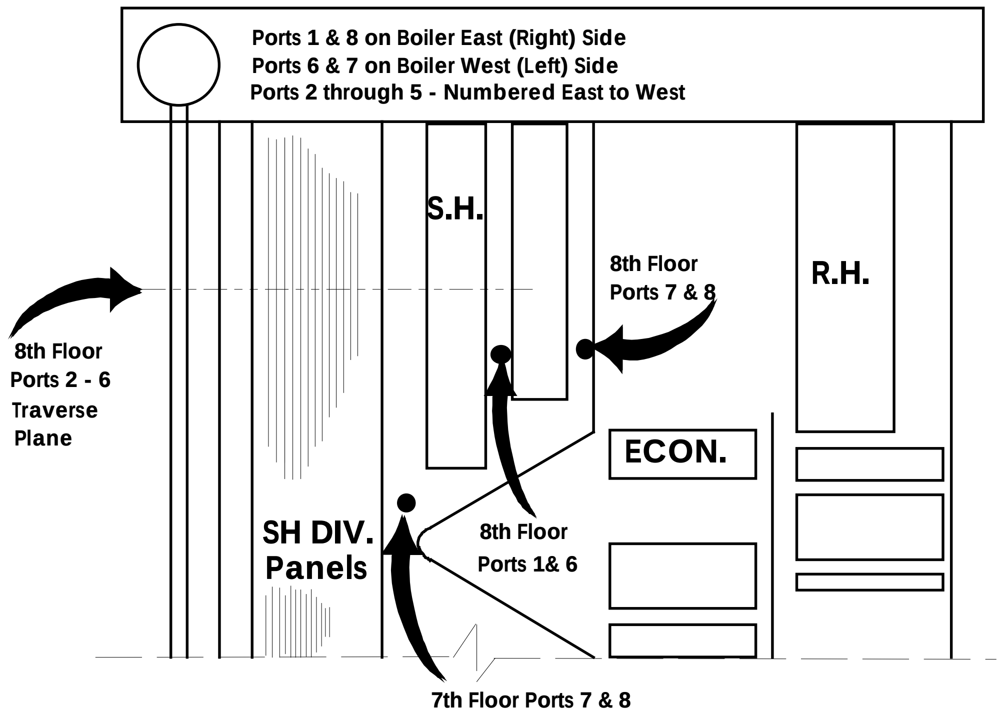


Figure 5-10 HVT Test Locations

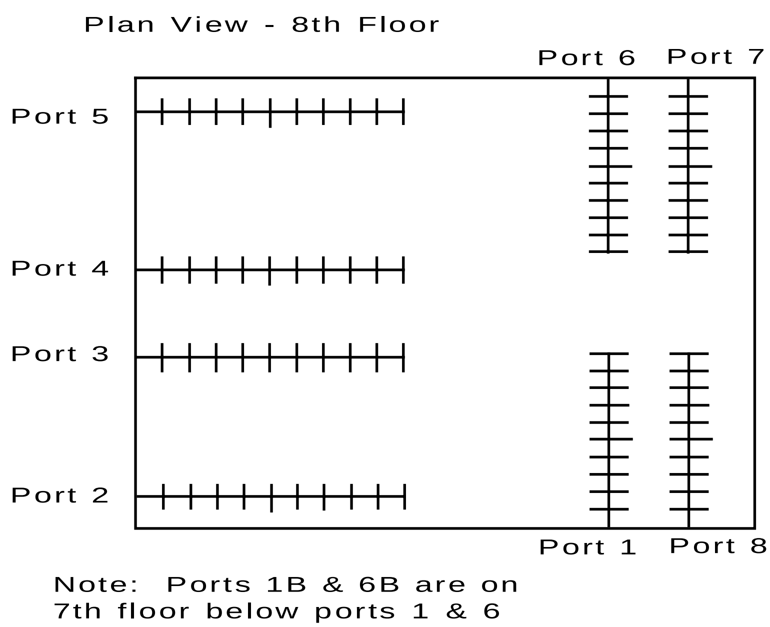


Figure 5-11 HVT Test Locations - Plan View

5.1.15 Total Particulate Emissions

Total particle mass loadings exiting the air heaters and entering the ESP were measured according to EPA Method 17 [Landham 1990; EPA 1978]. This system simultaneously determines total mass loading, gas velocity and temperature profiles, and flue gas moisture content. The Method 17 setup utilizes an in-stack filter to collect the particulate sample under flue gas conditions, thus avoiding measurement of condensables. Method 17 therefore provides the best estimate of the material that exists as a particulate at the inlet of the ESP (Figure 5-12).

Triplicate samples were obtained for each test sequence. In general, two sequences were performed at 480 MW and one each at 400 and 300 MW. Prior to each sequence, the velocity profile at the test points was determined and the sampling conditions established (nozzle size and sampling rate). The sample probe with in-stack filter was suspended vertically during the sampling. A total of 24 discrete sample points were used in a matrix of four depths at each of six test ports across the width of the flue gas ducts.

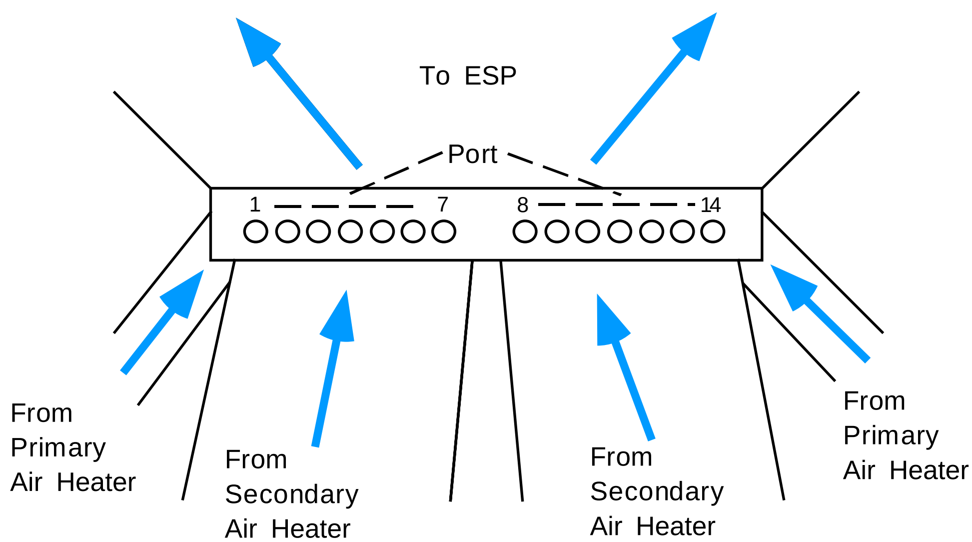


Figure 5-12 HVT Test Locations - Plan View

5.1.16 Fly Ash Particle Size

An important factor affecting the efficiency of particulate control equipment is the distribution of particle sizes present. Very small particles (less than 2 micron) are difficult to capture, especially in a device such as an ESP. It is important to document whether the retrofit NOx control technologies employed have a net positive or negative effect on the fly ash particle size, with respect to its ease of control by standard control devices, in this case an ESP.

Cascade impactors were used to measure the size distribution of particles entering the ESP at Plant Hammond [Landham 1990]. The procedures used in the preparation and operation are described in detail by Harris [Harris 1979]. In an impactor, the aerosol stream is constrained to follow a path of such curvature that the particles tend to move radially outward toward a collection surface because of their inertia. This effect is achieved by constraining the sample aerosol to pass through a circular hole to form a jet that is directed toward an impaction surface. Particles that have sufficient momentum will cross the gas streamlines and impact on the collection surface, while particles that have lower momentum will follow the air stream to lower stages where the jet velocities are progressively higher. For each impactor stage, there is a characteristic particle size that theoretically has a 50 percent probability of striking the collection surface. This particle size, or D50, is called the effective cut size for that stage. The number of holes or jets on any one stage ranges from one to several hundred depending on the desired jet velocity and total volumetric flow rate. Most commercially available impactors have between five and ten stages. Parameters that determine the collection efficiency for a particular geometry are the gas viscosity, the particle density, the jet diameter or width, the jet-to-plate spacing, and the velocity of the air jet.

Modified Brink model C impactors were used for the inlet measurements at Hammond. The modified Brink is a single jet, low sample rate, cascade impactor that is suitable for measurements of high mass loadings at a precipitator inlet. This impactor has a cyclone precollector, six impaction stages, and a backup filter. The nominal sampling rate for the Brink impactor is 0.03 acfm. Reeve-Angel 934 AH glass fiber substrates were used as collection media to reduce particle bounce. The substrates were sulfuric-acid-washed to reduce weight gains caused by chemical interaction between the flue gas and components of the glass fiber. To compensate for remaining substrate interactions, one blank impactor was run on each test day. (A blank impactor is treated exactly like a real run except that filtered, particle-free, flue gas is sampled.) The average stage weight gain of the blank impactor was subtracted from the real runs.

In general, six impactor runs were obtained for each of the three test conditions during the baseline test series. For each sample, the impactor was inserted at four depths in a single port and flue as drawn at the rate of 0.03 acfm. Glass fiber substrates were used in each impactor stage to minimize particle bounce. The substrate material was pre-washed with sulfuric acid to reduce interaction with flue gases and particulates. Six separate impactors were used each day plus a seventh blank impactor subjected to conditions identical to the sampling impactors. Each of the six impactor runs for each test was made in a different port and the results were averaged. Samples were obtained in ports 2, 4, 6, 9, 11, and 13 (Figure 5-12). The impactor data was reduced using a computer program developed at Southern Research under EPA sponsorship [EPA 1978].

5.1.17 Fly Ash Resisitivity

Measurements of the electrical resistivity of the dust entering the ESP were made in situ with a point-to-plane resistivity probe [Landham 1990]. The probe was inserted vertically down into the dust laden gas stream and allowed to come to thermal equilibrium. The particles passing through the measurement cell are electrically charged by a high voltage corona discharge from the stationary point electrode. A dust layer is formed on the collection plate through the interaction of the charged particles with the electrostatic field adjacent to the plate. Thus, this device is intended to simulate the behavior of a full-scale precipitator and to provide a realistic value for the resistivity of the dust that should be comparable to that in an actual precipitator.

Following sample collection, two methods of measuring resistivity on the same sample were used. In the *V I method*, a voltage current curve is obtained before the electrostatic deposition of the dust, while the collecting disk is clean. A second voltage current curve is obtained after the dust layer has been collected. The voltage drop across the dust layer for a given current is then determined by the shift in the voltage vs. current characteristics along the voltage axis. After the clean and dirty voltage current curves have been established, the *spark method* is employed. In this method, a disk electrode is lowered onto the collected sample. Increasing voltages are applied to the dust layer and the resulting current is recorded until the dust layer breaks down electrically and a sparkover occurs. The resistivity is calculated for the voltage and current at the point just prior to sparkover (ASME 1985).

Laboratory measurements were made of ash resistivity using ash samples from the onsite testing and a basic laboratory resistivity cell as defined by ASME PTC 28 (ASME 1985). The test environment was controlled to approximate the important components and conditions of the flue gas stream. A descending temperature test was performed on all samples over the range from 460°C to 84°C. This technique is defined by IEEE standard 548-1981 (IEEE 1981).

5.1.18 SO3 / SO2 Tests

Sulfur trioxide is a vapor or solid depending upon temperature. It has electrical properties that can substantially affect the net average resistivity of the fly ash, and therefore the collection efficiency of ESPs. The degree to which sulfur is oxidized to SO_3 or to SO_2 is dependent upon many combustion factors, including stoichiometry and temperature histories in the boiler. Tests were performed to determine the emissions of SO_3 and SO_2 [Landham 1990].

The procedure selected for the tests was the Cheney-Homolya method [Cheney 1979] that consists of:

- Extracting gas through a probe which has a filter at its tip to exclude fly ash;
- Maintaining the extracted gas at a temperature above the condensation points of SO_3, H_2SO_4 and water;
- Condensing out the SO_3 in a helical glass coil controlled to approximately l50°F (between the dew points of SO_3 and H_2SO_4) and;

- Condensing SO_2 in a cooled impinger train containing water and hydrogen peroxide.

The helical coil was washed with distilled water and the catch titrated for sulfur content. This titration method is sufficiently sensitive for use in determining SO_3 in flue gas concentations down to 0.1 ppm with samples of reasonable volume. It is also sufficiently sensitive in determining the characteristically much higher concentrations of SO_2. The impinger catch was similarly analyzed for total sulfur.

5.1.19 ESP Performance Prediction

A mathematical model was utilized to project the performance three hypothetical ESPs operating under the conditions measured at Hammond [Landham 1990]. This model is documented in detail by EPA publications [Faulkner]. The ESP model performs a detailed mathematical simulation of the precipitation process along one gas passage of a wire-plate precipitator. Each electrical section of the gas passage is divided into small computational length increments, within each of which the electrical conditions (including both ionic and particulate space charge densities) are approximately uniform. The inlet aerosol particle size distribution is divided into small bands, within each of which the particle size is approximately uniform. The ideal collection efficiency for each particle size, in each computational length increment, is calculated using the Deutsch-Anderson equation. The degrading effects of gas sneakage, non-rapping reentrainment, and non-uniform flow in a precipitator are accounted for in the model by user specified parameters. The ESP model assumes that all particles reentrained by rapping upstream of the outlet field are recollected, and that particles reentrained by rapping in the outlet field are lost. The correction for rapping reentrainment from the outlet field is based on data from six field tests of full-scale fly ash precipitators. The simulation accuracy of the ESP model has been validated by detailed comparison of computed collection efficiencies, using measured input data, with 18 measurements of collection efficiency at cold-side utility fly ash precipitators [DuBard 1987].

Because the modeling at Plant Hammond was of a hypothetical ESP, the EPRI database operating point correlation [DuBard 1987] was used to estimate electrical operating points. The correlation relates the resistivity of the ash and the ESP duct width in each field to the V-I curves for ESPs in the database to obtain electrical operating points for ESPs of up to five fields.

5.2 Data Analysis Methodologies

Two distinctly different types of data analyses are utilized to characterize the data: discrete analyses for short-term data, and statistical analysis for long-term data. The short-term data are used to establish emission trends, provide information for engineering assessments, and provide data for evaluating guarantees or goals established with the equipment vendors. Long-term data are used to statistically establish the long-term emission trends and regulatory assessments when the unit is operated in an economic dispatch mode.

5.2.1 Short-Term Characterization Data Analysis

The short-term data collection portion of the project is divided into diagnostic and performance test efforts. The diagnostic data collection effort is used to establish the trends of NOx versus load, mill patterns, and excess oxygen. The performance data collection effort is used to establish input/output characterizations of fuel, air, flue gas emissions, and boiler efficiency. The diagnostic and performance efforts are performed under well-controlled conditions with the unit off of load dispatch. Each data point is for a single operating condition. Unlike the data collected in the long-term effort, the data collected during the short-term effort is generally not of sufficient quantity to apply sophisticated mathematical analysis.

5.2.2 Diagnostic Data

Although much more information is obtained, the primary emphasis of the diagnostic testing is to determine the NOx emission characteristics of the unit. The ECEM allows sampling of the flue gas stream from a number of locations via a distribution manifold. The manifold allows sampling from individual probes or combinations of probes located in the economizer exit upstream of the primary and secondary air heaters. The composite emission measurement over the entire economizer exit (average of 28 probes) for the period of a diagnostic test represents a single data point for one configuration. The NOx, O_2, and CO levels are automatically recorded. Generally, the NOx measurements of interest during this element of the short-term testing are those obtained from the sample flow distribution manifold.

A single data point is obtained by selecting a probe group and obtaining numerous one-minute averages of the five-second data over the one- to three-hour period of the test. Sampling of one of the groupings is made for a sufficient time to insure that the readings are steady. The DAS is then prompted to gather data for one minute (12 five-second readings) and to calculate the statistics for that period (e.g. average and standard deviation). The average of all of the one-minute average measurements over the test duration constitutes a single data point for NOx for the condition under which the test was performed.

Early diagnostic test efforts showed that the variability of the NOx emissions was significant for seemingly identical conditions, i.e., load, O_2, and mill pattern. Because only a limited amount of short-term data was to be collected in the diagnostic effort, the high variability jeopardized the ability to trend the emissions data adequately. If the diagnostic test effort had included many more data points (requiring significantly more test days), the approach may have provided sufficient information to perform experimental design regression analyses. As a result of the NOx variability, the test plan reverted to a more or less sequential approach to collecting emission data, i.e., one load and mill pattern per day with a range of excess oxygen levels measured during steady-state conditions.

During diagnostic testing, attempts were made to gather three sequential data points (either increasing or decreasing excess oxygen level) at each load level (or mill pattern). With three data points on one day with a minimum variation of the other influencing parameters, the general trend of NOx versus load (or mill pattern) could be determined. Test points that were not sequential (different loads or mill patterns on the same day) were used to indicate the potential variability about the trend lines. It is assumed that the trends for these single, non-sequential data points is similar to that determined for sequential data and that families of curves exist

5.2.3 Performance Data

Performance data is used to: (1) to establish baseline evaluation criteria for retrofits, (2) to quantify the boiler characteristics for comparison with other phases of the program and (3) for comparison with the results of the diagnostic trends. The emphasis for the performance tests was on the analysis of the flows, solids capture, and boiler efficiency rather than on the NOx trends. As with the diagnostic test data, insufficient data samples were available to perform meaningful advanced statistics.

For each performance configuration (10- to 12-hour test day) the following types of data were obtained:

- Two gaseous emission measurements of NOx, O2, and CO, each composed of at least 10 one-minute sample distribution manifold composite flue gas measurements,
- Two ASME PTC 4.1 boiler efficiency determinations and two air heater leakage determinations,
- A minimum of three repetitions of specific flue gas solids emission parameters, and
- A minimum of one repetition of inlet fuel and air measurements (primary air distribution, secondary air distribution, coal particle size, or coal mill pipe distribution), or furnace combustion gas temperature and species.

5.3 Long-Term Characterization Data Analysis

During this portion of the test program, the emission and plant operating data input was automatically recorded on the DAS and archived. The emission input was handled automatically by the ECEM. A single emission measurement point in the duct following the ESP was monitored 24 hours per day during the entire long-term effort. The emission sample was brought to the ECEM through heated lines to preclude condensation of SO_2 in the lines. The ECEM was certified during each test phase.

The primary focus of the long-term test effort was to monitor the natural variation of the data in the normal mode of operation. During the entire long-term effort, no intervention by the test team members occurred or was for that matter allowed. This was to insure that this type of input would not bias the long-term data. For all practical purposes, the boiler was operating in its normal day-to-day configuration under control of the load dispatcher.

The thrust of the analysis of the long-term data is its interpretation primarily by statistical methods. The specific types of analysis used are related to regulatory issues and the engineering interpretation of long-term results compared to short-term diagnostics results. The analyses related to the regulatory issues were associated with the determination of the 30-day rolling average and annual average emissions and the estimation of an achievable emission level. The analyses related to the engineering interpretations were associated with the determination of the best statistical estimates of the operating characteristics, i.e., NOx versus load, mill pattern, etc.

The following two subsections provide information on: (1) the processing of the long-term data to produce a valid emission data set and (2) the fundamentals of the data-specific analytic techniques.

5.3.1 Data Set Construction

5.3.1.1 Five-minute Average Emission Data

The data collected during the long-term test program consisted of 5-minute averages of parameters related to boiler operating conditions and emissions. Because the intent of all analyses of the long-term test periods is to depict normal operating conditions, data collected during startup, shutdown, and unit trips were excluded from the analyses.

The 5-minute average data are also used to compute hourly averages that are in turn used to compute daily average NOx emissions. The daily average emissions are used to estimate the achievable NOx emission limit.

The loss of 5-minute data due to CEM failure was treated based on an adaptation of EPA NSPS guidelines for determining how much data is sufficient to compute an hourly average for emissions monitoring purposes. Also, in the case of daily average emissions, EPA NSPS guidelines (at least 18 hours of valid hourly data per day) were used to define a valid daily average.

5.3.1.2 Data Analysis Procedures

<u>Five-minute Average Emission Data</u>

The edited 5-minute average data from the long-term tests were used to determine: (1) the NOx versus load relationship and (2) the NOx versus O_2 response for various load levels.

<u>Hourly Average Emission Data</u>

The purpose of the hourly average emission analyses was to assess the hour-to-hour variation in NOx, O_2, and load for these periods. The within-day data analyses are performed by sorting the hourly averages by hour of the day and computing the average NOx, O_2, and load for these periods. The statistical properties for these hourly periods and the upper 95 and lower 5 percentile bands were determined for each hourly data subset. This data was used to compare the effectiveness of each technology against the baseline load scenario.

Daily Average Emission Data

The daily average emission data is used primarily to establish the trends in NOx, O_2, and load, and to calculate the 30-day rolling NOx emission levels for the entire long-term period. The daily average emissions data is analyzed both graphically and statistically. The graphical analyses consist of a series of plots to depict the daily variations in NOx, O_2 and load to establish trends. The purpose of the statistical analyses was to determine the population mean, variability (standard deviation), distribution form (normal, log-normal), and time series (autocorrelation) properties of the 24-hour average NOx emissions. The SAS Institute statistical analysis packages UNIVARIATE and AUTOREG were used to perform the statistical analyses.

Achievable Emission Rate

The results of the UNIVARIATE and AUTOREG analyses were used to determine the achievable emission limit on a 30-day rolling average and an annual (block 365 day) basis. The achievable emission limit on a 30-day rolling average basis is defined as the value that will be exceeded, on average, no more than one time per ten years. This compliance level is consistent with the level used by EPA in the NSPS Subpart Da and Db rulemakings. The achievable emission limitation for an annual average NOx emission limitation was also determined to reflect the requirements of the 1990 amendments to the CAAA. A compliance level of 95 percent was chosen for this case.

The achievable emission limit can be computed analytically using the following relationship if the emissions data are normally distributed:

$$Z = (L - X) / (S_{AVG})$$

where:	Z	=	the standard normal deviate
	L	=	the emission limit
	X	=	the long-term mean, and
	S_{AVG}	=	the standard deviation of the 30-day averages. S_{AVG} is computed using the estimated standard deviation (SDay) and autocorrelation (r) level for daily averages.

For 30-day averages:

$$S30 = \frac{SDay}{\sqrt{30}} \left| \frac{1 + \rho}{1 - \rho} - \frac{(2)(\rho)(1 - \rho^{30})}{30\,(1 - \rho)^2} \right|^{1/2}$$

1

For 365-day averages:

$$S365 = \frac{SDay}{\sqrt{365}} \left| \frac{1 + \rho}{1 - \rho} - \frac{(2)(\rho)(1 - \rho^{365})}{365\,(1 - \rho)^2} \right|^{1/2}$$

Because there are 3,650 thirty-day rolling averages in ten years, one exceedance per ten years is equivalent to a compliance level of (3649/3650), or 0.999726. For a compliance level of one violation in ten years, Z is determined to be 3.46 (based upon the cumulative area under the normal curve). The calculation of the annual average emission limitation is performed in a manner similar to that for the 30-day limitation. For annual averages, a 95 percent compliance level was arbitrarily chosen. The Z value for 95 percent compliance is 1.645.

6 PHASE 1 - BASELINE TRIALS

6.1 Short-Term Testing

The Phase l Baseline short-term characterization testing was conducted from November 2 through December 5, l989. A total of 36 diagnostic tests were performed during this period. An additional eleven tests were performed during the verification test effort. During the entire Phase 1 effort, 47 short-term tests were performed. All short-term tests were conducted within the normal limits of operating parameters for the unit, with the exception of excess oxygen. Excess oxygen was exercised well above and below the plant specified range to the potential levels that might be encountered during long-term test phase. All major boiler components, as well as ancillary equipment, were in the normal "as-found" operating condition. The fuel burned throughout the Phase 1 short-term program was from the normal supply source and was handled according to common plant practice. No special efforts were taken to maintain a consistent coal source for these tests. Subsequent to the completion of the long-term test period, a short verification test effort was undertaken to determine if significant changes occurred during the long-term test effort. This section describes both the diagnostic, performance, and verification testing performed during the Phase 1 effort.

6.1.1 Diagnostic Tests

The Phase 1 diagnostic effort consisted of characterizing emissions under "as found" conditions before any subsequent repairs or retrofits had been implemented. Thirty-six tests were performed at nominal loads of 185, 300, 400, and 480 MW during the period from November 2 through November 13, 1989 (Table 6-1). Immediately before the start of the diagnostic testing effort began, exploratory tests were performed to establish the general boiler operating characteristics and to establish steam, fuel and combustion air stabilization times. Generally, changes between test conditions took from one to three hours to insure stable steam temperature and pressure conditions. Each test condition (load, excess oxygen and mill configuration) was held steady for a period of from one to three hours depending upon the type of test performed. During this period, data was logged in the control room, boiler operational data was recorded on the DAS, furnace backpass ash grab samples were collected, coal samples were collected from the individual mills, and economizer exit and air heater exit species were determined utilizing the sample distribution manifold.

6.1.1.1 Unit Operating Condition

The potential for opacity excursions (opacity > 40 percent) under certain high O_2 operating conditions as well as other minimum low O_2 operating conditions dictated by unit safety considerations affected the ability to test over a wide range of O_2 levels at loads near 480 MW. As with most boilers of this vintage, burner register drives are either not operable or the position is not accurately known. This operational condition was present on nearly half of the burners. As a result of normal system dispatch requirements during the period of testing, it was difficult to obtain low load operating conditions (185 to 300 MW). This significantly reduced the amount of data that could be obtained at these loads. This is not unusual for a base loaded unit. Thorough characterization at these low loads was, consequently, felt to be inappropriate for this phase of the program since they would not be experienced to any great extent during the long-term characterization portion of the Phase 1 effort. Without the long-term data at these low loads, no comparison could be made as to the equivalency of short-term and long-term characteristics.

Table 6-1 presents the "as-tested" conditions during the diagnostic portion of the testing. Eleven days of testing were planned and executed comprising 36 individual tests at various excess oxygen, mill pattern, and load conditions. Because high load was the normal mode of operation for this unit during this period, most of the testing (14 out of the 36 diagnostic test conducted) was at or near 480 MW with slightly fewer test (11) being conducted at 400 MW. The testing between 185 and 300 MW consisted of nine individual tests.

6.1.1.2 Gaseous Emissions

During both the diagnostic and performance test efforts, flue gas data and boiler operating data were collected on the data acquisition system (DAS). The ECEM allowed measurement of NOx, CO, O_2, SO_2, and total hydrocarbons (THC) from 48 probe locations within the flue gas stream both upstream and downstream of the air heater. Two basic types of tests were performed - overall NOx characterization and economizer exit plane species distribution characterization. The overall NOx characterization tests were performed over a period of approximately one hour and was used to obtain composite average specie concentrations from the individual probes in a duct sampled as a group. The economizer exit plane species distribution characterizations were performed over a period of approximately two to three hours. These tests used data from the individual probe species concentrations in the A- and B-side economizer exit planes to establish the extent of maldistribution of combustion products emanating from the boiler. These maldistributions are an indication of the uniformity of combustion due either to fuel and/or air non-uniformities.

The range of excess oxygen and resulting NOx emissions for the four nominal load levels tested during the diagnostic portion of the Phase 1 effort are shown in Figures 6-1 and 6-2. The conditions represented in these figures include excess oxygen variation, mill-out-of-service variation, and mill biasing. Figure 6-1 serves to illustrate that the testing was performed over a range of excess oxygen levels that were both below and above the levels recommended for this unit. The solid curve represents the normal operating O_2 level. During normal dispatch control of the unit, excursions to these levels are frequently experienced during transient load conditions. To properly compare the short-term and long-term characteristics, this O_2 excursion testing during the short-term diagnostic effort was required.

As diagnostic testing progressed, it became evident that other variables potentially were greatly influencing the NOx emissions, however, their influence could not be quantified. These influencing factors were believed to be the result of mill operating conditions (flows, grind and condition) and secondary air non-uniformity (air register settings). The secondary air registers on almost half of the burners were either inoperative or their position could not be accurately determined. It is believed that these combined factors made it virtually impossible to repeat test conditions on different days.

Figure 6-2 is a summary of all of the NOx data obtained for all test configurations. These configurations represented the range of normal configurations that were believed to be the predominant modes of operation that might be experienced during the system load dispatch mode of operation during long-term testing. The data scatter is partially the result of the fact that different configurations are represented and also to the lack of data repeatability discussed above. It is not mathematically appropriate to attempt to statistically characterize this data because of the small population within each load category and the number of variables imbedded in the data. For engineering purposes, it is helpful to place a band of confidence about the data to illustrate the general trend of NOx versus load. At loads below 300 MW, insufficient data was available even for that purpose. The band (1σ standard deviation) and the mean NOx line shown in Figure 6-2 for loads from 480 to 300 MW indicate that, at least for this set of data, the trend is increasing NOx with increasing load. It should be pointed out that with more NOx data, the slope of the trend may change. Analyses performed for data gathered during the long-term testing where virtually thousands of data points were used for the characterization provide a more statistically appropriate NOx trend.

During this phase, short-term characterizations of the NOx emissions could only be made for trends determined on the same day of testing for a particular configuration. The variation is believed to be the result of the influence of uncontrollable parameters described. Figures 6-3 through 6-7 show the diagnostic test results for the four nominal loads tested: 480, 400, 300, and 180 MW. The legend for each data point indicates the test day for the particular data point. In some instances, the mill flows were biased (to nominally equal flows) from the settings normally used by the operators in order to determine the influence on NOx emissions. Because the variability of the NOx emissions for seemingly similar configurations was relatively large, this biasing influence could not be discerned.

Figure 6-3 shows the NOx data for the 480 MW test point. At this load, the only operational mill pattern is with all mills-in service (AMIS). As explained above, due to opacity and safety considerations, the excess oxygen range that could be tested was relatively small (approximately one percent). Over this range, it is difficult to obtain a definitive trend for the NOx versus O_2. It is evident from the figure that the slope for the three characteristic curves varies greatly (0.023, 0.102, and 0.1854 lb/MBtu / %O_2) (17, 75, and 136 ppm/% O_2). Over this small range of O_2 the most that can be said is that the NOx increases with increasing excess oxygen. It is also evident that for seemingly identical test conditions the NOx varied by as much as 6 percent (0.218 lb/MBtu or 160 ppm) for tests conducted on different days.

NOx data for the 400 MW test point is shown in Figure 6-4, primarily for two mill patterns - B-MOOS and E-MOOS. According to plant personnel, these were the most commonly used mill patterns at this load. One data point with AMIS was tested as well. The opacity and safety limitations for the 480 MW testing were not factors at the 400 MW test point and below, consequently, a wider range of excess oxygen could be tested. For all mill patterns, the NOx trends appeared to be similar, however, they were offset from one another. With this small amount of data and the variability exhibited for all of the data taken during this diagnostic test phase, it is not possible to determine if this offset is a trend. It is evident, however, that the NOx versus O_2 characteristic does exhibit a definite repeatable trend based upon this data. On average the NOx varied approximately 0.100 lb/MBtu / percent O_2 (73 ppm/percent O_2) over the three percent excess oxygen excursion. Partially as a result that three mill patterns were tested, the NOx varied by as much as 25 percent (0.311 lb/MBtu or 228 ppm) for tests conducted on different days.

Because 300 MW is not a common load point for this unit, a relatively small amount of NOx data was obtained compared to that obtained at the higher load test points. Figure 6-5 shows the data for three mill patterns (B-, E- and B & E-MOOS). Sufficient data was available only for the E-MOOS pattern to assess the NOx versus O_2 characteristics. For the two days when the E-MOOS pattern was tested, the trend agreed quite well. Both days exhibited a 0.0845 lb/MBtu / percent O_2 (62 ppm/percent O_2) slope, which illustrates the repeatability of the trend. It should be pointed out, however, that as with the high load points, the data scatter resulted in an offset between the absolute NOx emissions for the two days. The data scatter amounted to approximately 11 percent for the small amount of data collected. With more data, it likely would have been greater based upon data obtained at the higher loads.

Only two data points were obtained at the 180 MW load point. This load point is used infrequently when the unit is either coming up from an outage or when the load is required to perform maintenance that can not otherwise be performed at higher loads. This condition amounts to less than ten percent of the operating time. Figure 6-6 shows the trend for one mill pattern (B and E MOOS). For this one day of testing, the data exhibits a 0.117 lb/MBtu / percent O_2 (86 ppm/percent O_2) NOx characteristic near the normal operating excess oxygen level. This is consistent with the data obtained at the 400 and 300 MW test points, i.e., 0.100 lb/MBtu / percent O_2 and 0.085 lb/MBtu / percent O_2 (73 and 62 ppm/percent O_2), respectively.

From these figures it is evident that while trends (NOx vs. O_2) determined on the same day are similar, the day-to-day variation can be larger than the effect of excess oxygen on NOx for seemingly identical conditions. Even when mill biasing was introduced as a variable, the effect was within the normal scatter caused by other influencing variables.

Table 6-1 Baseline / Diagnostic Tests Conducted

Test	Date	Test Conditions	Load MW	MOOS Pattern	Excess O_2 %
1-1	11/2/89	OPERATIONAL RANGE	480	NONE	HIGH
1-2	11/2/89	OPERATIONAL RANGE	480	NONE	LOW
1-3	11/2/89	HI LOAD O2 VARIATION	480	NONE	3.1
2-1	11/3/89	HI LOAD O2 VARIATION	480	NONE	2.5
2-2	11/3/89	HI LOAD MILL BIAS	480	NONE	2.7
2-3	11/3/89	MID LOAD O2 VARIATION	400	E	3.3
3-1	11/4/89	LOW LOAD O2 VARIATION	185	B&E	7.2
3-2	11/4/89	"	185	B&E	6.2
4-1	11/5/89	HI LOAD O2 VARIATION	480	NONE	2.5
4-2	11/5/89	"	480	NONE	2.2
5-1	11/6/89	HI LOAD MILL BIAS	480	NONE	2.4
5-2	11/6/89	MID LOAD O2 VARIATION	400	E	2.4
6-1	11/7/89	MID LOAD O2 VARIATION	300	E	3.8
6-2	11/7/89	"	300	E	5.2
6-3	11/7/89	MID LOAD MILL VARIATION	400	NONE	3.5
7-1	11/8/89	MID LOAD O2 VARIATION	300	E	4.3
7-2	11/8/89	MID LOAD MILL VARIATION	300	B	4.2
7-3	11/8/89	MID LOAD O2 VARIATION	400	E	4.3
7-4	11/8/89	"	400	B	3.2
7-5	11/8/89	HI LOAD O2 VARIATION	480	NONE	2.9
8-1	11/9/89	MID LOAD MILL VARIATION	300	B&E	4.0
8-2	11/9/89	MID LOAD O2 VARIATION	479	NONE	3.0
8-3	11/9/89	"	478	NONE	2.7
8-4	11/9/89	HI LOAD O2 VARIATION	478	NONE	2.2
9-1	11/10/89	MID LOAD O2 VARIATION	400	B	2.3
9-2	11/10/89	"	400	B	3.5
9-3	11/10/89	"	400	B	5.1
9-4	11/10/89	HIGH LOAD O2 VARIATION	480	NONE	3.3
9-5	11/10/89	"	480	NONE	2.9
10-1	11/11/89	MID LOAD O2 VARIATION	405	E	2.0
10-2	11/11/89	"	403	E	3.1
10-3	11/11/89	"	400	E	4.5
10-4	11/11/89	"	305	E	2.8
10-5	11/11/89	"	315	E	4.8
11-1	11/13/89	HIGH LOAD O2 VARIATION	478	NONE	2.9
11-2	11/13/89	"	480	NONE	2.9

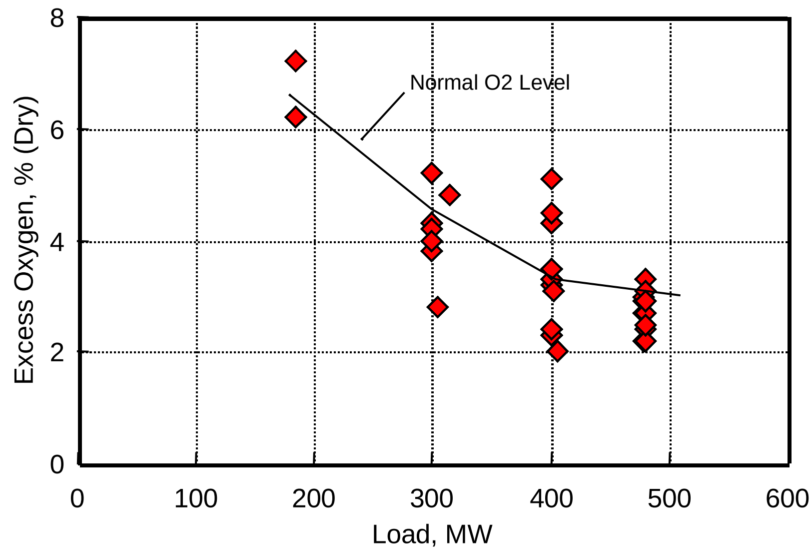


Figure 6-1 Baseline / Short-Term Tests / Oxygen Levels Tested

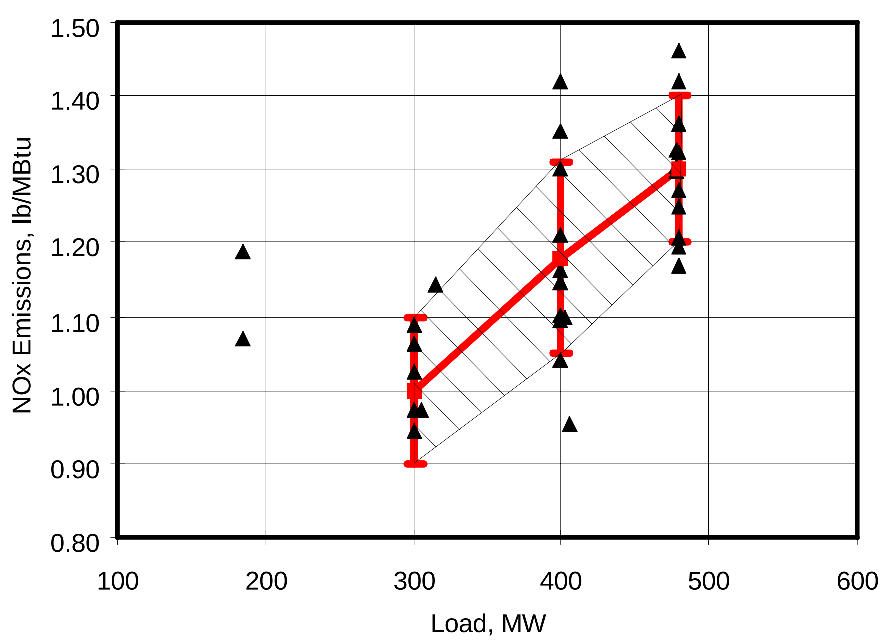


Figure 6-2 Baseline / Short-Term Tests / NOx Emissions

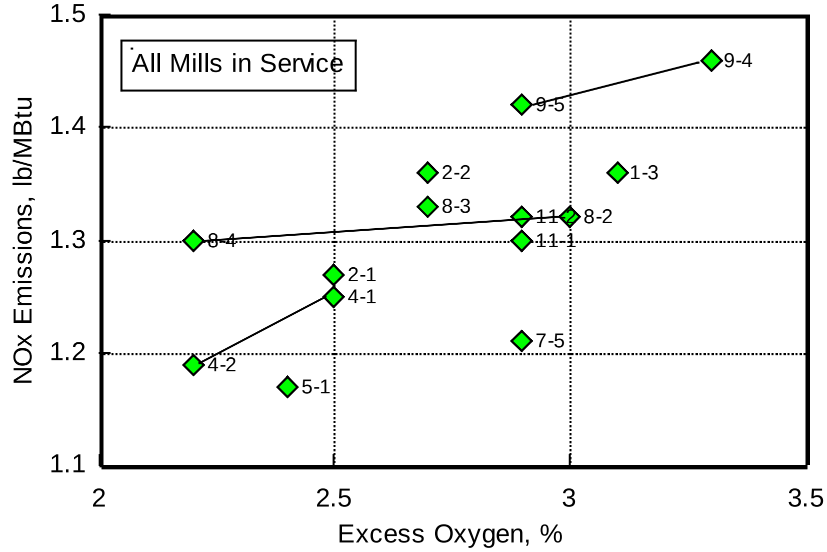


Figure 6-3 Baseline / Short-Term Tests / NOx Characterization at 480 MW

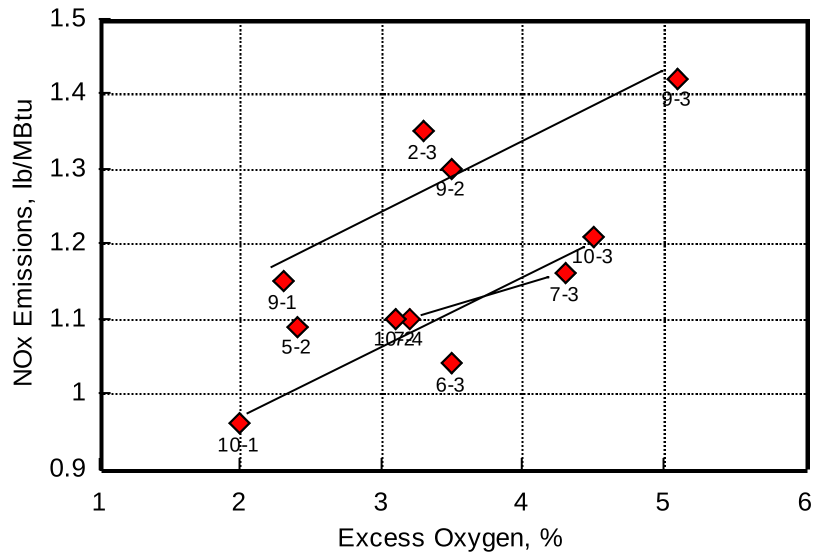


Figure 6-4 Baseline / Short-Term Tests / NOx Characterization at 400 MW

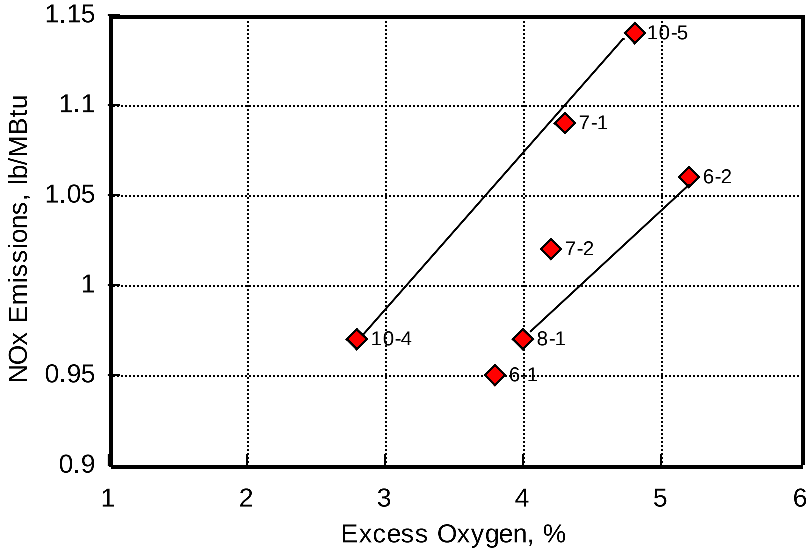


Figure 6-5 Baseline / Short-Term Tests / NOx Characterization at 300 MW

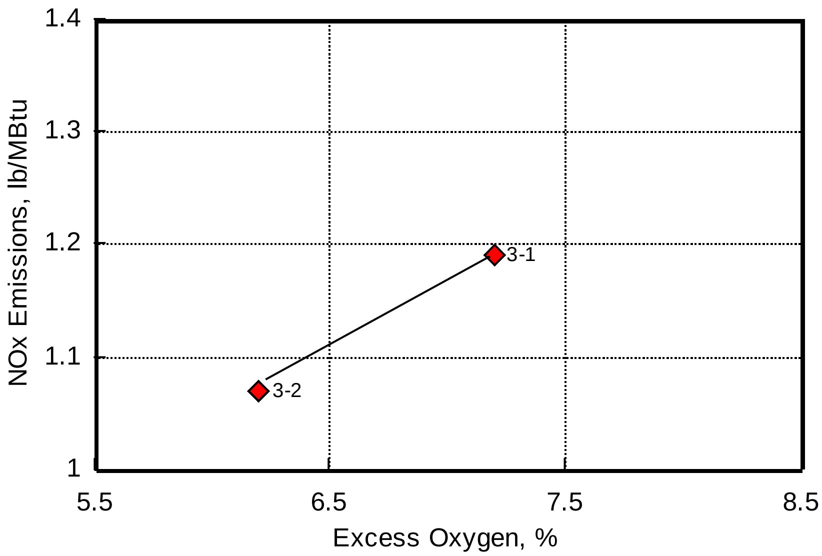


Figure 6-6 Baseline / Short-Term Tests / NOx Characterization at 185 MW

6.1.2 Performance Tests

Seven performance tests were conducted at nominal gross loads of 300, 400, and 480 MW (Table 6-2). At each nominal load, the coal firing rate was kept as constant as possible and the load allowed to swing slightly as affected by coal variations, boiler ash deposits, ambient temperature, etc. The maximum load swing recorded during any test was 6 MW (< 2 percent). Each test covered a period of from ten to twelve hours during which time boiler operational data was recorded, fuel and ash samples acquired, and gaseous and solid emissions measured.

Table 6-2 Baseline / Performance Tests Conducted

Test	Date	Conditions	Load MW	MOOS Pattern
12	11/29/89	High Load Med O2	477	NONE
13	11/30/89	High Load High O2	476	NONE
14	12/01/89	Med Load	298	E
15	12/02/89	Med Load	301	E
16	12/03/89	Med Load	389	E
17	12/04/89	High Load Low O2	469	NONE
18	12/05/89	Med Load	390	E

6.1.2.1 Unit Operating Data

For each performance test, the desired test conditions were established and allowed to stabilize at least one hour prior to commencement of testing. To the extent possible the active coal mills were balanced with respect to coal feed rate. Normal primary air/coal ratios and mill outlet temperatures were maintained, within the capacity of the existing primary air system. When the desired operating conditions were established, the fuel and air masters were placed on manual control to minimize fluctuations in the fuel or air firing rate. This technique resulted in extremely stable operation over the test duration with only minor adjustments to the airflow over the day.

Because a portion of the testing was concerned with measurement of various particulate emission characteristics, it was decided that soot blowing (both furnace and air heaters) should be suspended during the particulate sampling periods. As such, test measurements would include only particulate matter actually generated by the coal combustion at the time of testing (plus any normal attrition of wall or air heater deposits) and not periodic portions of ash loosened by soot blowing. When necessary for proper unit operation, air heaters were blown between repetitions in the solids emissions testing.

At each nominal load level, at least two tests were performed over a two-day period to accommodate all of the specific test measurements desired. A third test at 469 MW was performed as a result of load requirements on December 4 which precluded testing at the scheduled 400 MW test. A summary of important operating and emissions parameters recorded during this test series can be found in Appendix A.

6.1.2.2 Gaseous Emissions

During the performance tests, gaseous emissions were measured with the ECEM operating in the manual mode. At various times during the performance tests, flue gas was sampled from selected probes or probe groups in the primary and secondary air heater inlet and outlet ducts. These groupings consisted of composites of the individual east and west economizer exit ducts and individual measurements from each probe in these ducts. Composite groupings are used to establish the overall emission characteristics while the individual probe measurements are used to establish spatial distributions of emission species.

Composite samples were acquired from the east and west duct probes at the secondary air heater inlet to represent the stoichiometric conditions in each half of the furnace. The ECEM excess O_2 values were used for the composite readings rather than the six existing plant O_2 analyzers because the ECEM obtains samples from 24 individual points in the two ducts. Table A-3 lists the composite average values of O_2, CO, and NOx measured over a several hour period for each test condition. Each complete performance test consisted of two separate but nearly equal conditions for a given load, e.g., conditions for Test 12-1 or 12-2. The composite values recorded are the average of the east and west duct composites, each consisting of simultaneous sampling from l2 probes per duct for the two test conditions. Each value of O_2, CO, and NOx represent at least two sets of ten readings per duct over the full 10 to 12 hour performance test duration.

Although the presence of visible smoke (opacity) is frequently of more value than CO measurement as an indicator of undesirable coal combustion conditions, the presence of an ESP on this unit precluded the use of this tool. CO can be a useful tool in diagnosing combustion anomalies and is a measure of the quality of combustion. The low levels of CO measured during the present tests are in the instrument background noise level and are therefore not indicative of any combustion irregularities. The low levels of LOI during these tests confirmed that there were in fact no major combustion irregularities.

From Figure 6-7, it can be seen that the NOx emissions vary for seemingly identical test conditions. There is considerable variability in NOx emissions, at the middle and high load levels. The data scatter of l0 to l5 percent from nominal reflects the influence on NOx emissions of combustion variables that could not be controlled or measured adequately. Variations in coal nitrogen content, fuel/air distribution, coal fineness, furnace wall cleanliness, etc., could all contribute to variability in the measured NOx emissions.

Comparing these performance data with the diagnostic test data shows that the variability is similar for these two test elements. It should be noted that the measurement of NOx levels of 1.52 lb/MBtu (1117 ppm) and 1.43 lb/MBtu (1049 ppm) for the 480 and 400 MW performance tests, respectively, are higher than any measured during the diagnostic testing. This supports the earlier contention that additional short-term data could exhibit even greater variability if more data were available.

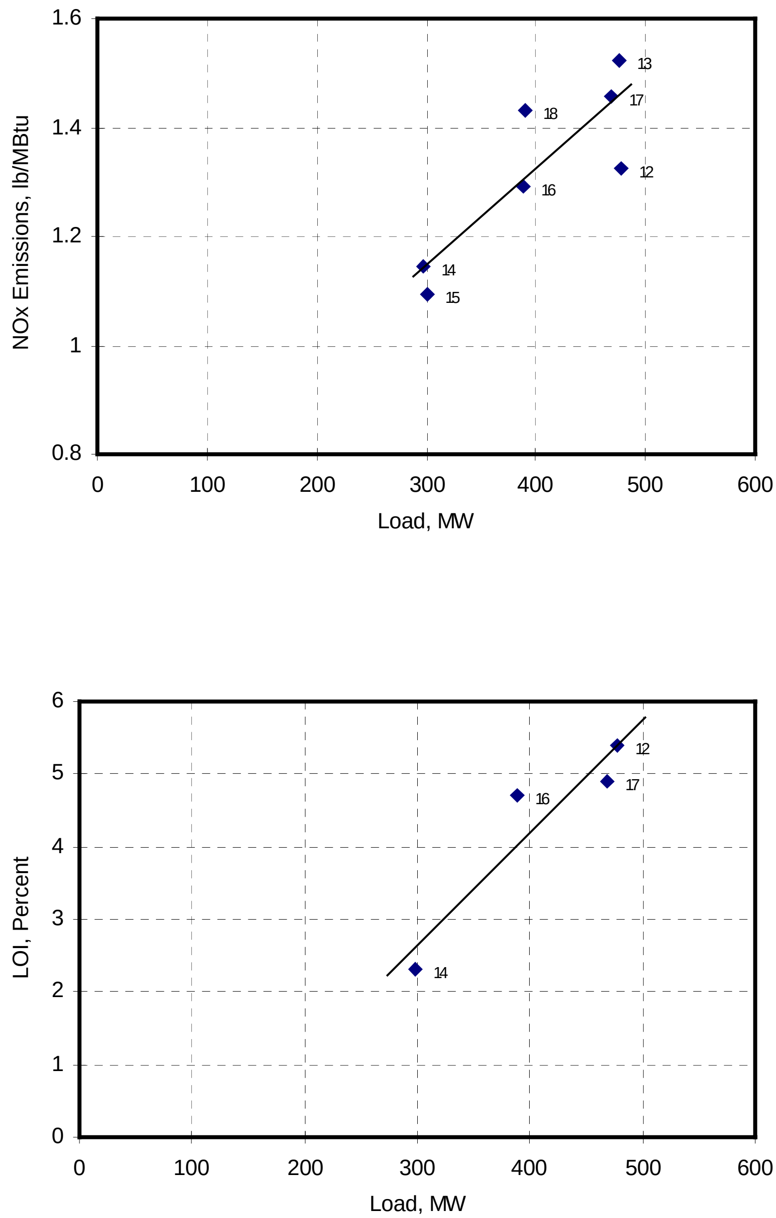


Figure 6-7 Baseline / Performance Tests / NOx Emissions and LOI

6.1.2.3 Combustion System Tests

These tests were performed at each of the three load levels (Tests 13, 15 and 16) to document the specific performance parameters related to the fuel and air combustion systems.

Mill Performance

The airflow to each mill and the particle size and mass flow distributions of coal to each burner were measured as described previously.

Duplicate tests were performed at 480 MW and 300 MW nominal load levels. Only selected mill and coal pipe measurements were made at 400 MW. Table 6-3 and Figures 6-8 through 6-9 summarizes the results of these tests. From Figure 6-8, it can be seen that despite the mills being set to approximately equal coal flows with the boiler controls, the measured coal flows varied ±11 percent from mill to mill. Also evident is the variation in coal flow from pipe to pipe. For Test 13-1 the standard deviation in pipe to pipe coal flow was 21 percent of the mean flow. The measured ratio of primary air to coal flow varied from approximately 2.5 at 475 MW to 3.5 at 306 MW (Figure 6-9). The range was required to maintain the desired mill outlet coal/air temperature of approximately 170ºF. A potential impact of these levels of primary airflow could be high NOx emissions.

During these mill tests, the coal fineness was found to be below 70 percent through 200 mesh (except for mills C and F at 300 MW) (Table 6-3). This condition (lower fine particle through 200 mesh) could be partially attributable to the low Hargrove Grindability Index (HGI) of the coal tested. The HGI was about 44, which is typical of Central Appalachian coals. Although the relatively poor grinding performance of the mills may have adversely affected unburned carbon levels, it is unlikely that NOx emissions were directly affected.

Table 6-3 Baseline / Average Coal Fineness

	Remaining on 50 Mesh	Passing 100 Mesh	Passing 200 Mesh
Test 12	3.14	na	62.2
Test 13	2.41	na	64.0
Test 14	1.76	na	67.5
Test 15	1.16	na	70.5
Test 16	na	na	na
Test 17	na	na	na

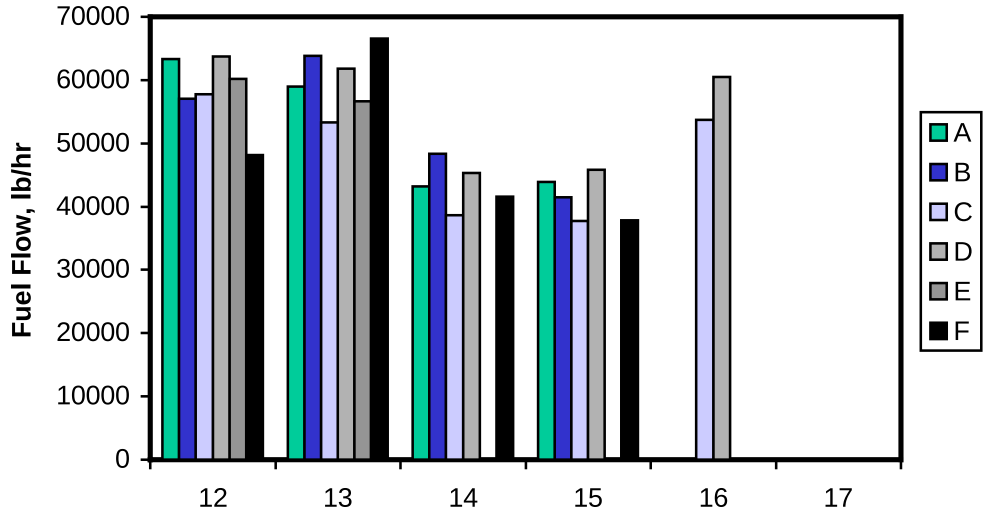


Figure 6-8 Baseline / Fuel Distribution

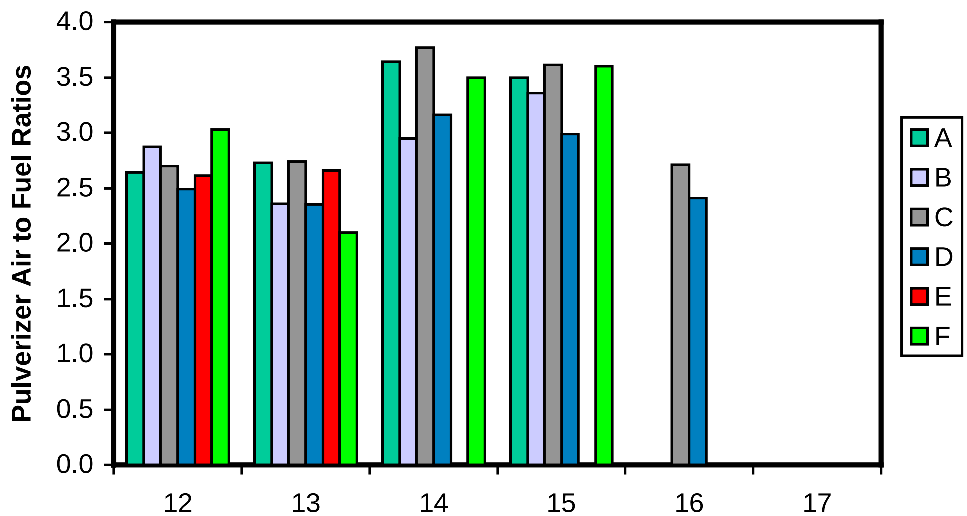


Figure 6-9 Baseline / Pulverizer Air to Fuel Ratio

Secondary Air Supply

The secondary combustion airflow was measured at four locations as described earlier. Figures 6-10 and 6-11 present the results of the flow measurements for Tests l3 through l8. At the three load test points, the airflow distribution ranged from 80/20 to 66/34 percent, front to rear, except for one 400 MW test (Test l6) which showed a remarkably uniform distribution. These results are in question due to the difficulty in obtaining accurate flow measurements within the windbox. The front windbox sample test ports are located in the side ducts in close proximity to the 90 degree turn prior to the entrance to the windbox. There was considerable turbulence and a large velocity gradient at this measurement location; however, no other adequate location was available. To better define the flow in this region, separate measurements were made with a Fecheimer velocity probe (which can measure the angle of the velocity vector in a plane perpendicular to the probe axis). These measurements produced essentially the same results as the standard Type S pitot probe measurements. An independent measurement could not be made at the rear windbox because of lack of access for a velocity probe in that location. The calculated flow to the rear windbox was determined by subtracting the measured flow to the front windbox from the measured total flow. The large indicated imbalance in flow to the front and rear windboxes could be due to the combined effects of the air duct geometry and the inability to adjust a substantial portion of the individual burner air registers. As a result of these potential inaccuracies, the front-to-rear measurements should only be used as qualitative assessments of the flow distribution rather than as accurate quantitative measurements.

The measurements made at the venturi throats in the secondary air supply ducts were very repeatable. The measurements taken at this location did not suffer from the inadequacies of the windbox flow locations. Thus, there is a high level of confidence in the total air flow measurements based upon the location and the repeatability.

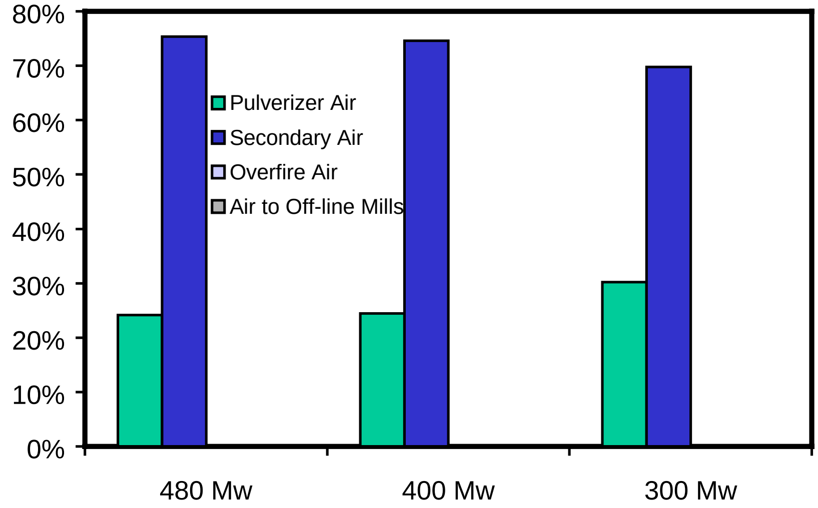


Figure 6-10 Baseline / Distribution of Unit Air Flow by Load

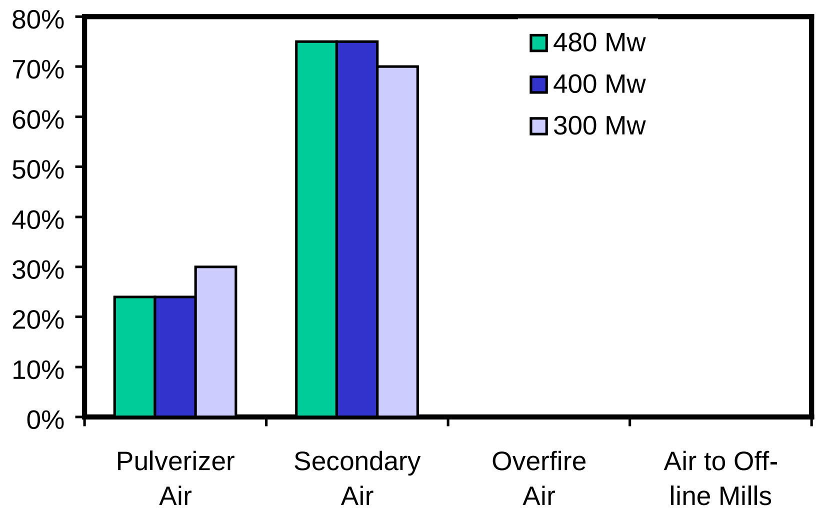


Figure 6-11 Baseline / Distribution of Unit Air Flow by Component

<u>Furnace Measurements</u>

Measurements were made of combustion gas temperatures and species concentrations (O_2 and CO) at eight locations within the boiler furnace at the 7th and 8th floor levels. At each port, approximately 10 measurements were made.

Figure 6-12 depicts the temperature and oxygen profiles at the 8th floor level for the nominal 480, 400, and 300 MW test points. The x-y plane in these figures represents the horizontal cross-section of the furnace at the 8th floor and the y-axis represents the magnitude of the measured variable (temperature or O_2). These plots clearly illustrate the non-uniformity at the 8th floor sample plane that could be the result of fuel and air maldistribution. For lower loads, the extremes (high to low measurements), in both O_2 (stoichiometry) and temperature, were significantly less than for the 480 MW test. This could be the result of the reduced gas velocities providing longer residence times for completion of combustion within the furnace at these lower loads. Species concentrations of O_2 and CO measured simultaneously with the temperature measurements indicate significant stoichiometry non-uniformity within the furnace. Generally speaking the excess O_2 level was low (0 to l percent) and the CO concentration high (500 to l000+ ppm) near the center of the furnace, and along the front wall. Oxygen levels were higher (and CO lower) toward the rear and side walls.

As expected, the measured temperatures close to the side walls and the rear wall or nose tubes are lower in temperature than those measurements made away from these points (ports 3 and 4). This is evident at both the high and low load points. The high mid-furnace temperatures leaving the furnace (2300-2400°F) could be the result of primary combustion extending upward from the burner zone. One potential reason for this could be due to the coal fineness distribution (< 70 percent through 200 mesh) and the non-uniformity of coal and air distributions to the burners.

Temperature measurements attempted through the front wall ports at the 7th floor were aborted due to melting of the probe's stainless steel radiation shield. This indicates a temperature in excess of 2600°F in this region.

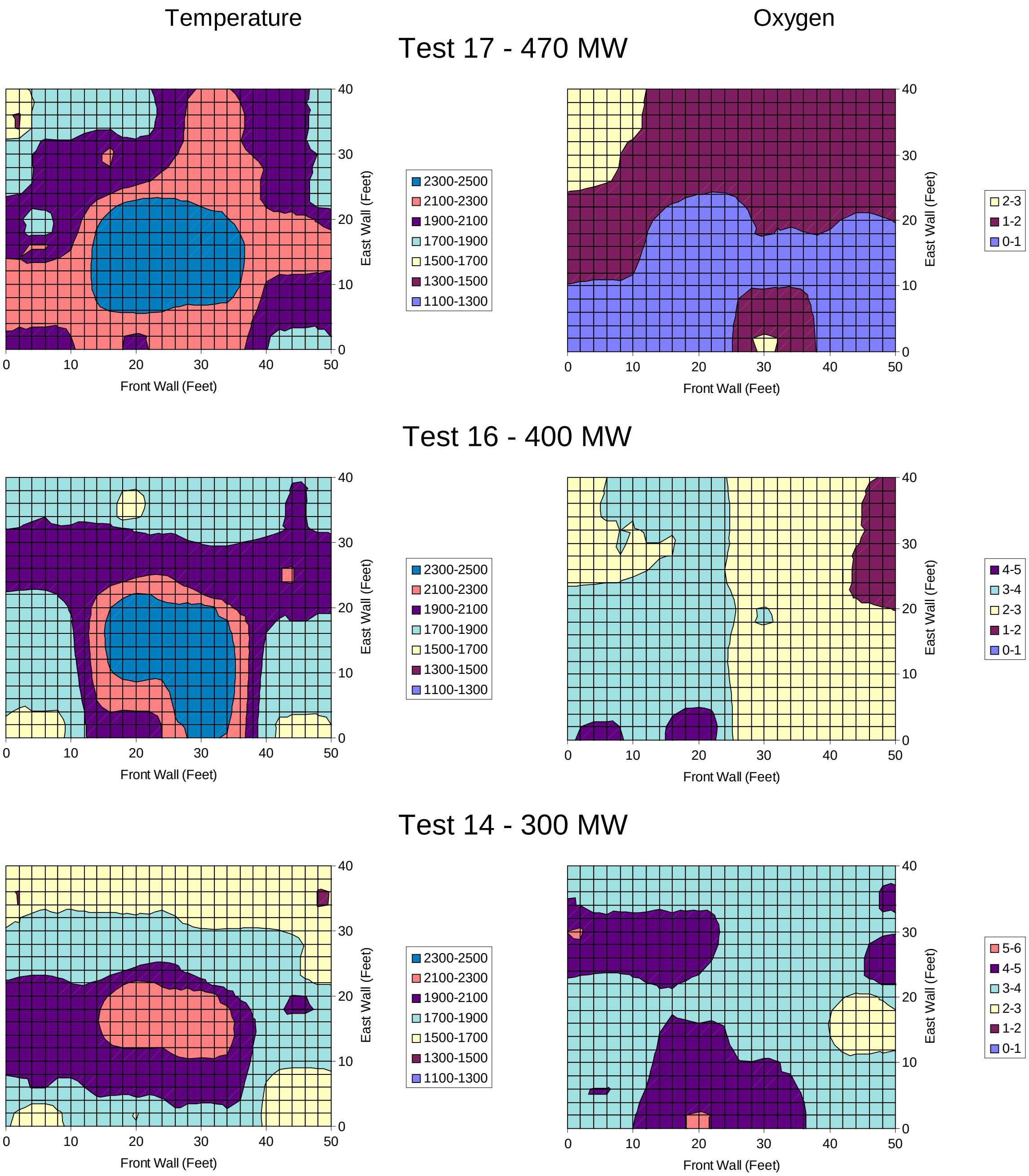


Figure 6-12 Baseline / Furnace Exit Temperatures and Oxygen

6.1.2.4 Coal Analyses

During each of the six days of the performance tests, samples were obtained of coal entering the active mills, fly ash exiting the furnace (east and west sides), and bottom ash collected in the furnace ash pit. The coal samples were analyzed for proximate and ultimate composition, calorific value, grindability, and ash fusion properties. Table 6-4 presents the summary of the results of these analyses. Individual analyses can be found in Appendix A. The coal is representative of high volatile, eastern bituminous coal, particularly, Central Appalachian coal [Combustion 1991]. Also, these analyses show that the coal properties remained very consistent over the duration of the testing.

Table 6-4 Baseline / Average Coal Analysis (As Received)

Test	Average	Standard Deviation	Variance
Ultimate Analysis			
H_2O %	4.28	0.63	0.39
C %	72.4	0.7	0.5
H %	4.69	0.07	0.01
N %	1.43	0.07	0
Cl %	0.031	0.004	0
S %	1.72	0.11	0.01
Ash %	9.8	0.4	0.1
O %	5.65	0.48	0.23
Total %	100.02	0.01	0
HHV Btu/lb	12921	117	13708
VM %	33.5	0.5	0.3
FC %	52.7	0.9	0.9

6.1.2.5 Solid Emissions

Ash particulate emissions were measured both for total mass emission rate and for characteristic properties related to ash collection within an ESP. The specific measurements and analyses that were performed included: (1) total mass emissions, (2) particle size, (3) chemical composition, and (4) fly ash resistivity. These measurements were made in the flue gas stream immediately after the air heater (Figure 5-17), just prior to entry to the ESP. The following paragraphs describe the results from these measurements.

Mass Loading, Gas Flow, and Temperature

Total mass emissions reflect both a fraction of the total coal ash injected into the furnace (l00 percent minus the ash which drops into the furnace bottom hopper or the economizer hopper), plus most, if not all, of any unburned carbon leaving the flame zone. Table 6-5 presents the results of the Method 17 tests performed at each load level. For all tests the sampling rate was within 3.6 percent of isokinetic. The results shown for each load level represent the average of three replicate tests. For all tests, the data was remarkably consistent. Within each replicate series, the standard deviation of mass loading was less than 3 percent of the mean value. At the 480 MW (nominal) load, the two test series conducted 5 days apart resulted in measured mass flux within 8 percent of their mean value. The within test repeatability as well as the test repeatability was surprisingly good during this performance test series.

Table 6-5 Baseline / Summary of Solid Mass Emissions Tests

Test No.	Load MW	O_2 %	Loading gr/dscf	Gas Flow ACFM	Loading %	Carbon %	LOI %
12	480	3.0	2.63	1,229,667	3.69	4.9	5.4
17	480	2.5	2.42	1,252,000	3.39	4.5	4.9
16	400	3.7	2.23	1,112,667	3.13	4.1	4.7
14	300	4.7	2.60	913,333	3.64	1.9	2.3

Ash Resistivity

One of the most important properties affecting ESP performance is the resistivity of the ash particles. Ash resistivity is a measure of the ash's ability to retain an electrical charge that allows it to migrate and adhere to the ESP plates. Twenty-six measurements of ash resistivity were made using in situ probes employing two different measurement techniques, i.e., spark and voltage/current (V-I) methods. The results of those measurements are presented in Figure 6-13. Further details can be found in Appendix A.

All measurement techniques indicate that during low boiler load (400 and 300 MW), the electrical operating conditions and resulting performance of the ESP would not be limited by resistivity of the collected dust layer. In the absence of other problems, resistivity values below 2 x $l0^{10}$ ohm-cm should not have any effect on ESP electrical conditions. During two days of high load tests (Tests 12 and 13), the spark resistivity data disagreed with the low indications by the other techniques by indicating mid-$l0^{11}$ ohm-cm values. On the last day of high load tests (Test 17), all techniques once again agreed that resistivity was low. No changes in dust chemistry, flue gas composition, or temperature can be identified which should have produced a real change in resistivity. Therefore, the spark data for Tests l2 and l3 are believed to have been invalidated by carbon in the ash, to which this measurement is particularly susceptible. As discussed previously, the LOI and carbon values were the highest measured for the test program during the period that spark measurement problems were encountered (see Appendix A).

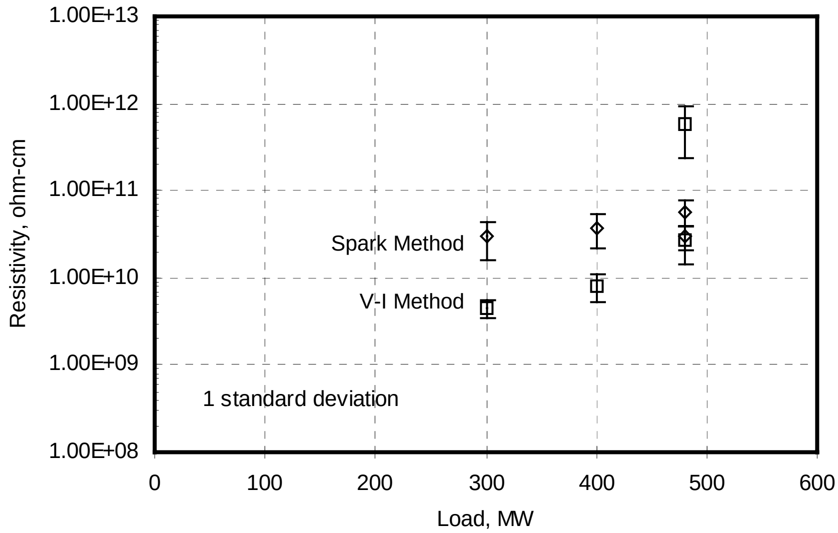


Figure 6-13 Baseline / In Situ Ash Resistivity Results

Chemical Composition

The performance of an electrostatic precipitator is heavily influenced by the electrical resistivity of the fly ash entering the device. The resistivity of the ash is established by the chemical composition of the ash, the amount of SO_3 adsorbed on the ash, the amount of water vapor in the flue gas, and the temperature of the ash and flue gas. The chemical composition of fly ash collected in the ESP hoppers was determined from proportional blends of samples taken from the hoppers. Each field was assumed to have equal collection efficiency and the individual hopper samples were proportionally combined to match the predicted amount of fly ash collected in each hopper. The blended sample should closely represent the inlet ash composition.

The ESP hopper samples (east and west composites separately) were analyzed for mineral composition (Figure 6-14). The samples showed only minor variations in the mineral constituents known to significantly affect the electrical properties of the precipitator. Tables A-9 and A-10 provide additional information and allows a comparison of carbon and LOI between the economizer exit (Method 17) and the ESP hopper chemical analysis. The good agreement between the ESP hopper and Method 17 LOI values (with the exception of one spurious ESP sample) and between the Method 17 LOI and carbon analyses indicate that the small portion of ash passing through the ESP is not due to high carbon or LOI content. Also it appears that carbon constitutes roughly 90 percent of the material driven off in the LOI analysis.

As mentioned above, the carbon and LOI data are useful primarily to establish a reference level to which post-retrofit results can be compared. The precise relation of carbon or LOI content of ash on ESP performance is not well understood and no current algorithms can confidently predict the effect of changes in their values on ESP performance. This data was collected not only to establish the relationship between the ESP and Method 17 results but also to archive for future use if an algorithm is developed in the future.

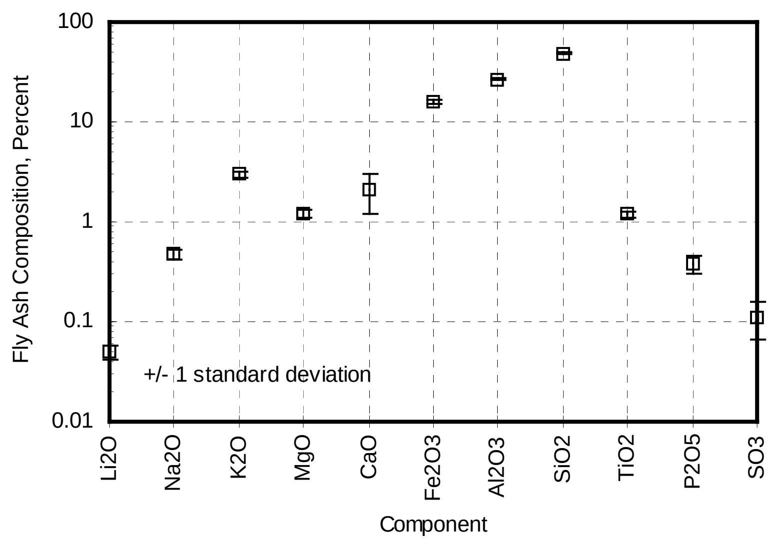


Figure 6-14 Baseline / Fly Ash Composition

<u>Flue Gas SO_3 Concentration</u>

The concentrations of SO_2 and SO_3 (as separate species) were measured in both the east and west ducts at the air heater exit for every load condition. Figure 6-15, adapted from Table A-11, presents the results of the tests for the three load points. From the table some important observations related to the SO_2 can be made. First, the SO_2 value is relatively constant for any particular test sequence (e.g., Test 12 or 13), which indicates good repeatability. Second, the SO_2 varies considerably between sampling periods (e.g., between Tests 12 and 13). This variation was also exhibited in the ECEM data collected during these test periods. This phenomenon could potentially be the result of short-time variations in fuel sulfur content or by the non-uniform distribution of various sulfur-level coal batches to the east or west side burner groups. The measured SO_2 variations, however, do not correlate with the average coal sulfur values (average of 2 to 5 samples) for the corresponding test day. Because the coal samples were acquired during the testing period from the mill inlet chutes, very little time delay should have passed between coal sampling and combustion in the furnace (via, a few minutes at most). The exact reason for the variation is unexplained at this time, however, the fact that SO_2 measurements were made at only a single point in one duct tends to favor the conclusion that SO_2 was stratified within the boiler.

Some of the east duct temperatures at the sample points were below the dew point of sulfuric acid at 300 and 400 MW, i.e., Tests 14 and 18, respectively, (see Table A-11). At temperatures below the dew point, the measured SO_3 concentration is invalid since some SO_3 could precipitate out as sulfuric acid. This precipitation is evident by comparing Tests 14 and 18 with 15 and 16. It can be seen that the latter test group (above the dew point) is higher than the former test group.

The data for Tests 14 and 18 are therefore invalid. From the data above for the test with the gas temperature above the dew point temperature, the SO_3 concentrations varies inversely with load as a result of the higher excess O_2 and lower furnace temperatures associated with low load operation.

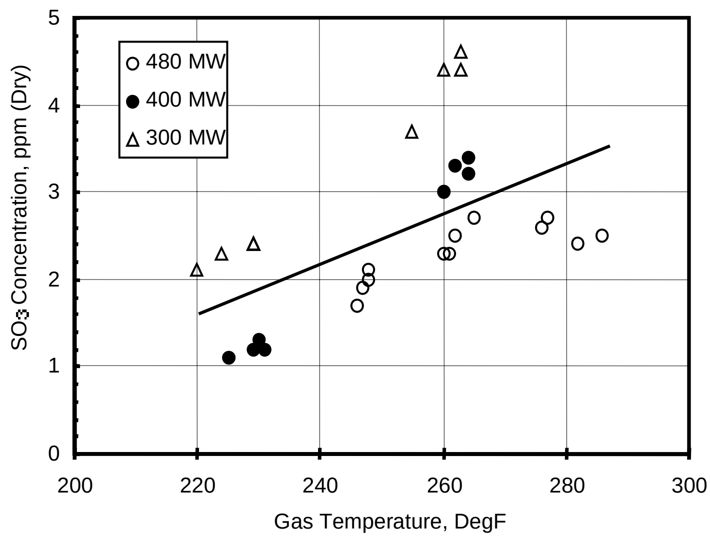


Figure 6-15 Baseline / SO_3 Concentration

<u>Particle Size</u>

The particle size distribution of ash exiting the secondary air heaters was determined using a cascade impactor. Six samples were obtained for each test condition. Figure 6-16 shows the particle size distributions for all test conditions as the total percentage of cumulative mass (4-axis comprising particles smaller than the aerodynamic diameter D_{50}). The vertical bars visible to the upper right show the 90 percent confidence level for the mass values determined at the indicated particle diameter while the symbols show the average of the replicate samples for each load. For most of the data, the 90 percent confidence interval is smaller than the plotting symbols. For large particle sizes, the confidence band is exaggerated because of the exponential scale. The confidence interval for these points is still in the one percent range.

The very close overlapping of all of the data indicates both excellent replication of tests under common conditions and also the relatively minor effect of load on the ash particle size distribution. From Figure 6-16 the mass-median diameter is about l8 microns for all tests. The geometric standard deviation (assuming log-normal distribution) is 2.3 microns for all data. These results compare closely with EPRI data base predictions of l6 micron, 3.4 standard deviations [DuBard 1987]. The slightly larger median size of the present baseline tests is conducive to a slightly better than average ESP performance.

The derivative of cumulative mass with respect to diameter is presented in Figure 6-17. This type of presentation emphasizes the predominant concentration of mass vs. particle size. This format facilitates comparison of test data from subsequent phases of the program with this

Phase 1 data and will highlight any significant changes in particle size distribution and potential effects on ESP performance deriving from the low NOx retrofits.

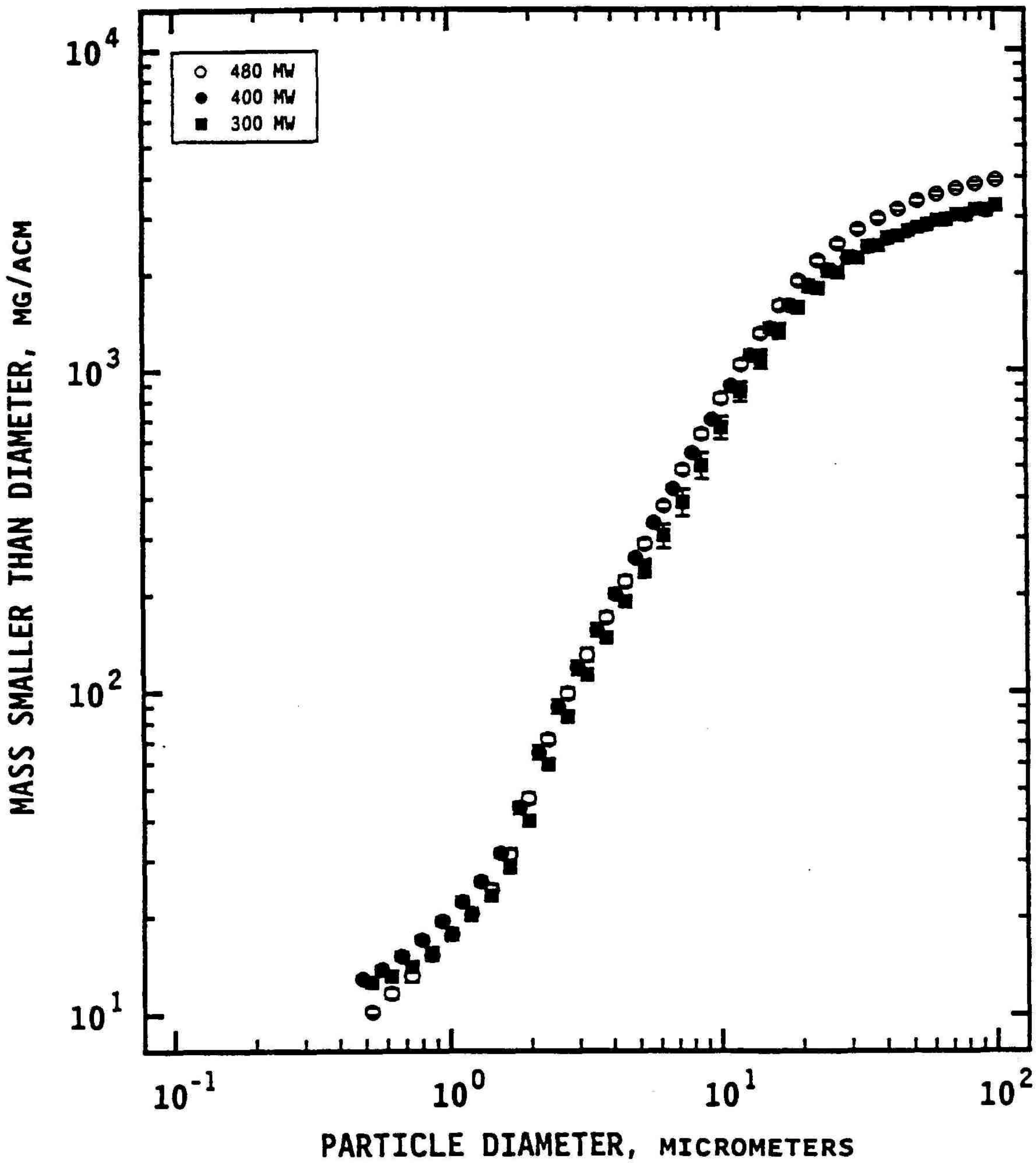


Figure 6-16 Baseline / Fly Ash Particle Size Distribution

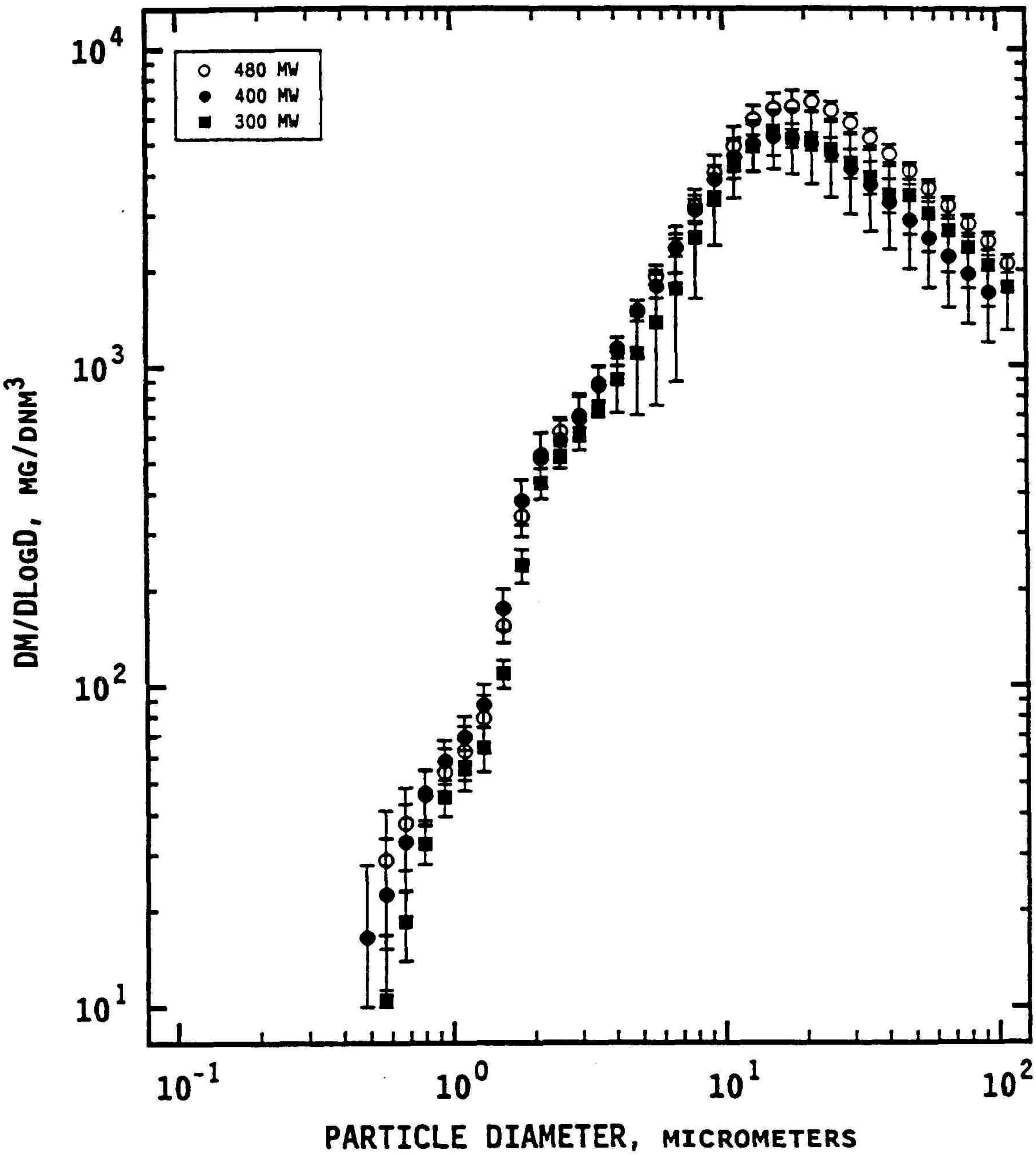


Figure 6-17 Baseline / Fly Ash Differential Mass Size Distribution

6.1.3 Verification Tests

Subsequent to the long-term testing, testing was performed to ascertain if significant changes in the NOx characteristics had occurred during the long-term test period. These tests were performed during the week of April 4, 1990. During this period, eleven tests were performed at high loads. During the verification test period, system load requirements was such that it was not possible to obtain low load data (300 and 185 MW loads). Figures 6-18 and 19 presents a summary of the data taken during the verification testing. Five tests were performed at the 480 MW load point and six were performed at the 400 MW load point. Based on the results of these tests, it was evident that the NOx characteristics of the unit were the same at the beginning and end of the test period.

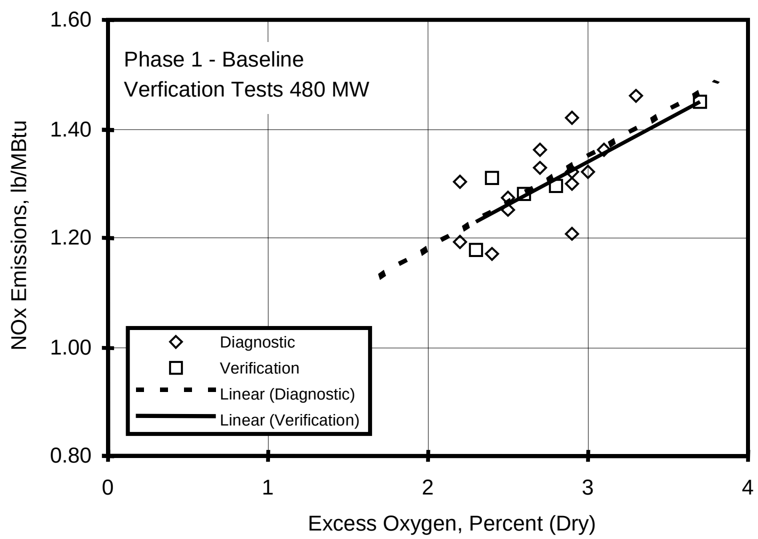


Figure 6-18 Baseline / Verification Tests / 480 MW

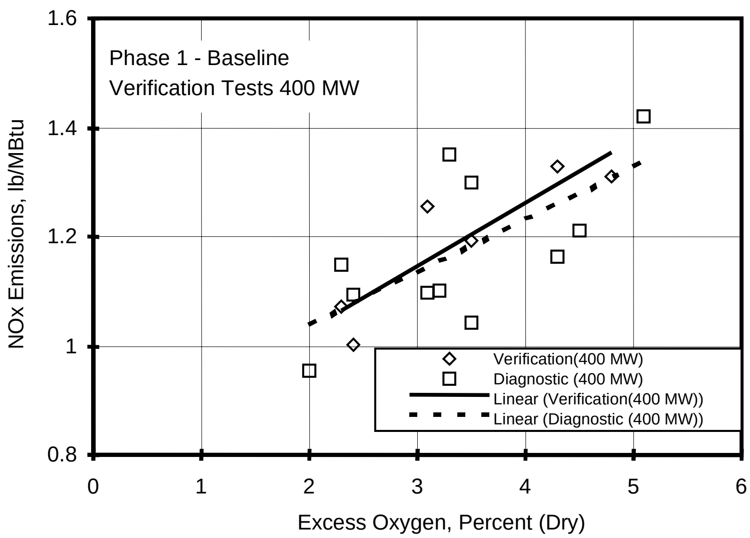


Figure 6-19 Baseline / Verification Tests / 400 MW

6.2 Long-Term Testing

The long-term testing consisted of continuous measurement of operating parameters while the unit was under system load dispatch. This long-term testing was performed from December 26, 1989 through April 5, 1990. During this period, three unit outages were experienced. In addition, the ECEM experienced difficulties that resulted in lost days of data capture. The data capture was, however, sufficient to fully characterize the unit both from an engineering perspective as well as a regulatory point of view.

The focus of the analysis of this long-term data was:

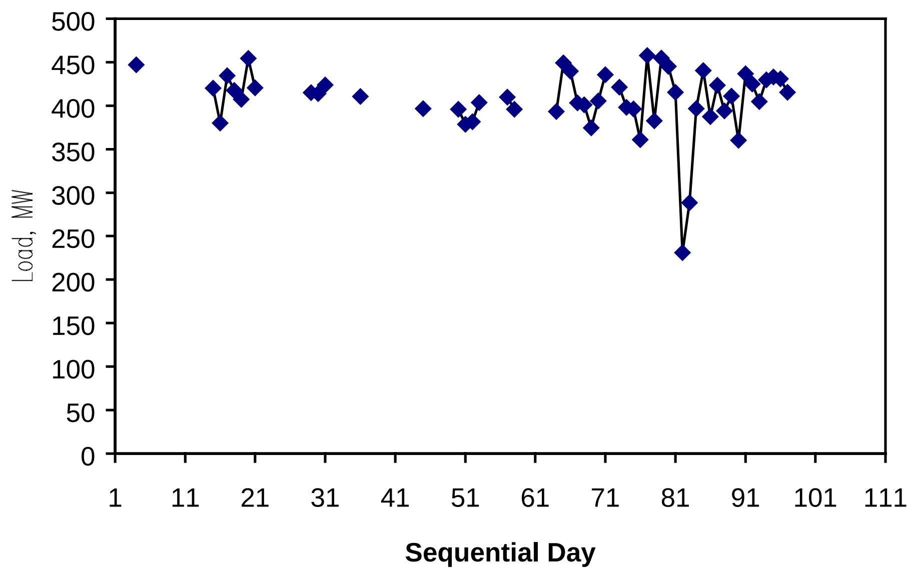
- Characterization of the daily load and NOx emissions and the within day statistics,
- Characterization of the NOx emissions as a function of load, excess O_2, and mill patterns,
- Determination of the thirty-day rolling average NOx, and
- Determination of the achievable NOx emission level based upon valid days of ECEM data.

The following paragraphs describe the results of these analyses.

6.2.1 Unit Operating Characteristics

As was mentioned earlier, difficulties were experienced with the ECEM system. The system experienced difficulties that resulted in loss of data capture during the first month of the long-term test effort. From the data for the long-term testing (December 1989 through April 1990), the daily averages of load and NOx were determined and are shown in Figure 6-20. This daily average data was determined using the EPA criteria for valid data explained earlier. Only days with at least 18 hours of data are presented in this figure. It is evident that during the long-term testing that the average daily load was in excess of 400 MW. Only two days were at a load below 300 MW. For this period, the daily average NOx emissions ranged from approximately 1.3 to 0.8 lb/MBtu.

One method of characterizing the boiler operating characteristics during the long-term testing is to examine the within-day variation of load and NOx. This was accomplished by segregating the data by hour of the day, i.e., 0100, 0200,…2400. For these segregated data, the mean load and NOx were computed. In addition, the hourly values representing the lower 5 percent and upper 95 percent of all values were determined Figure 6-21 illustrates the daily trend for load and NOx emissions over the entire long-term test period. The figure illustrates that the unit was operated as a base loaded unit for most of the day (on average 16 hours were near the maximum continuous load of 480 MW). It is evident from these figures that NOx generally increases with increasing load.



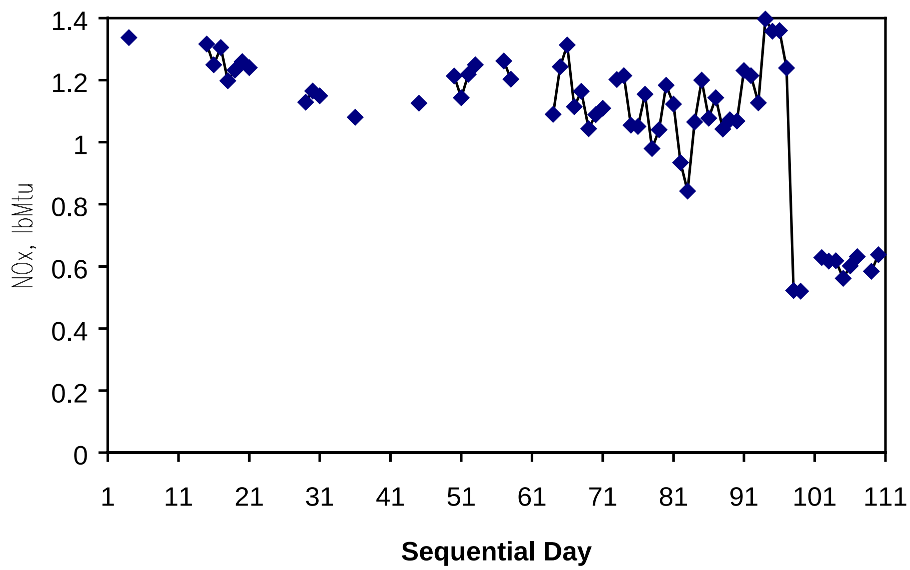


Figure 6-20 Baseline / Long-Term Daily Average Characteristics

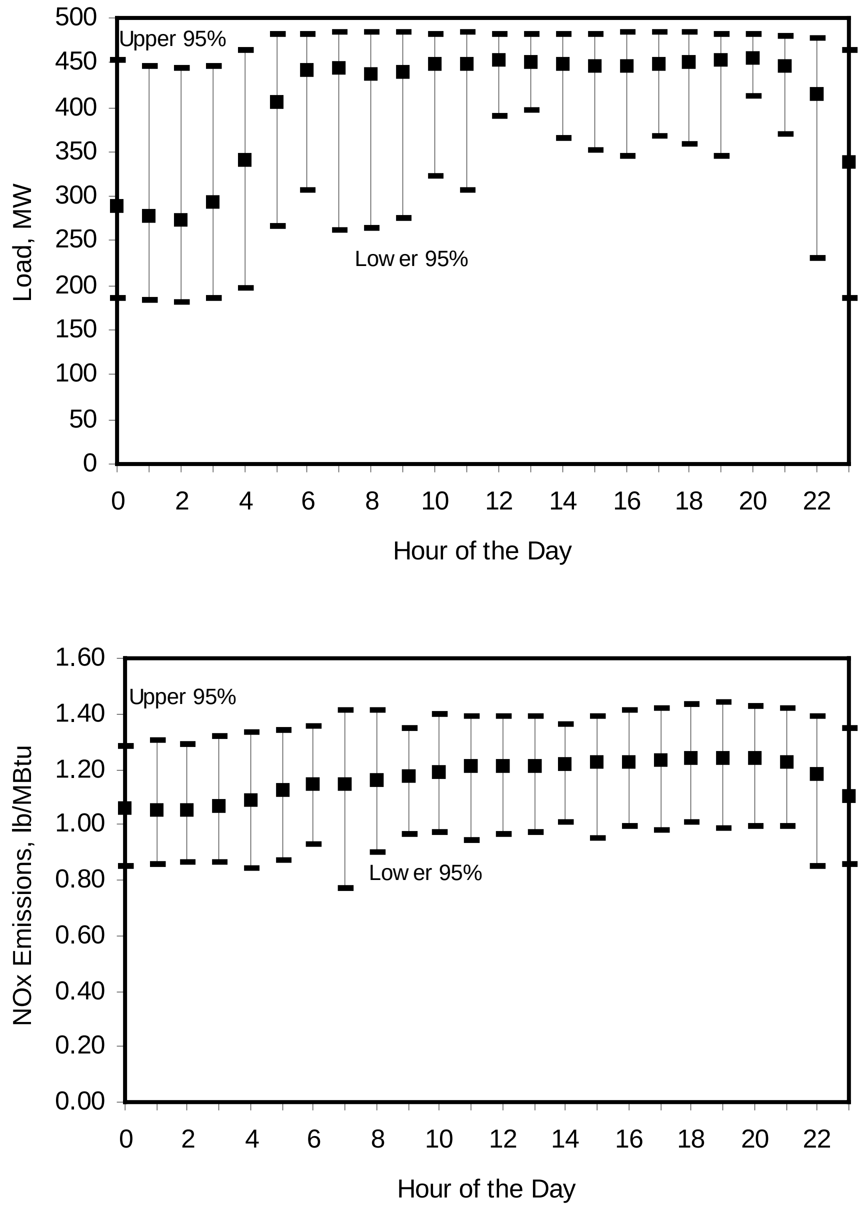


Figure 6-21 Baseline / Long-Term Daily Average Characteristics

6.2.2 Parametric Test Results

For the parametric analyses, all of the valid five-minute data was used. The 5-minute and hourly average emission data was analyzed to determine the overall relationship between NOx and load and the effect of boiler O_2 on NOx emissions for certain frequently used mill patterns. Because this data was obtained while the unit was under normal load dispatch, they represent the long-term NOx characteristics.

The NOx versus load relationship was determined by first segregating the 5-minute average load data into 20 MW wide load ranges. Figure 6-22 through 6-25 illustrates the load trend for NOx, excess oxygen, SOx, and CO, respectively. The population for each load range, as well as the mean lower five percentile and upper ninety-five percentile are shown for both load and NOx emission values. For loads above 200 MW, the trend is slightly increasing NOx with increasing load. In this load range the mean NOx varied by approximately 30 percent ranging from 0.95 to 1.27 lb/MBtu. The slight rise in NOx emissions at loads below 200 MW were most likely the result of higher excess oxygen levels used at these reduced loads.

The effect of operating O_2 on NOx emissions for certain mill patterns was examined for load ranges that corresponded to those tested during the short-term test portion of the Phase 1 test effort. These ranges were the 180-190, 290-300, 390-400 and 470-480 MW ranges. All of the valid five-minute data for these load ranges was used to assess the impact of excess oxygen level for the most commonly used mill patterns. In order to determine the most frequently used patterns, the frequency distribution of the mills in service (MOOS) pattern was determined. Table 6-6 presents the frequency distribution for this data. It is apparent that there are certain preferred mill patterns for each load range. These patterns are dictated by the operational requirements of the unit, e.g., slag minimization, steam temperature control.

Prior to commencing the short-term testing effort, discussions with plant operations indicated that certain mill patterns were the preferred patterns. These patterns were then used during the diagnostic and performance testing with the intent of comparing the results with the same patterns during long-term testing. The mill patterns used during the short-term test effort were the B-, E- and B&E-MOOS at loads below 400 MW. Referring to Table 6-6, it is evident that these patterns were not the most prevalent during this long-term test effort.

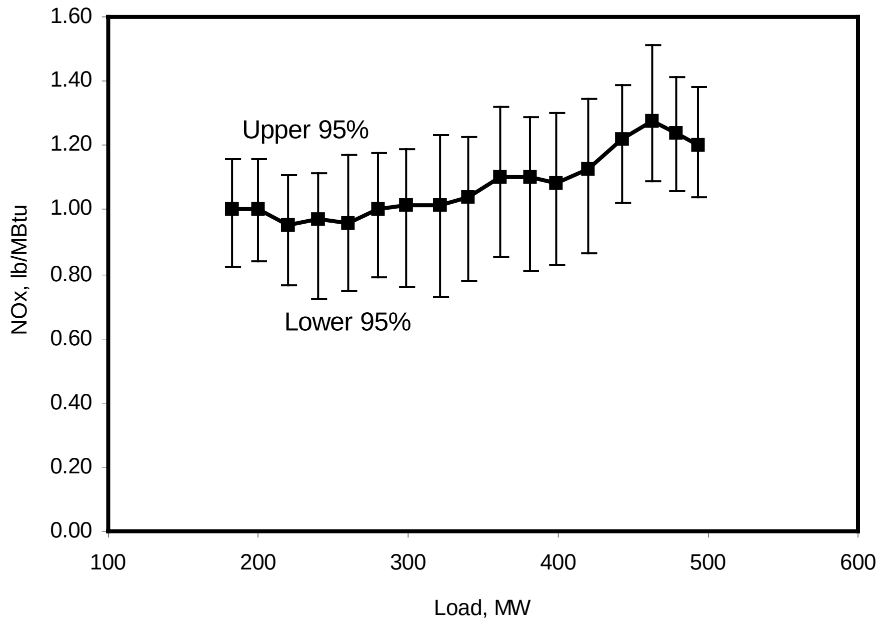


Figure 6-22 Baseline / Long-Term / NOx vs. Load Characteristic

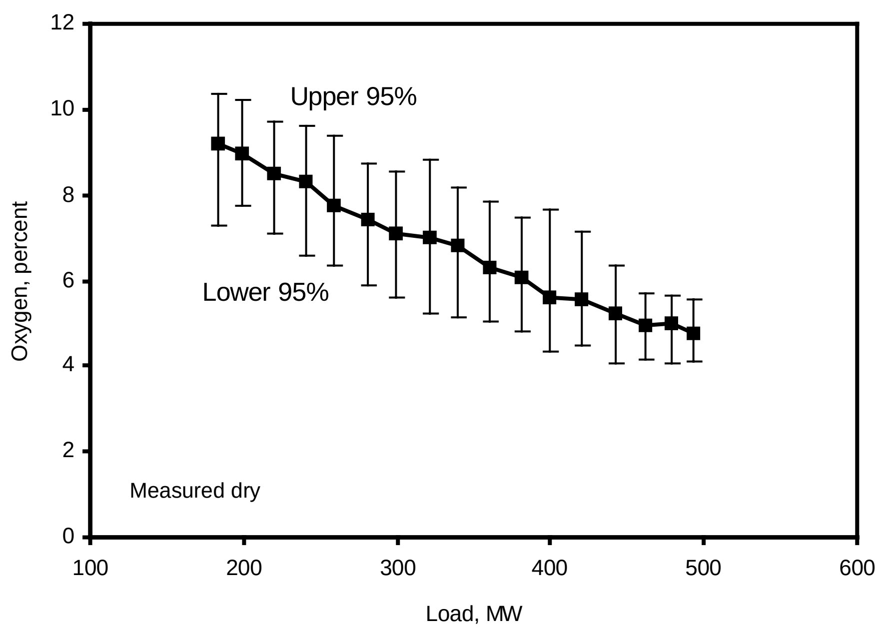


Figure 6-23 Baseline / Long-Term / Stack O_2 vs. Load Characteristic

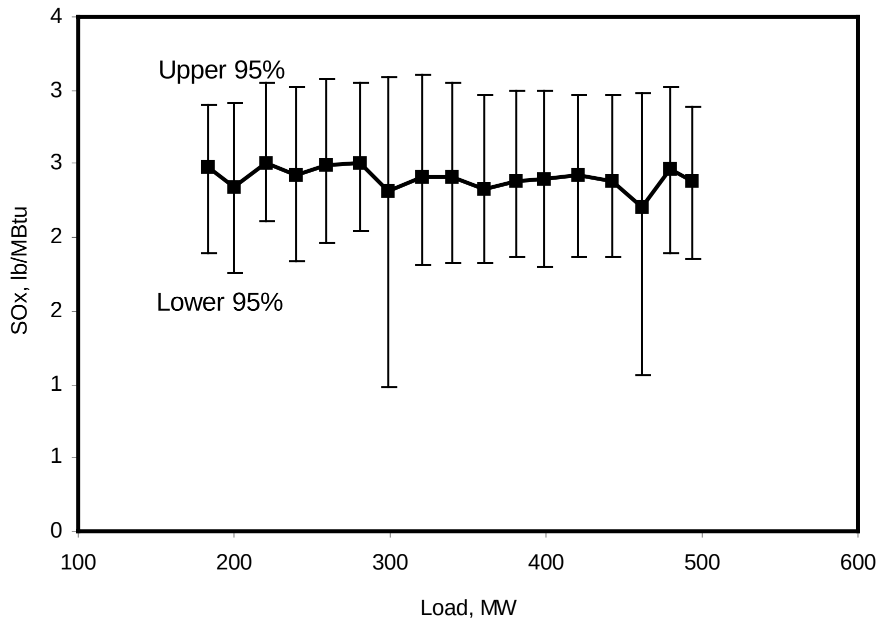


Figure 6-24 Baseline / Long-Term / SOx vs. Load Characteristic

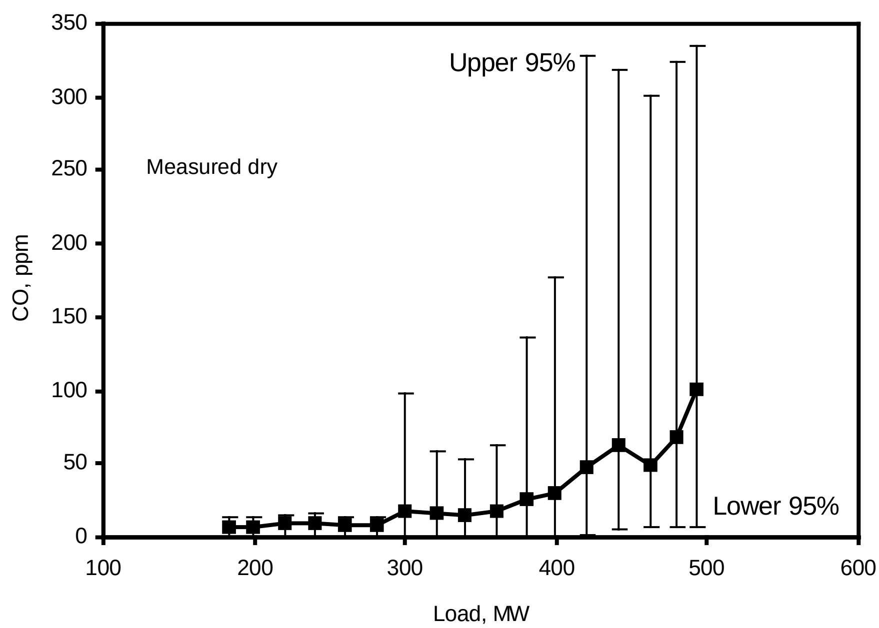


Figure 6-25 Baseline / Long-Term / CO vs. Load Characteristic

Table 6-6 Baseline / Mill Pattern Use Frequency

Load Cell MW	MOOS	Sample Size	Load MW	Average NOx lb/MBtu	Average O_2 %
180-190	B,C,E	359	185.5	1.01	9.01
	D,F	39	185.4	0.90	9.05
	B,C,F	24	184.6	0.90	8.79
	D,E	4	184.2	1.04	9.50
290-300 E	E	145	294.7	1.08	7.08
	None	51	295.1	0.96	7.03
	F	39	295.0	0.84	6.83
	B,C,E	9	294.9	1.03	7.25
390-400	None	257	394.4	1.13	5.72
	B,C	116	395.1	1.02	4.80
	E	56	396.0	1.16	5.45
	F	26	396.0	0.97	7.49
470-480	None	2580	475.4	1.22	4.91

6.2.3 Thirty-day Rolling Averages

The NSPS Subpart Da and Db standards are based upon compliance on a thirty-day rolling average. While this unit is not required to comply with these standards, it is of some value to evaluate the data for Phase 1 on a thirty-day rolling average basis and later compare it to the results from subsequent phases. Thirty-day rolling average load, NOx, and O_2 were computed using the valid hourly data as defined by the EPA criteria explained earlier. These thirty-day rolling averages are shown in Figure 6-26 for the 92 (63 rolling averages) valid days (by EPA criteria) of data.

It should be pointed out that the thirty-day rolling average results shown in Figure 6-26 are only representative of the load scenario that was experienced by the unit during this long-term test period. During other periods when the load might be significantly different, the rolling averages would be expected to be somewhat different. For this particular period, it can be seen that there was a slight decrease in the daily load as the testing progressed as evidenced by the declining thirty day rolling average load. Because it was shown in the previous paragraphs that the NOx increases with increasing load, it is obvious that the rolling average NOx emissions should decrease as the testing progressed.

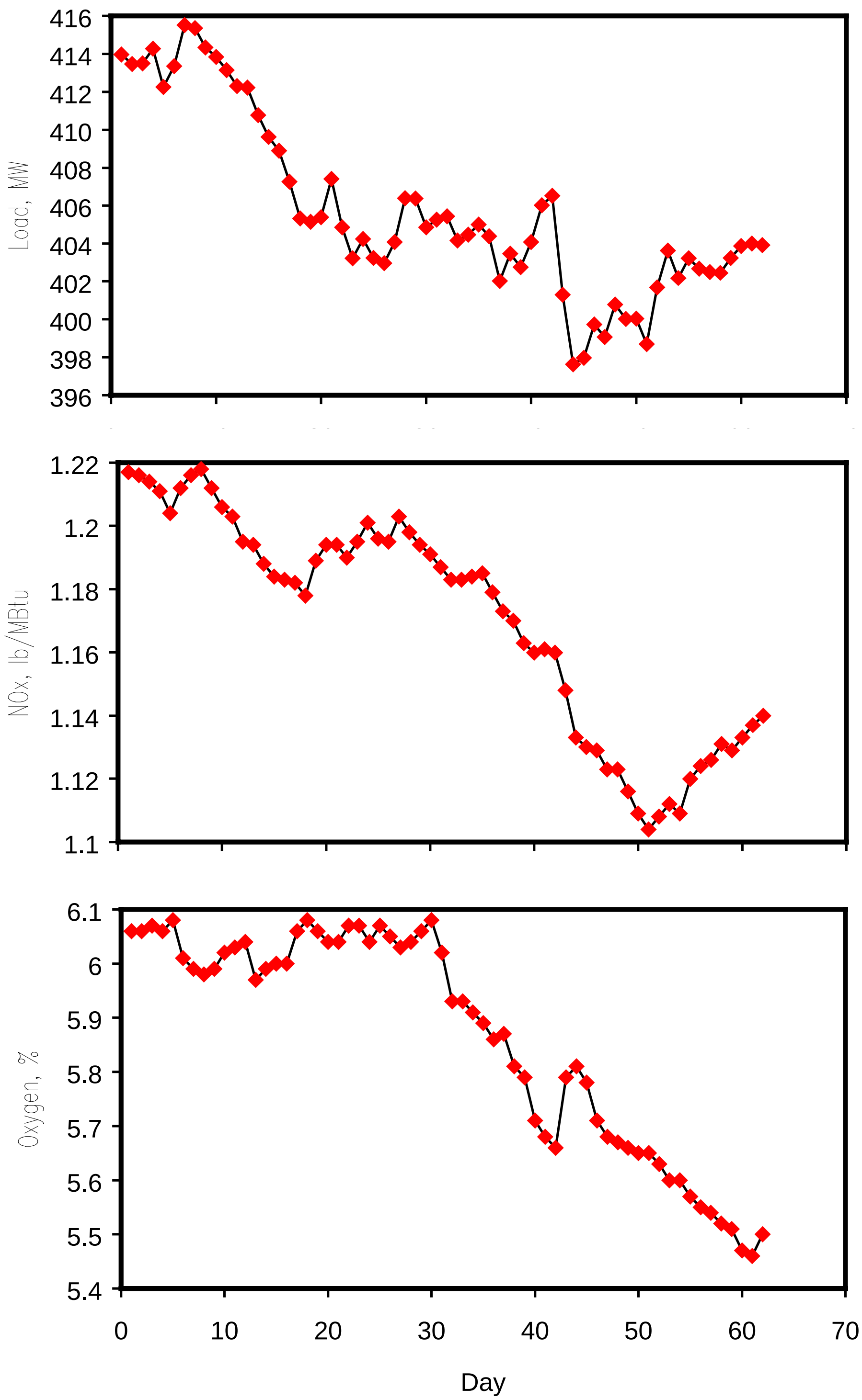


Figure 6-26 Baseline / Long-Term 30 Day Rolling Average

6.2.4 Achievable Emission Characterization

EPA in their rule making process establishes an achievable emission level based upon daily average data samples obtained from CEMs. Most of this data is from NSPS Subpart Da units or units that used CEMs to obtain data during demonstration programs. The achievable NOx emission limit on a 30-day rolling average basis is determined using the descriptive statistics for 24-hour average NOx emissions. As discussed earlier, the SAS UNIVARIATE and AUTOREG procedures are used to determine the descriptive statistics for the 24-hour average NOx emissions data. The results of the UNIVARIATE and AUTOREG analyses of the 24-hour average NOx emissions are presented in Table 6-7. The UNIVARIATE analysis indicated that the daily emissions were normally distributed. The AUTOREG analysis also indicated that the day-to-day fluctuations in NOx emissions followed a simple first order auto-regressive model.

Table 6-7 Baseline / Descriptive Statistics For Daily Average NOx Emissions

Statistic	
Number of Daily Values	52
Average Emissions (lb/MBtu)	1.166
Standard Deviation (lb/MBtu)	0.111
Distribution	Normal
First Order Auto-correlation (r)	0.539
Standard Error of Auto-correlation	0.119

Based upon the EPA criteria, the achievable NOx emission limit should only be exceeded, on average, once per 10 years on a 30-day rolling average basis. The achievable emission depends on the long-term mean, variability, and auto-correlation level shown in Table 6-7.

Table 6-8 provides the achievable emission level. The achievable NOx emission limits shown in this table, are computed for two conditions - no auto-correlation ($r = 0$) and the estimated value of 0.539. The assumption in this table is that the unit will be operated in the future under similar load dispatching as that during the baseline test phase. As explained above under other load scenarios, the thirty-day rolling averages would be different and therefore the achievable emission level would also be different.

It should be noted that the mean, variability, and auto-correlation levels given in Table 6-8 are only estimates of the true mean, variability, and auto-correlation. There is an uncertainty level implicit in the estimates of each of these statistical parameters. The uncertainty level for the first order auto-correlation is given in Table 6-9. The uncertainty level in the mean is dependent on the variability. The estimated variability is, to some extent, dependent on the level of auto-correlation. Thus, uncertainty levels in the descriptive statistics are linked.

As noted earlier, methods are available to incorporate uncertainty levels into the determination of the achievable NOx emission limit. Because the achievable emission limit is dependent upon the auto-correlation level, factoring in the uncertainties in the statistical parameters results in various levels of the achievable emission limit. Table 6-9 provides estimates of the achievable emission limit for the various levels of uncertainty. The achievable emission level can vary from 1.18 to 1.55 lb/MBtu depending upon the degree of auto-correlation and the level of uncertainty.

Table 6-8 Baseline / 30 Day Rolling Average Achievable NOx Emission Limit

Auto-correlation	Achievable Emission Limit (lb/MBtu)
r = 0	1.18
r = 0.539	1.24

Table 6-9 Baseline / Effect of Uncertainty Level on NOx Emission Limit

Assumed Uncertainty Level	Achievable Limit (lb/MBtu)
None, r = 0	1.18
None, r = 0.539	1.24
Uncertainty level in mean, variability, r = 0.539	1.39
Uncertainty level in mean, variability, r = 0.739 (upper 95% [one tail])	1.55

6.2.5 Comparison of Short- and Long-Term NOx Emissions

As mentioned previously, the unit configurations tested during the short-term test effort were, unfortunately, not the most frequent configurations used during the long-term test period. A comparison of the NOx emissions obtained during the short- and long-term testing is shown in Figure 6-27. The data shown includes all of the configurations normally experienced during the period from late December 1989 through early April 1990. From the comparison, it is evident that the data obtained during the short-term testing was in a few cases outside the confidence interval (upper 95 percent to lower 95 percent) of the long-term data. This was likely the result of testing being conducted at higher excess O_2 levels than that observed during the long-term data collection period. However, for the most part, the measured data falls within the band observed during long-term, and it is evident that the short- and long-term trends agree between the two data sets.

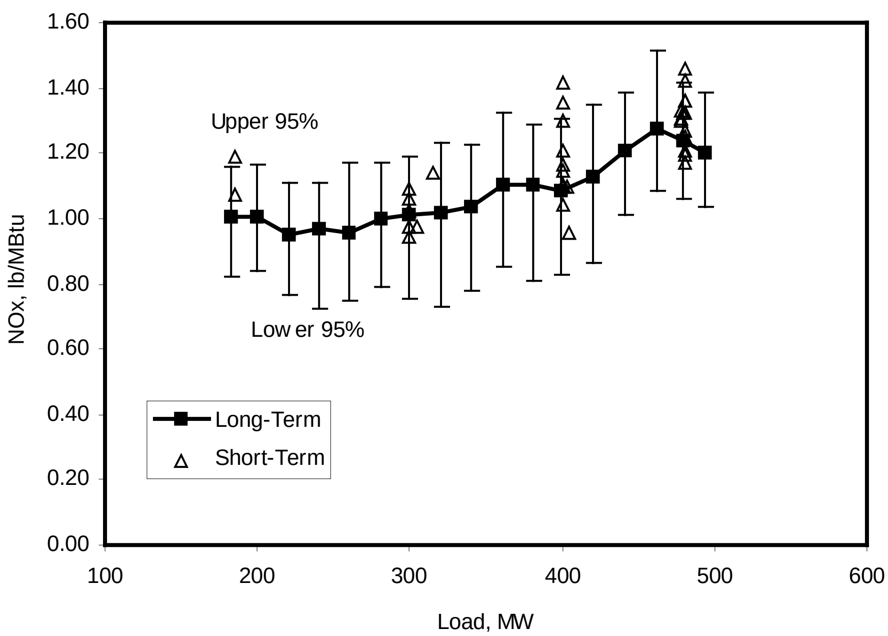


Figure 6-27 Baseline / Comparison of Short- and Long-Term NOx Emissions

6.2.6 Process Data

In addition to the emissions data described earlier, process data was collected to provide insight to changes in the boiler performance and turbine cycle heat rate as a result of the installation of the tested technologies. The most important of these variables are discussed below.

Steam Temperatures and Spray Flows

Main steam and hot reheat temperatures, both as measured at the turbine, are shown in Figures 6-28 and 6-29, respectively.

Superheat temperature is controlled at two different locations in the boiler. First, the division wall inlet superheat temperature is controlled by the use of both the left and right hand lower spray valves. The division wall inlet temperature setpoint is 20°F above the drum saturation temperature. The final superheat temperature is controlled by the use of both the left and right hand upper spray values. The pass damper control is the primary means for controlling reheat outlet temperature. Nominally, the final superheat and reheat temperatures are controlled to 1000°F. If these temperatures are below the set point, there are significant heat rate penalties. If there are high temperature excursions, there is the potential for damage to either the boiler or turbine. The control of these variables is made more difficult as the result of the inherent limitations of the pneumatic boiler control system in use during this test phase.

As shown, main steam temperature averaged from approximately 950°F at low load to near 1000°F at full load. As shown in Figures 6-30 and 6-31, there was spray flow even when the main steam temperature was considerably below 1000°F. This flow could be the result of: (1) the superheat outlet temperature being controlled to set point (1000°F) and the temperature difference between boiler and turbine being the result of heat loss and pressure drops in the main steam line or (2) inaccuracies in the temperature measurement either at the turbine or boiler.

Reheat temperature averaged near 990°F from 160 MW to near 270 MW before dropping at intermediate loads. There was a slight recovery in reheat temperature as load increased.

Excess Oxygen Levels

In addition to the ECEM excess oxygen measurement, excess oxygen was also measured at the economizer and air heater outlet using in situ oxygen probes. The load characteristic for this data, along with the data obtained through the ECEM, is shown in Figures 6-32 through 6-37. Excess oxygen (Figures 6-32 and 6-33) as measured at the economizer outlet is used by the control system to maintain combustion stoichiometry at prescribed levels. Excess oxygen as measured at the air heater outlet is used for determination of air heater and boiler performance and not for control. In all figures, the reading obtained by the in situ instrumentation is well below that obtained by the ECEM. This difference is the result of:

- The ECEM is a dry reading whereas the in situ instrumentation provides excess oxygen on a wet basis.

- The ECEM samples flue gas considerably downstream of the in-situ monitors and thus there is potential for air in-leakage.

For Phase 1, the stack oxygen was, on average, a very good estimator for economizer oxygen when these factors are taken into consideration (Figure 6-35).

The air heater outlet oxygen characteristics are shown in Figures 6-36 and 6-37. As with the economizer inlet O_2 levels, the outlet levels tracked well with the ECEM reading.

Economizer Exit and Air Heater Exit Temperatures

The economizer exit and air heater exit gas temperatures are shown in Figures 6-38 through 6-41. As shown, full load economizer exit temperatures average approximately 725°F with the east side being nearly 30°F greater than the west side. The design at full load is near 710°F. As expected, the temperature dropped with decreasing load, averaging near 620°F at 250 MW. The design temperature at this load is near 590°F. The secondary air heater outlet temperature averaged approximately 300°F at full load -- the design value is near 282°F. As shown, the east side temperatures were less than the west side which is reflective of higher air leakage for this side.

Fly Ash LOI

An estimate for the fly ash LOI is shown in Figure 6-42. In that there was no on-line carbon-in-ash measurement during this phase, the carbon-in-ash measurement is based on the LOI as determined during the performance tests and the deviation between the stack O_2 during these tests and the long-term stack O_2 levels.

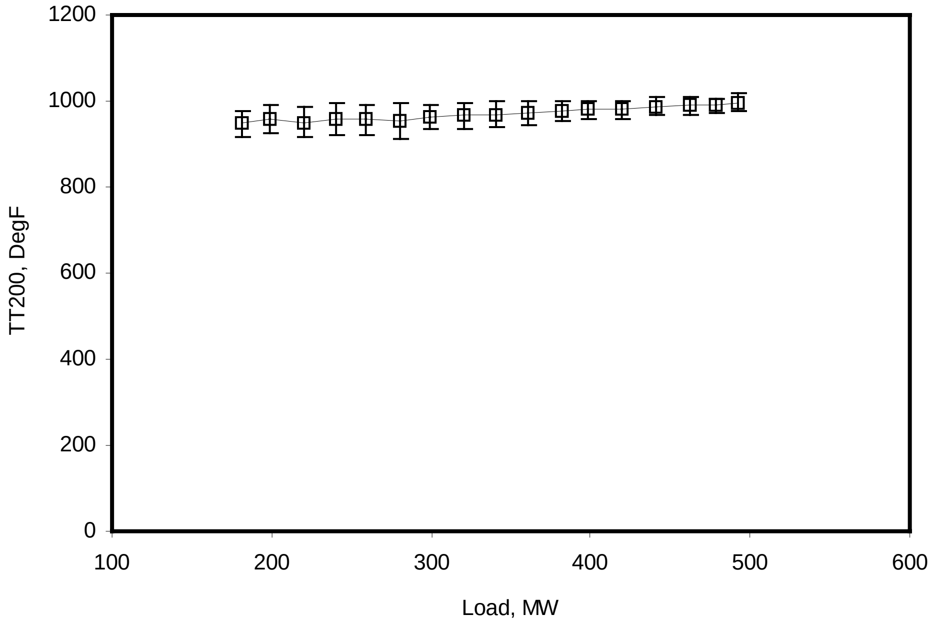


Figure 6-28 Baseline / Long-Term / Main Steam at Turbine Temperature

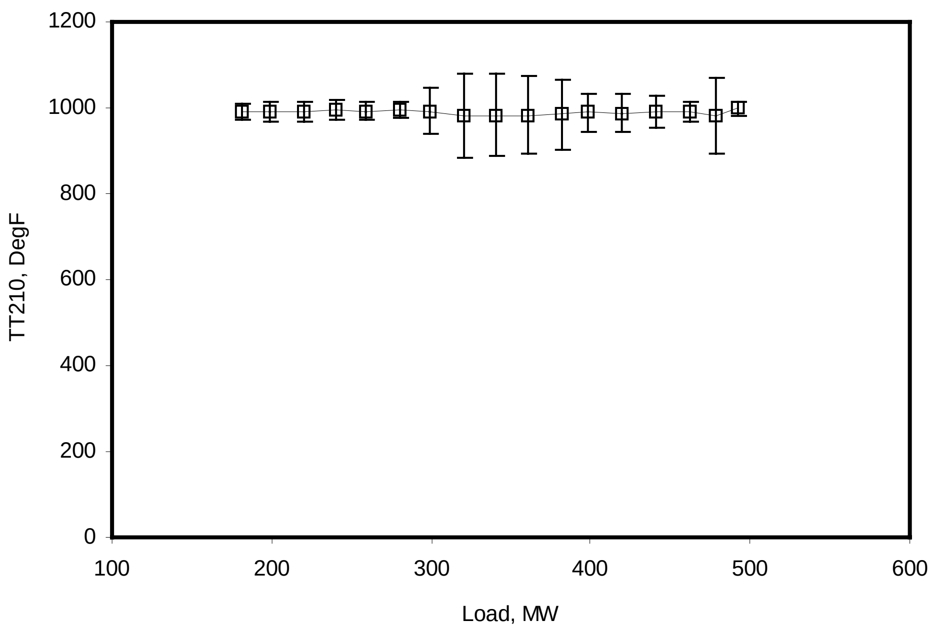


Figure 6-29 Baseline / Long-Term / Reheat Temperature

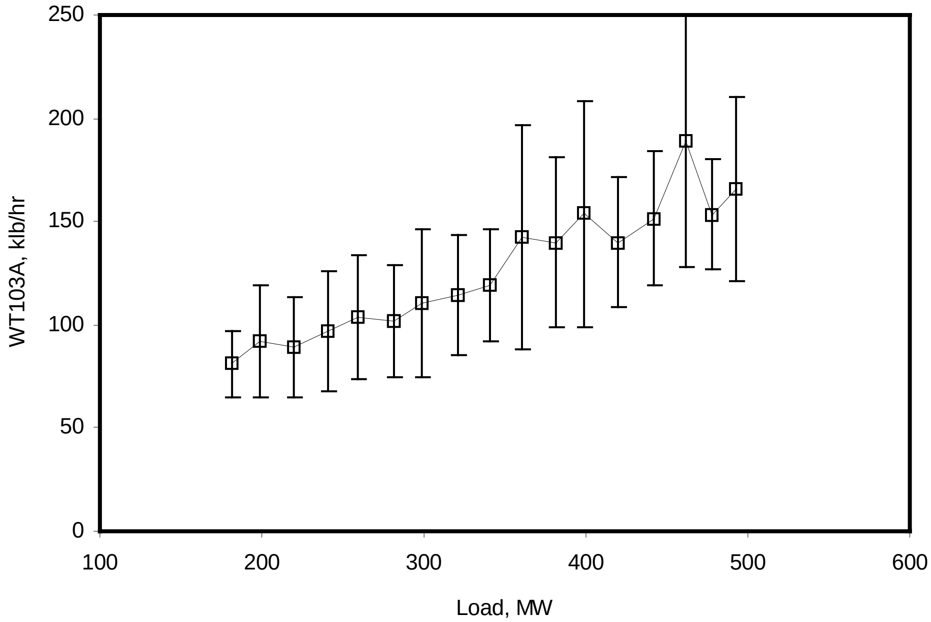


Figure 6-30 Baseline / Long-Term / Superheat Spray Flow Lower

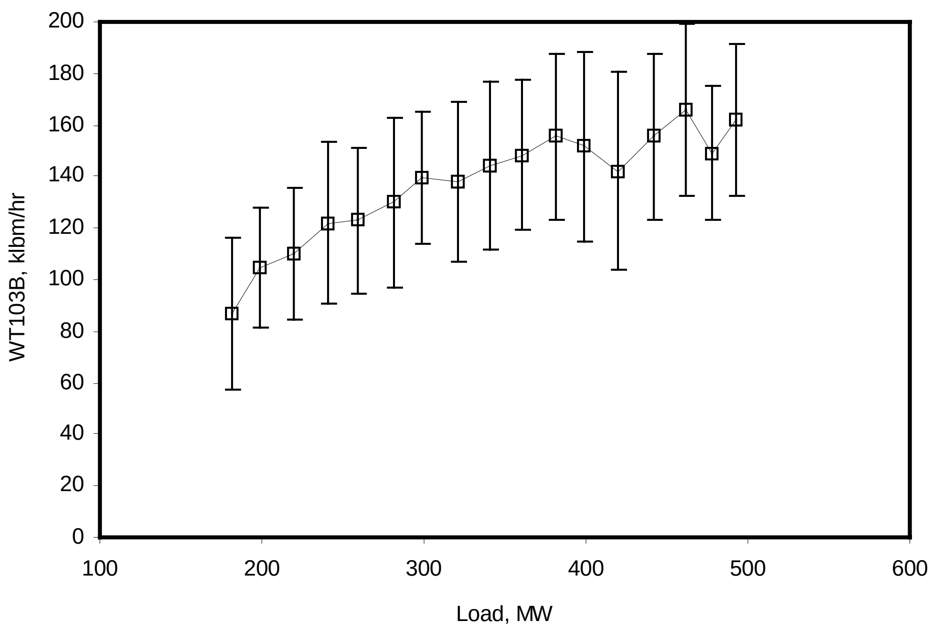


Figure 6-31 Baseline / Long-Term / Superheat Spray Flow Upper

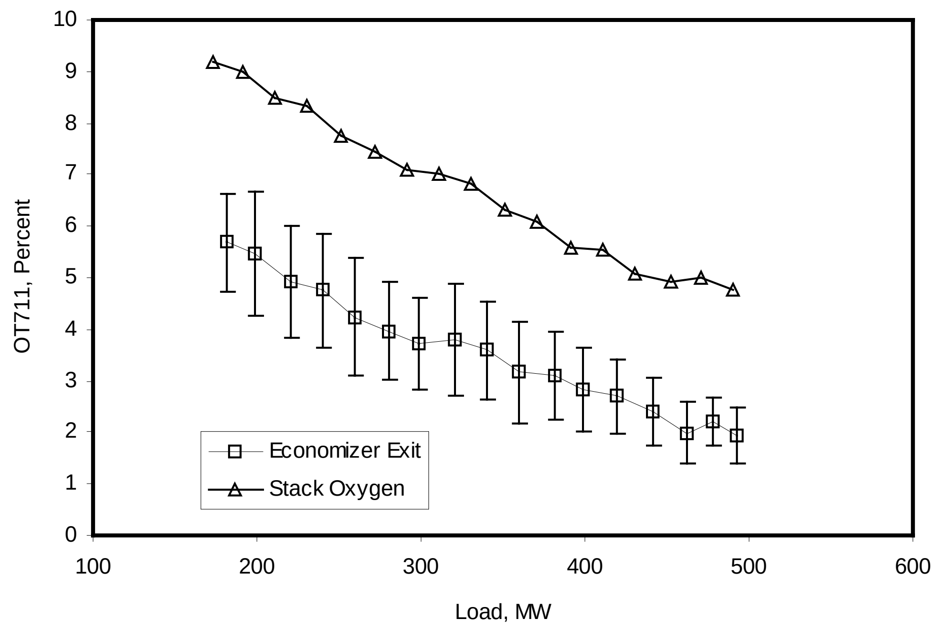


Figure 6-32 Baseline / Long-Term / Excess Oxygen at Economizer Outlet / East

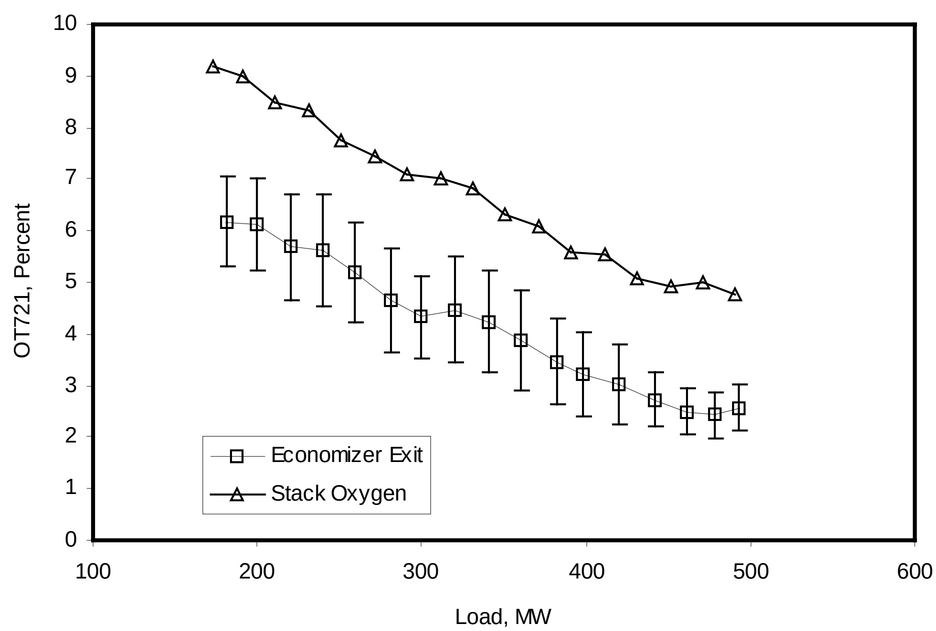


Figure 6-33 Baseline / Long-Term / Excess Oxygen at Economizer Outlet / West

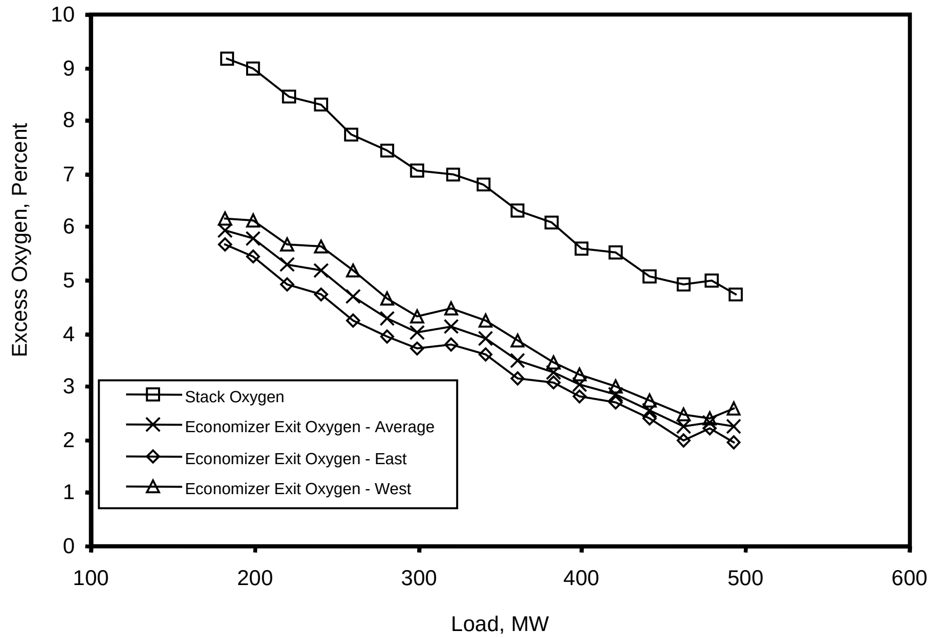


Figure 6-34 Baseline / Long-Term / Excess Oxygen at Economizer Outlet / Average

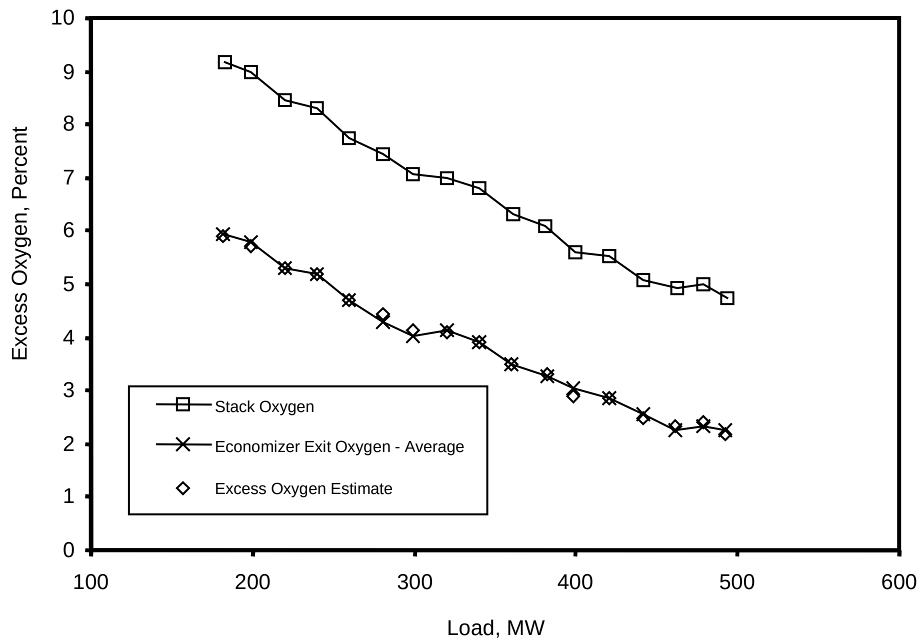


Figure 6-35 Baseline / Long-Term / Estimating Economizer Outlet Oxygen

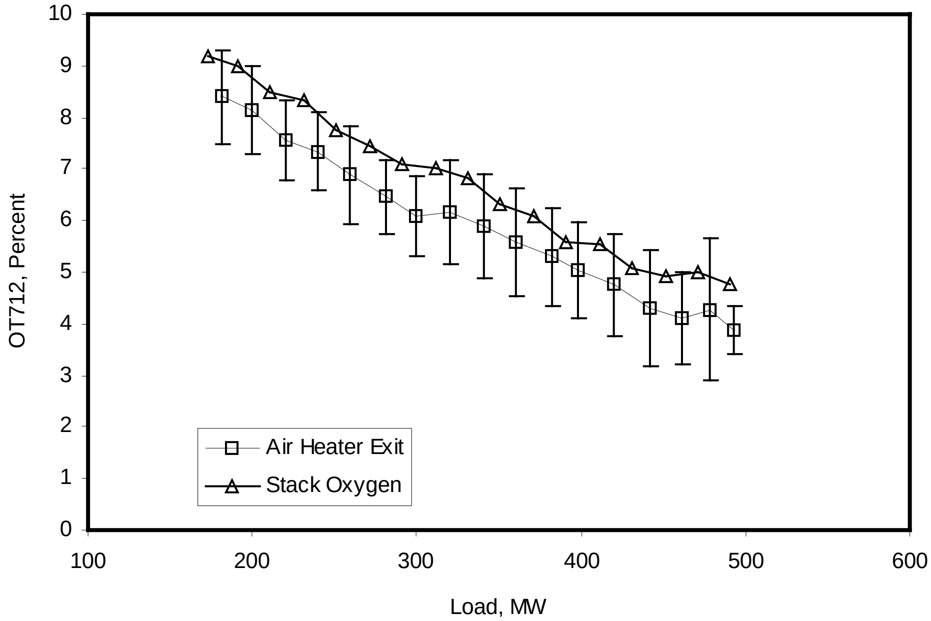


Figure 6-36 Baseline / Long-Term / Excess Oxygen at Air Heater Outlet / East

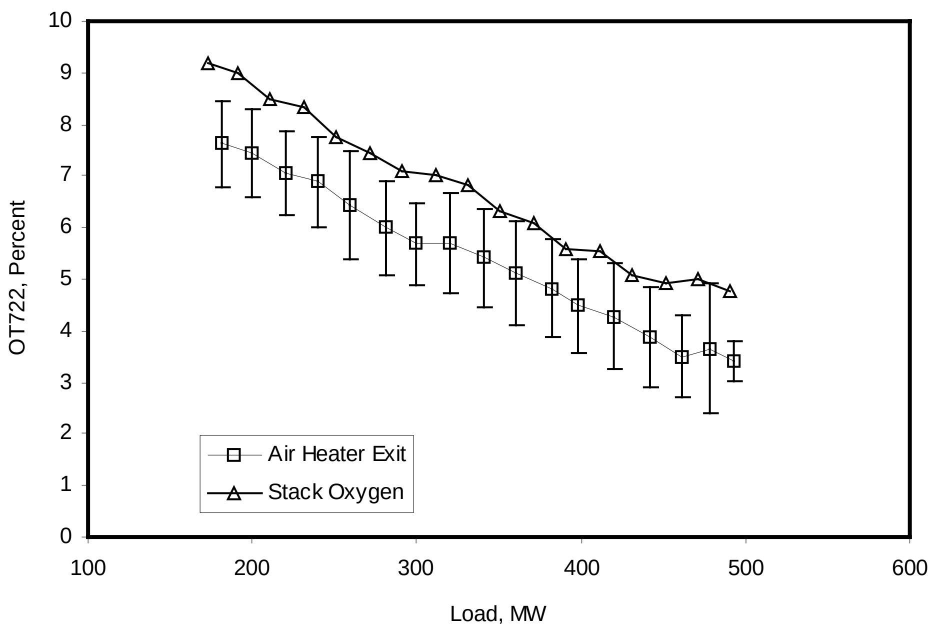


Figure 6-37 Baseline / Long-Term / Excess Oxygen at Air Heater Outlet / West

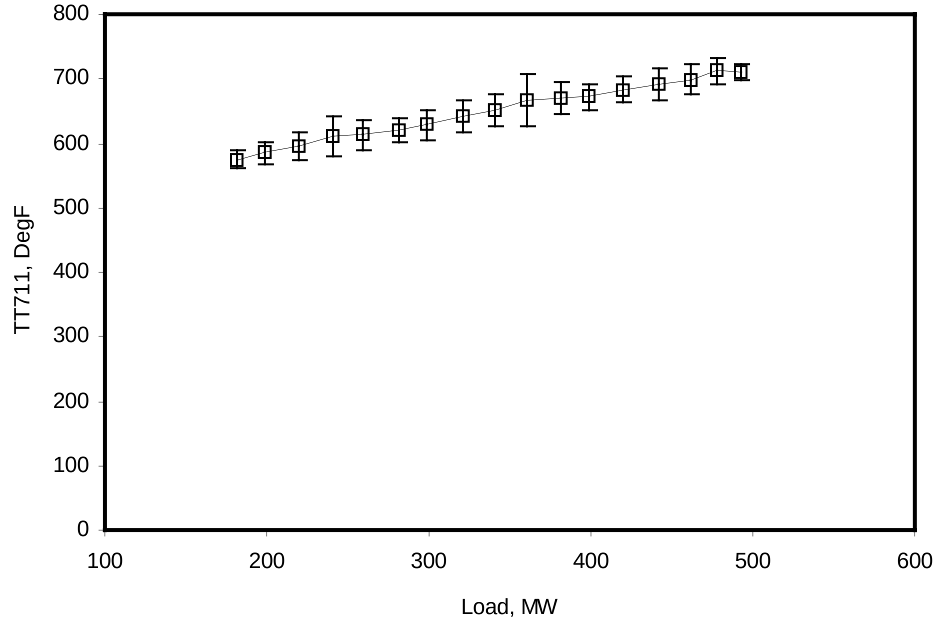


Figure 6-38 Baseline / Long-Term / Flue Gas Temperature at Air Heater Inlet / East

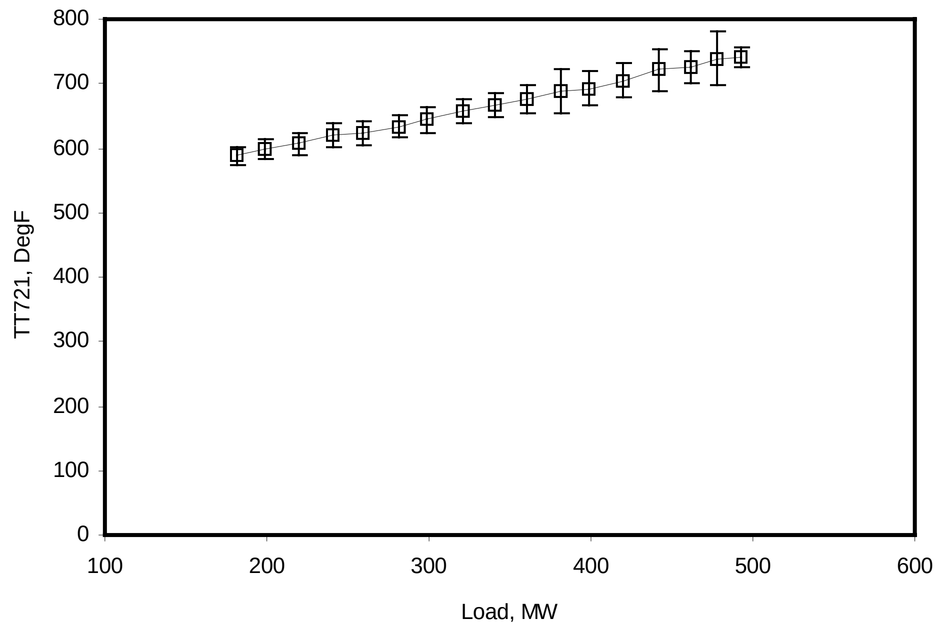


Figure 6-39 Baseline / Long-Term / Flue Gas Temperature at Air Heater Inlet / West

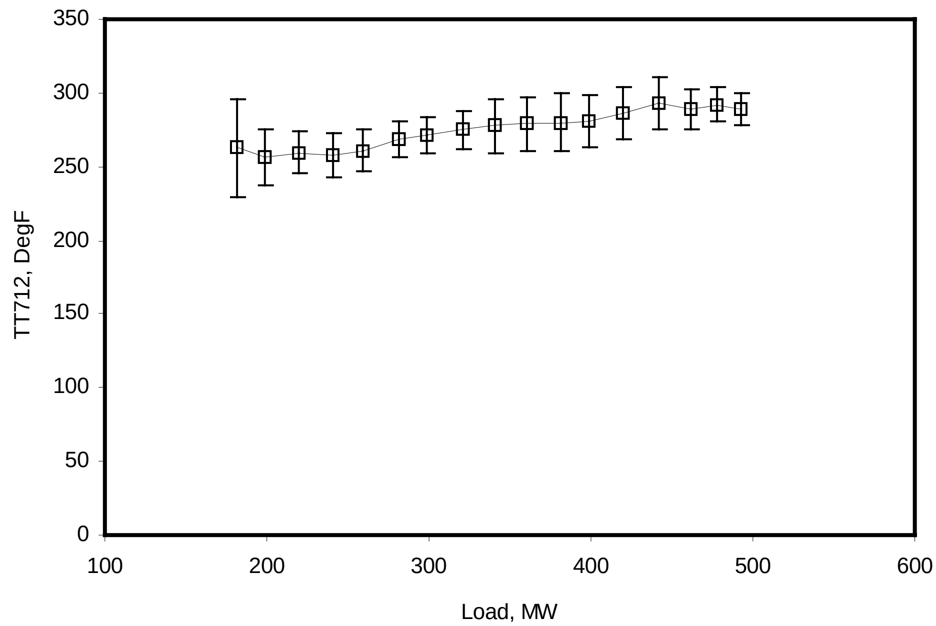


Figure 6-40 Baseline / Long-Term / Flue Gas Temperature at Air Heater Outlet / East

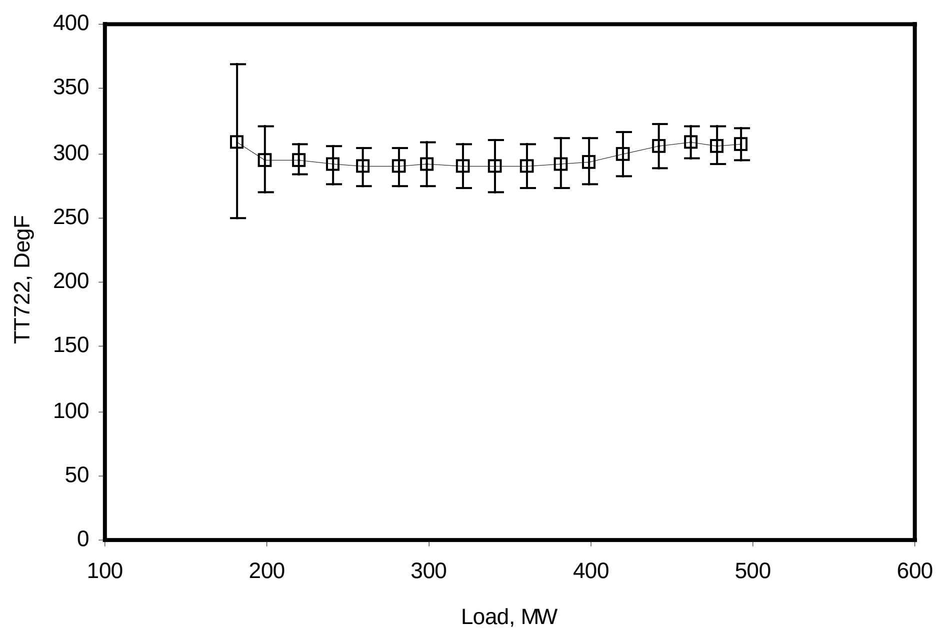


Figure 6-41 Baseline / Long-Term / Flue Gas Temperature at Air Heater Outlet / West

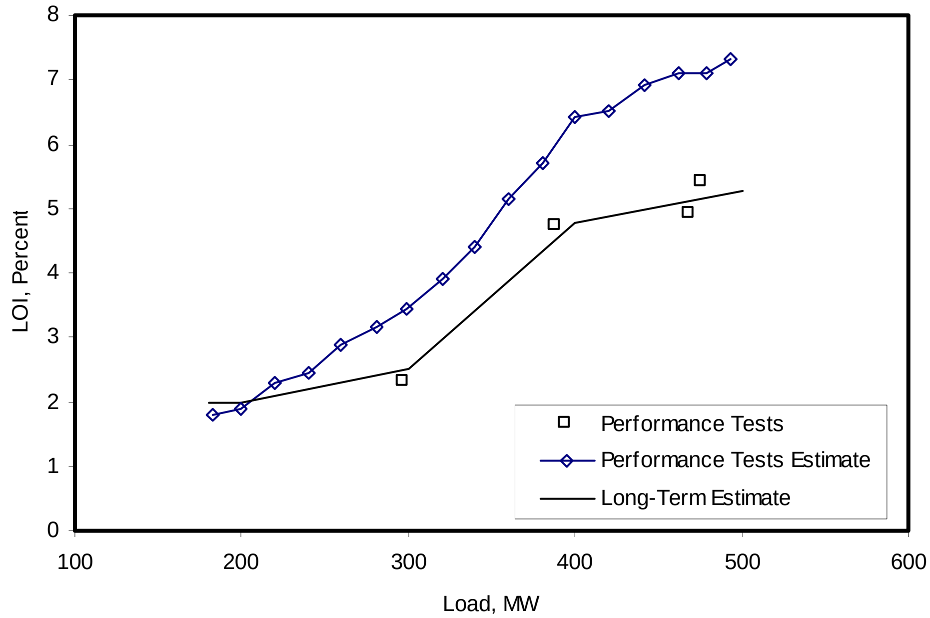


Figure 6-42 Baseline / Long-Term / LOI

7 PHASE 2 - AOFA TRIALS

7.1 Short-Term Test Results

The Phase 2 short-term characterization testing began on May 23, 1990 and was completed on August 16, 1990. A total of 82 diagnostic tests were conducted during this period. An additional 15 tests were performed during the verification test effort at the end of the Phase 2 effort. The short-term testing consisted of first performing diagnostic testing to establish the general NOx and operating trends followed by performance testing to establish the characteristics of the fuel/air feed systems and the solid and gaseous emissions for the most representative configuration. All tests during both the diagnostic and performance portions of the short-term test effort were conducted within the normal limits of operating parameters for the unit, with the exception of excess oxygen. Excess oxygen was exercised well above and below the normal operational range to the potential levels that might be encountered during transients in the long-term test phase. All major boiler components, as well as ancillary equipment, were in the normal "as-found" operating condition. The fuel burned throughout the Phase 2 short-term program was from the normal supply source and was handled according to common plant practice. Subsequent to the completion of the long-term testing, a short verification test effort was undertaken to determine whether significant changes had occurred during the long-term test effort.

The following paragraphs describe the diagnostic, performance, and verification testing performed during the Phase 2 effort.

7.1.1 Diagnostic Tests

The Phase 2 diagnostic effort consisted of characterizing emissions of the unit with AOFA system installed and operational. Eighty-two tests were performed at nominal loads of 300, 400 and 480 MW (Table 7-1). The diagnostic test were interrupted to accomplish the performance testing as a result of scheduling conflicts. Diagnostic testing was then completed after the performance testing was completed. The diagnostic testing began shortly after start-up testing of the AOFA system was completed by FWEC personnel. Generally, changes between test conditions during the diagnostic testing took from one to two hours to insure stable steam temperature and pressure conditions. Each test condition (load, excess oxygen and mill configuration) was held steady for a period of from one to three hours depending upon the type of test performed. During this period, data was collected from the control room, boiler operational data was recorded on the DAS, and economizer exit and air heater exit species and temperatures were recorded utilizing the sample distribution manifold. When sufficient time permitted, furnace backpass ash grab samples were collected from the manual ash samplers and coal samples were collected from the individual mills.

7.1.1.1 Unit Operating Condition

During the diagnostic tests, no unusual operating conditions were encountered that placed restrictions on the test effort. Figure 7-1 presents the "as-tested" conditions during the diagnostic portion of the testing. Over a sixteen-day period, 82 tests were conducted representing various excess oxygen, mill pattern, OFA, and load conditions. The recommended minimum O_2 levels shown in this figure are based upon results obtained during performance testing that indicated the necessity for increased O_2 levels to minimize LOI. Because historic load profiles indicated that a large majority of the operating time of the unit was above 400 MW, diagnostic testing was conducted more extensively at the higher load levels.

7.1.1.2 Gaseous Emissions

During both the diagnostic and performance test efforts, flue gas and boiler operating data were collected on the data acquisition system (DAS). The gas analysis system allowed measurement of NOx, CO, O_2, and total hydrocarbons (THC) from 48 probe locations within the flue gas stream both upstream and downstream of the air heater. Two basic types of tests were performed -- overall NOx characterization and economizer exit plane species distribution characterization. The overall NOx characterization tests were performed over a period of approximately one-hour and were used to obtain composite average specie concentrations from the individual probes in a duct sampled as a group. In general, the groups were: 1) A-side economizer outlet, 2) B-side economizer outlet, 3) A-side air heater outlet, and 4) B-side air heater outlet. The economizer exit plane species distribution characterizations were performed over a period of approximately two to three hours. These tests used data from the individual probe species concentrations in the A- and B-side economizer exit planes to establish the distribution of combustion products.

A summary of important emission and operating parameters recorded on the DAS during the diagnostic test effort can be found in Tables B-1 and B-2. These operating parameters provide information on the steaming conditions and the fuel supply configuration. The range of excess oxygen and resulting NOx emissions for the four nominal load levels tested during the diagnostic portion of the Phase 2 effort are shown in Figures 7-1 and 7-2. The conditions represented in these figures include excess oxygen variation, mill-out-of-service variation, mill biasing, etc. As shown in Table 7-1, tests were run at various OFA damper openings to establish an "optimum" setting over the load range taking into account both NOx reduction and effects on boiler operation (excess O_2 level vs. CO and carbon loss).

Figure 7-1 illustrates that the testing was performed over a range of excess oxygen levels that were both below and above the levels recommended for this unit. The solid curve represents the mean level of the data sample at each given load. During economic dispatch of the unit, excursions to these levels are frequently experienced during transient load conditions. To properly compare the short-term and long-term characteristics, the O_2 excursion testing during the short-term diagnostic effort was required.

Figure 7-2 is a summary of all of the NOx data obtained for all test configurations. These configurations represented the range of normal configurations that were believed to be the predominant modes of operation that might be experienced during the system load dispatch mode of operation during long-term testing. The data scatter results partially from the fact that different configurations are represented. The solid line in Figure 7-2 for loads from 280 to 490 MW represents the recommended excess O_2 operating level. It should be pointed out that with more NOx data, the slope of the trend might change slightly. It is also emphasized that analyses performed for data gathered during the long-term testing, where virtually thousands of data points were used for the characterization, provide a more statistically appropriate NOx trend.

Short-term characterization of the NOx emissions generally were made for trends determined on the same day of testing for a particular configuration. This is believed to eliminate, to some extent, the influence of the uncontrollable parameters. Figures 7-3 through 7-6 show the diagnostic test results for the four nominal loads tested -- 480, 450, 400, and 300 MW, respectively. The legend for each data point indicates the test day for the particular data point. Tests were run at various OFA damper openings in order to establish an "optimum" setting over the load range taking into account both NOx reduction and effects on boiler operation (excess O_2 level vs. CO and carbon loss).

Figure 7-3 shows the NOx data for the 480 MW test point at the nominal OFA damper setting of 50 percent open. At this load, the only mill pattern tested was all-mills-in-service (AMIS). Over the wide range of usable excess oxygen (2.0 to 4.5 percent), NOx increases with increasing excess oxygen and the rate of change is nearly constant at 0.089 lb/MBtu/percent. The data is labeled according to the test day in the program.

NOx data for the 450 MW test point is shown in Figure 7-4 for all mills in service and 50 percent OFA damper. The NOx increased at a rate of approximately 0.10 lb/MBtu/percent O_2 at this load over an excess oxygen excursion from 2.5 to 4.5 percent.

At 400 MW, the oxygen range could be tested over the O_2 excursion range from 3.0 to 4.5 percent (Figure 7-5). For the two mill patterns tested at this load point (E MOOS and AMIS), the NOx trends appeared to be similar to the variability at 480 MW load. On average, the NOx increased at a rate of approximately 0.11 lb/MBtu/percent O_2 over the excess oxygen excursion range.

Figure 7-6 shows the data for the single MOOS pattern (E MOOS) at the 300 MW test point. For this mill pattern, the NOx trend characteristic exhibited a nominal 0.14 lb/MBtu/percent O_2 slope.

Table 7-1 AOFA / Diagnostic Tests Conducted

TEST NO.	DATE	TEST CONDITIONS	LOAD (MW)	MOOS PATTERN	GUILLOTINE POSITION	OFA DAMPER (%)	DAS O2 DRY (%)
23-1	05/23/90	START-UP TEST	478	NONE	CLOSED	52	2.7
24-1	06/11/90	HI LOAD O2 VARIATION	482	NONE	CLOSED	52	2.1
24-2	06/11/90	"	480	NONE	CLOSED	52	3.0
25-1	06/12/90	HI LOAD NORMAL O2	475	NONE	CLOSED	52	2.8
25-2	06/12/90	"	478	NONE	CLOSED	52	2.5
25-3	06/12/90	HI LOAD 02 VARIATION	478	NONE	CLOSED	1	2.5
25-4	06/12/90	"	479	NONE	CLOSED	10	2.5
25-5	06/12/90	"	476	NONE	OPEN	25	2.4
25-6	06/12/90	"	475	NONE	OPEN	100	2.4
26-1	06/13/90	HI LOAD OFA VARIATION	478	NONE	OPEN	0	2.1
26-2	06/13/90	"	478	NONE	OPEN	50	2.8
27-1	06/15/90	HI LOAD REGISTER MALDISTR	480	NONE	OPEN	6	2.8
27-2	06/15/90	HI LOAD REGISTER ADJ	478	NONE	OPEN	6	5.3
27-3	06/15/90	"	478	NONE	OPEN	7	
27-4	06/16/90	"	475	NONE	OPEN	7	
27-5	06/16/90	"	476	NONE	OPEN	7	2.6
28-1	06/16/90	HI LOAD OFA VARIATION	482	NONE	OPEN	7	2.6
28-2	06/16/90	"	483	NONE	OPEN	20	2.7
28-3	06/16/90	"	483	NONE	OPEN	35	2.9
28-4	06/16/90	"	480	NONE	OPEN	51	2.8
28-5	06/16/90	HI LOAD OFA/O2 VARIATION	482	NONE	OPEN	51	2.3
29-1	06/17/90	MID LOAD OFA VARIATION	405	NONE	OPEN	5	4.4
29-2	06/17/90	"	405	NONE	OPEN	14	4.3
29-3	06/18/90	"	408	NONE	OPEN	30	4.2
29-4	06/18/90	"	408	NONE	OPEN	39	4.4
30-1	06/19/90	HI LOAD 02 VARIATION	487	NONE	OPEN	5	2.5
30-2	06/19/90	"	487	NONE	OPEN	4	2.7
30-3	06/19/90	HI LOAD 02/0FA VARIATION	487	NONE	OPEN	30	2.5
31-1	06/20/90	HI LOAD REGIST ADJ	482	NONE	OPEN	5	2.4
31-2	06/20/90	"	487	NONE	OPEN	5	2.0
31-3	06/20/90	"	490	NONE	OPEN	5	2.1
31-4	06/20/90	HI LOAD OFA VARIATION	490	NONE	OPEN	30	2.2
32-1	06/21/90	HI LOAD OFA VARIATION	485	NONE	OPEN	4	2.5
32-2	06/21/90	"	485	NONE	OPEN	20	2.6
32-3	06/21/90	"	482	NONE	OPEN	50	2.9
33-1	06/25/90	LOW LOAD OFA VARIATION	308	E	OPEN	5	4.6
33-2	06/26/90	"	300	E	OPEN	25	4.1
33-3	06/26/90	"	302	E	OPEN	50	5.1
33-4	06/26/90	"	310	E	OPEN	75	4.0
33-5	06/26/90	LOW LOAD OFA/O2 VARIATION	302	E	OPEN	75	3.3
34-1	06/26/90	LOW LOAD NORMAL	290	E	OPEN	5	3.2
34-2	06/26/90	LOW LOAD O2 VARIATION	305	E	OPEN	50	4.2
34-3	06/27/90	"	295	E	OPEN	50	3.2
34-4	06/27/90	"	295	E	OPEN	50	3.5
34-5	06/27/90	MID LOAD OFA VARIATION	390	E	OPEN	50	3.4
34-6	06/27/90	"	390	E	OPEN	35	3.4
34-7	06/27/90	"	390	E	OPEN	20	3.3
34-8	06/27/90	"	390	E	OPEN	5	3.0

Table 7-1 AOFA / Diagnostic Tests Conducted (continued)

TEST NO.	DATE	TEST CONDITIONS	LOAD (MW)	MOOS PATTERN	GUILLOTINE POSITION	OFA DAMPER (%)	DAS O2 DRY (%)
35-1	06/26/90	MID LOAD OFA VARIATION	405	E	OPEN	5	3.4
35-2	06/27/90	"	405	E	OPEN	25	3.4
35-3	06/28/90	"	402	E	OPEN	50	3.5
35-4	06/28/90	MID LOAD OFA/O2 VARIATION	407	E	OPEN	50	3.2
35-5	06/28/90	"	410	E	OPEN	50	4.0
35-6	06/28/90	MID LOAD OFA VARIATION	407	E	OPEN	75	
35-7	06/28/90	"	410	E	OPEN	5	
36-1	06/29/90	HI LOAD OFA VARIATION	475	NONE	OPEN	5	2.9
36-2	06/29/90	"	475	NONE	OPEN	25	2.9
36-3	06/29/90	"	480	NONE	OPEN	50	3.1
36-4	06/29/90	"	480	NONE	OPEN	75	2.9
46-1	08/14/90	LOW LOAD O2 VARIATION	300	E	OPEN	50	3.5
46-2	08/14/90	"	300	E	OPEN	50	4.4
46-3	08/14/90	"	300	E	OPEN	50	5.1
46-4	08/14/90	"	300	E	OPEN	50	5.6
47-1	08/14/90	MID LOAD	400	NONE	OPEN	50	3.4
47-2	08/14/90	MID LOAD REPEAT	400	NONE	OPEN	50	3.4
47-3	08/15/90	MID LOAD O2 VARIATION	400	NONE	OPEN	50	3.5
47-4	08/15/90	"	400	NONE	OPEN	50	4.0
47-5	08/15/90	"	400	NONE	OPEN	50	4.6
48-1	08/15/90	HI LOAD O2 VARIATION	455	NONE	OPEN	50	2.5
48-2	08/15/90	"	455	NONE	OPEN	50	3.2
48-3	08/15/90	"	455	NONE	OPEN	50	3.9
48-4	08/15/90	HI LOAD 02/OFA VARIATION	455	NONE	OPEN	50	4.3
48-5	08/15/90	"	450	NONE	OPEN	35	4.2
48-6	08/15/90	"	450	NONE	OPEN	20	4.4
48-7	08/15/90	"	450	NONE	OPEN	5	4.6
48-8	08/15/90	"	450	NONE	OPEN	0	4.2
49-1	08/16/90	HI LOAD OFA VARIATION	475	NONE	OPEN	5	3.8
49-2	08/16/90	"	480	NONE	OPEN	20	2.9
49-3	08/16/90	"	482	NONE	OPEN	35	3.1
49-4	08/16/90		482	NONE	OPEN	50	3.2
49-5	08/16/90		480	NONE	OPEN	50	3.6
49-6	08/16/90		485	NONE	OPEN	50	4.3

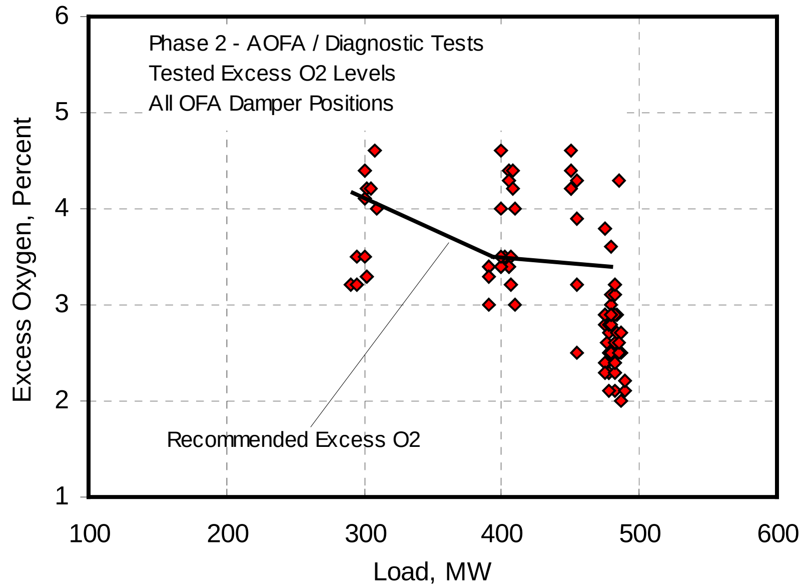


Figure 7-1 AOFA / Diagnostic Tests / Oxygen Levels Tested

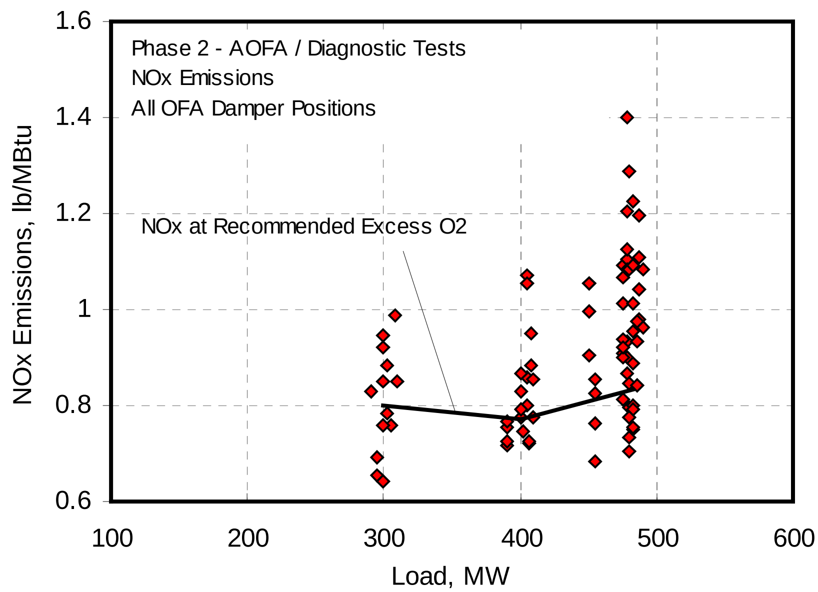


Figure 7-2 AOFA / Short-Term Tests / NOx Emissions

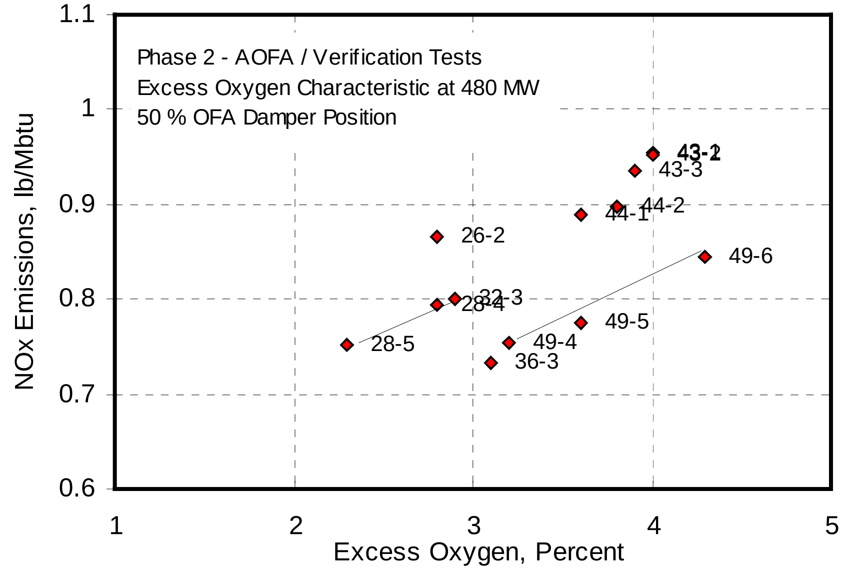


Figure 7-3 AOFA / Diagnostic Tests / NOx Characterization at 480 MW

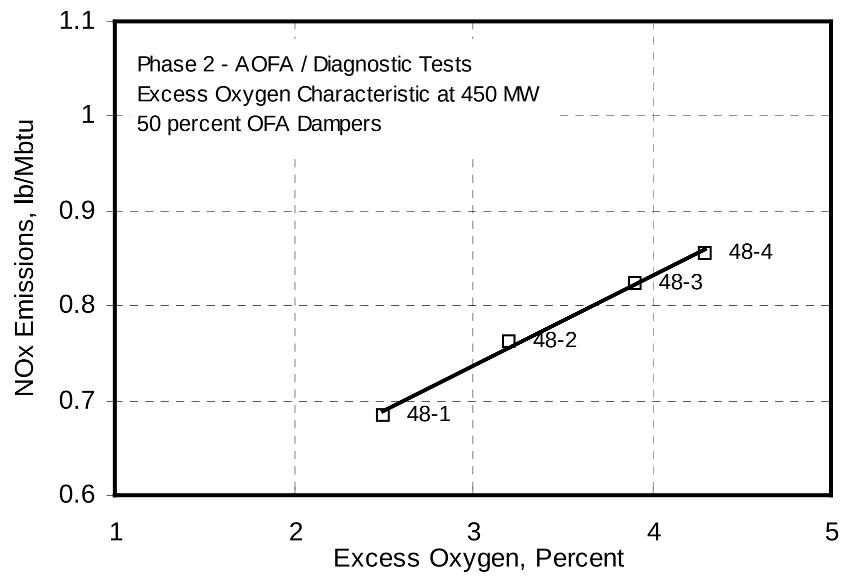


Figure 7-4 AOFA / Diagnostic Tests / NOx Characterization at 450 MW

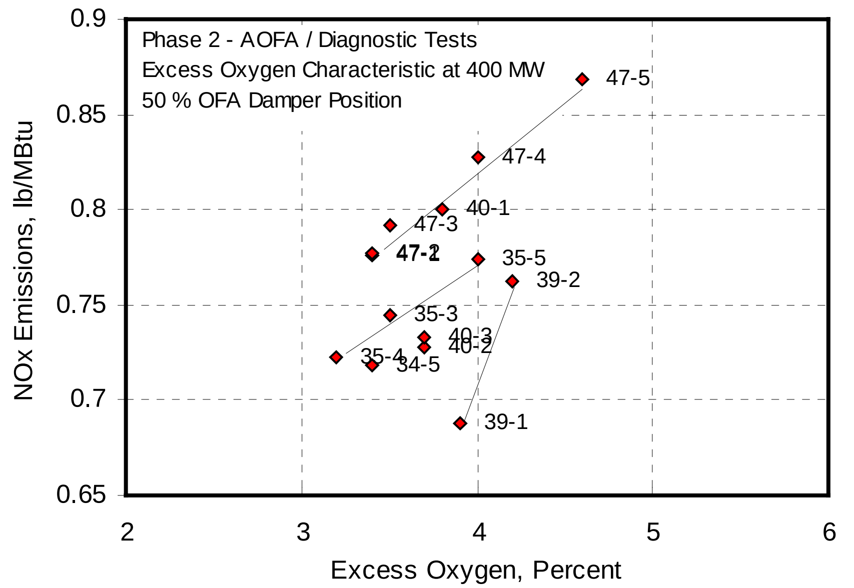


Figure 7-5 AOFA / Diagnostic Tests / NOx Characterization at 400 MW

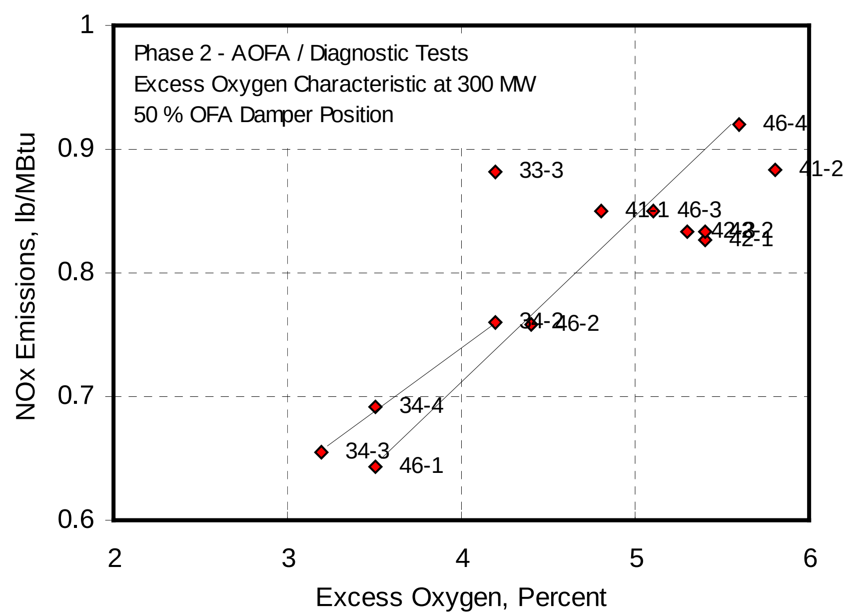


Figure 7-6 AOFA / Diagnostic Tests / NOx Characterization at 300 MW

7.1.2 Performance Tests

Six performance tests were conducted at nominal gross loads of 480, 400, and 300 MW with 50 percent OFA damper setting (Table 7-2). Testing at each load point required two consecutive days to complete sampling of all of the parameters included in the performance matrix. At each nominal load, the coal firing rate was kept as constant as possible and the electric load allowed to swing slightly as affected by coal variations, boiler ash deposits, ambient temperature, etc. Additional tests were performed at the 480 MW load point to determine the impact of an increase in OFA damper setting on the NOx emissions. Each performance test covered a period from ten to twelve hours during which boiler operational data was recorded, fuel and ash samples acquired, gaseous and solid emissions measurements performed, and the engineering performance tests conducted.

One additional test with abbreviated solid emissions measurements was made at 490 MW with the OFA ports nominally closed.

Table 7-2 AOFA / Performance Tests Conducted

Test	Date	Conditions	Load MW	MOOS Pattern	OFA Damper
37	07/10/90	HI LOAD PERFORMANCE	480	NONE	75
38	07/11/90	HI LOAD PERFORMANCE	485	NONE	75
39	07/12/90	MID LOAD PERFORMANCE	400	E	50
40	07/13/90	MID LOAD PERFORMANCE	405	E	50
41	07/14/90	LOW LOAD PERFORMANCE	298	E	50
42	07/15/90	LOW LOAD PERFORMANCE	300	E	50
43	07/17/90	HI LOAD PERFORMANCE	487	NONE	50
44	07/18/90	HI LOAD PERFORMANCE	487	NONE	50
45	07/18/90	HI LOAD PERFORMANCE	489	NONE	1

7.1.2.1 Unit Operating Data

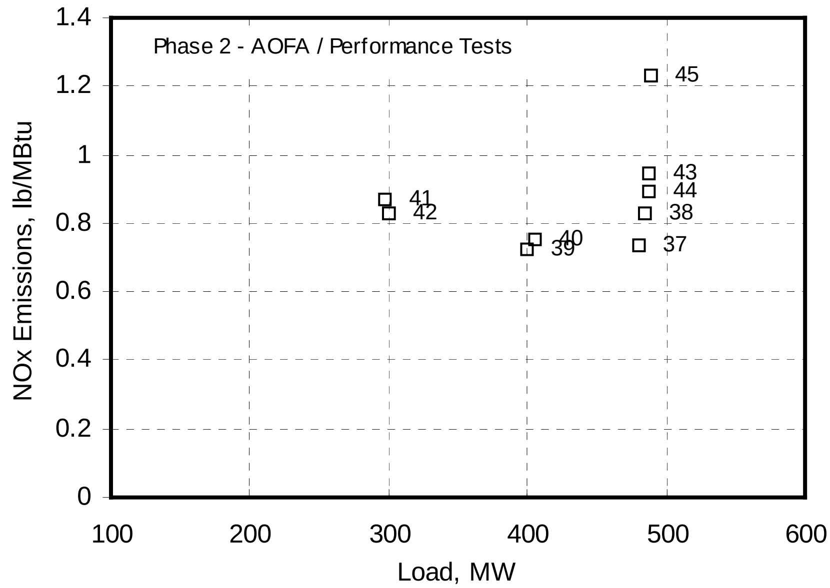
For each performance test, the desired test conditions were established and allowed to stabilize at least one hour prior to commencement of testing. To the extent possible, the active coal mills were balanced with respect to coal feed rate. Normal primary air/coal ratios and mill outlet temperatures were maintained, within the capacity of the existing primary air system. When the desired operating conditions were established, some controls were placed in manual mode to minimize fluctuations in the fuel or combustion air. This technique resulted in extremely stable operation over the test duration with only minor adjustment to the airflow over the day to maintain a near-constant stoichiometry.

Because a portion of the testing was concerned with measurement of various particulate emission characteristics, it was decided that soot blowing (both furnace and air heaters) should be suspended during the particulate sampling periods. When necessary for proper unit operation, air heaters were blown between repetitions in the solids emissions testing.

A summary of important operating parameters recorded on the DAS during this test series can be found in Table B-4. The values shown in this table represent averages over the duration of the test segment during the day.

7.1.2.2 Gaseous Emissions

During the performance tests, gaseous emissions were measured with the CEM operating in the manual mode. At various times during the performance tests, flue gas was sampled from selected probes or probe groups in the primary and secondary air heater inlet and outlet ducts. These groupings consisted of composites of the individual east and west economizer exit ducts and individual measurements from each probe in these ducts. The composite measurements used to establish the overall emission characteristics while the individual probe measurements were used to establish spatial distributions of emission species. Composite average values of NOx measured during each test are shown in Figure 7-7.



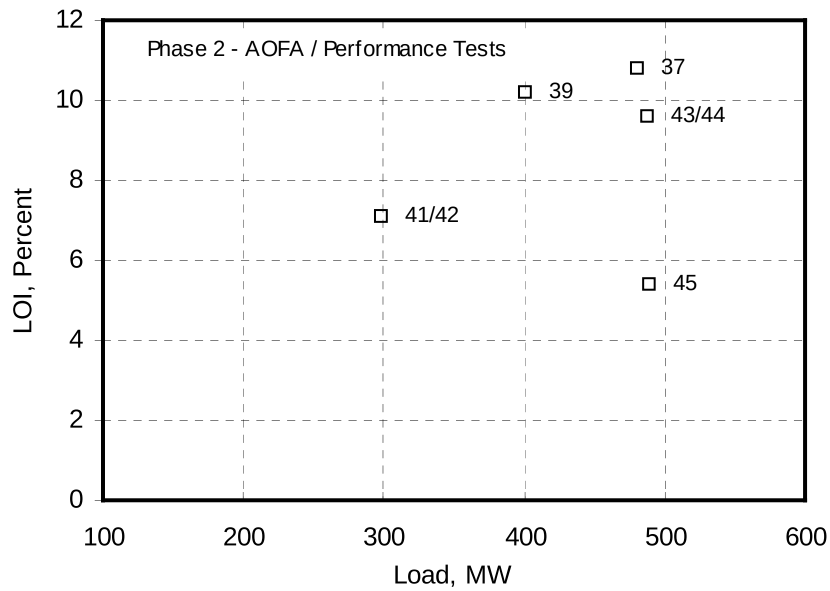


Figure 7-7 AOFA / Performance Tests / NOx Emissions and LOI

7.1.2.3 Combustion System Tests

As in the Phase 1 baseline testing, combustion performance tests were performed at each of three load levels to document the specific performance parameters related to the fuel and air combustion systems. The results of the Phase 2 testing are presented below.

Mill Performance

The air flow to each mill and the particle size and mass flow distributions of coal to each burner were measured as described in Section 5. Duplicate tests were performed at all three load levels (480, 400 and 300 MW). Table 7-3 and Figures 7-8 and 7-9 summarize the results of these tests. From Figure 7-8, it can be seen that despite the mills being set to approximately equal coal flows with the boiler controls, the measured coal flows varied considerably from mill to mill. The measured ratio of primary air-to-fuel ratio varied from approximately 2.2 to 3.7 over the load range (Figure 7-9). Fuel balance within each pulverizer's four coal pipes was ±45 percent deviation from the mean to ±12 percent deviation from the mean (Appendix B).

During these mill tests the coal fineness was found to be below 70 percent through 200 mesh on all mills except for E Mill at 480 MW and C and D Mills at 300 MW. Although the relatively poor grinding performance of the mills may have adversely affected unburned carbon levels, it is unlikely that NOx emissions were directly affected.

Table 7-3 AOFA / Average Coal Fineness

	Remaining on 50 Mesh	Passing 100 Mesh	Passing 200 Mesh
Test 37	2.29	na	65.2
Test 38	2.41	na	68.2
Test 39	2.73	na	65.5
Test 40	na	na	na
Test 41	1.86	na	69.3
Test 42	na	na	na
Test 43	2.24	na	68.1
Test 44	na	na	na
Test 44	na	na	na

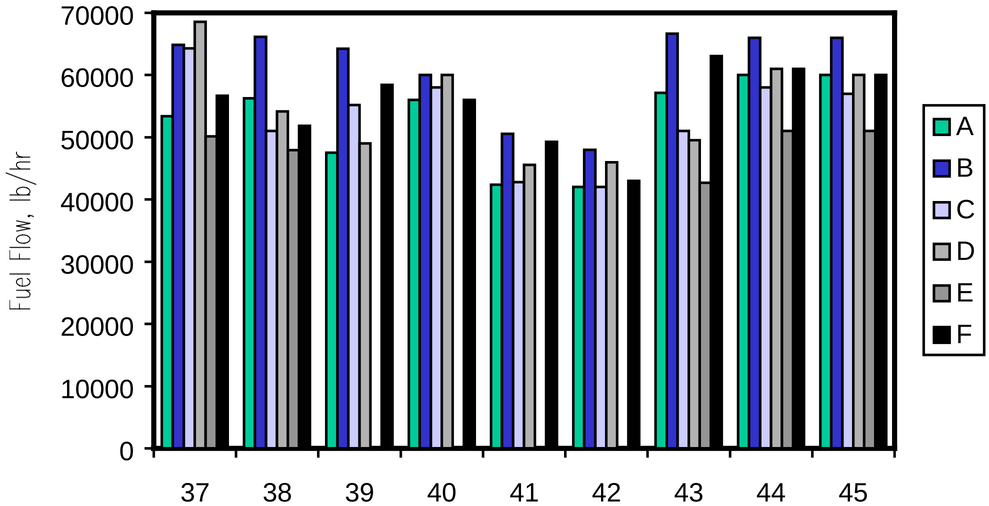


Figure 7-8 AOFA / Fuel Distribution

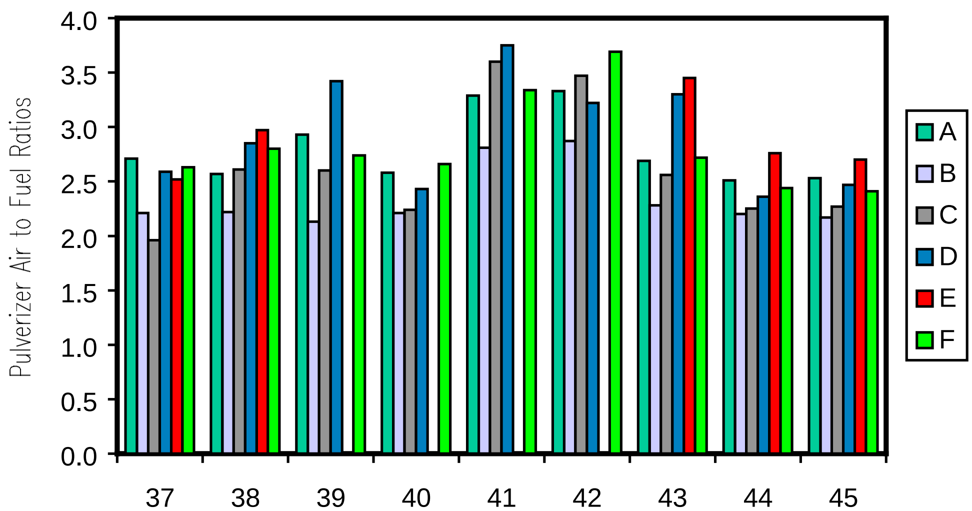


Figure 7-9 AOFA / Pulverizer Air to Fuel Ratio

Combustion Air Flow

The secondary combustion airflow was measured at two locations as described in Section 5. Figure 7-10 and 7-11 presents a summary of the flow measurements. The measurements made at the venturi throats in the secondary air supply ducts were very repeatable. The measurements taken at this location did not suffer from the inadequacies of the windbox flow measurement locations; thus, there is a high level of confidence in the total air flow measurements based upon the location and the repeatability. As shown, at 50 percent AOFA damper position, overfire air averaged approximately 20 to 25 percent of the total combustion airflow when the AOFA system was in service. The primary air contribution was approximately 20 to 30 percent whereas the secondary air was approximately 50 percent. The 50 percent damper position was the FWEC recommended set point.

Furnace Measurements

Measurements were made of combustion gas temperatures and species concentrations at eight locations within the boiler furnace at the 7th (furnace nose) and 8th floor (convective section above nose) levels. At each port, approximately nine measurements were made at different probe insertion depths. Temperature, excess oxygen and carbon monoxide were measured at loads of 480, 400, and 300 MW.

Figure 7-12 shows the distribution of temperature and excess oxygen at the 480 MW nominal load point with the OFA dampers set to 50 percent open. Species concentrations of O_2 and CO made simultaneously with the temperature measurements indicate combustion non-uniformity within the furnace. Generally speaking, the excess O_2 level ranged from 0.2 to 3.5 percent with the higher excess O_2 levels generally on the west side of the furnace. The furnace seemed to be most starved of oxygen in the southeast quadrant of the furnace. One possible reason for this non-uniformity is uneven coal flows to the burners; however, this is not clearly evident based on data collected during the tests. A more likely cause is differences in secondary air through the individual air registers. Because this flow is not readily measurable, this proposed cause could not be verified. Also shown in Figure 7-12 are temperature and excess oxygen distributions for the 400 and 300 MW loads. These distributions exhibit the same general non-uniformity as at 480 MW.

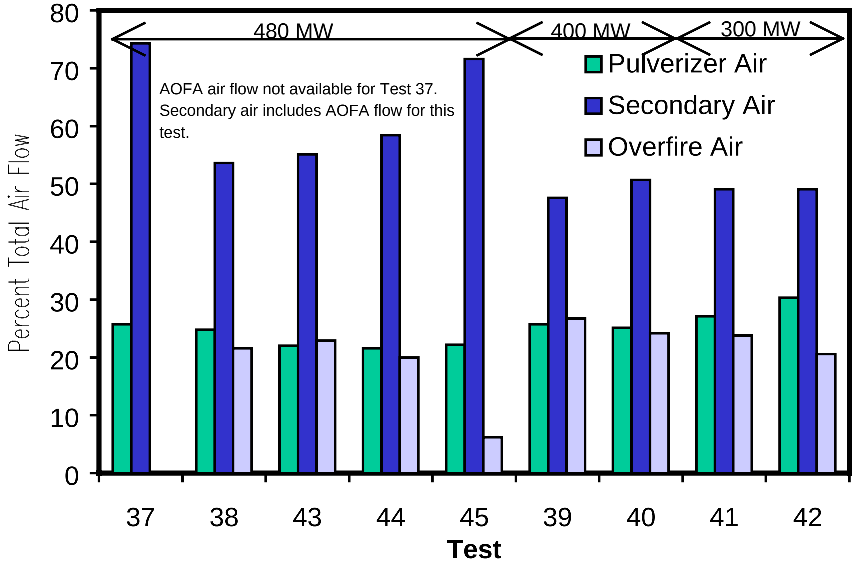


Figure 7-10 Baseline / Distribution of Unit Air Flow by Load

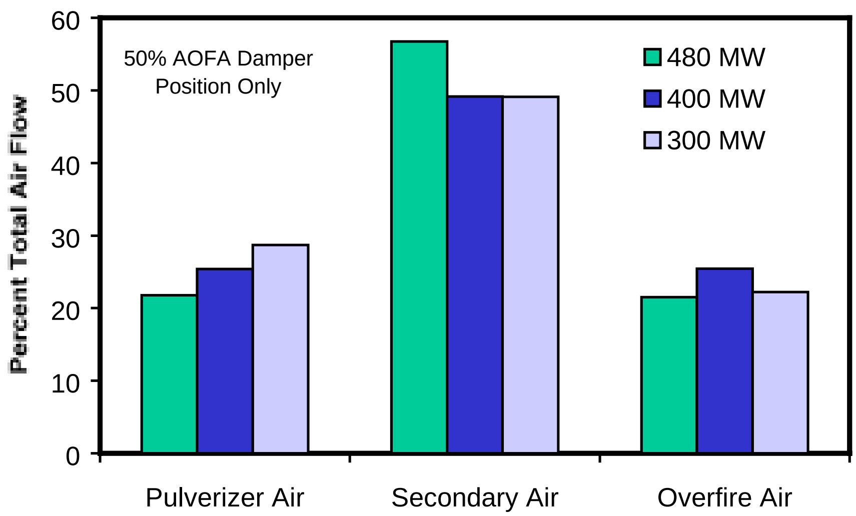


Figure 7-11 Baseline / Distribution of Unit Air Flow by Component

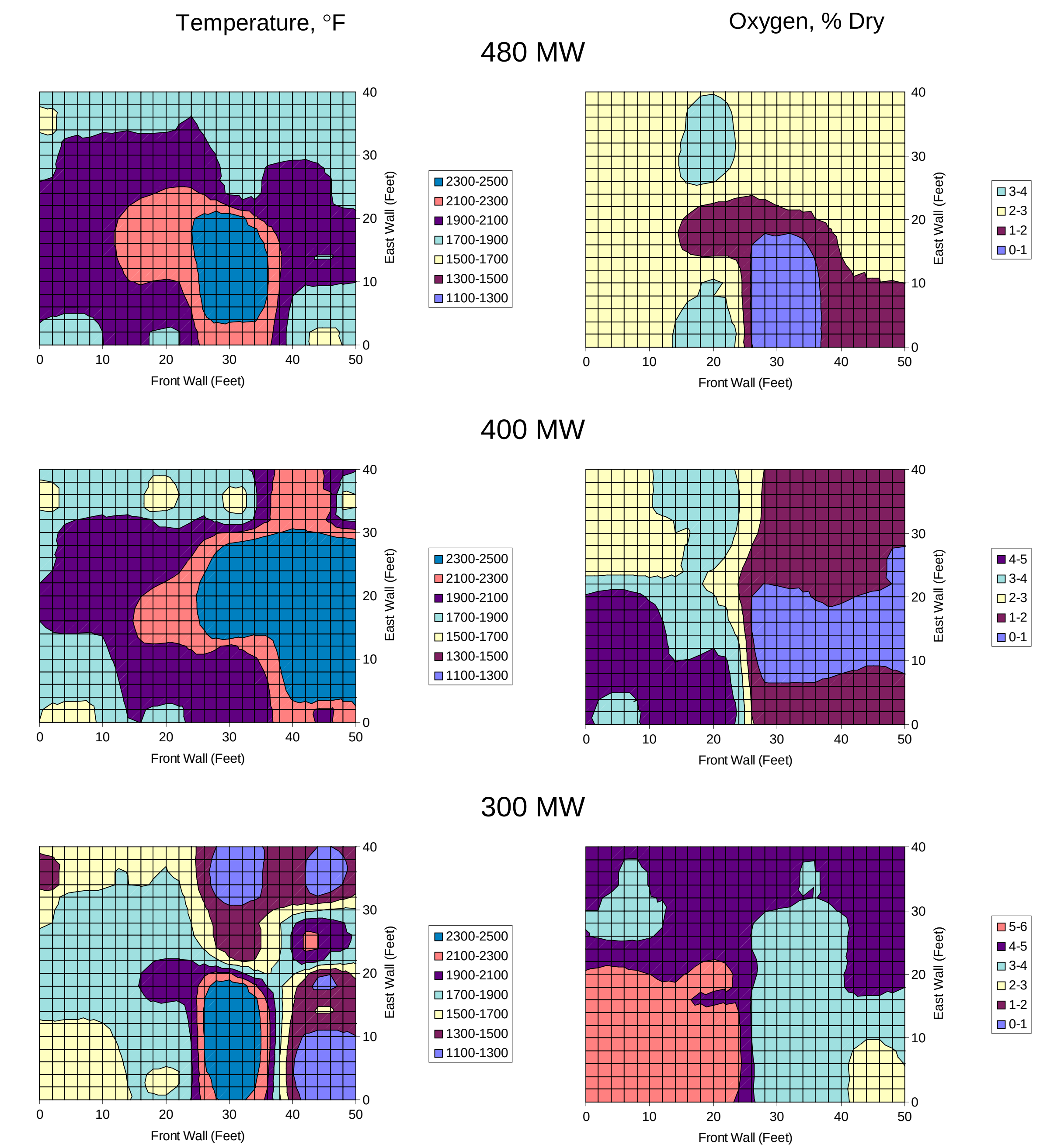


Figure 7-12 AOFA / Furnace Exit Temperatures and Oxygen

7.1.2.4 Coal Analyses

During each of the seven days of Phase 2 performance testing, samples were obtained of coal entering the active mills, fly ash exiting the furnace (east and west sides) and bottom ash collected in the furnace ash pit. The coal samples were analyzed for proximate and ultimate composition, calorific value, hardness, and ash fusion properties. Table 7-4 presents a summary of these analyses. These analyses show that the coal properties remained consistent over the duration of the testing and are consistent with the analyses obtained during the Phase 1 effort. Analysis of the individual samples can be found in Appendix B.

Table 7-4 AOFA / Average Coal Analysis

	Average	Standard Deviation	Variance
Ultimate			
H2O %	5.60	0.88	0.78
C %	73.17	0.77	0.59
H %	4.72	0.08	0.01
N %	1.42	0.07	0.00
Cl %	0.056	0.020	0.000
S %	1.64	0.09	0.01
Ash %	8.90	0.76	0.58
O %	4.55	0.33	0.11
Total %	100.04	0.07	0.01
HHV Btu/lb	13000	134	18037
VM %	33.27	0.64	0.41
FC %	52.22	0.46	0.58

7.1.2.5 Solid Emissions

Ash particulate emissions were measured both for total mass emissions rate and for characteristic properties related to ash collection within an ESP. The specific measurements and analyses that were performed included: (1) total mass emissions, (2) particle size, (3) chemical composition, and (4) fly ash resistivity. These measurements were made immediately after the air heater. The following paragraphs describe the results from these measurements.

Mass Loading, Gas Flow, and Temperature

EPA Method 17 mass train measurements were made at the ESP inlet for Tests 37, 39, 41, 43, and 45. Note that the reduced load tests were performed at only one setting of the OFA damper, namely 50 percent. The effect of OFA damper setting was evaluated only under full-load conditions. A summary of the results of the Method 17 measurements are given in Table 7-5 with more detailed information provided in Appendix B. For all tests, the sampling rate was within eight percent of isokinetic. The results for each load represent the average of three replicate samples.

Table 7-5 AOFA / Summary of Solid Mass Emissions Tests

Test No.	Load MW	O_2 %	OFA Pos. %	Loading gr/dscf	Gas Flow ACFM	Gas Temp. °F	Carbon %	LOI %
37	480	3.0	75	2.74	2,214,000	306	10.0	10.8
43/44	480	3.9	50	2.66	2,293,000	296	9.6	9.6
45	480	3.8	0	2.82	2,348,000	309	6.3	5.4
39	400	4.1	50	2.86	1,654,000	276	8.7	10.2
41	300	5.3	50	1.81	1,566,000	267	5.0	7.1

With one exception, all of the measured mass loadings fall within this confidence interval and agree very well with the EPRI quoted mean value of 2.67 gr/scf [DuBard 1987]. The 300 MW, 50 percent OFA test (Test 41) is the only exception. The mass loading was significantly lower during this test, with an average of only 1.81 gr/scf. Coal firing rate and flue gas flow theoretically should vary in direct proportion to the unit load, resulting in roughly the same mass loading at any given load (assuming the same coal composition and excess air). It is obvious from the data, however, that the gas flow is disproportionately high at 300 MW. This can also be seen by normalizing the gas flows to full load conditions by multiplying the measured flow by 480 and dividing by the load in MW (a ratio of 5.2 vs. 4.8). Thus, the gas flow at 300 MW is about 10 percent higher than expected based on a direct proportionality between load and gas flow. Similarly, the gas flow at 400 MW is about 13 percent lower than expected. The effect that this has on the mass loading can be taken into account by multiplying the 300 MW loading by 1.10 and dividing the 400 MW loading by 1.13. For the 400 and 300 MW tests, the mass loadings then become 2.53 and 1.99 gr/scf, respectively. This brings the 300 MW loading up to the point where it is almost equal to the lower limit on the EPRI typical mass loading (1.99 gr/scf versus 2.00 gr/scf) [DuBard 1987]. However, the 300 MW loading is still significantly lower than the others (1.99 gr/scf versus 2.53 to 2.82 gr/scf). One possible explanation for this observation would be greater dropout of the ash as bottom ash at the lower load, but there is no way to confirm this suspicion.

The ESP inlet temperature for each test is also shown in Table 7-5. As was found during the baseline test, the Method 17 traverses also revealed large variations in gas temperature with position in the duct (see Appendix B). Although these temperature gradients can have a detrimental impact on ESP performance, the distribution was not made worse by AOFA and the problem is largely specific to this unit.

<u>Ash Resistivity</u>

Measurements of in situ resistivity were made during each AOFA test condition. For each run, two values of resistivity are reported, one measured by the spark method and one measured by the V-I method. Considering the limitations of the two measurement techniques, relatively good agreement was observed. Because of the difficulty in measuring the voltage drop across the dust layer incrementally with the gas space voltage drop for low resistivities (<1 x 10^{10} ohm-cm), the spark data is considered more reliable.

Figure 7-13 provides the results of the in situ ash resistivity measurements made during the tests with AOFA. The AOFA data measured in-situ generally indicates that the resistivity was sufficiently low not to detrimentally affect ESP operation. The exceptions occurred on July 17, 1990 during 480 MW operation with 50 percent OFA damper settings and on July 18, 1990 with 0 percent OFA settings where the average values were in excess of $5x10^{10}$ ohm-cm. This level of resistivity will begin to affect ESP performance.

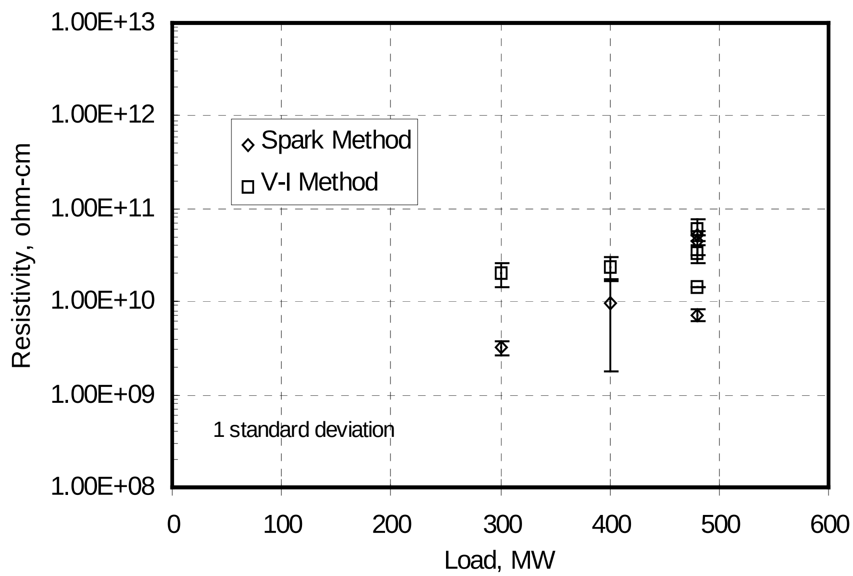


Figure 7-13 AOFA / Ash Resistivity

Chemical Composition

The ESP hopper samples (east and west composites separately) were analyzed for mineral composition, the composite averages thereof are shown in Figure 7-14. This figure was derived from the information contained in Appendix B. The samples showed only minor variations in the mineral constituents known to significantly affect the electrical properties of the precipitator. However, the samples from the east side of the ESP all showed unusually high LOI.

The high LOI was further investigated by analyzing mass train samples for LOI and carbon in both the +200 and -200 mesh size fractions (Table 7-6). This analysis was done because a high carbon content in the +200 mesh fraction usually indicates a problem with incomplete combustion. This analysis showed that most of the LOI is associated with the +200 mesh fraction (i.e., particles larger than 75 μm). The +200 mesh fraction accounted for 14 to 22 percent of the total sample. In general, the high LOI levels for the +200 mesh fraction are the result of the very high carbon content in the ash.

Flue Gas SO_3 Concentration

Ash resistivity is strongly attenuated by surface films of sulfuric acid produced by the adsorption of SO_3 and water vapor from the flue gas. Thus, ash resistivity can be significantly affected by changes in SO_3 and water vapor concentration in the flue gas. The concentrations of SO_3 measured at the ESP inlet during the AOFA tests are shown in Figure 7-15, which is derived from data that can be found in Appendix B. Because resistivity is affected by the actual concentration of SO_3 present, the values are not normalized to a constant oxygen level. However, because SO_3 is formed by the oxidation of SO_2, it is reasonable to expect the SO_3 concentration to vary with fluctuations in SO_2 and O_2 levels. As shown in Table 7-7, variations in SO_3 concentration do not necessarily track the variations in SO_2 level, i.e., the SO_3-to-SO_2 ratio is not constant. In fact, it varied from a low of 0.116 to a high of 0.385. Coincidentally, both of these extremes occurred during the same test (Test 37). Possible explanations for this variation are wider fluctuations in O_2 during these tests, or by other factors such as variations in temperature profiles or factors affecting catalytic conversion of SO_2 to SO_3.

The average SO_3 concentrations are very similar for three of the four tests for which data was obtained. Only the 400 MW, 50 percent OFA test shows a significant difference in SO_3, with a lower average of 1.6 ppm compared to 2.2 to 2.3 ppm for the other tests. This may be a result of the low gas temperatures experienced during this test resulting in sub-dewpoint operation. Fortunately, this appears to be a problem in only one of the test cases. Based on the data taken in the absence of dewpoint excursions, it appears that neither OFA damper setting nor load had a significant effect on SO_3 concentration.

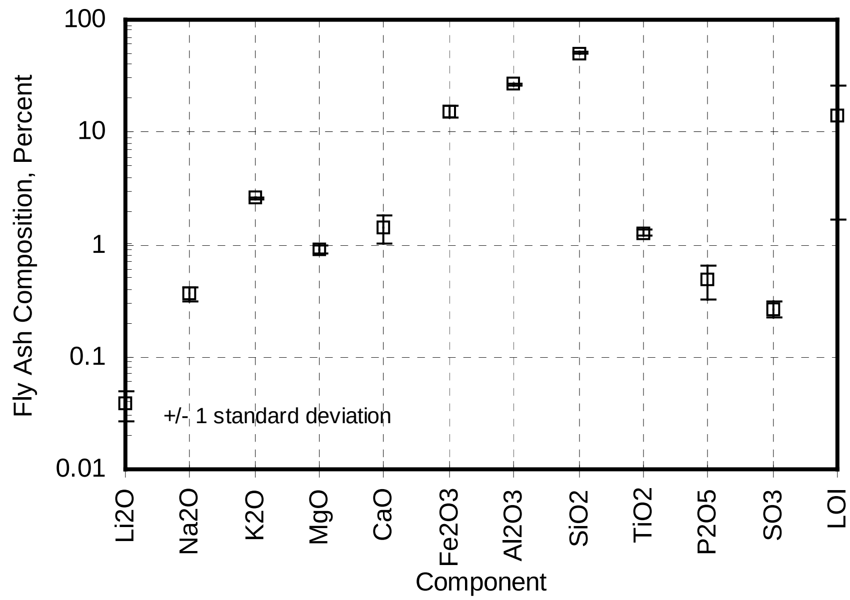


Figure 7-14 AOFA / Fly Ash Composition

Table 7-6 AOFA / Carbon and LOI Results

				MASS TRAIN SAMPLES				ESP Hopper	
				CARBON, %		LOI, %		LOI, %	
DATE	TEST	Boiler Load, MW	OFA Damper Setting, %	<200 mesh	>200 mesh	<200 mesh	>200 mesh	East Duct	West Duct
7/10/90	37	480	75	5.3	35.2	6.0	36.2	26.5	7.7
7/17/90	43	480	50	5.4	39.0	6.4	40.9	14.2	4.7
7/18/90	44	480	50	5.0	22.6	4.2	20.8	11.3	5.9
7/18/90	45	480	0	2.8	18.5	3.3	17.4	12.0	5.2
7/12/90	39	400	50	4.7	27.1	4.3	32.1	48.7	11.5
7/14/90	41	300	50	1.9	23.8	2.8	22.4	11.8	9.0

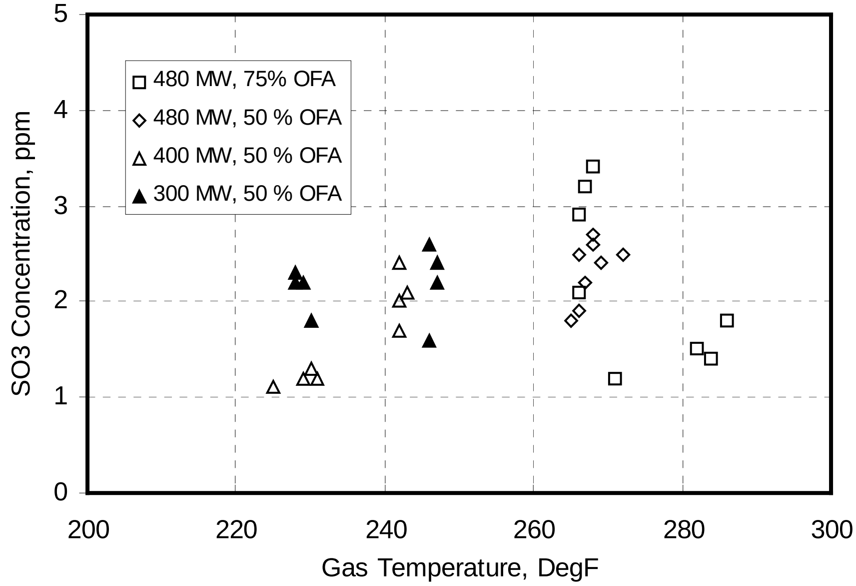


Figure 7-15 AOFA / SO_3 Concentrations

Table 7-7 AOFA / SO_3 Concentrations

{PRIVATE **}**Test Series	SO_3, ppm	COV	SO_3-to-SO_2 ratio	COV
480 MW, 75 percent OFA	2.2	0.39	0.237	0.471
480 MW, 50 percent OFA	2.3	0.14	0.299	0.137
400 MW, 50 percent OFA	1.6	0.31	0.191	0.367
300 MW, 50 percent OFA	2.2	0.15	0.297	0.152

COV = Coefficient of Variation, (s/Mean)100

<u>Particle Size</u>

The particle size distribution of ash exiting the secondary air heaters was determined using a cascade impactor. Six samples were obtained for each test condition. Figure 7-16 shows the particle size distributions for all test conditions as the total percentage of cumulative mass. The vertical bars visible to the upper right show the 90 percent confidence level for the mass values determined at the indicated particle diameter while the symbols show the average of the replicate samples for each load. For most of the data, the 90 percent confidence interval is smaller than the plotting symbols. For large particle sizes the confidence band is exaggerated because an exponential scale is used. The confidence interval for these points is still in the one percent range.

The very close agreement of all of the data indicates both excellent replication of test under common conditions and also the relatively minor effect of load on the ash particle size distribution. The total particulate mass collected per unit gas volume sampled in the particle size tests was comparatively less than in the Method 17 tests. This is attributed to the inability to sample as close to the bottom of the flue gas duct with the impactor probe as can be done with the Method 17 probe, resulting in the potential failure to capture some larger particle sizes which may stratify near the duct bottom. To account for the exclusion of some larger particle sizes (over 8 microns) when modeling ESP behavior, the 480 MW particle size data are "adjusted" by extrapolating the data above 8 microns to the total mass loading measure with Method 17. Figure 7-16 shows the additional mass of large particles associated with the "adjusted" 480 MW data. The derivative of cumulative mass with respect to diameter is presented in Figure 7-17. This type of presentation emphasizes the predominant concentration of mass vs. particle size.

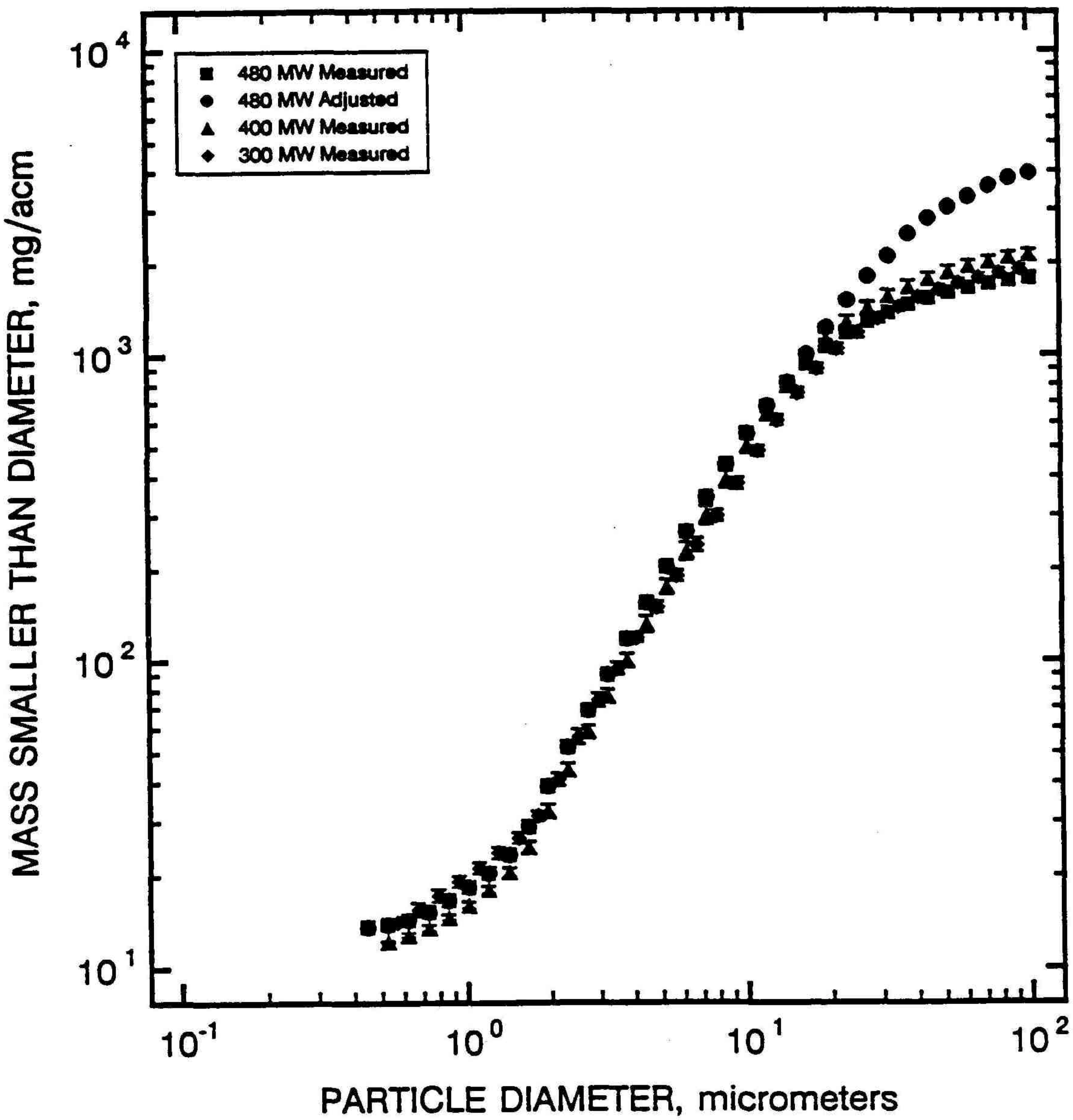


Figure 7-16 AOFA / Fly Ash Particle Size Distribution

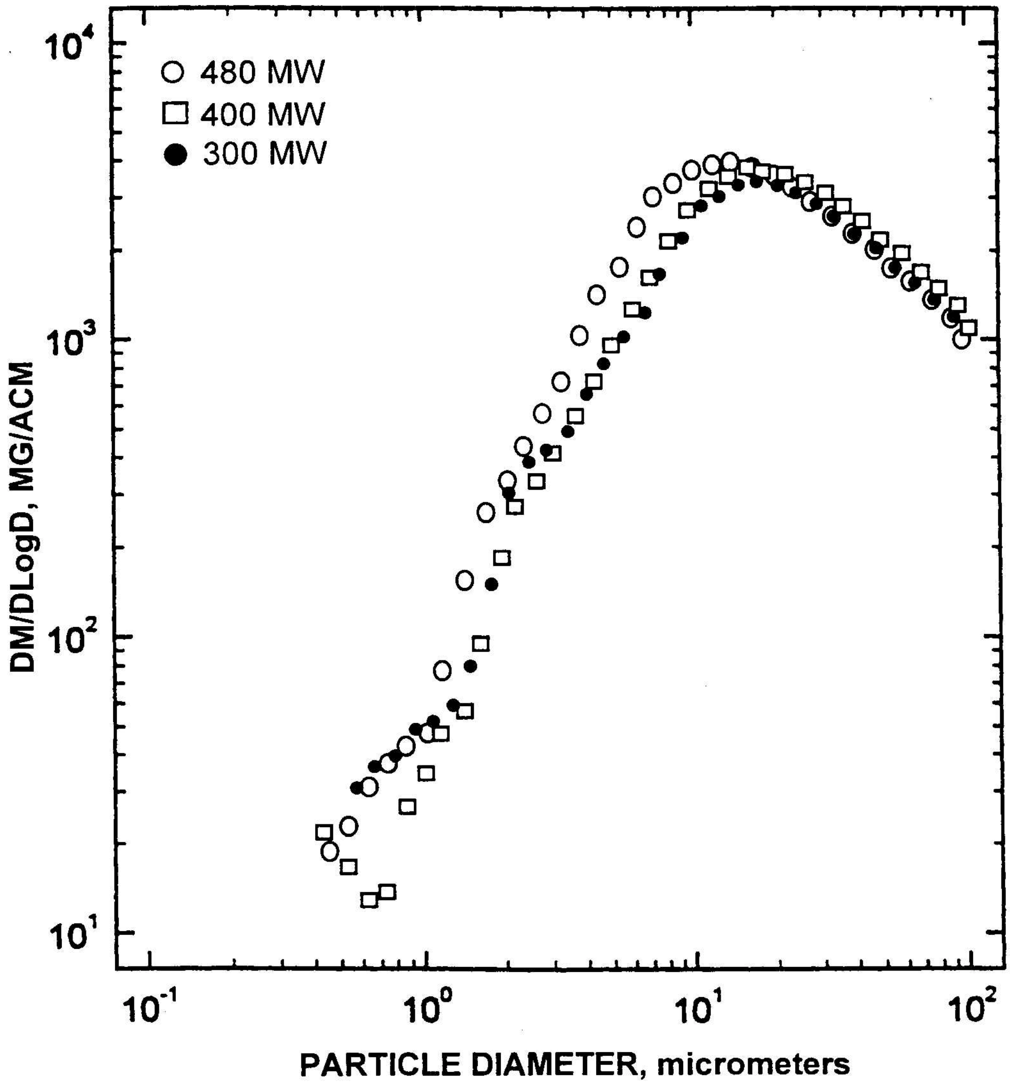


Figure 7-17 AOFA / Fly Ash Differential Mass Size Distribution

7.1.3 Verification Tests

Subsequent to the long-term testing, testing was performed to ascertain if significant changes in the NOx characteristics had occurred during the long-term test period. These tests were performed from February 22 to February 28, 1991. During this period, fifteen tests were performed at high loads. During the verification test period, the system load was such that it was not possible to obtain low load data at 300 MW. Six tests were performed at the 400 MW load point and nine were performed at the 480 MW load point. Testing at the 480 MW load was with all mills in service while testing at the 400 MW load was for the condition with E-mill out of service.

Figure 7-18 presents a comparison of the verification test results with those for the diagnostic testing for the 480 MW load point with 50 percent OFA damper. From this figure, it can be seen that for all practical purposes, the data for the two periods is the same and exhibit the same trend. The NOx data fits within the data scatter for the diagnostic tests. Based upon this it can be concluded that the full load NOx characteristics did not significantly change during the long-term test period.

Figure 7-19 presents a comparison of the verification test results with those for the diagnostic testing for the 400 MW load point with 50 percent OFA damper. Testing at the 400 MW load point was with only one of the two mill patterns used during the diagnostic testing (i.e. E MOOS). From this figure, it is evident that the verification trends and the absolute levels of NOx were remarkably similar to those for the diagnostic test results, although the oxygen levels were different for LOI considerations determined during performance tests.

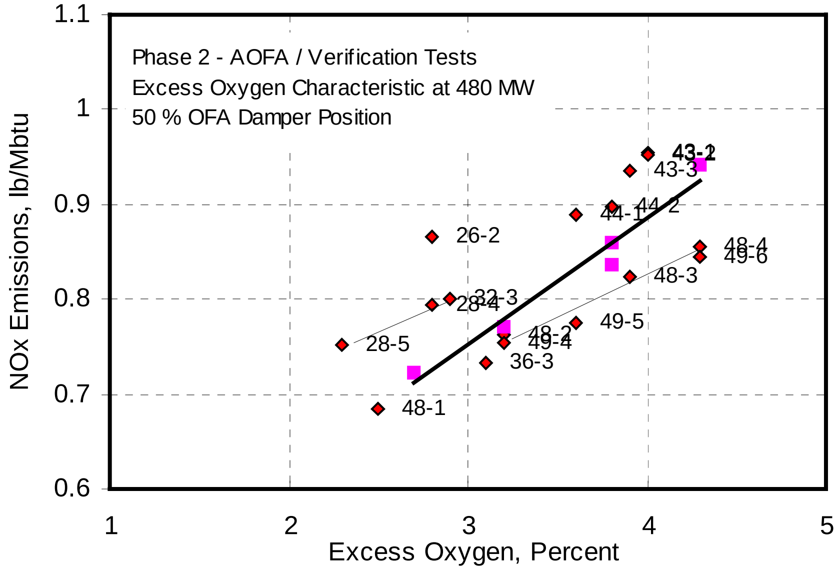


Figure 7-18 AOFA / Comparison of Verification and Diagnostic Test 480 MW

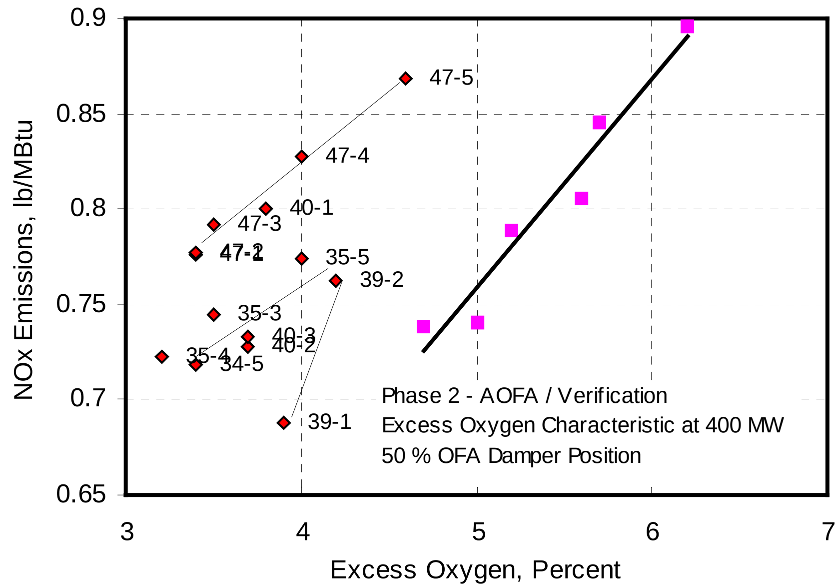


Figure 7-19 AOFA / Comparison of Verification and Diagnostic Test 480 MW

7.2 Long-Term Testing

The long-term testing consisted of continuous measurement of operating parameters while the unit was under normal load dispatch. This long-term testing was performed from October 14, 1990 through March 8, 1991. During this period, a number of unit outages were experienced that resulted in lost days of data capture. The data capture was, however, sufficient to fully characterize the unit both from an engineering perspective as well as a regulatory point of view.

The focus of the analysis of this long-term data was:

- Characterization of the daily load and NOx emissions and the within-day statistics,
- Characterization of the NOx emissions as a function of the O_2 and mill patterns.
- Determination of the thirty-day rolling average NOx emissions, and
- Determination of the achievable NOx emission level based upon valid days of ECEM data.

The following paragraphs describe the major results of these analyses.

7.2.1 Unit Operating Characteristics

From the data for the long-term testing (October 1990 through March 1991), the daily averages of load and NOx was determined and are shown in Figure 7-20. The daily average data was determined using the EPA criteria for valid data. Only days with at least 18 hours of data are presented in this figure. During the first half of the long-term testing, the average daily load was generally in excess of 400 MW. Midway during the long-term test effort, the load decreased to below 300 MW. For the Phase 2 long-term test period, the daily average emissions ranged from approximately 0.7 to 1.1 lb/MBtu.

One method of characterizing the boiler operating characteristics during the long-term testing is to examine the within-day variation of load and NOx. This was accomplished by segregating the data by hour of the day. For these segregated data, the average load and NOx were computed. In addition, the hourly values representing the lower 95 percent and upper 95 percent of all values were determined. Typical results of this type of analysis are shown in Figure 7-21. This figure illustrates the daily trend for load and NOx emissions over the entire long-term test period. The figure illustrates that the unit was operated at higher loads for most of the day (on average 13 hours were above 400 MW). It is evident from a comparison of the two graphs, that the NOx versus load characteristic is very flat. The exact relationship will be illustrated in the following paragraphs.

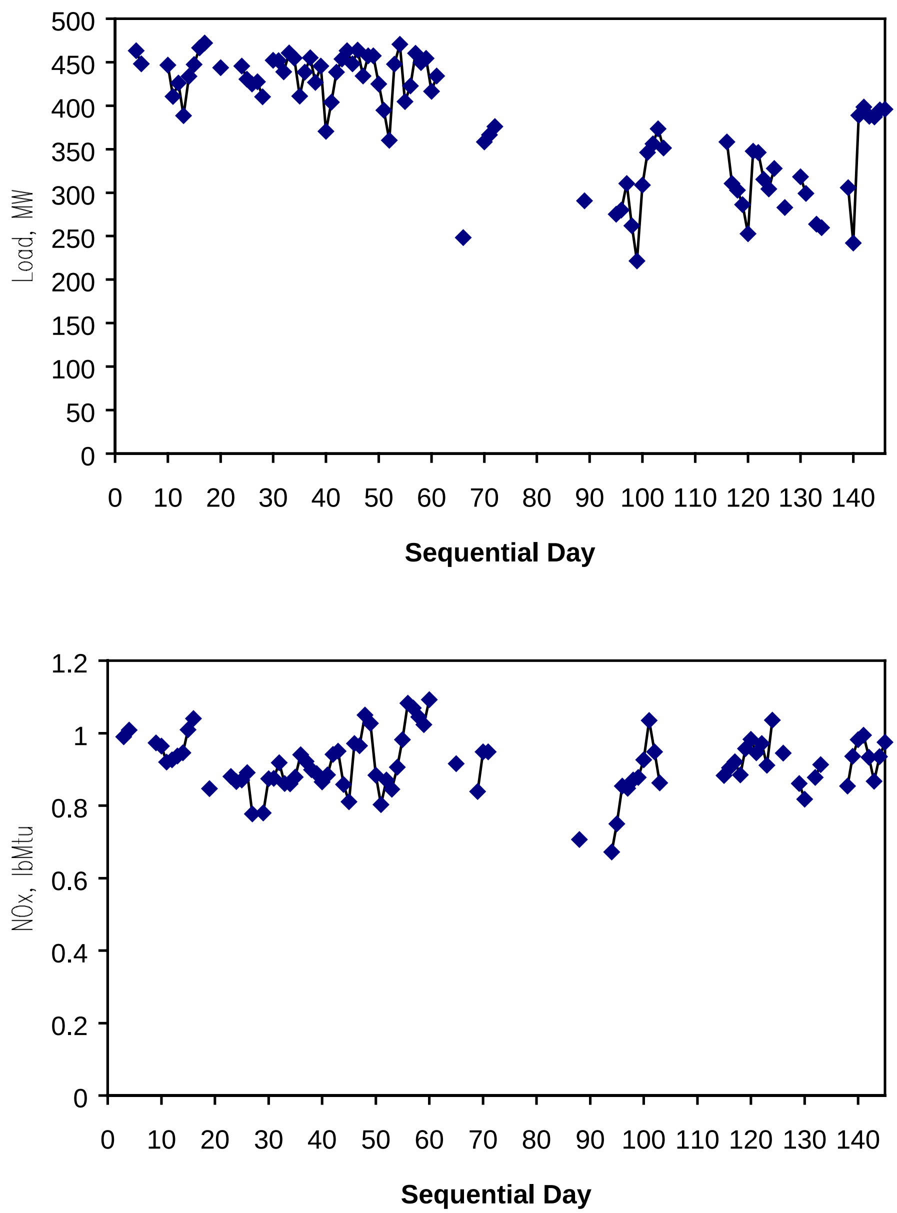


Figure 7-20 AOFA / Long-Term Daily Average Characteristics

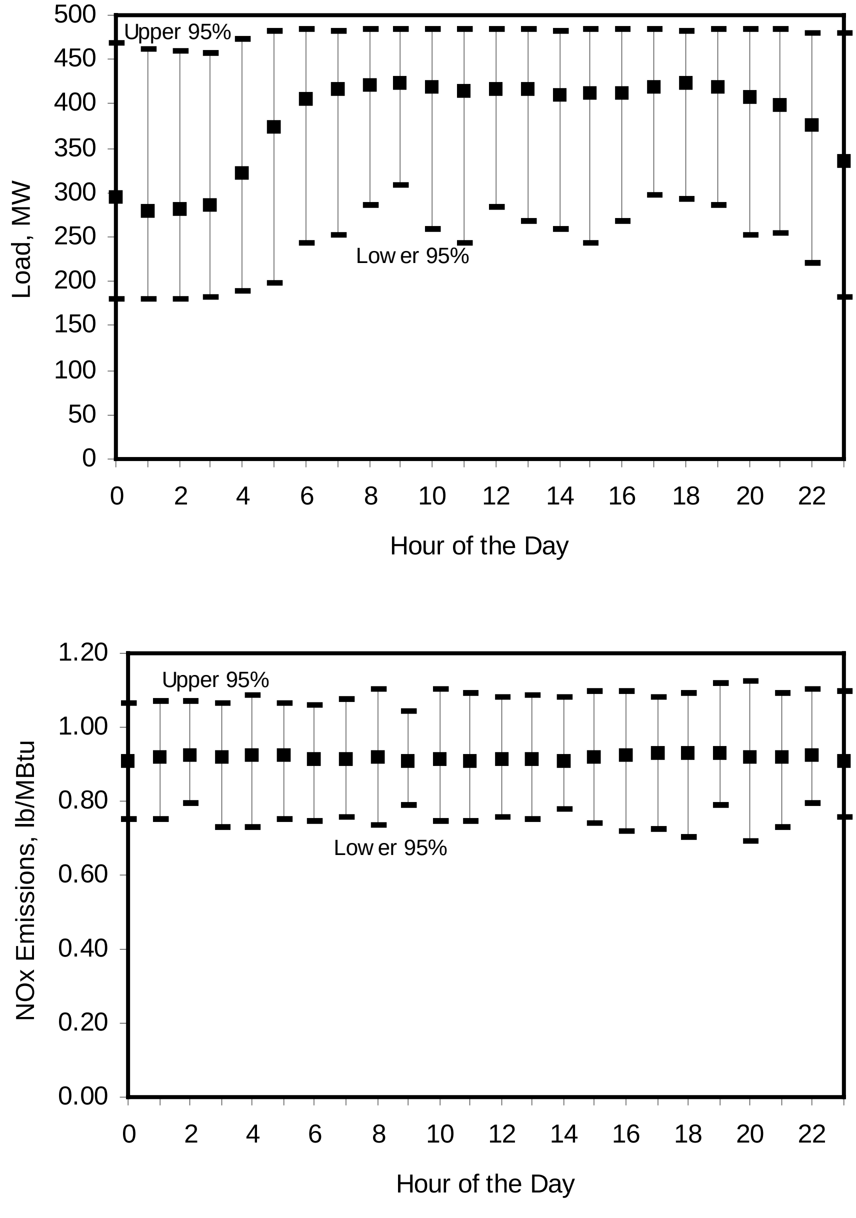


Figure 7-21 AOFA / Long-Term Daily Average Characteristics

7.2.2 Parametric Test Results

For the parametric analyses, all of the valid five-minute data was used. The 5-minute and hourly average emission data was analyzed to determine the overall relationship between NOx and load and the effect of boiler O_2 on NOx emissions for certain frequently used mill patterns. Because this data was obtained while the unit was under normal load dispatch, it represents the long-term NOx characteristics.

The NOx versus load relationship was determined by first segregating the 5-minute average load data into 20 MW wide load ranges. Figures 7-22 through 7-25 illustrates these load trends for NOx, stack oxygen, SOx, and CO for the Phase 2 test period. As shown, NOx emissions were not dependent on load during this test phase, averaging approximately 0.90 lb/MBtu over the load range. This flat NOx characteristic contrasts with the increasing NOx vs. load exhibited during Phase 1. Stack excess oxygen was a decreasing function of load. This is expected because the boiler control system maintains excess oxygen and the set point curve is also a decreasing function. SOx emissions also did not exhibit a load correlation. This characteristic is also expected because SOx emissions are generally not affected by combustion conditions. CO emissions remained relatively low during this phase, averaging below 15 ppm over all load categories.

The effect of operating O_2 on NOx emissions for certain mill patterns was examined for load ranges that corresponded to some of the loads tested during the short-term test portion of the Phase 2 test effort. These ranges were the 180-190, 290-300, 390-400, and 470-480 MW ranges. All of the valid five-minute data for these load ranges were used to assess the impact of excess oxygen level for the most commonly used mill patterns. To determine the most frequently used patterns, the frequency distribution of the mills-in-service pattern was determined. Table 7-9 presents the frequency distribution for the two most used mill patterns. It is apparent that there were certain preferred mill patterns for each load range. These patterns are dictated by the operational requirements of the unit (e.g., slag minimization, steam temperature control, mill condition).

Prior to commencing the short-term testing effort, discussions with plant operations indicated that certain mill patterns were preferred. These patterns were then used during the diagnostic and performance testing with the intent of comparing the results with the same patterns during long-term testing. The mill patterns used during the short-term test effort were the B-, E- and B and E-MOOS at loads below 400 MW. Referring to Table 7-8, it is evident that these patterns were not the most prevalent during this long-term test period.

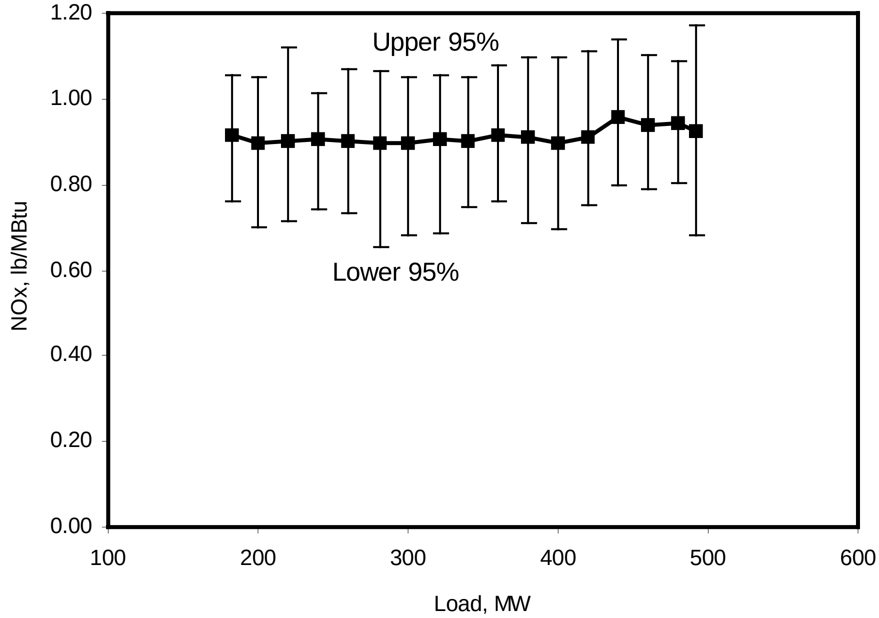


Figure 7-22 AOFA / Long-Term / NOx vs. Load Characteristic

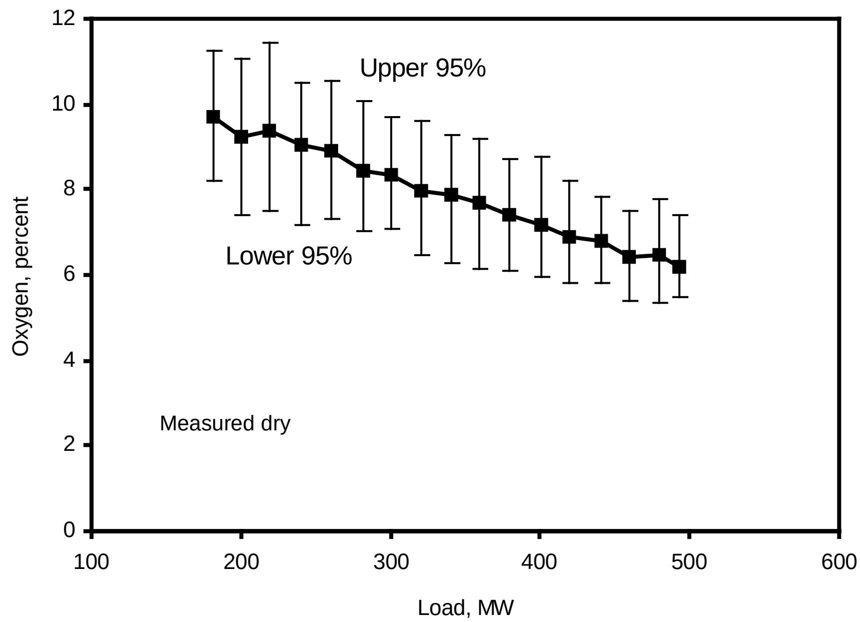


Figure 7-23 AOFA / Long-Term / Stack O2 vs. Load Characteristic

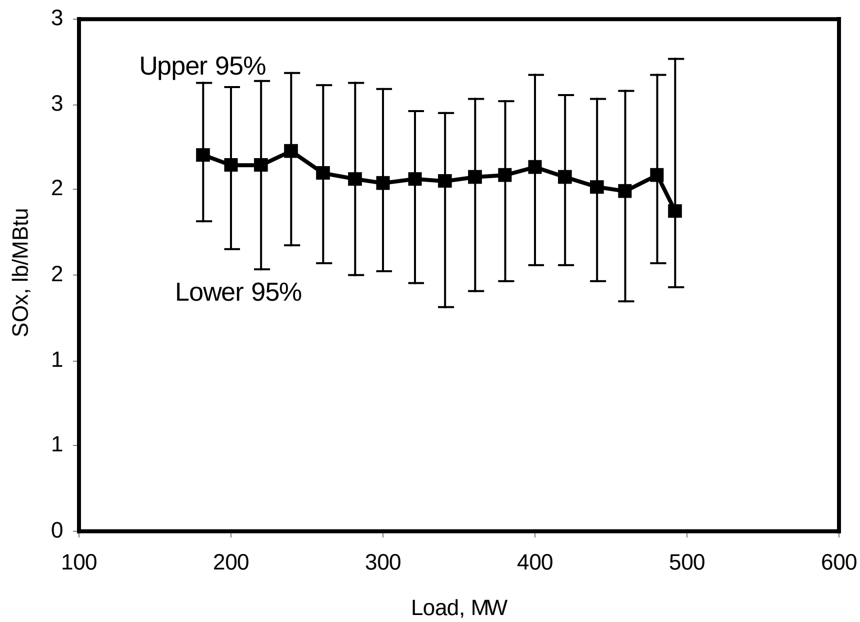


Figure 7-24 AOFA / Long-Term / SOx vs. Load Characteristic

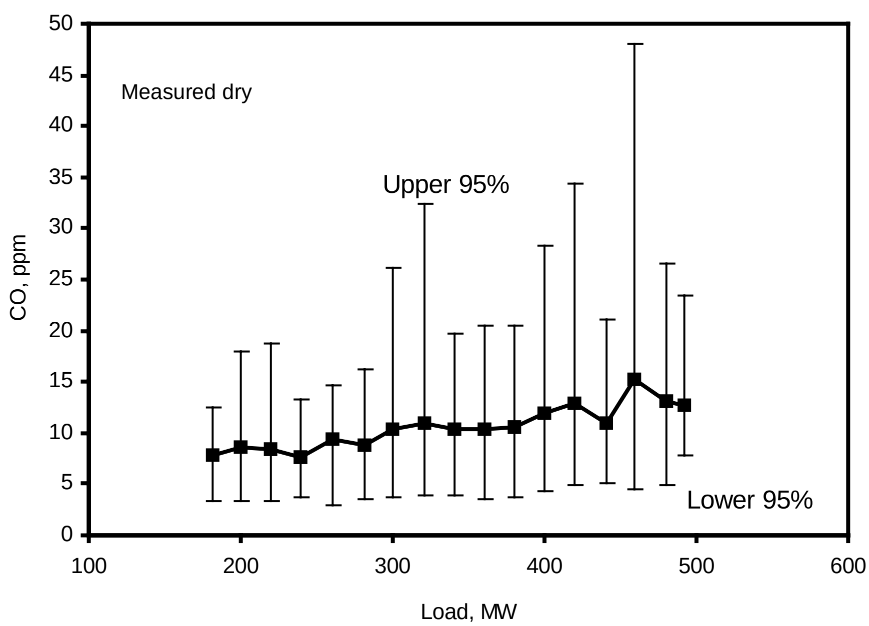


Figure 7-25 AOFA / Long-Term / CO vs. Load Characteristic

Table 7-8 AOFA / Mill Pattern Use Frequency

Average Load MW	MOOS	Sample Size	Average O_2 %	Average NOx lb/MBtu
184	A,E	179	8.6	0.84
184	B,E	655	9.0	0.87
295	B	81	6.0	0.85
295	E	367	8.5	0.93
395	B	97	6.5	0.82
395	NONE	319	7.1	0.94
477	NONE	3207	6.4	0.97

7.2.3 Thirty-day Rolling Averages

The NSPS Subpart Da and Db standards are based upon compliance on a thirty-day rolling average. While this unit is not required to comply with these standards, it is of some value to evaluate the data for Phase 2 on a thirty-day rolling average basis for the purpose of comparison to the average during other test phases. Thirty-day rolling average load, NOx, and O_2 were computed using the valid hourly data. These thirty-day rolling averages are shown in Figure 7-26 for the 92 (63 rolling averages) valid days (by EPA criteria) of data.

The thirty-day rolling average results shown in Figure 7-26 are only representative of the load scenario that was experienced by the unit during this long-term test period. During other periods when the load might be significantly different, the rolling averages would be expected to be somewhat different. For this particular period, it can be seen that there was a slight decrease in the daily load as the testing progressed as evidenced by the declining thirty day rolling average load. Because it was shown in the previous paragraphs that the NOx increases with increasing load, it is obvious that the rolling average NOx emissions should decrease as the testing progressed. The increase in O_2 is a result of the average load decrease during the period. Being relatively independent of load, NOx emissions did not exhibit this temporal variation.

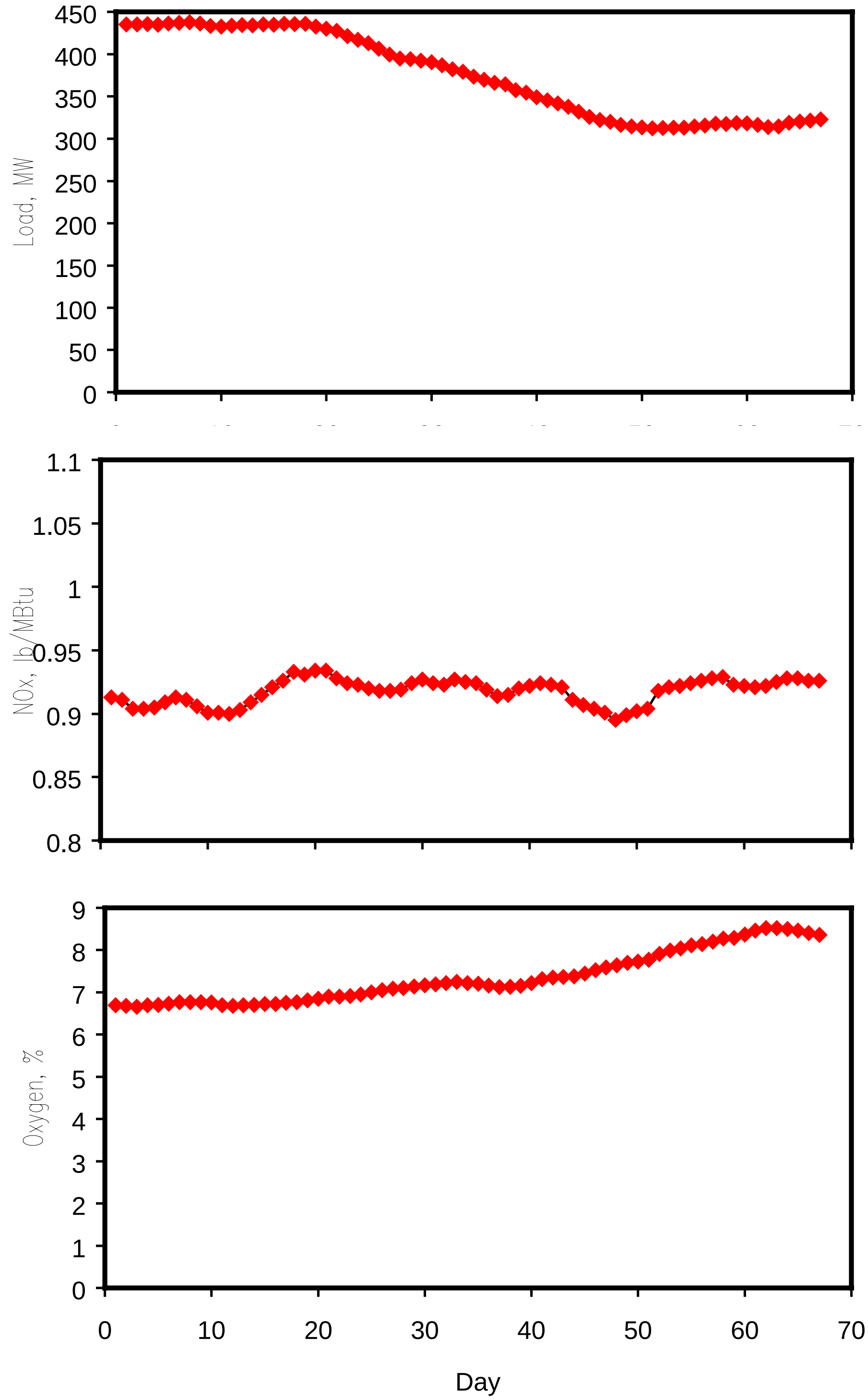


Figure 7-26 AOFA / Long-Term 30 Day Rolling Average

7.2.4 Achievable Emission Characterization

The EPA, in their rule making process, establishes an achievable emission level based upon daily average data samples obtained from CEMs. Most of this data is from NSPS Subpart Da units or units that used CEMs to obtain data during demonstration programs. The achievable NOx emission limit on a 30-day rolling average basis is determined using the descriptive statistics for 24-hour average NOx emissions. As discussed in previously, the SAS UNIVARIATE and AUTOREG procedures are used to determine the descriptive statistics for the 24-hour average NOx emissions data.

The results of the UNIVARIATE and AUTOREG analyses of the 24-hour average NOx emissions are presented in Table 7-9. The UNIVARIATE analysis indicated that the daily emissions were normally distributed. The AUTOREG analysis also indicated that the day-to-day fluctuations in NOx emissions followed a simple first order auto-regressive model.

Table 7-9 AOFA / Descriptive Statistics for Daily Average NOx Emissions

Statistic	Value
Number of Daily Values	86
Average Emissions (lb/MBtu)	0.92
Standard Deviation (lb/MBtu)	0.079
Distribution	Normal
First Order Autocorrelation (ρ)	0.69

Based upon the EPA criteria, the achievable NOx emission limit should only be exceeded, on average, once per 10 years on a 30-day rolling average basis. The achievable emission depends on the long-term mean, variability, and autocorrelation level. The achievable emission limit is computed using these values as discussed earlier. Table 7-10 provides the achievable emission level. The achievable NOx emission limits shown in this table, are computed for two conditions -- no autocorrelation ($\rho = 0$) and the estimated value of 0.69 (which indicates highly time dependent data). The assumption in this table is that the Hammond unit will be operated in the future under similar load dispatching as that during the baseline test phase. It should be noted that the mean, variability, and autocorrelation levels given in Table 7-9 are only estimates. There is an uncertainty level implicit in the estimates of each of these statistical parameters. The uncertainty level in the mean is dependent on the variability. The estimated variability is, to some extent, dependent on the level of auto-correlation. Thus, uncertainty levels in the descriptive statistics are linked.

Table 7-10 AOFA / 30-Day Rolling Average Achievable NOx Emission Limit

Auto-Correlation	AEL 30 Day	AEL Annual
$\rho = 0$	0.966	0.923
$\rho = 0.69$	1.03	0.93

7.2.5 Comparison of Short- and Long-Term NOx Data

A comparison of the short- and long-term NOx emissions data collected during this phase is shown in Figure 7-27. The data includes all of the configurations (including those with AOFA closed) tested during this period. From this figure, it is evident that the data collected during this period was in most cases within the ±95 percentile band of the long-term data. At the high load conditions, NOx was sometimes higher as a result of tests being conducted with the overfire air system isolated. Early in the diagnostic testing, the oxygen levels tested were those normally experienced during the baseline tests. Subsequent to these early tests, it was discovered that there was significant backpass leakage and as a consequence, the excess oxygen measured at the economizer outlet represented the air available for combustion plus leakage air. This resulted in some short-term tests being conducted at true furnace oxygen levels lower than that required for complete combustion. As a result, the LOI levels for these tests were high and it was recommended that the excess oxygen level be raised by one percentage point to compensate for the leakage.

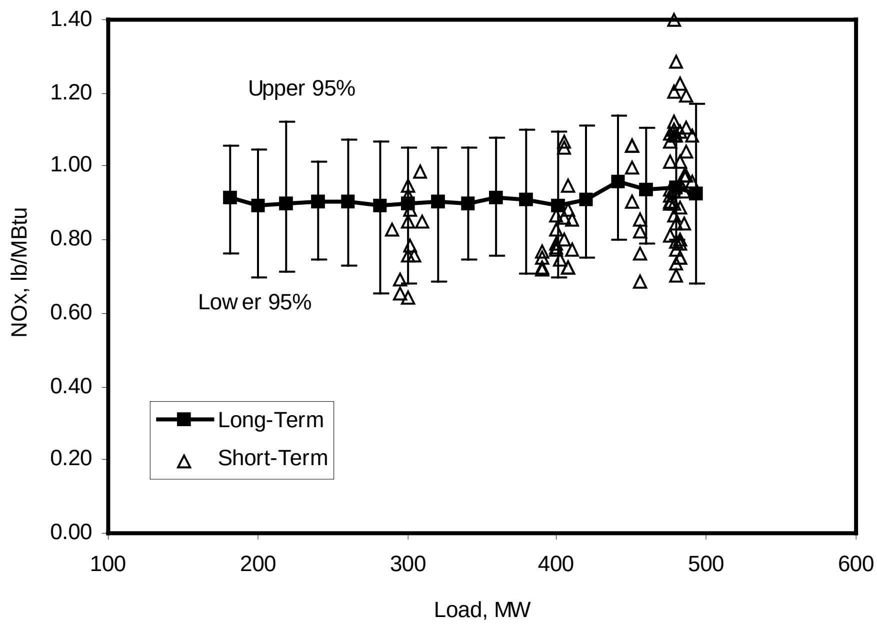


Figure 7-27 AOFA / Comparison of Short- and Long-Term NOx Emissions

7.2.6 Process Data

In addition to the emissions data described earlier, process data was collected to provide insight to changes in the boiler performance and turbine cycle heat rate as a result of the installation of the tested technologies. The more important of these variables are discussed below.

Steam Temperatures and Spray Flows

Main steam temperature as measured at the turbine inlet is shown in Figure 7-28. As a result of instrumentation failure, the reheat temperature was not available during this test phase. The project relied on plant instrumentation for this measurement. Reheat control relied on pneumatic sensors and thus was not directly available for measurement. As shown, main steam temperature averaged approximately 990°F over the entire load range. Superheat spray flows (lower and upper) are shown in Figures 7-29 and 7-30. The lower spray flow is used to control the division wall inlet temperature to 20°F above saturation, whereas the upper spray flow is used to control the superheat outlet temperature to 1000°F.

Excess Oxygen Levels

In addition to the ECEM excess oxygen measurement, excess oxygen was also measured at the economizer and air heater outlet using in situ instrumentation. The load characteristic for this data, along with the data obtained through the ECEM, is shown in Figures 7-31 through 7-35. Excess oxygen (Figures 7-30 and 7-31) as measured at the economizer outlet is used by the control system to maintain combustion stoichiometry at prescribed levels. Excess oxygen as measured at the air heater outlet is used for determination of air heater and boiler performance and not for control. In all figures, the reading obtained by the in situ instrumentation is well below that obtained by the ECEM. This difference is the result of:

- The ECEM is a dry reading whereas the in-situ instrumentation provides excess oxygen on a dry basis.
- The ECEM samples flue gas considerably downstream of the in-situ monitors and thus there is the potential for air in-leakage.

For Phase 2, the stack oxygen was, on average, a good estimator for economizer oxygen when these factors are taken into consideration, though not as good as estimator as seen in Phase 1 (Figure 7-33). The air-heater outlet oxygen characteristics are shown in Figures 7-34 and 7-35.

Economizer Exit and Air Heater Exit Temperatures

The economizer exit and air heater exit gas temperatures are shown in Figures 7-37 through 7-40. As shown, full load economizer exit temperatures average approximately for 670°F and 740°F for the east and west side, respectively. The design at full load is near 710°F. As expected, the temperature dropped with decreasing load, averaging near 640°F at 260 MW. The design temperature at this load is near 590°F. The secondary air-heater outlet temperature averaged approximately 305°F at full load -- the design value is near 282°F. As shown, the west side temperatures were less than the east side while the converse was true for Phase 1.

Fly Ash LOI

An estimate for the LOI is shown in Figure 7-41. Because there was no on-line carbon-in-ash measurement during this phase, the carbon-in-ash measurement is based on the LOI values obtained during the performance tests and the deviation between the stack oxygen levels during these tests and those during the long-term test period.

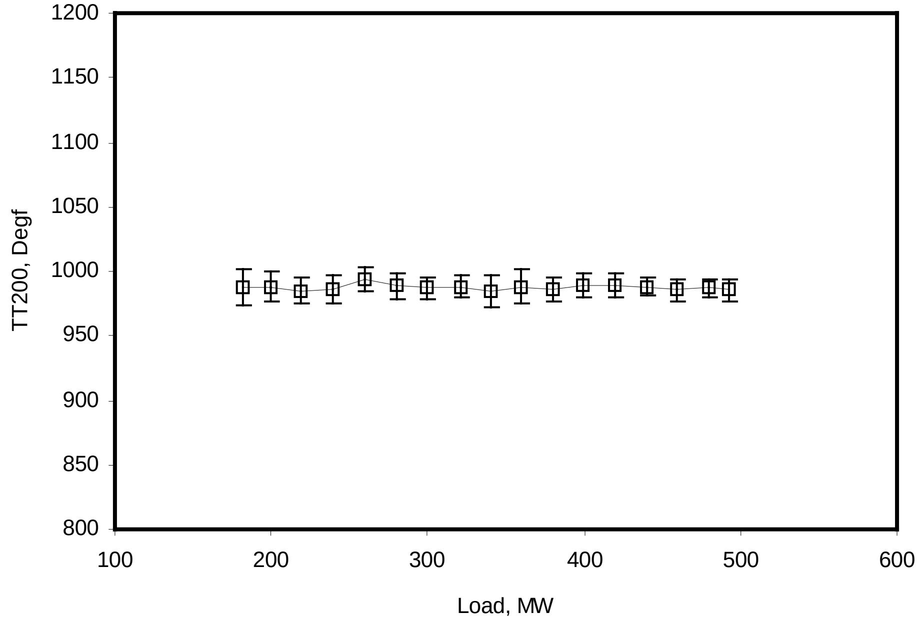


Figure 7-28 AOFA / Long-Term / Main Steam at Turbine Temperature

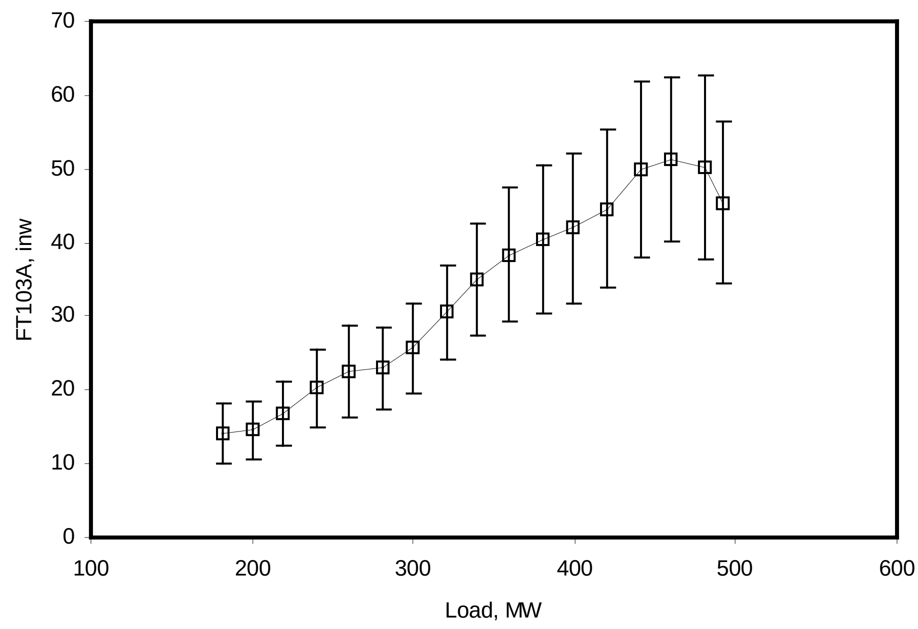


Figure 7-29 AOFA / Long-Term / Superheat Spray Flow Lower

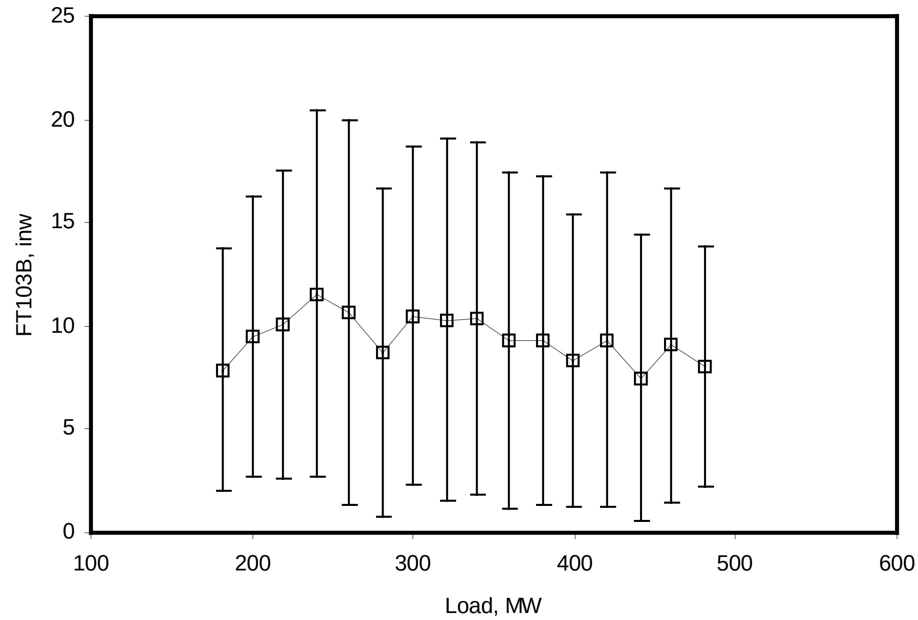


Figure 7-30 AOFA / Long-Term / Superheat Spray Flow Upper

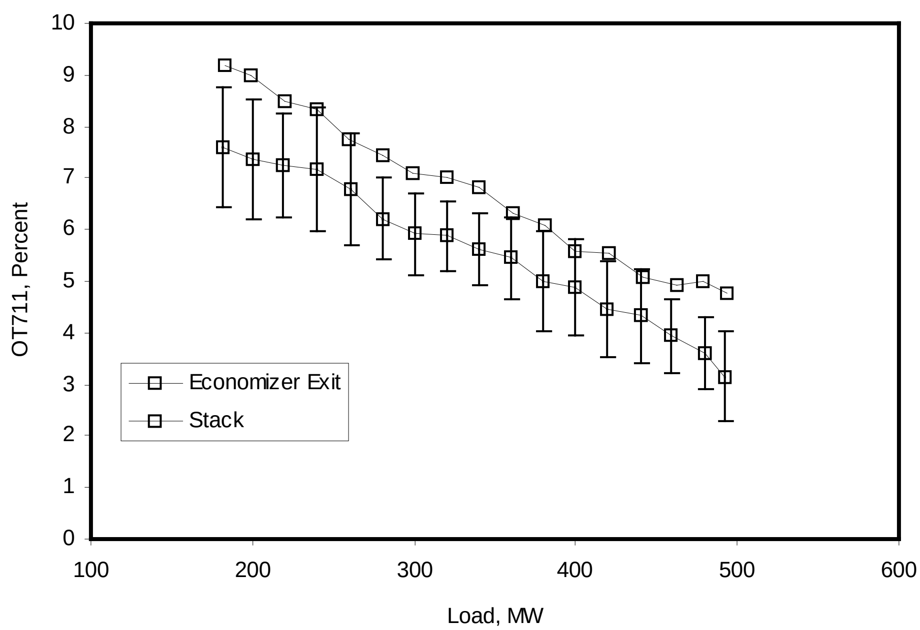


Figure 7-31 AOFA / Long-Term / Excess Oxygen at Economizer Outlet / East

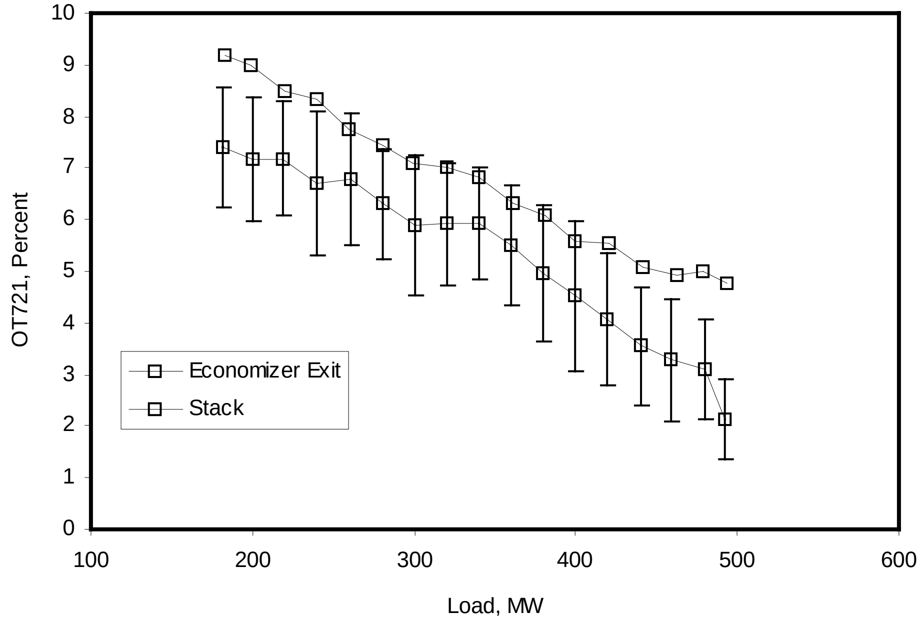


Figure 7-32 AOFA / Long-Term / Excess Oxygen at Economizer Outlet / West

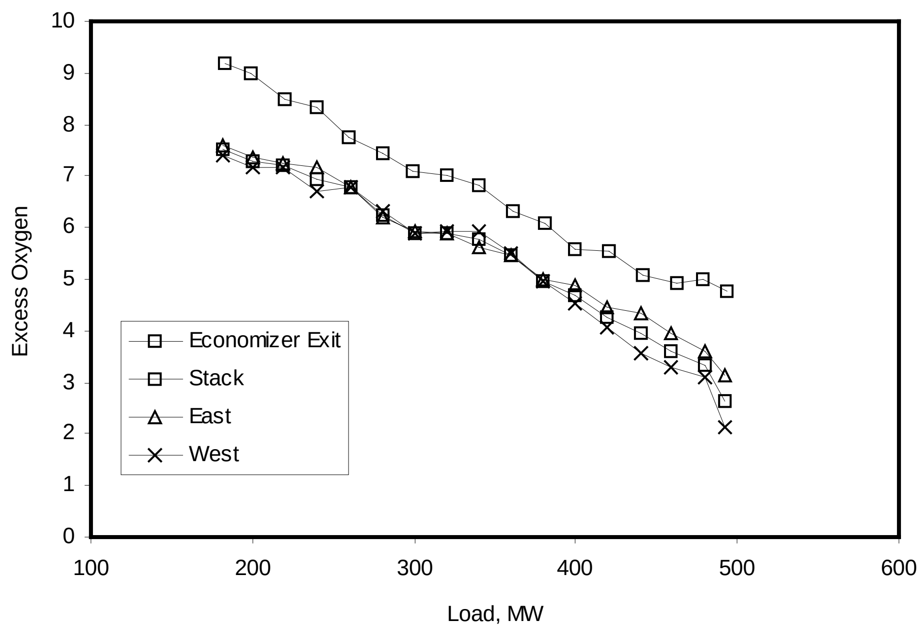


Figure 7-33 AOFA / Long-Term / Excess Oxygen at Economizer Outlet / Average

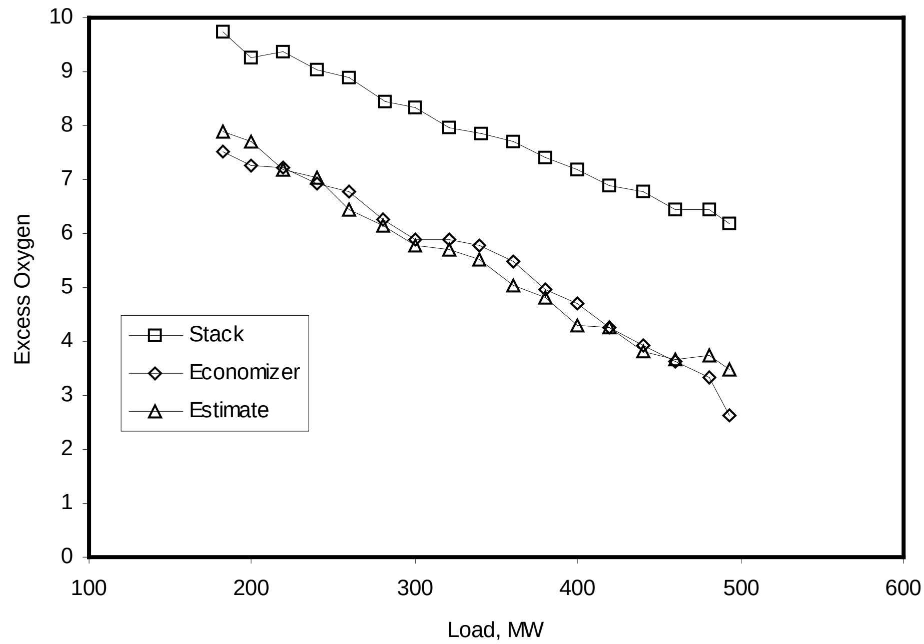


Figure 7-34 AOFA / Long-Term / Excess Oxygen at Economizer Outlet / Estimate

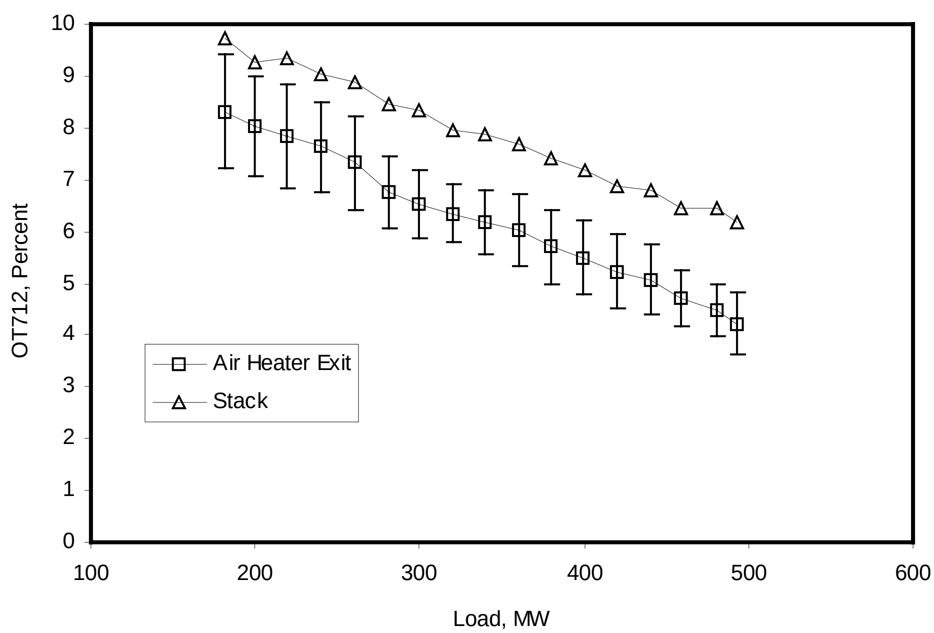


Figure 7-35 AOFA / Long-Term / Excess Oxygen at Air Heater Outlet / East

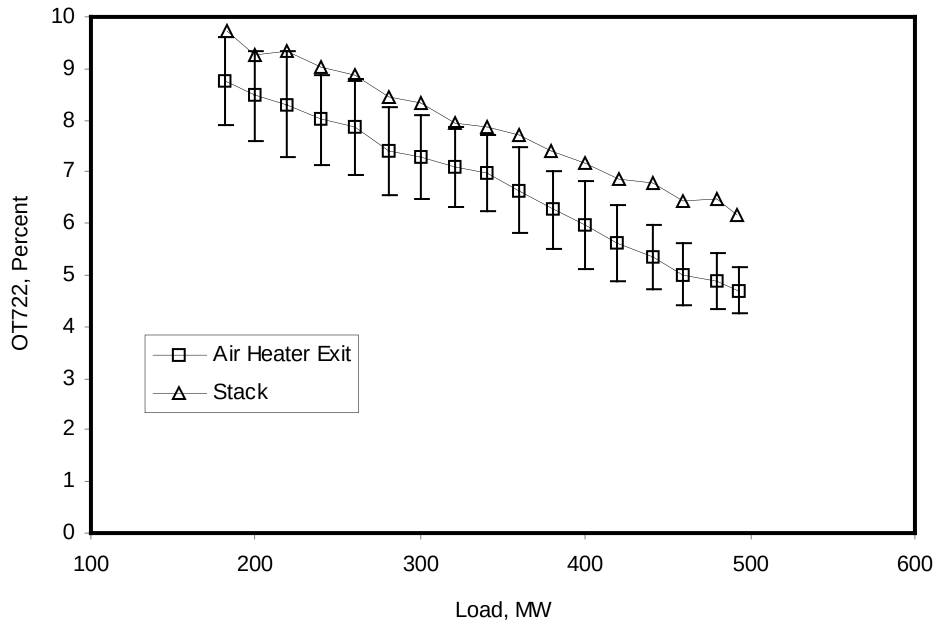


Figure 7-36 AOFA / Long-Term / Excess Oxygen at Air Heater Outlet / West

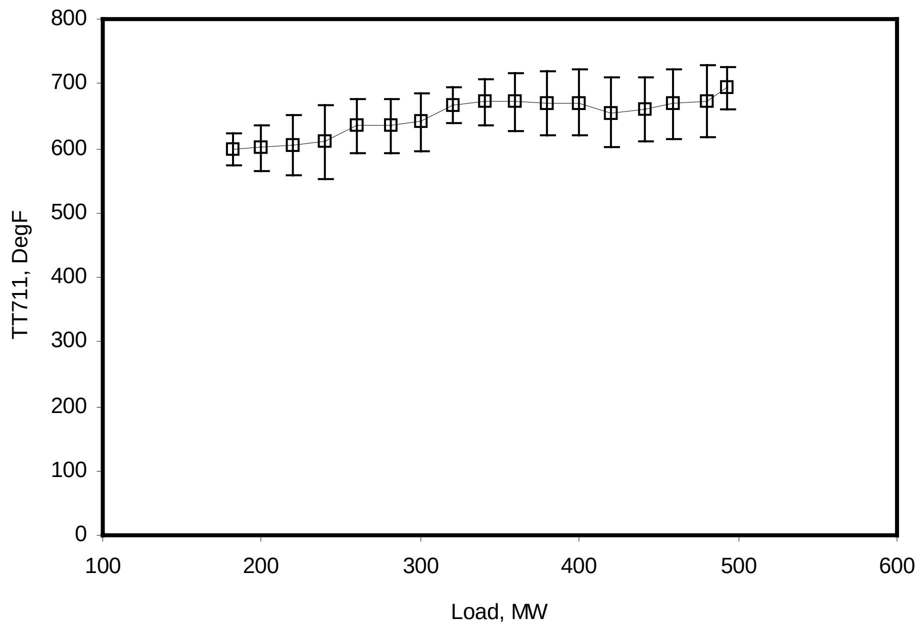


Figure 7-37 AOFA / Long-Term / Flue Gas Temperature at Air Heater Inlet / East

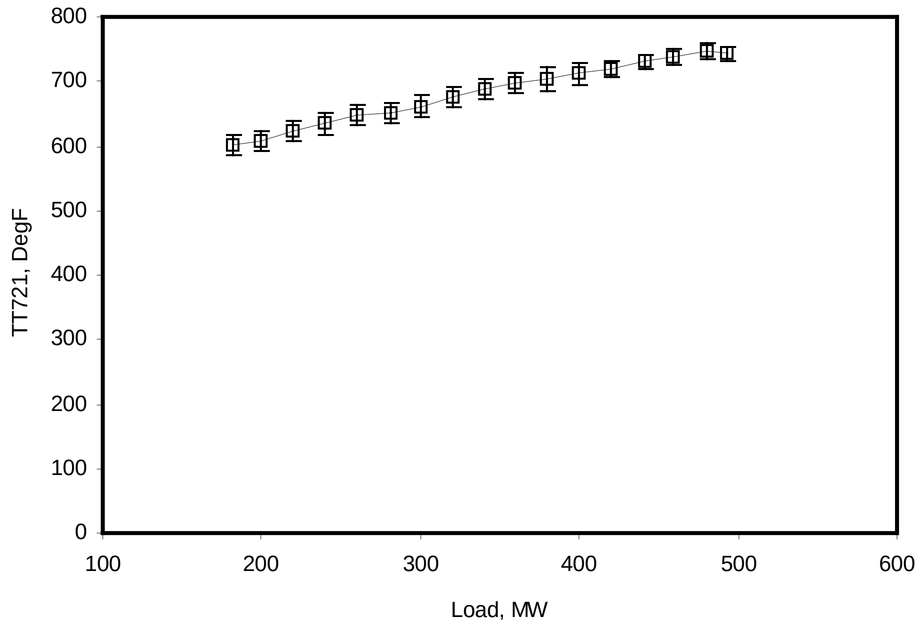


Figure 7-38 AOFA / Long-Term / Flue Gas Temperature at Air Heater Inlet / West

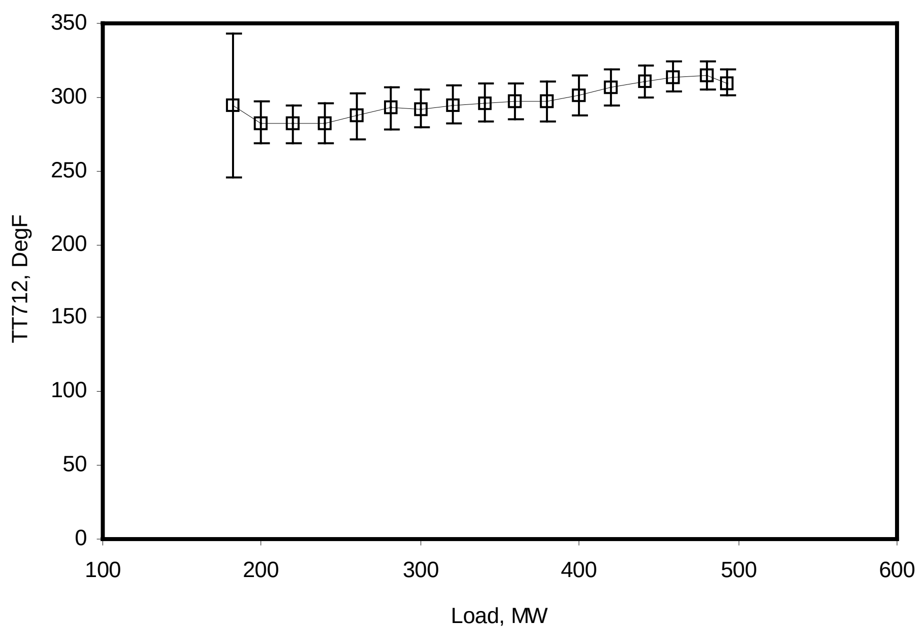


Figure 7-39 AOFA / Long-Term / Flue Gas Temperature at Air Heater Outlet / East

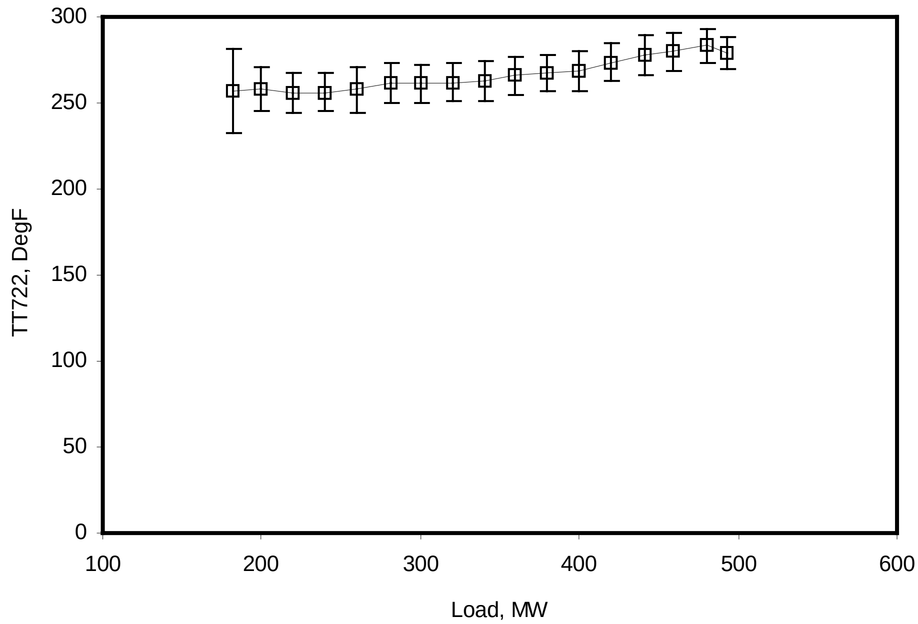


Figure 7-40 AOFA / Long-Term / Flue Gas Temperature at Air Heater Outlet / West

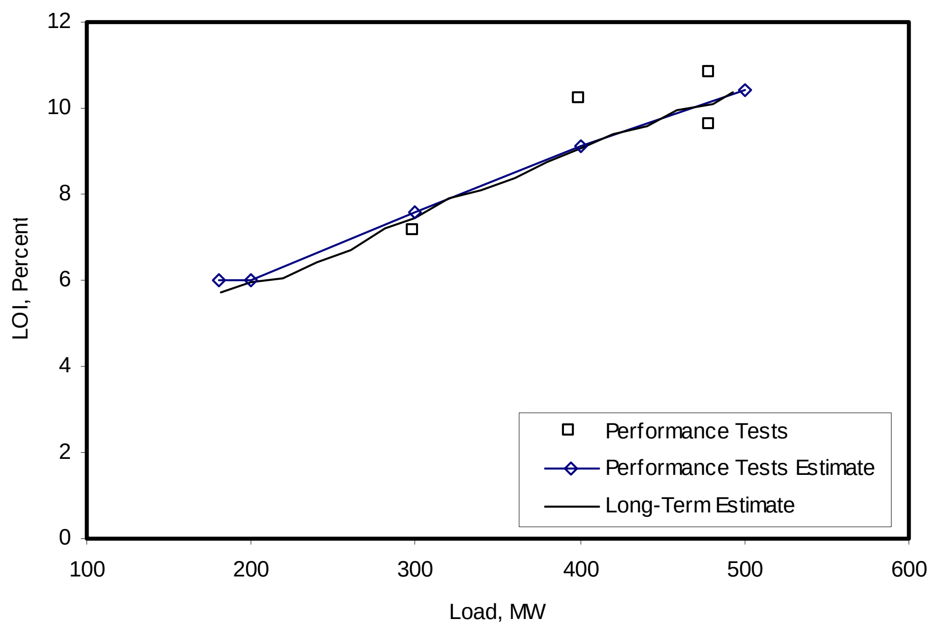


Figure 7-41 AOFA / Long-Term / LOI Estimate

7.3 Operational and Reliability Impacts

The main difference in the overall operation of the unit with the AOFA system compared to baseline was the manual operation of the AOFA dampers; a separate control panel was provided in the control room and the operators had to change the AOFA damper position manually. The damper position setpoint was a function of load. On units with a digital control system or other modern combustion control system, the dampers could readily be automated.

8 PHASE 3A - LNB TRIALS

8.1 Short-Term Test Results

The initial Phase 3A short-term characterization testing was begun on July 9, 1991 and was completed on January 15, 1992. A total of 52 diagnostic tests were performed during this period. An additional 40 tests were performed during a special series of LOI tests performed from October 15 through 28, 1992. The short-term testing consisted of first performing diagnostic tests to establish the general NOx and operating trends followed by performance testing to establish the characteristics of the fuel/air system and the solid and gaseous emissions for the most representative configuration. All tests during both the diagnostic and performance portions of the short-term test effort were conducted within the normal limits of operating parameters for the unit with the exception of excess oxygen which was exercised well above and below the plant-specified range to the potential levels that might be encountered during transients in the long-term test phase. All major boiler components, as well as ancillary equipment, were in the normal “as-found” operating condition as configured by FWEC. The fuel burned throughout the Phase 3A short-term program was from the normal source and was handled according to common plant practice. For all Phase 3A testing (LNB without AOFA), the main AOFA guillotine dampers and AOFA port dampers were left open but the AOFA flow control dampers were nominally “closed”, with only sufficient AOFA flow permitted to provide some cooling for the AOFA ports and dampers to prevent heat damage. The following paragraphs describe the diagnostic, performance, and LOI testing performed during the Phase 3A effort.

8.1.1 Diagnostic Tests

The Phase 3A diagnostic effort consisted of characterizing emissions under normal operating conditions with the LNBs installed and the AOFA flow control dampers nominally closed. Fifty-two tests were performed at nominal loads of 180, 300, 400, and 480 MW (Table 8-1). The diagnostic test efforts were interrupted to accomplish the performance testing due to scheduling conflicts. Diagnostic testing was then completed after the performance testing and long-term evaluation was completed. The initial diagnostic testing began shortly after FWEC completed LNB start-up testing. Each test condition (load, excess oxygen, and mill configuration) was held steady for a period of from one to three hours depending upon the type of test performed. During this period, data was collected from the control room, boiler operational data was recorded on the DAS, and economizer exit and air heater exit species and temperatures were recorded utilizing the sample distribution manifold and the DAS. When sufficient time permitted, furnace backpass ash grab samples were collected from the manual ash samplers and coal samples were collected from the individual mills.

Table 8-1 LNB / Diagnostic Tests Conducted

Test	Date	Test Conditions	Load MW	MOOS	Economizer O_2 %
58-1	7/9/91	HIGH LOAD, AMIS, HIGH O2-LOI TEST	477	NONE	4.6
58-2	7/9/91	HIGH LOAD, AMIS, NORM O2-LOI TEST	475	NONE	4.1
58-3	7/9/91	HIGH LOAD, AMIS, LOW O2-LOI TEST	473	NONE	2.9
59-1	7/10/91	HIGH LOAD, AMIS, HIGH O2-LOI TEST	471	NONE	5.0
59-2	7/10/91	HIGH LOAD, AMIS, NORM O2-LOI TEST	473	NONE	4.0
59-3	7/10/91	HIGH LOAD, AMIS, LOW O2-LOI TEST	475	NONE	3.1
59-4	7/10/91	HIGH LOAD, AMIS, MIN O2-LOI TEST	474	NONE	2.6
59-5	7/10/91	HIGH LOAD, AMIS, LO NORM O2-HVT TEST	474	NONE	3.7
60-1	7/11/91	MID LOAD, AMIS, HIGH O2	393	NONE	4.6
60-2	7/11/91	MID LOAD, AMIS, NORM O2	398	NONE	3.9
60-3	7/11/91	MID LOAD, AMIS, LOW O2	397	NONE	3.5
60-4	7/11/91	MAX LOAD, AMIS, NORM O2, GPC HEAT RATE	502	NONE	4.0
61-1	7/12/91	MID LOAD, AMIS, REPEAT HIGH O2	392	NONE	4.7
61-2	7/12/91	MID LOAD, AMIS, REPEAT NORM O2	392	NONE	4.1
61-3	7/12/91	MID LOAD, AMIS, REPEAT LOW O2	390	NONE	3.2
61-4	7/12/91	MAX LOAD, AMIS, NORM O2, GPC HEAT RATE	498	NONE	3.9
62-1	7/13/91	MID/LOW LOAD, E MOOS, HIGH O2	289	E	7.1
62-2	7/13/91	MID/LOW LOAD, E MOOS, MEDIUM O2	291	E	5.9
62-3	7/13/91	MID/LOW LOAD, E MOOS, NORM O2	290	E	4.8
62-4	7/13/91	MID/LOW LOAD, E MOOS, LOW O2-ABBREV.	289	E	4.0
62-5	7/13/91	HIGH LOAD, AMIS, NORM O2	474	NONE	4.3
63-1	7/14/91	MID/LOW LOAD, BE MOOS, HIGH O2	302	B&E	5.8
63-2	7/14/91	MID/LOW LOAD, BE MOOS, HIGH O2	305	E	5.7
63-3	7/14/91	MID/LOW LOAD, BE MOOS, NORM O2	303	E	4.8
64-1	7/15/91	HI LOAD, HI/MID O2, AMIS, BALANCED MILLS	467	NONE	4.6
64-2	7/15/91	HI LOAD, LOW O2, AMIS, BALANCED MILLS	470	NONE	3.3
67-1	7/18/91	HI LOAD, AMIS, HI O2-LOI TEST, OPEN INNER REG	472	NONE	4.3
67-2	7/18/91	HI LOAD, AMIS, MID O2-LOI TEST,	471	NONE	3.6
67-3	7/18/91	HI LOAD, AMIS, LOW 02-LOI TEST, OPEN OUT. REG	470	NONE	3.5
67-4	7/18/91	HI LOAD, LOW O2, LOI TEST, UF AIR AT 25%	465	NONE	3.5
68-1	7/19/91	HI LOAD, AMIS-LOI TEST, LOWER PRIM AIR FLOW	460	NONE	3.5
69-1	7/20/91	HI LOAD, AMIS-LOI TEST, MILL FINENESS A-MILL	473	NONE	3.2
69-2	7/20/91	HI LOAD, AMIS-LOI TEST, MILL FINENESS F-MILL	469	NONE	3.3
77-1	11/16/91	LOW LOAD, BC-MOOS, HI O2	180	BC	8.7
77-2	11/16/91	LOW LOAD, BC-MOOS, HI O2, REPEAT TEST	180	BC	8.5
77-3	11/16/91	LOW LOAD, BC-MOOS, MID O2	182	BC	7.4
77-4	11/16/91	LOW LOAD, BC-MOOS, LOW O2	185	BC	6.4
78-1	11/17/91	LOW LOAD, BE-MOOS, HI O2	181	BE	8.3
78-2	11/17/91	LOW LOAD, BE-MOOS, MID O2	183	BE	7.2
78-3	11/17/91	LOW LOAD, BE-MOOS, LOW O2	180	BE	5.8
79-1	11/18/91	MID/LOW LOAD, BE-MOOS, HI O2	305	BE	7.1
79-2	11/18/91	MID/LOW LOAD, BE-MOOS, MID O2	305	BE	6.1
79-3	11/18/91	MID/LOW LOAD, BE-MOOS, LOW O2	305	BE	5.3
80-1	11/18/91	MID/LOW LOAD, EF-MOOS, LOW O2	310	EF	4.8
80-2	11/18/91	MID/LOW LOAD, EF-MOOS, MID O2	308	EF	6.3
80-3	11/18/91	MID/LOW LOAD, EF-MOOS, MID O2, SLEEVES 50%	310	EF	6.2
81-1	1/14/92	MID/LOW LOAD, BE-MOOS, LOW O2	302	BE	5.0
81-2	1/14/92	MID/LOW LOAD, BE-MOOS, MID O2	299	BE	6.5
81-3	1/14/92	MID/LOW LOAD, BE-MOOS, HI O2	301	BE	7.0
82-1	1/15/92	MID LOAD, AMIS, LOW O2	395	NONE	3.8
82-2	1/15/92	MID LOAD, AMIS, MID O2	395	NONE	4.5
82-3	1/15/92	MID LOAD, AMIS, HI O2	395	NONE	5.4

8.1.1.1 Unit Operating Condition

During the diagnostic test efforts, no unusual operating conditions were encountered that placed restrictions on the test effort. Sixteen days of testing were conducted comprising 52 various excess oxygen, mill pattern, and load conditions. Because historic load profiles indicated much greater operating times at 400 MW and above, most diagnostic testing was conducted in this load range.

8.1.1.2 Gaseous Emissions

During the diagnostic and performance test efforts, flue gas data and boiler operating data was collected on the data acquisition system. The ECEM allowed measurement of NOx, CO, O_2, and total hydrocarbons (THC) from 48 probe locations within the flue gas stream both upstream and downstream of the air heater. Two basic types of tests were performed: (1) overall NOx characterization and (2) economizer exit plane species distribution characterization. The overall NOx characterization tests were performed over an approximately one-hour period and were used to obtain composite average specie concentrations from the individual probes in a duct sampled as a group. In general, the groups were (1) A-side economizer outlet, (2) B-side economizer outlet, (3) A-side APH outlet and (4) B-side APH outlet. The economizer exit plane species distribution characterizations were performed over a period of approximately two to three hours. These tests used data from the individual probe species concentrations in the A- and B-side economizer exit planes to establish the distribution of combustion products. A non-uniform distribution, if present, indicates fuel and/or air imbalances.

The range of excess oxygen and resulting NOx emissions for the four nominal load levels tested during the diagnostic portion of the Phase 3A effort are shown in Figures 8-1 and 8-2 (extracted from Appendix C). These operating parameters provide information on the steaming conditions and the fuel supply configuration. The conditions represented in these figures include excess oxygen variation, mill-out-of-service variation, mill biasing, etc. As shown, testing was performed over a range of excess oxygen levels that were both below and above the levels recommended for this unit. The solid curve represents the recommended excess oxygen operating level. During normal dispatch of the unit, excursions to these levels are frequently experienced during transient load conditions. To properly compare the short-term and long-term characteristics, this O_2 excursion testing during the short-term diagnostic effort was required.

Figure 8-2 is a summary of all of the NOx data obtained for all test configurations. These configurations represented the range of configurations that were believed to be the potential modes of operation that might be experienced during the normal dispatch of the unit during long-term testing. The data scatter is partially a result of different configurations being represented. The shaded area represents the range of NOx values experienced at excess O_2 levels within a ± 0.5 percent O_2 variation about the recommended O_2 level. It should be emphasized that analyses performed for data gathered during the long-term testing, where virtually thousands of data points were used for the characterization, provide a more statistically appropriate NOx band than that presented in Figure 8-2.

Short-term characterization of the NOx emissions generally were made for trends determined on the same day of testing for a particular configuration to eliminate, to some extent, the influence of the uncontrollable parameters. Figures 8-3 through 8-6 show the NOx vs. excess O_2 characteristic for the four nominal loads tested - 480, 400, 300, and 180 MW. The lines on the figures represent the excess oxygen trends for a given day of testing. In general, the sensitivity of NOx emissions to excess O_2 levels ranged from 0.059 lb/MBtu at full-load to 0.048 lb/MBtu at 300 MW.

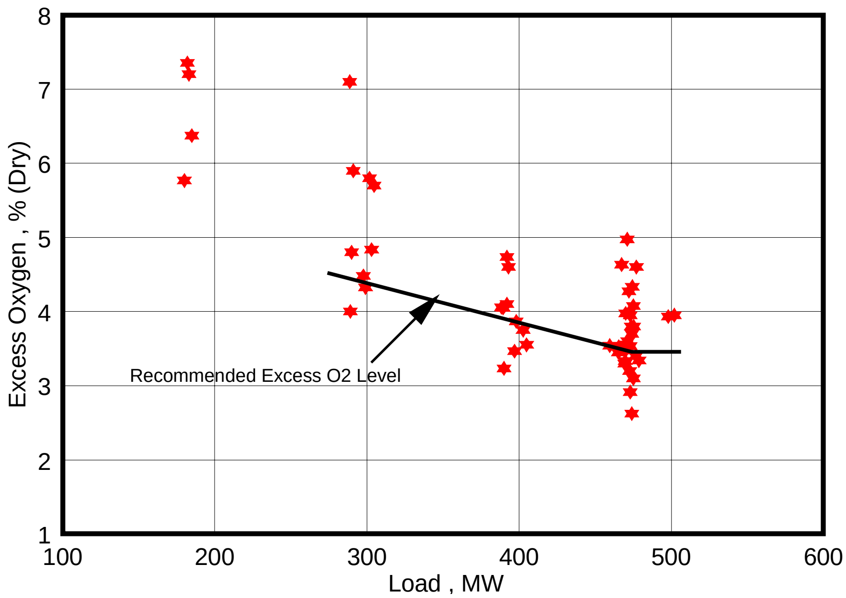


Figure 8-1 LNB / Diagnostic Tests / Oxygen Levels Tested

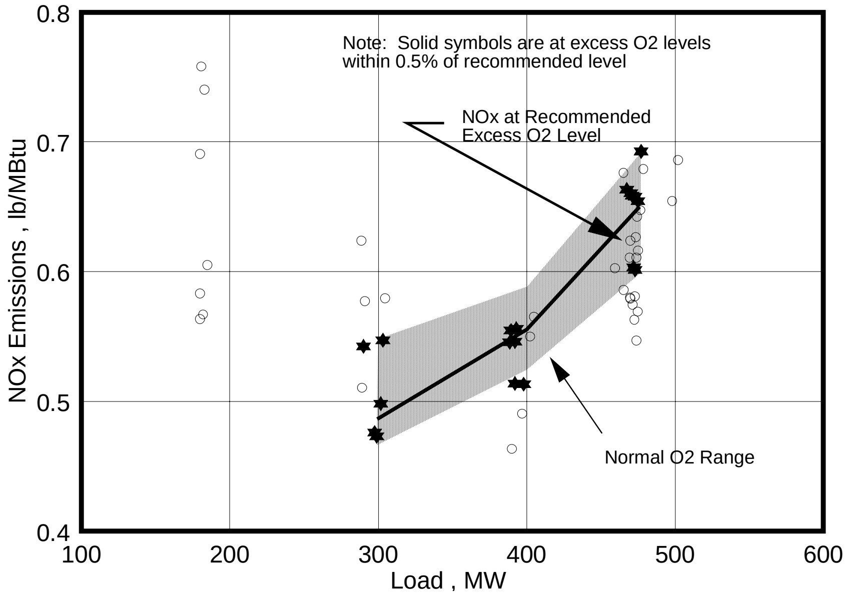


Figure 8-2 LNB / Diagnostic Tests / NOx Emissions

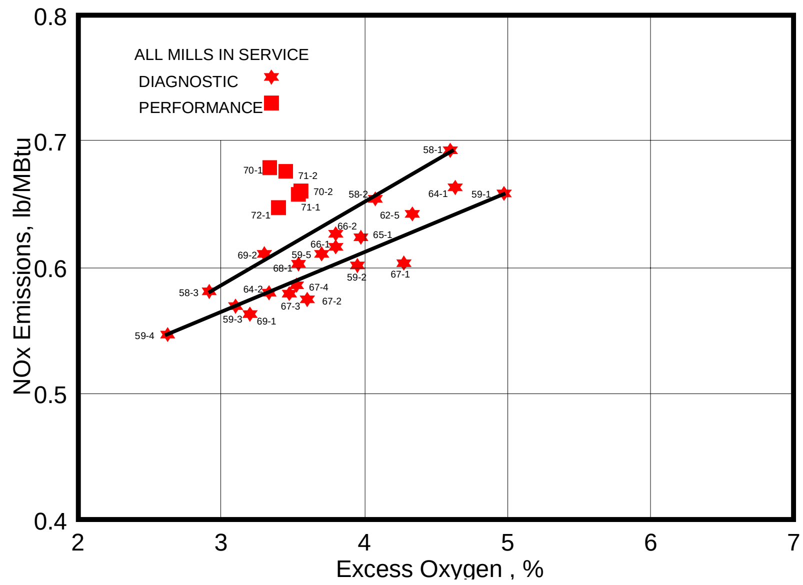


Figure 8-3 LNB / Diagnostic Tests / NOx Characterization at 480 MW

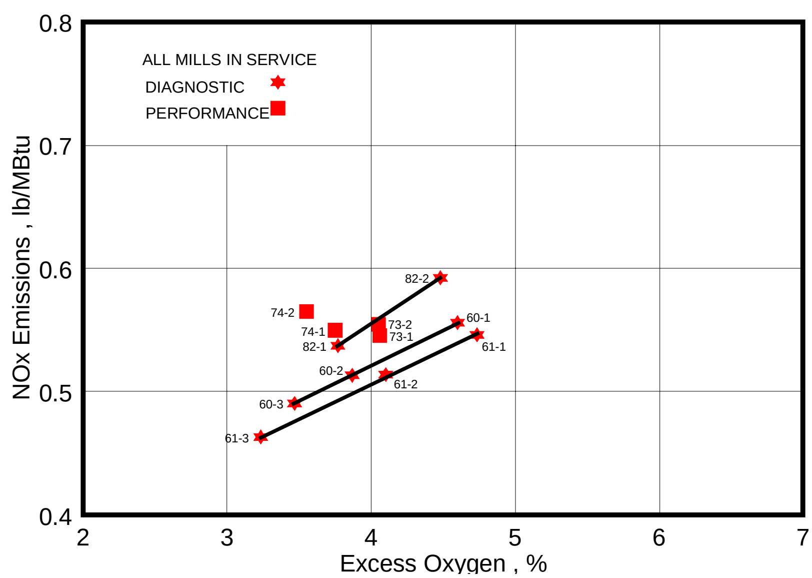


Figure 8-4 LNB / Diagnostic Tests / NOx Characterization at 400 MW

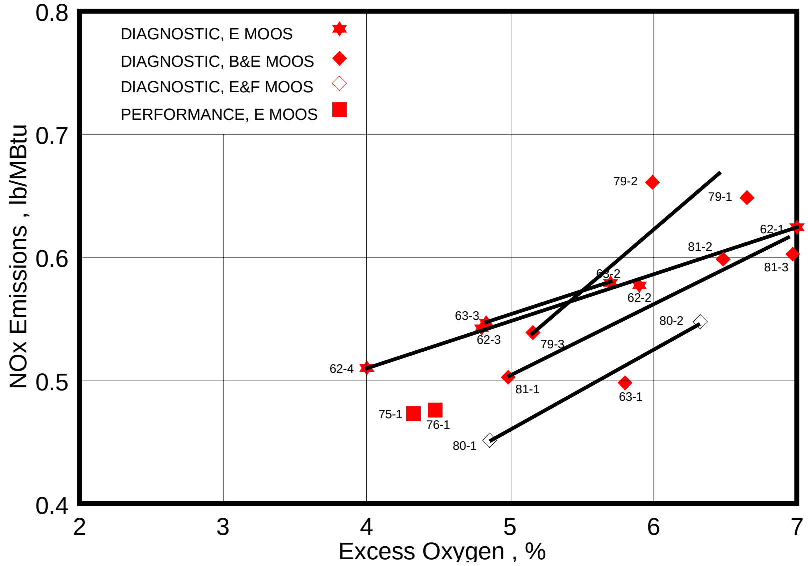


Figure 8-5 LNB / Diagnostic Tests / NOx Characterization at 300 MW

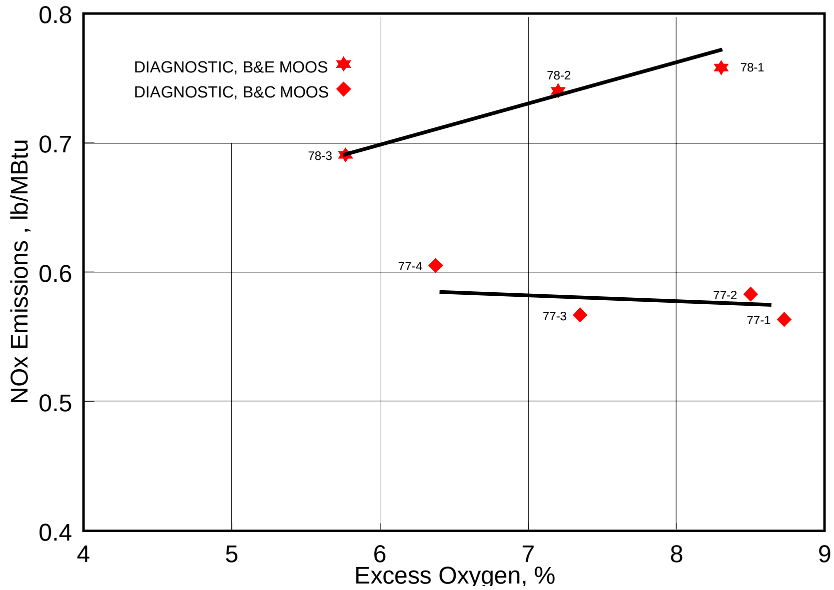


Figure 8-6 LNB / Diagnostic Tests / NOx Characterization at 180 MW

8.1.2 Performance Tests

Nine performance tests were conducted at nominal gross loads of 480, 400, and 300 MW (Table 8-2). Testing at each load point required two consecutive days to complete sampling of all of the parameters included in the performance matrix. At each nominal load, the coal firing rate was kept as constant as possible and the electric load allowed to swing as affected by coal variations, boiler ash deposits, ambient temperature, etc. Each performance test day covered a period from ten to twelve hours during which boiler operational data was recorded, fuel and ash samples acquired, gaseous and solid emissions measurements made, and fly ash resistivity measured in situ.

The initial two performance tests (65 and 66) were performed with the mills set to the normal primary air/fuel (A/F) ratio as initially recommend by FWEC personnel. Based on previous LOI results and existing stack opacity readings, the FWEC representative on-site for these tests recommended that some additional diagnostic tests be performed at alternative primary air/fuel ratios and burner air register settings, while taking fly ash samples for LOI analysis. The performance testing therefore was interrupted for five days to plan and perform the desired diagnostic tests (days 67, 68, and 69). Based upon the results of those tests, the performance testing was resumed with reduced primary air/fuel ratios and minor burner adjustments.

Table 8-2 LNB / Performance Tests Conducted

Test No.	Date	Test Conditions	Load	MOOS	ECONO O_2 %
65-1	7/16/91	HI LOAD, AMIS	470	NONE	4.0
66-1	7/17/91	HI LOAD, AMIS	475	NONE	3.8
66-2	7/17/91	HI LOAD, AMIS	474	NONE	3.8
70-1	7/22/91	HI LOAD, AMIS, REDUCED PRIM. AIR	479	NONE	3.3
70-2	7/22/91	HI LOAD, AMIS, REDUCED PRIM. AIR	470	NONE	3.6
71-1	7/23/91	HI LOAD, AMIS, 50% OUTER REG	473	NONE	3.5
71-2	7/23/91	HI LOAD, AMIS, REDUCED PRIM. AIR	465	NONE	3.5
72-1	7/24/91	HI LOAD, AMIS, REDUCED PRIM. AIR	477	NONE	3.4
73-1	7/26/91	MID LOAD, AMIS, HI O2	388	NONE	4.1
73-2	7/26/91	MID LOAD, AMIS, HI O2	389	NONE	4.1
74-1	7/27/91	MID LOAD, AMIS, HI O2	403	NONE	3.8
74-2	7/27/91	MID LOAD, AMIS, HI O2	405	NONE	3.6
75-1	7/28/91	MID/LOW LOAD, E MOOS	299	E	4.3
76-1	7/28/91	MID/LOW LOAD, E MOOS	298	E	4.5

8.1.2.1 Unit Operating Data

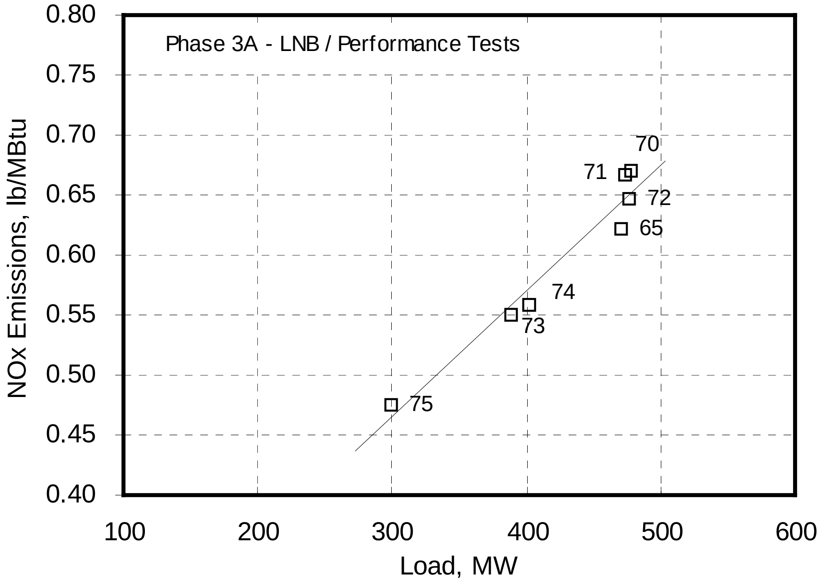
For each performance test, the desired test conditions were established and allowed to stabilize at least one hour prior to commencement of testing. To the extent possible, the active coal mills were balanced with respect to coal feed rate. Normal primary air/coal ratios and mill outlet temperatures were maintained within the capabilities of the existing primary air system. When the desired operating conditions were established, some controls were placed in manual mode to minimize fluctuations in fuel flow and airflow. This technique resulted in extremely stable operation over the test duration with only minor adjustments required to the airflow during the course of the test day.

Because a portion of the testing was concerned with measurement of various particulate emission characteristics, it was decided that soot blowing (both furnace and air heaters) should be suspended during the particulate sampling periods. This precaution would insure that the samples include only particulate matter actually generated by the coal combustion at the time of testing (plus any normal attrition of wall or air heater deposits) and not periodic portions of ash loosened by soot blowing. When necessary for proper unit operation, air heaters were blown between repetitions in the solids emissions sampling.

8.1.2.2 Gaseous Emissions

During the performance tests, gaseous emissions were measured with the ECEM operating in the manual mode. At various times during the performance tests, flue gas was sampled from selected probes or probe groups in the primary and secondary air heater inlet and outlet ducts. These groupings consisted of composites of the individual east and west economizer exit ducts and individual measurements from each probe in these ducts. Composite grouping was performed to establish the overall emission characteristics while the individual probe measurements were made to establish spatial distributions of emission species.

A summary of the NOx emissions data for these tests is shown in Figure 8-7. As shown, NOx emissions increased significantly with increasing load, ranging from a low of approximately 0.48 lb/MBtu at 300 MW to a high of approximately 0.65 lb/MBtu at 480 MW. The emissions for these tests were consistent with the diagnostic testing conducted earlier during the test period.



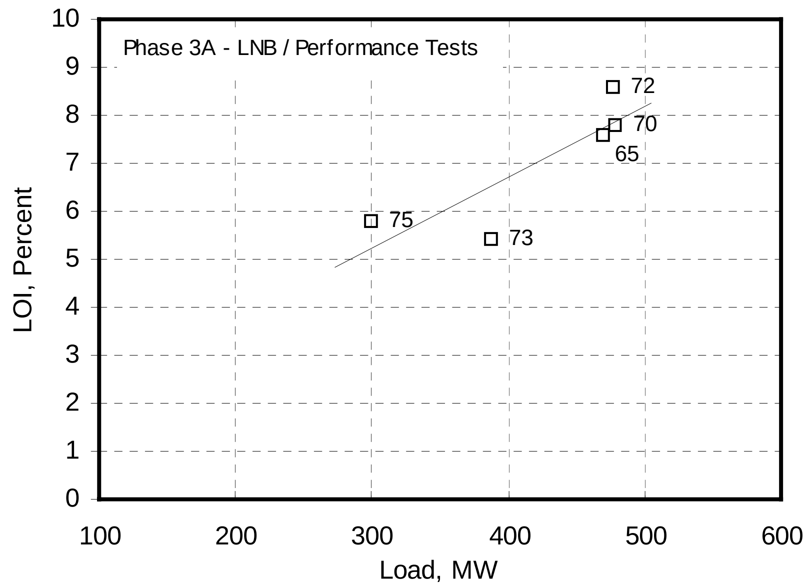


Figure 8-7 LNB / Performance Tests / NOx Emissions and LOI

8.1.2.3 Combustion System Tests

As in prior testing, combustion performance tests were performed at each of three load levels to document the specific performance parameters related to the fuel and air combustion systems. The results of the Phase 3A testing are summarized below.

Mill Performance

The airflow to each mill and the particle size and mass flow distributions of coal to each burner were measured as described in Section 5. Duplicate tests were performed at two load levels (480 and 400 MW). Figures 8-8 and 8-9 summarize the results of these tests. It can be seen that despite the mills being set to approximately equal coal flows with the boiler controls, the measured coal flows varied considerably from mill to mill.

As discussed above, the initial performance tests (65 and 66) were conducted with high primary air/fuel (A/F) ratios, which were subsequently reduced for the remaining tests (70 through 76). From Figure 8-9, it is seen that the initial full-load A/F ratios averaged around 2.5 (Test 66), whereas the reduced A/F ratios averaged about 2.2 (Tests 71 and 72). The A/F ratios increased somewhat as load was reduced to 300 MW to maintain sufficiently high coal pipe velocities to prevent coal layout. As in previous tests, mill D required substantially higher primary airflow to avoid mill loading.

During these mill tests, coal fineness was found to be below 70 percent through 200 mesh on all mills except for D mill, with E mill achieving 70 percent only marginally at times (Table 8-3). Mill performance was somewhat improved over baseline. Coal fineness has only a minor effect on NOx emissions but a substantial effect on fly ash LOI/carbon content.

Table 8-3 LNB / Average Coal Fineness

	Remaining on 50 Mesh	Passing 100 Mesh	Passing 200 Mesh
Test 65	1.22	91.7	67.1
Test 66	1.67	90.1	66.2
Test 70	1.21	92.0	68.0
Test 71	1.26	91.7	67.2
Test 72	1.52	90.7	65.8
Test 73	0.89	93.0	69.0
Test 74	1.13	92.1	67.6

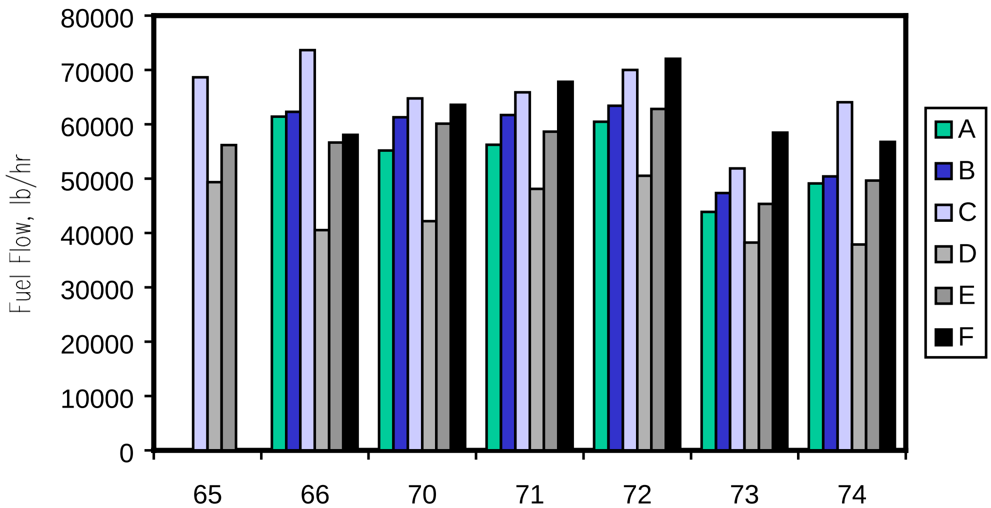


Figure 8-8 LNB / Fuel Distribution

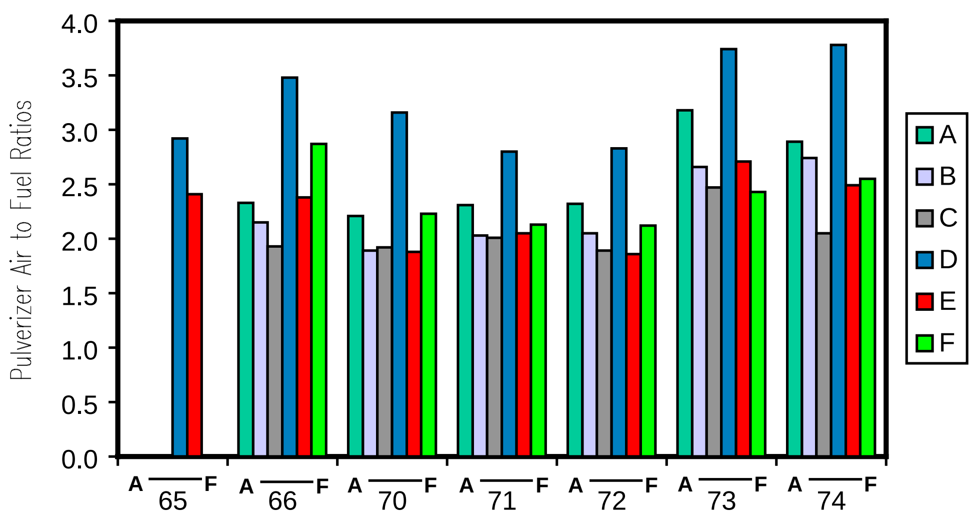


Figure 8-9 LNB / Pulverizer Air to Fuel Ratio

Combustion Air Flow

The secondary combustion airflow was measured at the east and west secondary air duct prior to the overfire air take off ducts, and therefore the uncorrected measurement includes the overfire flow, if any. The measurements made at the venturi throats in the secondary air supply ducts were very repeatable. The measurements taken at this location did not suffer from the inadequacies of the windbox flow locations used in previous phases of the program. Thus, there is a high level of confidence in the total air flow measurements based upon both the location and repeatability. During this test phase, the overfire airflow control dampers were at minimum, allowing only cooling air to the AOFA ports, as recommended by FWEC.

Figures 8-10 and 8-11 present the results of the flow measurements. As shown, secondary air accounted for approximately 75 to 80 percent of the total combustion air at the loads tested. This level is typical for pulverized coal units. The west secondary airflow was consistently slightly above that from the east, with the west averaging 53 percent of the total secondary air over the tests conducted. For all tests, it appeared from windbox flow measurements that the secondary combustion airflow was substantially greater to the front of the windbox than to the rear, in some cases by a ratio of 2 to 1. However, only the flow to front of the windbox was measured and that to the rear inferred by difference. These results are in question due to the difficulty in obtaining accurate flow measurements within the windbox. The front windbox sample ports are located in the side ducts in close proximity to the 90° turn prior to the entrance to the windbox and as a result, there was considerable turbulence and a large velocity gradient at this location. Because of access limitations, an independent measurement could not be made of the flow to the rear of the windbox. The furnace and economizer outlet oxygen measurements did not corroborate this severe front to rear imbalance (see below). Hence, the large indicated imbalance in flow from the front to the rear is likely the result of the inability to measure the flow accurately.

Furnace Measurements

Measurements were made of combustion gas temperatures and oxygen at eight locations within the boiler furnace nose and convective pass entrance. Figure 8-12 shows the distribution of temperature and excess oxygen at the 480, 400, and 300 MW nominal load point. At 480 MW, there was some combustion non-uniformity within the furnace, probably due to non-uniformity of coal and air flows to the individual burners, however, both the temperature and oxygen maldistributions are less severe than in either Phase 1 or 2. The excess oxygen level ranged from 2.5 to 5.0 percent. The temperature and excess oxygen distributions for 400 and 300 MW load, on average exhibit the same temperature and oxygen trends as at 480 MW. Again, the temperature and oxygen distributions are more uniform than in either Phase 1 or 2. In general, the furnace gas temperatures are roughly 200 to 400^{o}F lower and the oxygen levels 2 to 4 percent higher than prior phases confirming the higher oxygen levels exhibited at the stack were indeed the result of increased combustion requirements rather than furnace backpass leakage.

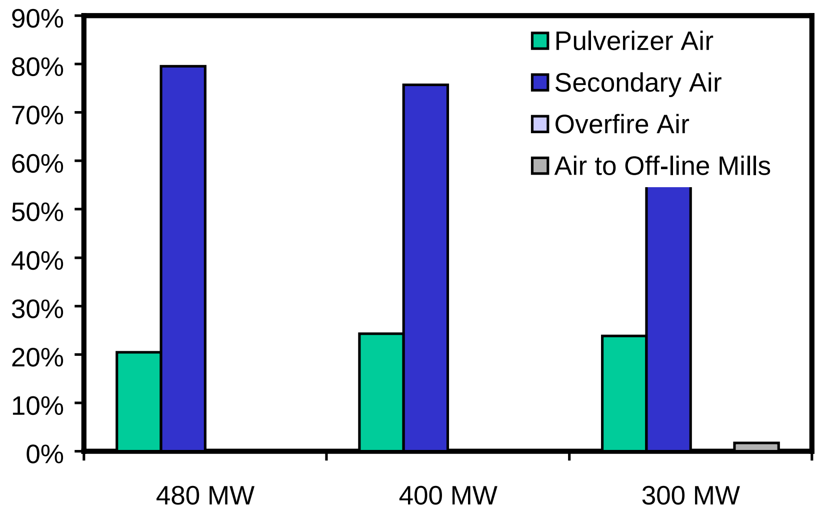


Figure 8-10 LNB / Distribution of Unit Air Flow by Load

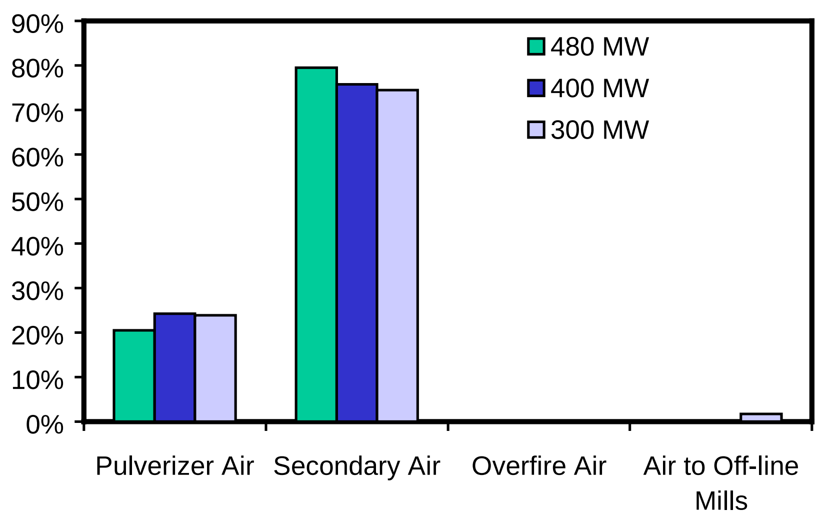


Figure 8-11 LNB / Distribution of Unit Air Flow by Component

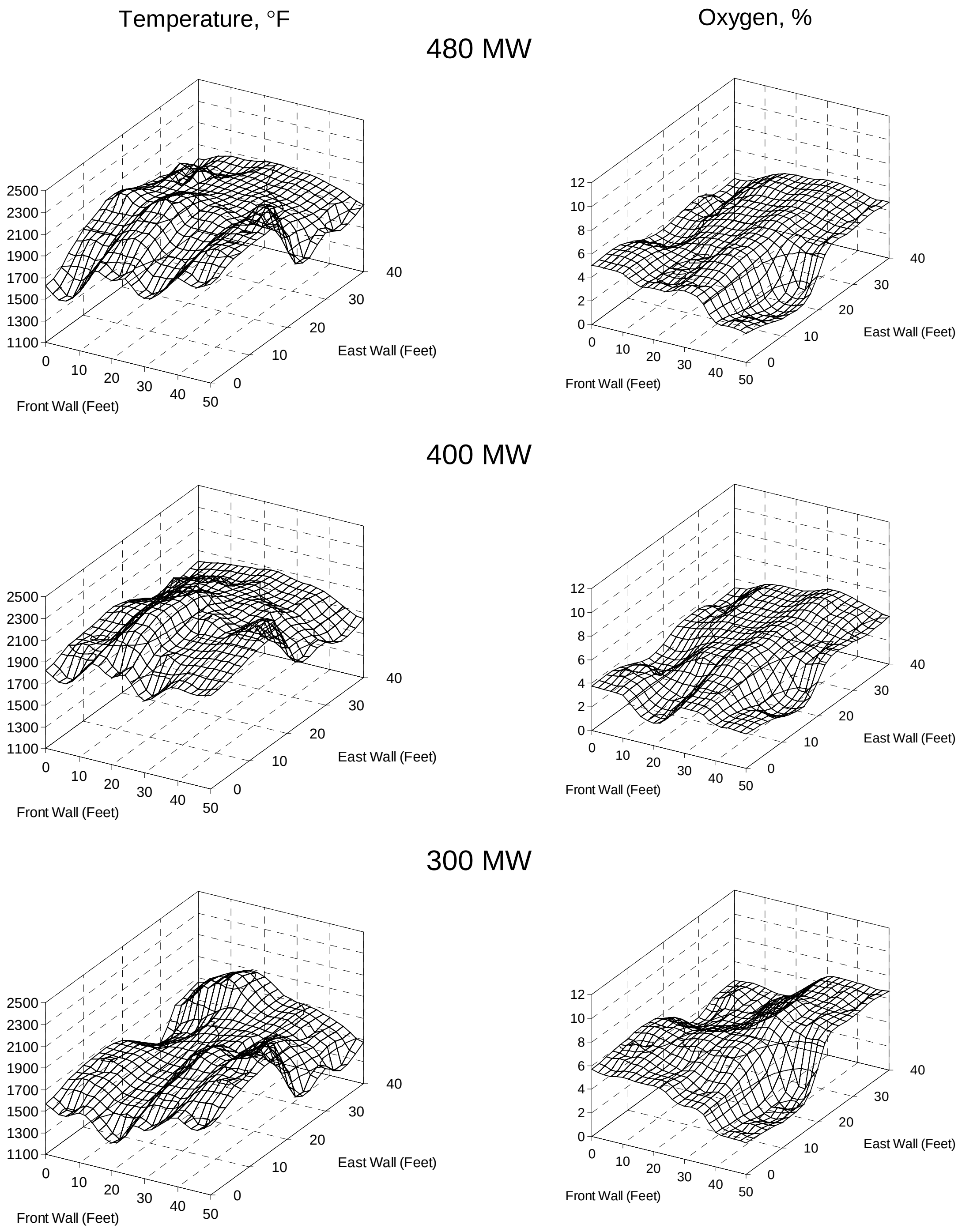


Figure 8-12 LNB / Furnace Exit Temperatures and Oxygen

8.1.2.4 Coal and Ash Analyses

During each of the nine days of Phase 3A performance testing, samples were obtained of the coal entering the active mills, fly ash collected in the ESP (east and west sides), and bottom ash collected in the furnace ash pit.

The coal samples were analyzed for proximate and ultimate composition, heating value, grindability, and ash fusion properties. Table 8-4 presents a summary of the results of these analyses. These analyses show that the coal properties remained consistent over the duration of the testing and are similar to the analyses obtained during the Phase 1 effort. The analysis of specific samples can be found in Appendix C.

Table 8-4 LNB / Performance Tests / Average Coal Analysis

	Average	Standard Deviation	Variance
Ultimate			
H2O %	5.69	1.91	3.63
C %	72.53	1.87	3.5
H %	4.67	0.14	0.02
N %	1.39	0.05	0
Cl %	0.01	0.01	0
S %	1.53	0.11	0.01
ASH %	9.44	0.43	0.18
O	4.74	0.36	0.13
Total %	100	0.09	0.01
HHV Btu/lb	12869	339	114794
VOL %	32.56	0.87	0.76
FC %	52.29	1.5	2.26

8.1.3 Solid Emissions

Ash particulate emissions were measured both for total mass emissions rate and for characteristic properties related to ash collection within an ESP. The specific measurements and analyses that were performed included: (1) total mass emissions, (2) particle size, (3) chemical composition, and (4) ash resistivity. These measurements were made immediately after the air heater.

Mass Loading, Gas Flow, and Temperature

The particulate mass loadings for the three full load conditions are very similar. Ideally, the particulate mass loading would be constant for any boiler load. However, it is normal to increase excess air at lower loads, so that flue gas volumes per MW of load are expected to rise and mass loadings to fall. The measurements of oxygen concentrations at the ESP inlet show an increase as load decreases. In Table 8-5, it can be seen that the mass loading for both 400 and 300 MW are lower than the average seen at 480 MW. It is expected that the 300 MW mass loading would be even less than that seen at 400 MW (as a result of an increase in oxygen levels), but Table 8-5 reports our finding that the mass loading at 300 MW is slightly higher. This slight deviation from expectation is likely the result of a relatively small increase in excess O_2 levels between 400 and 300 MW and measurement inaccuracies. As expected, total flue gas volumes decreased as load was reduced.

A summary of the flue gas temperatures measured at the ESP inlet is shown in Table 8-5. As shown, these temperatures were approximately 300ºF at 480 MW -- the design value is approximately 282ºF. At the 300 MW load level, the mean temperature was 273ºF. The full-load air heater exit design temperatures exhibits the same variability as seen in previous measurements at this location. The temperature tended to decrease from the center of each duct to the outside (going from port 6 to 2 or port 9 to 13) and to generally increase from the top to the bottom of the duct (going from point 4 to 1)(see Appendix C). The east and west sides are mirror images of each other and this symmetry is preserved in the temperature measurements. The air heaters counter rotate, which would also serve to preserve the mirror symmetry.

Table 8-5 LNB / Summary Of Solid Mass Emissions Tests

Test Number	Load MW	O2 %, Dry	Loading gr/dscf	Gas Flow acfm	Gas Temp. °F	Carbon %	LOI %
65	470	4.0	3.39	2,258,000	306	7.0	7.6
70	479	3.4	3.17	2,189,000	299	7.3	7.8
72	477	3.4	3.26	2,187,000	301	8.4	8.6
73	388	4.1	2.83	1,865,000	287	5.1	5.4
75	299	4.3	2.90	1,510,000	273	5.3	5.8

Fly Ash Chemical Composition

The performance of an electrostatic precipitator is heavily influenced by the electrical resistivity of the fly ash entering the device. The resistivity of the ash is established by the chemical composition of the ash, the amount of SO_3 adsorbed on the ash, the amount of water vapor in the flue gas, and the temperature of the ash and flue gas. The chemical composition of fly ash collected in the ESP hoppers was determined from proportional blends of samples taken from the hoppers. Each field was assumed to have equal collection efficiency and the individual hopper samples were proportionally combined to match the predicted amount of fly ash collected in each hopper. The blended sample should closely represent the inlet ash composition. The ESP hopper samples (east and west composites separately) were analyzed for mineral composition and loss-on-ignition (LOI), a summary of which is shown in Figure 8-13. Because these tests were performed over a relatively short period, it is not surprising that the elemental composition of the fly ash to be very similar for the test conditions. The loss-on-ignition results mostly from unburned carbon and is highly influenced by the extent of combustion and therefore its larger variation is dependent on the test conditions.

The Method 17 mass loading samples were sieved into two fractions by splitting the sample with a 200-mesh (75 µm) screen. Both size fractions of each sample were analyzed for carbon content and loss-on-ignition (LOI). The results of these analyses are summarized for the LNB tests in Table 8-6. It can be seen in the table that the minus 200-mesh fraction of the samples typically contain about 5 percent carbon at the full load test conditions, and about 3.5 percent carbon in the two reduced load tests. The bulk of the carbon is found in the plus 200-mesh samples, signifying that the carbon is present as large unburned char particles. A preponderance of the unburned carbon in the larger size fractionations can be indicative of combustion problems. The mass train samples show a consistent trend of lower carbon in the lower load samples.

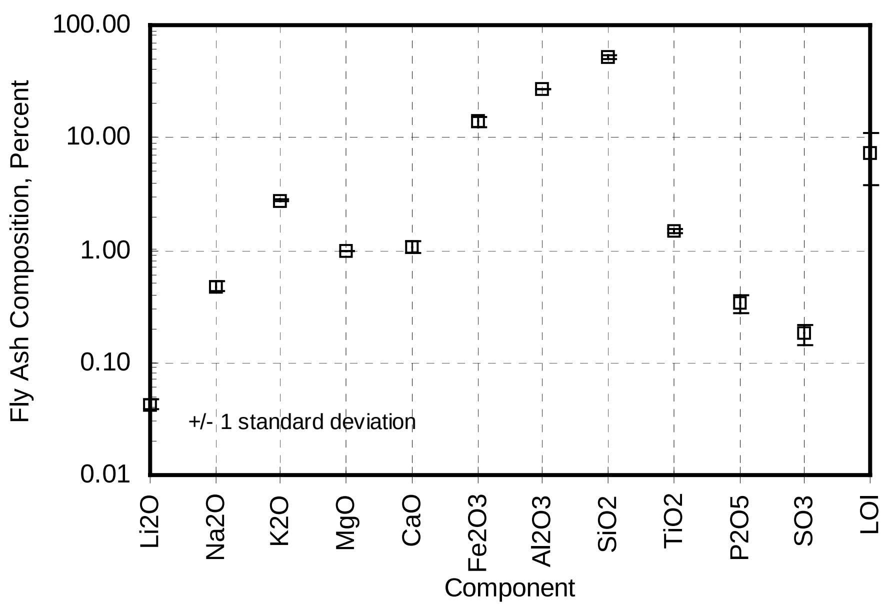


Figure 8-13 LNB / Fly Ash Chemical Composition

Table 8-6 LNB / Fly Ash Carbon Content by Size Fraction

			MASS TRAIN SAMPLES					
			CARBON, %			LOI, %		
DATE	TEST	Boiler Load, MW	<200 mesh	>200 mesh	Total	<200 mesh	>200 mesh	Total
7/16/91	65	480	4.8	20.4	7.0	5.1	22.3	7.6
7/22/91	70	480	4.8	21.1	7.3	5.1	22.5	7.8
7/24/91	72	480	5.4	23.2	8.4	5.5	24.3	8.6
7/26/91	73	400	3.2	16.5	5.1	3.5	17.1	5.4
7/28/91	75	300	3.2	19.0	5.3	3.6	20.1	5.8

Flue Gas SO_3 Concentration

Ash resistivity is strongly attenuated by surface films of sulfuric acid produced by the adsorption of SO_3 and water vapor from the flue gas. Thus, ash resistivity can be significantly affected by changes in SO_3 and water vapor concentration in the flue gas. The concentrations of SO_3 measured at the ESP inlet during the LNB tests are provided in Figure 8-14 with further information provided in Appendix C. Because resistivity is affected by the actual concentration of SO_3 present, the values are not normalized to a constant oxygen level. However, because SO_3 is formed by the oxidation of SO_2, it is reasonable to expect the SO_3 concentration to vary with fluctuations in SO_2 and O_2 levels. Variations in SO_3 concentration do not necessarily track the variations in SO_2 level, i.e., the SO_3-to-SO_2 ratio is not constant (see Appendix C). In fact, it varied from a low of 0.396 percent to a high of 0.778 percent. This could be explained by fluctuations in O_2 during these tests, or by other factors, such as variations in temperature profiles or factors affecting catalytic conversion of SO_2 to SO_3.

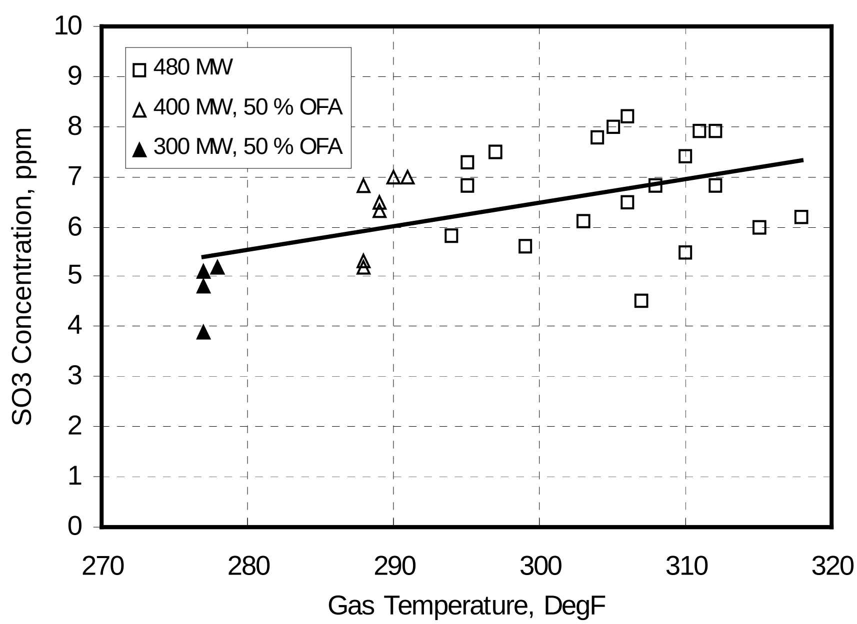


Figure 8-14 LNB / SOx Results

Fly Ash Resistivity

The electrical resistivity of fly ash is one of the main factors that determine the ability to collect an ash in a precipitator. The in situ resistivity measurements are presented in Figure 8-15, with two methods of resistivity determination being reported. The in situ measurement normally shows some variability, but, with the exception of the spark method at 300 MW, the averages for all the boiler loads are very consistent. The data measured in situ generally indicate that the resistivity was sufficiently low not to detrimentally affect ESP operation. Information on the individual runs can be found in Appendix C.

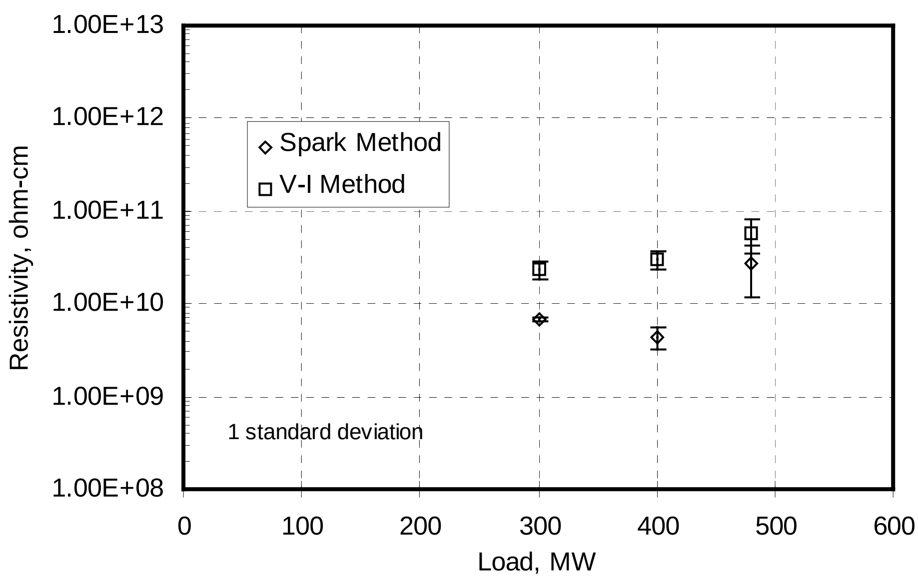


Figure 8-15 LNB / In-Situ Ash Resistivity Results

Particle Size

The particle size distribution of ash exiting the secondary air heaters was determined using a cascade impactor. Six samples were obtained for each test condition. Figure 8-16 shows the particle size distributions for all test loads as total percentage of cumulative mass. Error bars representing the 90 percent confidence limits are plotted on this figure. For most of the data, the 90 percent confidence interval is smaller than the plotting symbols. For large particle sizes the confidence band is exaggerated because of the exponential scale. The confidence interval for these points is still in the one percent range.

The very close agreement of all of the data indicates both excellent replication of testing under common conditions and also the relatively minor effect of load on the ash particle size distribution. The total particulate mass collected per unit gas volume sampled in the particle size tests was comparatively less than in the Method 17 tests. This is attributed to the inability to sample as close to the bottom of the flue gas duct with the impactor probe as can be done with the Method 17 probe, resulting in the potential failure to capture some larger particle sizes that may stratify near the duct bottom.

The derivative of cumulative mass with respect to particle diameter is presented in Figure 8-17. This type of presentation emphasizes the particle size where mass is concentrated. This format facilitates comparison of the test data from various phases of the program and highlights any significant changes in particle size distribution and potential effects on ESP performance resulting from the low NOx retrofits.

Analysis of the particle size data from an initial "high LOI" test (Test 65) and a subsequent "low LOI" test (Test 72) showed that the adjustment of the air/fuel ratios and burner registers had no effect on the fly ash particle size distribution.

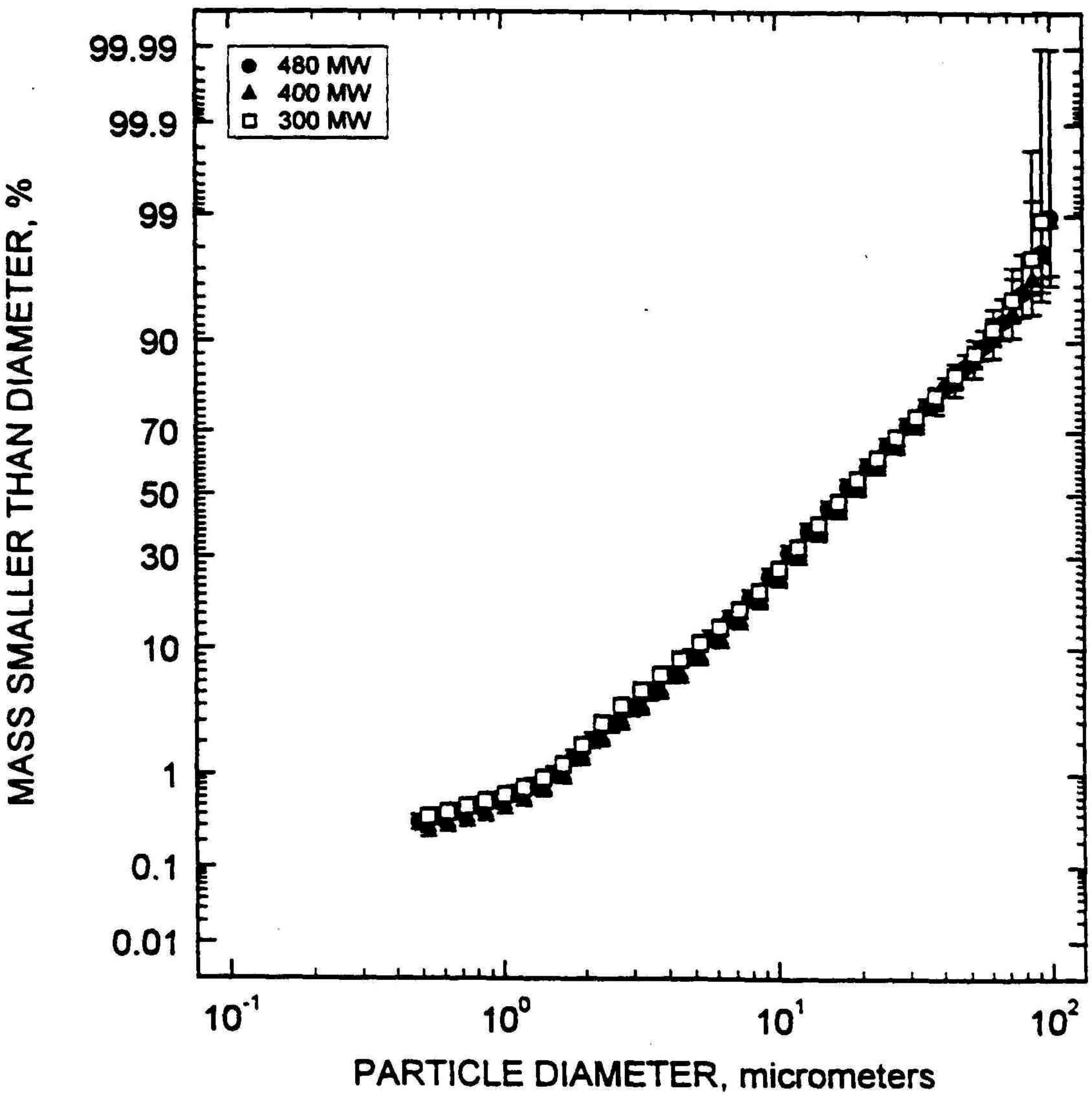


Figure 8-16 LNB / Fly Ash Particle Size Distribution by Cumulative Mass Loading

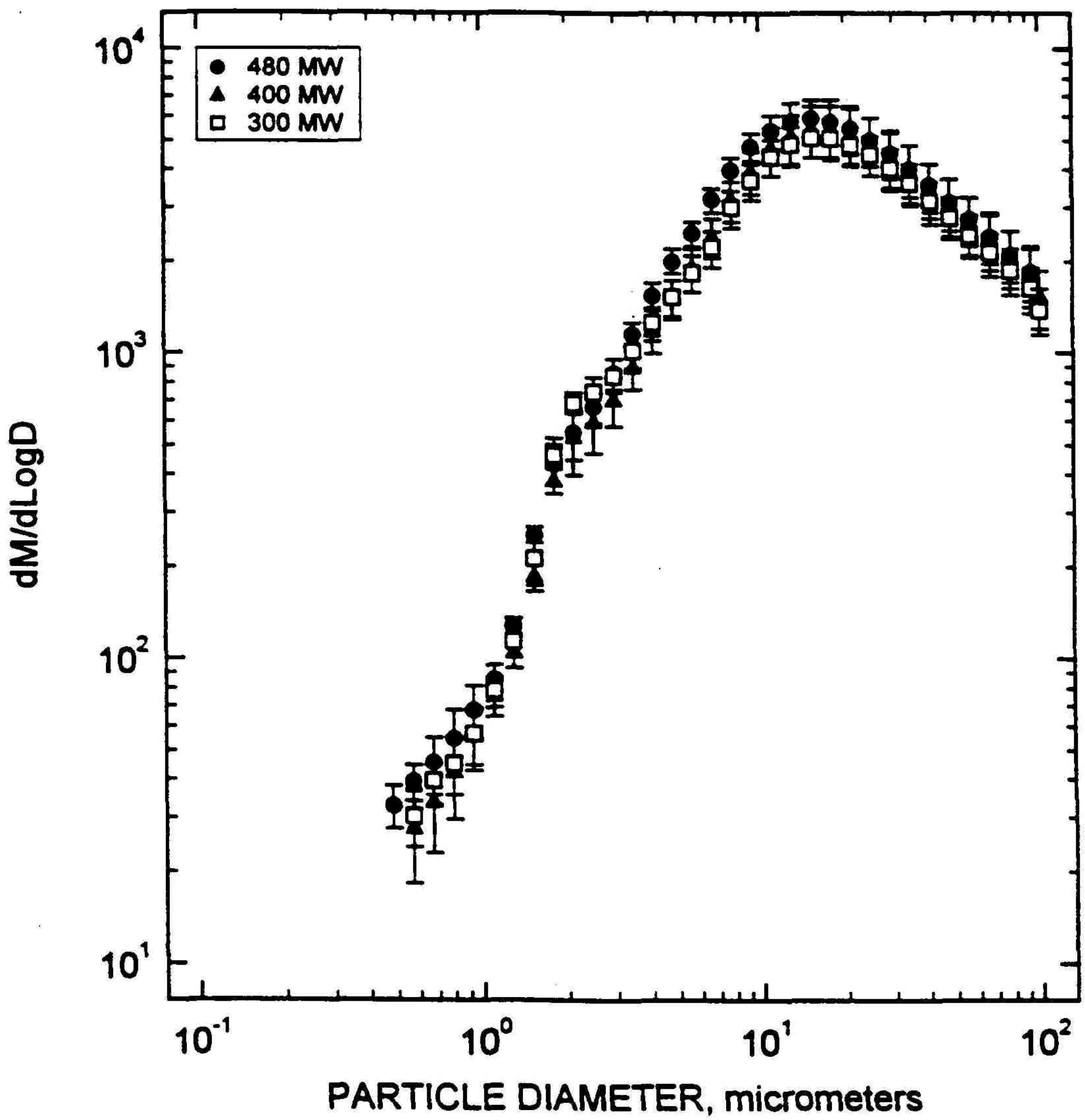


Figure 8-17 LNB / Fly Ash Particle Size Distribution by Differential Mass Size

8.1.4 Special LOI Tests

Testing to evaluate the effects of various burner and boiler operating settings on LOI and carbon content of ash particulate emissions from Plant Hammond Unit 4 was conducted between October 15 and 28, 1992. The testing consisted of: (1) measurement of the coal and primary air flow rates through each mill at a nominal load of 450 MW, as well as the coal and primary air distributions and particle size range in each individual coal pipe; (2) fly ash sampling at the precipitator inlet; and (3) measurement of gaseous emissions.

8.1.4.1 Test Methods

The methods used in these LOI evaluation tests were identical to the methods used in the diagnostic and performance test efforts. To expedite the collection of ash samples, two separate Method 17 samples were collected simultaneously, traversing the ESP inlet duct in opposite directions, but using the same test ports and probe insertion points. In this manner, duplicate samples could be obtained in about one hour for a single test condition

8.1.4.2 Test Results

The following paragraphs present a summary of the most important findings of the test effort.

Mill Characterization Tests

As a precursor to the actual NOx and LOI characterization, tests were performed to evaluate the condition of the coal and primary air supply systems with regard to coal flow and airflow distributions and coal particle size in each coal pipe. In addition, measurements were made of the secondary airflow in each duct (east and west) in an attempt to explain an apparent imbalance in those flows as indicated by plant instrumentation.

The results of the mill characterization testing can be found in Appendix C. Several important conclusions can be drawn from this data. First, it is apparent that the newer B&W MPS mills (A, C, E, and F) provide excellent fineness, both at the small sizes (passing 200 mesh, all better than 70 percent) and the largest sizes (larger than 50 mesh, all less than 0.23 percent). The older FWEC MB mills (B and D) provided less than 70 percent passing 200 mesh, and approximately 2.0 percent remaining on 50 mesh. Second, there is a large variation in coal flow measured from pipe to pipe for all mills, varying from about ±8 percent from the mean coal flow for the B mill, to over ±30 percent for the D mill. Third, the D mill had substantially lower coal flow (and higher A/F ratio) than the other mills. This characteristic is consistent with the results observed during the previous Phase 3A performance test series (test days 66 through 73). For the current mill tests, the D mill feeder coal flow, as indicated by the feeder instrumentation, was approximately the same as the other mill feeders. The conclusion is that either: (1) the D mill feeder calibration is not correct, or (2) the measurement of the D mill coal flow in the burner pipes is incorrect due to some abnormal flow condition such as roping or channeling which prevents the capture of a representative coal sample by the Flame technique. With the exception of the D mill, the A/F ratios were consistently between 2.0 and 2.3.

In addition to the mill testing, Flame also measured the total air flow rates through the east and west secondary air venturi ducts. Although the existing plant airflow instrumentation indicated a significant imbalance between the two venturi flow measurements (1,555,600 lb/hr - west, and 2,214,000 - east), the Flame measurements, made with type "S" pitot tube traverses across the ducts, indicated that the airflows were equal within 0.5 percent (west - 1,651,008 lb/hr vs. east - 1,642,427 lb/hr). As a result of the apparent error in the east plant instrument reading, the plant instrumentation department had disconnected the east input to the plant air flow totalizer and was using the west venturi input only (doubled) to indicate total air flow for control and monitoring purposes.

LOI Testing

The intent of the special LOI investigation was to determine the effects of various burner settings and mill operation on the carbon/LOI content of the fly ash leaving the boiler. To assess the effects of each selected parameter independently, a matrix of test conditions was devised such that a single parameter would be varied during each test day, and to the extent possible, other parameters held constant. The main parameters evaluated were overall boiler excess O_2, mill coal flow bias, burner inner and outer register settings, and coal pipe position (insertion depth). A summary of the parameters tested is shown in Table 8-7. Specifically excluded as a variable parameter was adjustment to the burner slide dampers, which control the total air flow to each burner. Because there are innumerable variations that could be made to the slide damper settings, which could affect the furnace combustion balance considerably, it was decided that any adjustment to these dampers should constitute a completely separate test series. As established by FWEC, the slide damper positions of the outer burners in each row (the A and D burners) were set at the 7 inch position, and the inner burners (B and C) at the 4 inch position. The test series was conducted at a nominal load level of 450 MW, with all mills in service. This was the same condition that the mill coal/air flow and fineness tests were performed.

Table 8-7 LNB / NOx vs. LOI / Parameters Tested

		Range Tested	
Parameter	Nominal Value	Low	High
Excess Air	4%	2.8%	5.0%
Inner Register	~15%	Nominal	Nominal + 40%
Outer Register	~60%	-20% of nominal	+20% of nominal
Sliding Tip	+4 inches	+2 inches	+4 inches
Mill Bias	No bias	Upper Mills +10% Lower Mills -10%	Upper Mills -10% Lower Mills +10%

The “baseline” or nominal condition for all tests was with equal coal flow to each mill and all burner mechanisms set to the “nominal” positions established by FWEC. Prior to the commencement of testing, all pertinent burner and AOFA damper settings that constitute the “nominal” condition were noted. FWEC also advised the test coordinator verbally as to proper procedures to be used in operating the burner mechanisms and the maximum degree of movement from “nominal” that should be made. This advice was followed in all subsequent testing. The principal precautions expressed by FWEC were: (1) not to close the inner or outer swirl registers excessively and (2) not to withdraw the burner inner coal pipe tips more than 2 inches from the current “nominal” setting of 4 inches insertion. The reason for the latter precaution was to prevent exposure of the burner ignitors to excessive radiant heat. Also, FWEC requested that the AOFA flow control dampers not be closed any more than would permit a minimal air flow of 50 klb/hr through each of the four dampers, so as to prevent excessive slagging or heating of the AOFA ports. Examination of the burners revealed that there were clear markings of the full-open, full-closed and “nominal” positions for the slide dampers, inner and outer registers and coal pipe positions on most burners. However, several of the indicated markings, especially for the inner registers, did not agree with the written listings supplied by FWEC. The test coordinator assumed that all of the burner markings were correct and recorded the various burner settings throughout the testing program.

Because the inner and outer register position indicators were circular dials, with only the closed, open and “nominal” settings indicated by FWEC, the test coordinator had to estimate the degree of travel from the nominal position. This was done as a percentage of the total travel indicated between the closed and open indications. In all cases, the movement indicators responded properly to the operator actuation of the mechanism. Therefore, it is believed that the indicated positions recorded on the data sheets during the testing reflect a reasonably accurate account of the burner positions relative to the “nominal” positions marked on the burner housings. On each day of testing, coal samples were taken in accordance with normal plant procedures, a composite sample being obtained from equal samples from each mill feeder.

A total of 40 tests were conducted between October 20 and 28, 1992. Table 8-8 summarizes the tests conducted during this program. Tests are numbered according to the format XX-Y, where XX represents the sequential test day since the program began at Plant Hammond, and Y represents the sequential test performed on that day.

Four tests were performed with the coal flow to all mills approximately equal, and with all burner settings at their “nominal” positions as established by FWEC. This was then the current “baseline” LNB case. The boiler excess O_2 was varied from a “nominal” value of about 4.0 percent (ECEM composite economizer outlet average - the plant instrumentation indicated approximately 2.7 percent O_2), to a minimum of 2.8 percent (high CO readings) and a maximum of 4.6 percent (high opacity and ID fan control). Throughout the testing, the plant average O_2 reading was consistently 1.0 to 1.5 percent below the ECEM composite economizer outlet reading.

Table 8-8 LNB / NOx vs. LOI / Tests Conducted

Test	Date	Load	AOFA	Burner Settings IR	OR	CPP	Mill Bias	Description
92-1	10/20/92	452	MIN	NOM	NOM	NOM	NONE	BASELINE
92-2	10/20/92	450	MIN	NOM	NOM	NOM	BOTTOM	COAL BIAS TO LOWER 2 MILLS
92-3	10/20/92	450	MIN	NOM	NOM	NOM	TOP	COAL BIAS TO UPPER 2 MILLS
93-1	10/21/92	448	MIN	NOM	NOM	NOM	NONE	MEDIUM O2
93-2	10/21/92	447	MIN	NOM	NOM	NOM	NONE	HIGH O2
93-3	10/21/92	442	MIN	NOM	NOM	NOM	NONE	MIN O2, CO POINT
93-4	10/21/92	442	MIN	NOM	NOM	NOM	NONE	MEDIUM O2
94-1	10/22/92	443	MIN	NOM	NOM	NOM	NONE	BASELINE
94-2	10/22/92	442	MIN	+ 20%	NOM	NOM	NONE	INNER REGS + 20%
94-3	10/22/92	441	MIN	+ 40%	NOM	NOM	NONE	INNER REGS + 40%
94-4	10/22/92	441	MIN	+ 40%	NOM	NOM	NONE	INNER REGS + 40%
94-5	10/22/92	442	MIN	NOM	NOM	NOM	NONE	BASELINE
95-1	10/23/92	443	MIN	NOM	- 30%	NOM	NONE	OUTER REGS - 30%
95-2	10/23/92	445	MIN	NOM	NOM	NOM	NONE	BASELINE
95-3	10/23/92	443	MIN	NOM	+ 30%	NOM	NONE	OUTER REGS + 30%
95-4	10/23/92	442	MIN	NOM	NOM	NOM	NONE	BASELINE
96-1	10/24/92	445	MIN	NOM	NOM	NOM	UPPER	COAL FLOW BIASED TO TOP BURNERS
96-2	10/24/92	441	MIN	NOM	NOM	NOM	NONE	BASELINE, NO COAL BIAS
96-3	10/24/92	440	MIN	NOM	NOM	NOM	LOWER	COAL FLOW BIASED TO BOT BURNERS
96-4	10/24/92	441	MIN	NOM	NOM	NOM	NONE	BASELINE, NO COAL BIAS
96-5	10/24/92	440	NOR	NOM	NOM	NOM	NONE	BASELINE WITH STD AOFA
97-1	10/25/92	447	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MINIMUM AOFA
97-2	10/25/92	442	MIN	NOM	NOM	3	NONE	COAL PIPES AT 3" INSERTION
97-3	10/25/92	441	MIN	NOM	NOM	2	NONE	COAL PIPES AT 2" INSERTION
97-4	10/25/92	445	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MINIMUM AOFA
98-1	10/26/92	447	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MINIMUM AOFA
98-2	10/26/92	441	MIN	NOM	NOM	NOM	UPPER	COAL FLOW BIAS TO TOP BURNERS
98-3	10/26/92	441	MIN	NOM	NOM	2	NONE	COAL PIPES AT 2" INSERTION
98-4	10/26/92	440	MIN	NOM	- 20%	NOM	NONE	OUTER REGISTERS - 20%
98-5	10/26/92	441	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MIN AOFA
99-1	10/27/92	442	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MIN AOFA
99-2	10/27/92	445	MIN	NOM	-20%	2	NONE	COAL PIPES AND OUT. REGS ADJ.
99-3	10/27/92	440	MIN	NOM	-20%	2	NONE	SAME, MINIMUM O2
99-4	10/27/92	445	MIN	NOM	-20%	2	NONE	SAME, HIGH O2
99-5	10/27/92	445	MIN	NOM	-20%	2	NONE	SAME AS 99-2
100-1	10/28/92	446	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MIN AOFA & MED O2
100-2	10/28/92	442	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MIN AOFA & LOW O2
100-3	10/28/92	443	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MIN AOFA & HIGH O2
100-4	10/28/92	442	MIN	NOM	NOM	NOM	NONE	BASELINE WITH MIN AOFA & MED O2
100-5	10/28/92	443	NOR	NOM	NOM	NOM	NONE	BASELINE WITH NOR AOFA, MED O2

As shown in Figures 8-18 and 8-19, the excess O_2 level has a considerable effect on both ash LOI and NOx emissions. The figures also include data from subsequent test days which reflect the "baseline" condition of all "nominal" burner settings, balanced coal flows to each mill and "minimal" air flow to the AOFA ports (flow control dampers virtually closed off). The lines shown in the figures depict linear, least-squares approximations to the "baseline" data. These approximations were used to normalize the subsequent parametric data to mitigate the effects of minor variations in excess O_2 on LOI and NOx emissions when comparing the effects of the other parameters being tested. Figures 8-18 and 8-19 also show the results obtained when the AOFA dampers were set to their "nominal" open positions (providing approximately 600 klb/hr of total AOFA flow). It can be seen that the use of "nominal" AOFA had a minor effect on LOI (slightly above the extended curve fit line). While the increased AOFA flow (from approximately 200 klb/hr minimum to 600 klb/hr nominal) does reduce NOx below the curve fit line substantially, the increased excess O_2 required to maintain CO emissions at a reasonable level results in little or no actual reduction in total NOx emissions compared to NOx emissions at the lower excess O_2 levels possible with reduced or no AOFA flow.

In all of the subsequent figures of LOI and NOx variation with burner settings, the results are normalized to a consistent excess O_2 level by using the slopes of the linear approximations determined in Figures 8-18 and 8-19. Thus, the "normalized" values represent what the LOI or NOx "would have been" if the excess O_2 level had been maintained absolutely constant.

On two days, adjustments were made to the inner and outer air register positions. The inner registers were positioned to approximately 20 and 40 percent of their full travel from the "nominal" positions. Most of the "nominal" markings were very close to the zero position, so no further closed adjustments were attempted. The outer registers were adjusted approximately 20 percent more open and more closed than the "nominal" settings (60 percent open). The results of these tests showed that the inner and outer registers have only a minimal effect on either LOI or NOx within the range of adjustments made.

In one test series, the coal flow to the mills was biased to provide first higher coal flow to the upper burner levels (mills C and F) and lower coal flow to the lower burner levels (mills A and E), with the coal flow to the center burners (mills B and D) in between. All burner settings were normal. Another test was performed with the coal bias reversed, i.e. lower coal flow to the upper burners and higher to the bottom burners. Two tests were also conducted with balanced flow to all burners (according to the feeder coal flow indicators). Figures 8-20 and 8-21 show the results of these tests. Clearly, the mill bias affects the LOI substantially while it only affects the NOx emissions moderately.

In another series of tests, the positions of the inner coal pipe tips were adjusted (all burners equally) from the "nominal" position established by FWEC. The "nominal" position was 4 inches insertion from the "zero", or neutral position. In keeping with FWEC's request, the tips were withdrawn only to the 2 inch insertion position so as to prevent excessive thermal radiation exposure to the ignitors. As shown in Table 8-8, four tests were performed, two at the "nominal" setting and one each at the 2 inch and 3 inch positions. All other burner settings were at their "nominal" positions and the coal flow was equal to each mill. Figures 8-22 and 8-23 show that

LOI was slightly decreased and NOx slightly increased as the coal pipes were withdrawn to the 2 inch position.

A summary of the sensitivities is shown in Figure 8-24. As can be seen, for excess O_2, mill bias, inner register, and sliding tip, any adjustments to reduce NOx emissions are at the expense of increased LOI. In contrast, the slope of the outer register characteristic suggests that an improvement in *both* NOx emissions and LOI can be achieved by adjustment of this damper. However, because of the relatively small impact of the outer register adjustment on both NOx emissions and LOI, it is likely that the positive NOx / LOI slope is primarily an artifact of process noise. It should be stressed that Figure 8-24 is a parametric plot and that neither NOx nor LOI are the independent variables.

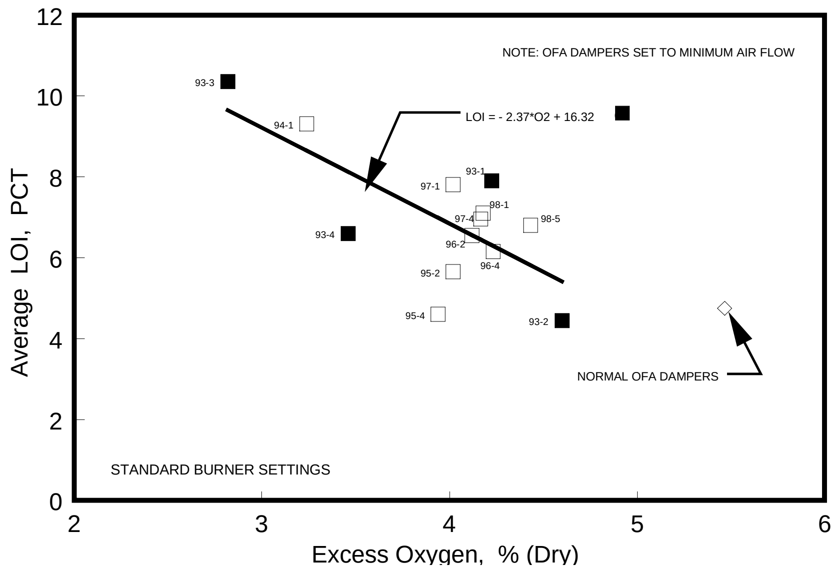


Figure 8-18 LNB / NOx vs. LOI Testing / LOI vs. O_2

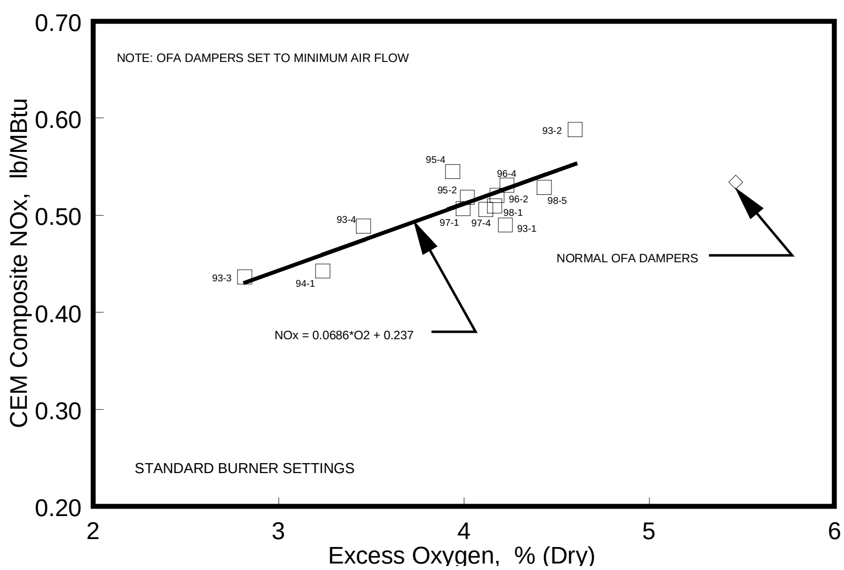


Figure 8-19 LNB / NOx vs. LOI Testing / NOx vs. O_2

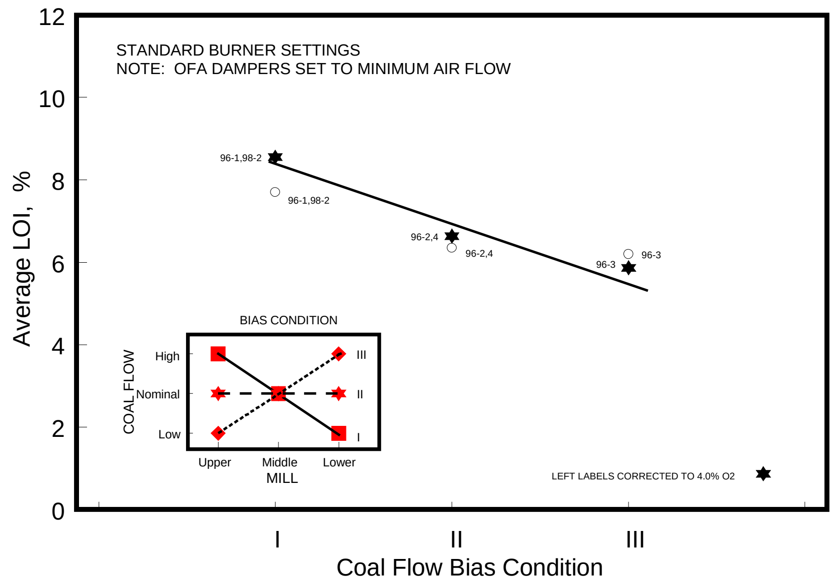


Figure 8-20 LNB / NOx vs. LOI Testing / LOI vs. Mill Bias

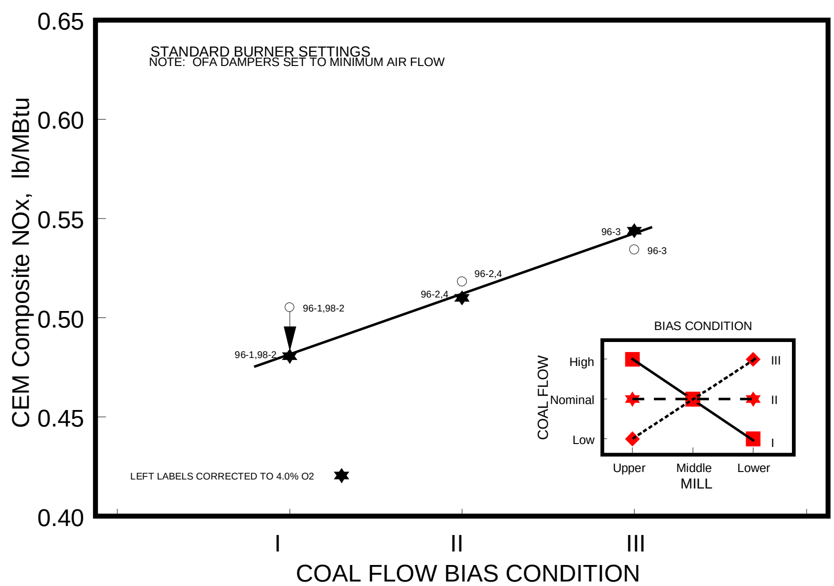


Figure 8-21 LNB / NOx vs. LOI Testing / NOx vs. Mill Bias

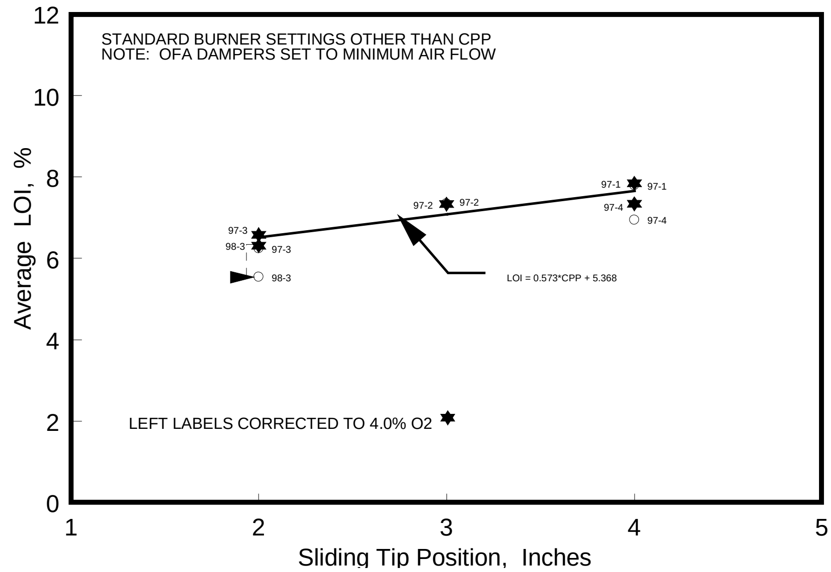


Figure 8-22 LNB / NOx vs. LOI Testing / LOI vs. Sliding Tip Position

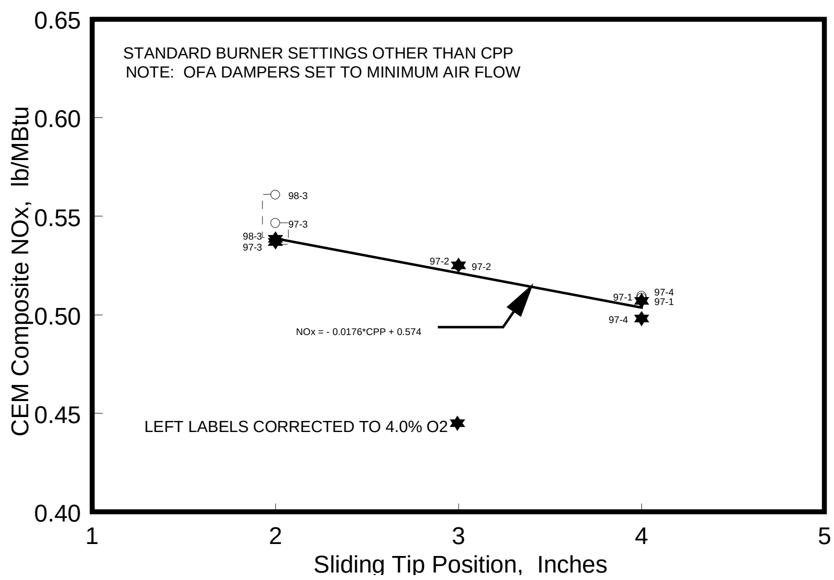


Figure 8-23 LNB / NOx vs. LOI Testing / NOx vs. Sliding Tip Position

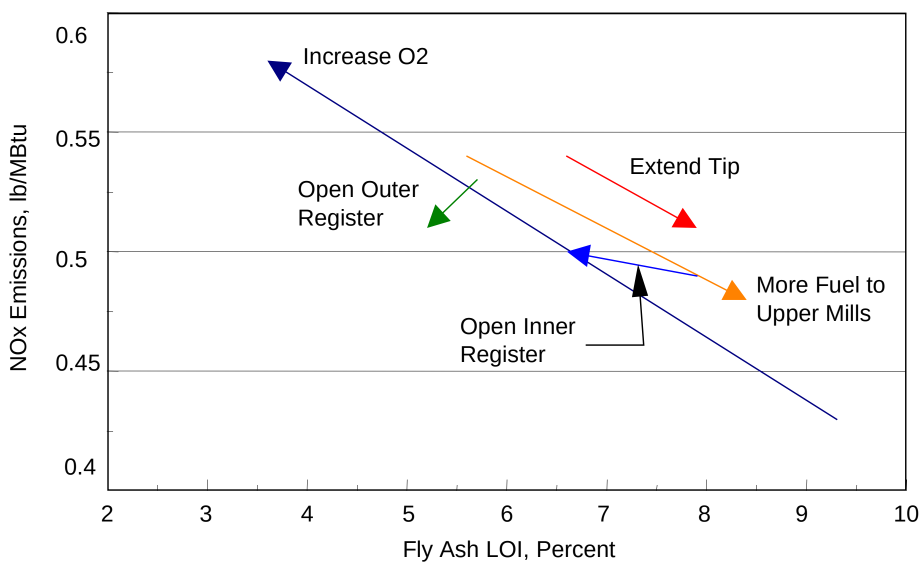


Figure 8-24 NOx vs. LOI Testing / All Sensitivities

8.2 Long-Term Data Analysis

The long-term testing consisted of continuous measurement of operating parameters while the unit was under normal load dispatch. This long-term testing was performed from August 7 through December 19, 1991. During this period, a number of unit outages were experienced that resulted in lost days of data capture. However, data capture was sufficient to fully characterize the unit both from an engineering perspective as well as a regulatory point of view. As before, the focus of the analysis of this long-term data was:

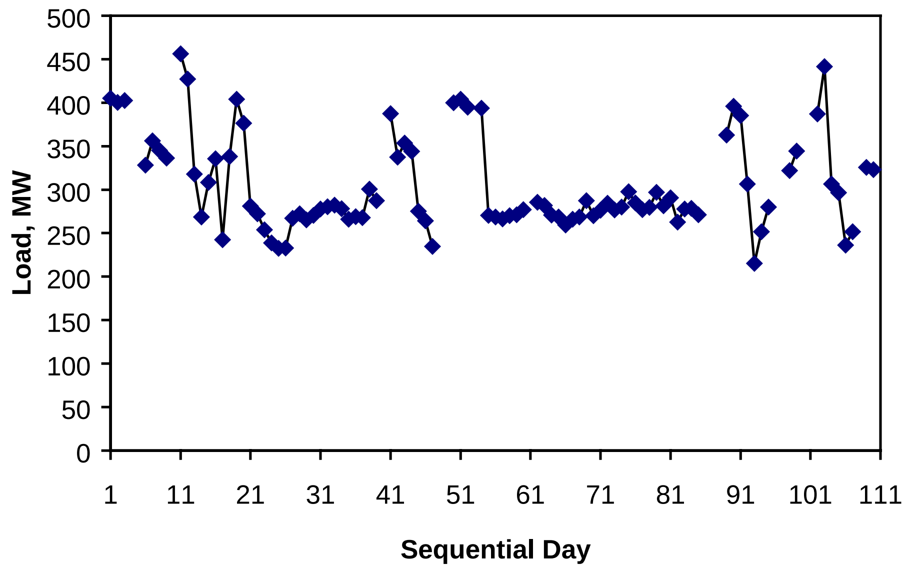
- Characterization of the daily load and NOx emissions and the within-day statistics,
- Characterization of the NOx emissions as a function of the O_2 and mill patterns ,
- Determination of the thirty-day rolling average NOx emissions,
- Determination of the achievable NOx emission level, and
- Comparison of long-term results to short-term results.

The following paragraphs describe the major findings of these analyses.

8.2.1 Unit Operating Characteristics

Based on the long-term emissions data, the daily averages of load and NOx were determined and are shown in Figure 8-25. The daily average data was determined using the EPA criteria for valid data explained previously. Only days with at least 18 hours of data are presented in this figure. Over most of the long-term test period, the daily average load was generally in the vicinity of 300 MW with brief periods where the average load was nearer to 400 MW. The 300 MW daily average is indicative of running the unit at full-load (480 MW) for approximately 14 hours and minimum load (170 MW) for 12 hours. This unit has been a base loaded unit in the past that was generally the first unit on and the last unit off of dispatch. During the Phase 2 test effort, the unit was reclassified within the system and, while still a base loaded unit, was operated at lower load than in the past. This situation continued into the Phase 3A test period. For the Phase 3A long-term test period, the daily average emissions ranged from approximately 0.4 to 0.7 lb/MBtu.

One method of characterizing the boiler operating characteristics during the long-term testing is to examine the within-day variation of load and NOx. This was accomplished by segregating the data by hour of the day, i.e., 0100, 0200...2400. For these segregated data, the mean load and NOx were computed. In addition, the hourly values representing the lower 95 percent and upper 95 percent of all values were determined. The results for the entire long-term test period are shown in Figure 8-26. The figure illustrates that the unit was operated as a base loaded unit for most of the day (on average 16 hours were above 300 MW). This is a considerably lower base load than experienced during the previous two program phases.



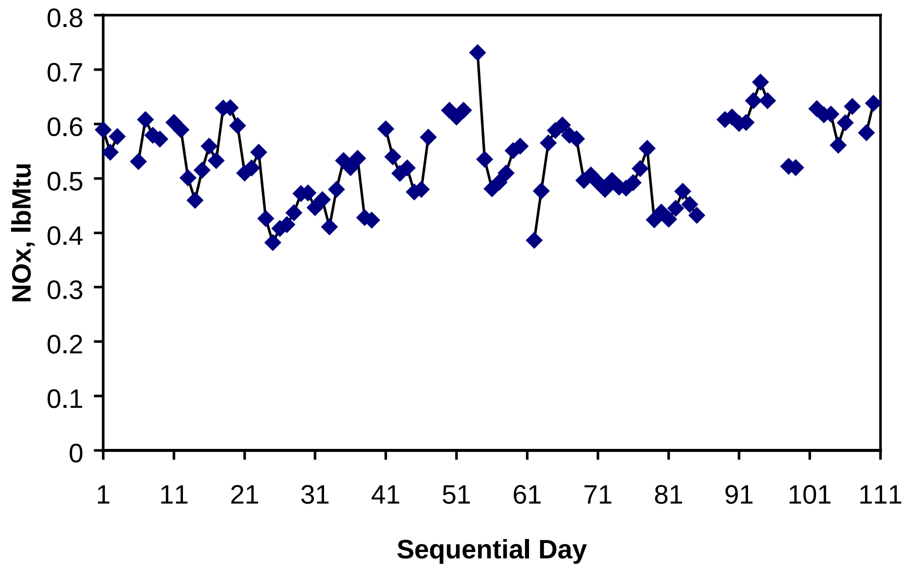
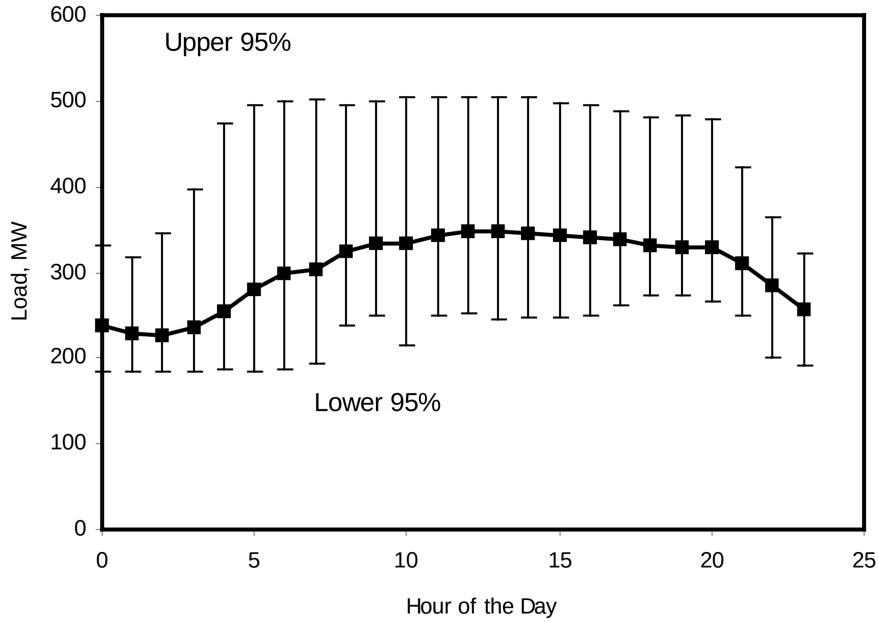


Figure 8-25 LNB / Long-Term Daily Average Characteristics



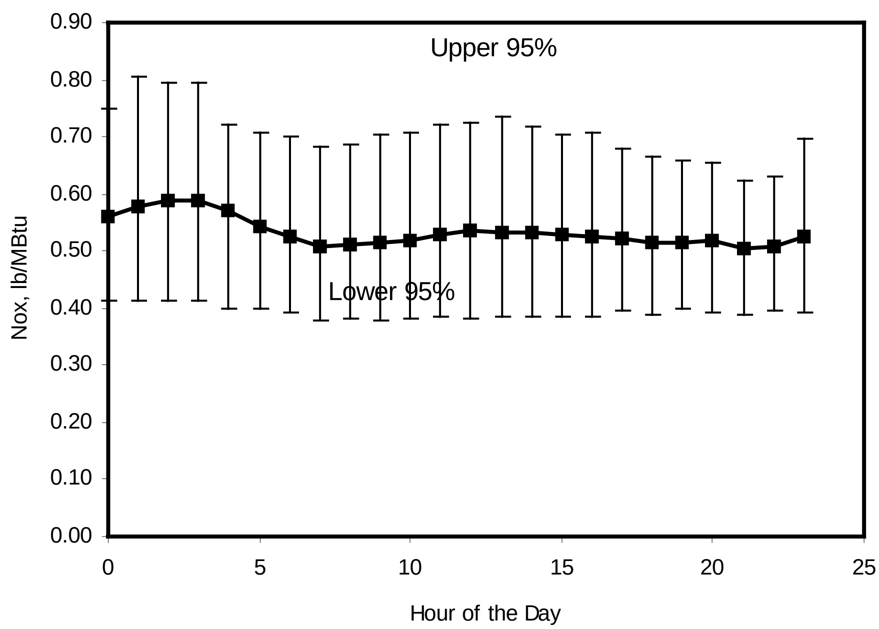


Figure 8-26 LNB / Long-Term Diurnal Characteristics

8.2.2 Parametric Test Results

For the parametric analyses, all of the valid five-minute data was used. The five minute and hourly average emission data was analyzed to determine the overall relationship between NOx and load and the effect of boiler O_2 on NOx emissions for frequently used mill patterns. Because this data was obtained while the unit was under normal load dispatch, it is representative of the long-term NOx characteristics.

The NOx versus load relationship was determined by first segregating the 5-minute average load data into 20 MW wide load ranges. The population for each load range, as well as the lower 95 percentile and upper 95 percentile are shown for both load and NOx emission values. Figures 8-27 through 8-30 illustrates the load trend for this data. As expected, stack excess oxygen decreased as load increased reflecting the boiler control system imposed constraint. NOx emissions exhibited an increased dependency on load compared to proceeding phases with the lowest emissions occurring near mid-load and higher emissions at full load. NOx emissions also increased at reduced loads. This “U” characteristic is consistent with that observed during the diagnostic test. Because of its dependency on load, the average NOx emission over a specific period is highly dependent on the load profile during that period. Because the fuel source is not a function of load, as expected, SO_2 emissions were also not dependent on load. CO emissions were consistently low over the load range, with the mean not exceeding 20 ppm for any load category.

The effect of operating O_2 on NOx emissions for certain mill patterns was examined for load ranges that corresponded to some of the loads tested during the short-term test portion of the Phase 3A test effort. These ranges were the 180-190, 290-300, 390-400, and 470-480 MW ranges. All of the valid five-minute data for these load ranges was used to assess the impact of excess oxygen level for the most commonly used mill patterns. To determine the most frequently used patterns, the frequency distribution of the mills-in-service pattern was determined. Table 8-9 presents the frequency distribution for the two most used mill patterns. It is apparent that there are certain preferred mill patterns for each load range. These patterns are dictated by the operational requirements of the unit (e.g., slag minimization, steam temperature control).

Prior to commencing the short-term testing effort, discussions with plant operations indicated that certain mill patterns were preferred. These patterns were then used during the diagnostic and performance testing with the intent of comparing the results with the same patterns during long-term testing. The mill patterns used during the short-term test effort were the E, B and E, B and C, and E and F-MOOS at loads below 400 MW. Referring to Table 8-9, it is evident that these patterns were not the most prevalent during this long-term test effort. As a consequence of this, some comparisons will not be able to be made between the short- and long-term results.

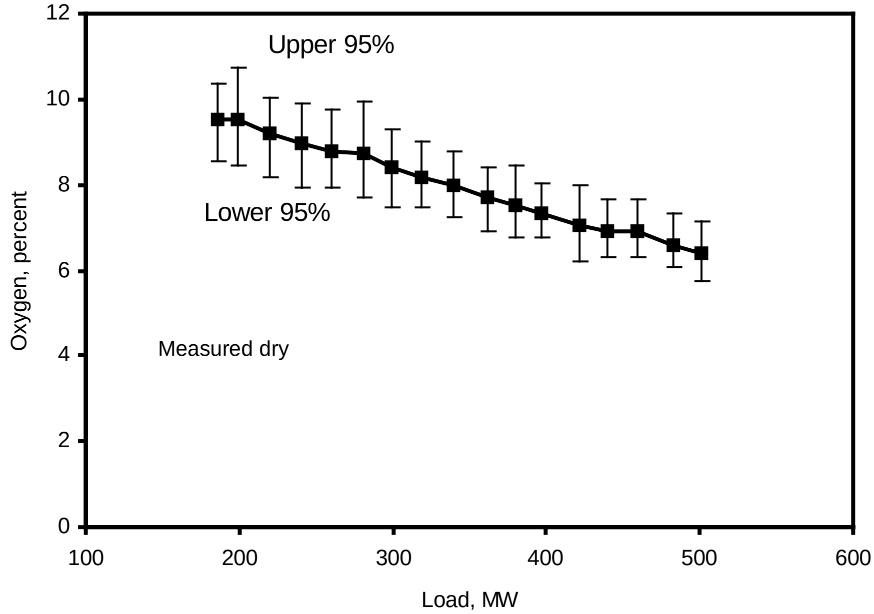


Figure 8-27 LNB / Long-Term Stack O_2 vs. Load Characteristics

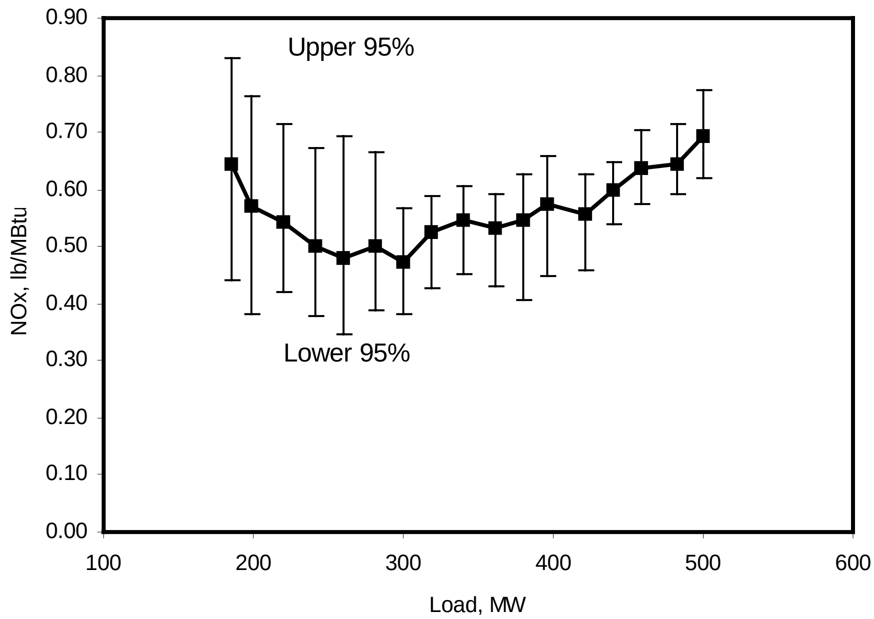


Figure 8-28 LNB / Long-Term NOx vs. Load Characteristics

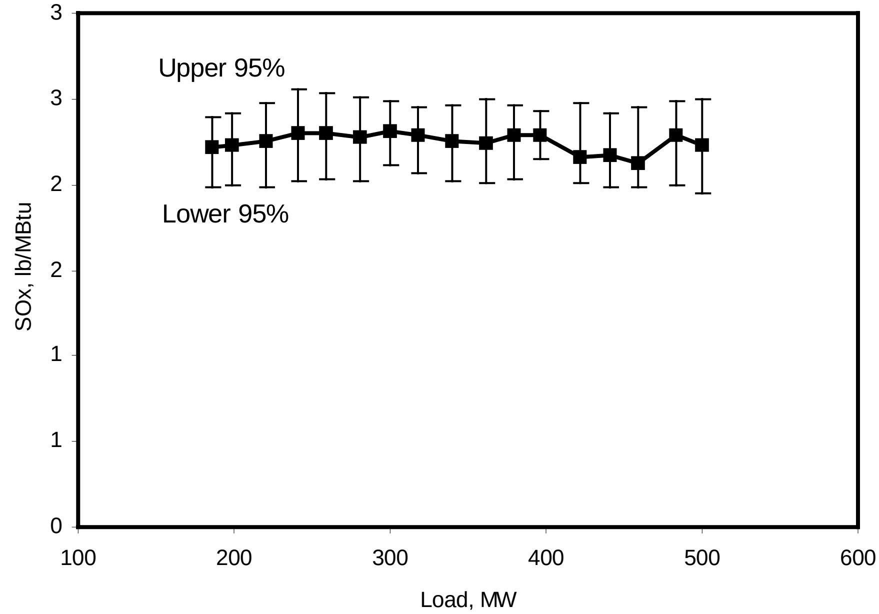


Figure 8-29 LNB / Long-Term SOx vs. Load Characteristics

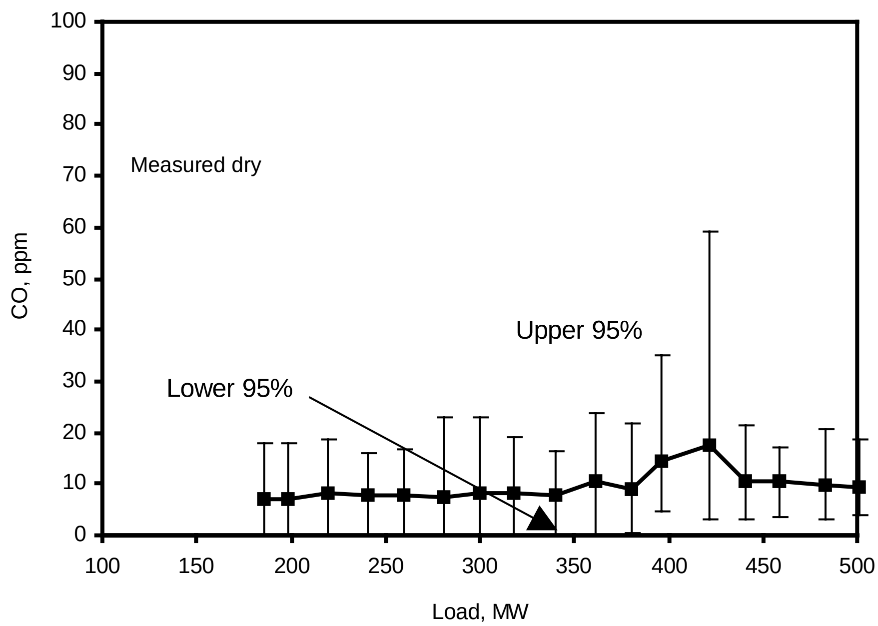


Figure 8-30 LNB / Long-Term CO vs. Load Characteristics

Table 8-9 Mill Pattern Use Frequency

Average Load MW	MOOS	Sample Size	Average O_2 Percent	Average NOx lb/MBtu
186	B, E	1070	9.6	0.69
186	C, F	379	9.2	0.63
296	B, E	1180	8.4	0.51
296	B, C	834	9.0	0.44
396	E	717	7.3	0.61
396	F	307	7.1	0.48
474	NONE	142	6.6	0.64

* Measurements at stack

8.2.3 Thirty-day Rolling Averages

The NSPS Subpart Da and Db standards are based upon compliance on a thirty-day rolling average. While this unit is not required to comply with these standards, it is of some value to evaluate the data for Phase 3A on a thirty-day rolling average basis and later compare it to the results from previous and subsequent phases of the program. Thirty-day rolling average load, NOx, and O_2 were computed using the valid hourly data as defined by the EPA criteria described earlier. These thirty-day rolling averages are shown in Figure 8-31 for load, NOx, and excess oxygen (as measured at the stack using the ECEM). The thirty-day rolling average results are only representative of the load scenario that was experienced by the unit during this long-term test period. During other periods when the load might be significantly different, the rolling averages would be expected to be somewhat different. For this particular period, it can be seen that the 30-day rolling average load was generally in the 300 MW range (292 MW ±18 MW) over the entire long-term test period. NOx emissions, as well as oxygen levels, tracked load during the period.

8.2.4 Achievable Emission Characterization

The EPA, in their rule making process, establishes an achievable emission level based upon daily average data samples obtained from CEMs. Most of this data is from NSPS Subpart Da units or units that used CEMs to obtain data during demonstration programs. The achievable NOx emission limit on a 30-day rolling average basis is determined using the descriptive statistics for 24-hour average NOx emissions. As discussed earlier, the SAS UNIVARIATE and AUTOREG procedures are used to determine the descriptive statistics for the 24-hour average NOx emissions data. The results of the UNIVARIATE and AUTOREG analyses of the 24-hour average NOx emissions are presented in Table 8-10. The UNIVARIATE analysis indicated that the daily emissions were normally distributed. The AUTOREG analysis also indicated that the day-to-day fluctuations in NOx emissions followed a simple first order auto-regressive model.

Based upon the EPA criteria, the achievable NOx emission limit should only be exceeded, on average, once per 10 years on a 30-day rolling average basis. The achievable emission depends on the long-term mean, variability, and autocorrelation level, which are shown in Table 8-10. Table 8-11 provides the achievable emission level, based on the daily values given in Table 8-10. The achievable NOx emission limits shown in this table, are computed for two conditions - no autocorrelation ($\rho = 0$) and the estimated value of 0.73 (which indicates highly time dependent data). The assumption in this table is that the Hammond unit will be operated in the future under similar load dispatching as that during the baseline test phase. As explained above, under other load scenarios, the thirty-day rolling averages would be different and therefore the achievable emission level would also be different.

It should be noted that the mean, variability, and auto-correlation levels given in Table 8-10 are only estimates. There is an uncertainty level implicit in the estimates of each of these statistical parameters. The uncertainty level in the mean is dependent on the variability. The estimated variability is, to some extent, dependent on the level of autocorrelation. Thus, uncertainty levels in the descriptive statistics are linked.

Table 8-10 Descriptive Statistics for Daily Average NOx Emissions

Number of Daily Values	94
Average Emissions (lb/MBtu)	0.53
Standard Deviation (lb/MBtu)	0.073
Distribution	Normal
First Order Autocorrelation (r)	0.73

Table 8-11 Achievable NOx Emission Limit

Autocorrelation (lb/MBtu)	Achievable Emission Limit 30-Day	Achievable Emission Limit Annual
r = 0	0.58	0.54
r = 0.73	0.64	0.55

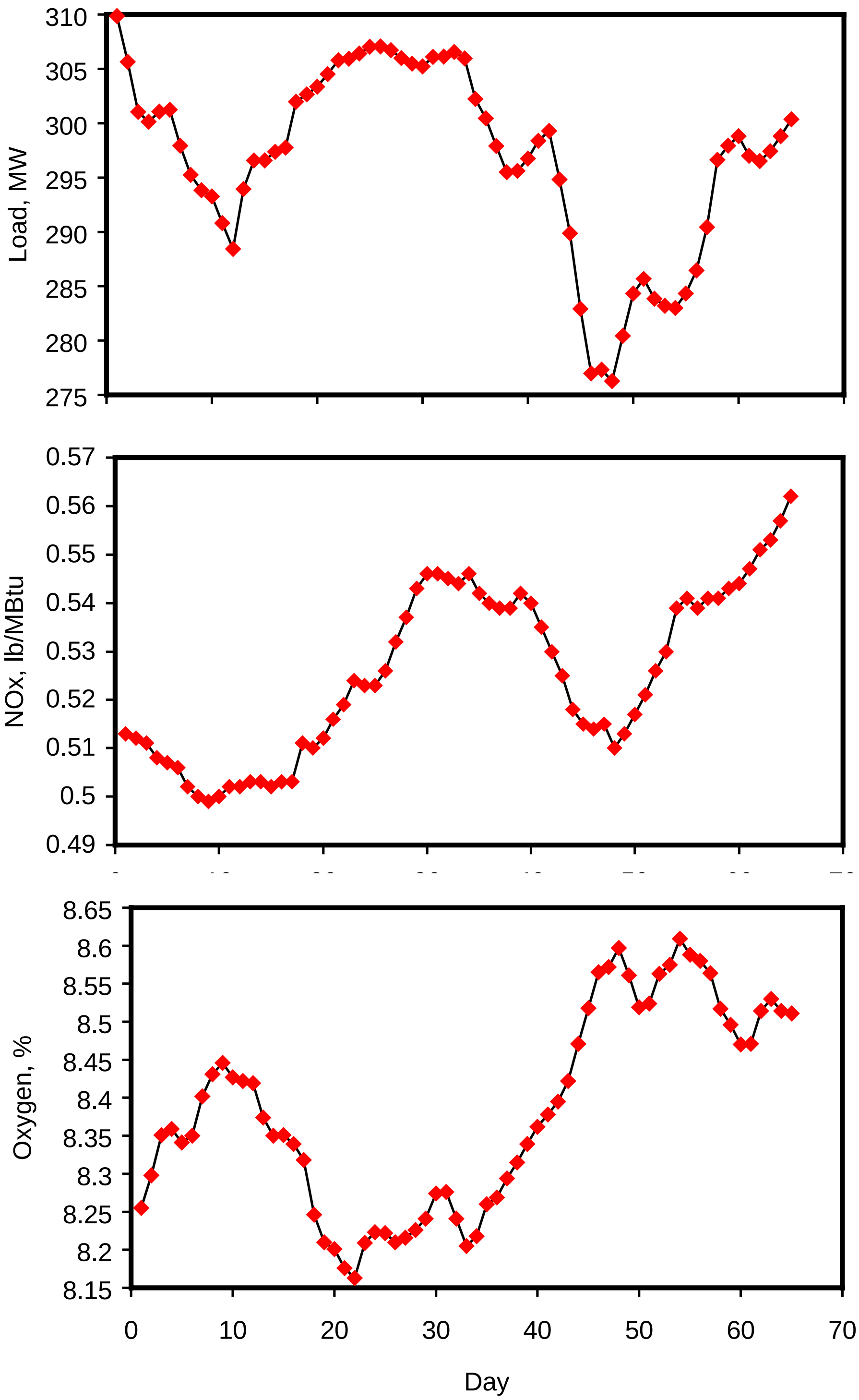


Figure 8-31 LNB / Long-Term 30 Day Rolling Average

8.2.5 Comparison of Short- and Long-Term NOx Data

A comparison of the short- and long-term NOx emissions data collected during this phase is shown in Figure 8-32. The data includes all of the configurations tested during this period. From this figure it is evident that the data collected during this period was in most cases within the ±95 percentile band of the long-term data. The agreement between short- and long-term data was much better than that observed in prior phases.

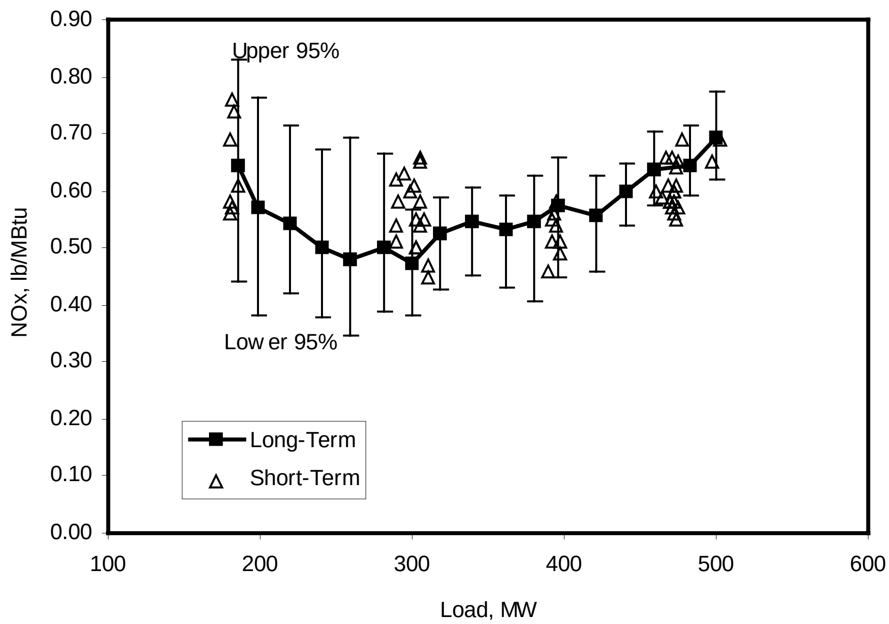


Figure 8-32 LNB / Comparison of Short- and Long-Term NOx Emissions

8.2.6 Process Data

In addition to the emissions data described earlier, process data was collected to provide insight to changes in the boiler performance and turbine cycle heat rate as a result of the installation of the tested technologies. The most important of these variables are discussed below.

Steam Temperatures and Spray Flows

Main steam and reheat temperatures as measured at the turbine are shown in Figures 8-33 and 8-34, respectively. As shown, main steam temperature averaged approximately 990°F to 1000°F over the entire load range with only a slight degradation at mid load. Reheat temperature, although near 1000°F at full load, dropped to near 950°F at lower loads. Superheat sprays control main steam temperature whereas reheat temperature is controlled primarily with the backpass dampers. As shown in Figures 8-35 and 8-36, lower superheat spray flow was near zero over the load range while the upper spray flow increased substantially with load. The sharp decline in spray flow at the 400 MW point is likely the result of mills being brought into service.

Excess Oxygen Levels

In addition to the ECEM excess oxygen measurement, excess oxygen was also measured at the economizer and air heater outlet using in situ instrumentation. The load characteristic for this data, along with the data obtained through the ECEM, is shown in Figures 8-37 through 8-42. Excess oxygen (Figures 8-37 and 8-38) as measured at the economizer outlet is used by the control system to maintain combustion stoichiometry at prescribed levels. Excess oxygen as measured at the air heater outlet is used for determination of air heater and boiler performance and not for control. In all figures, the reading obtained by the in situ instrumentation is well below that obtained by the ECEM. This difference is the result of:

- The ECEM is a dry reading whereas the in-situ instrumentation provides excess oxygen on a dry basis.
- The ECEM samples flue gas considerably downstream of the in-situ monitors and thus there is the potential for air in-leakage.

For Phase 3A, the stack oxygen was, on average, a good estimator for economizer oxygen when these factors are taken into consideration (Figure 8-42).

Economizer Exit and Air Heater Exit Temperatures

The economizer exit and air heater exit gas temperatures are shown in Figures 8-43 through 8-44. As shown, full load economizer exit temperatures average approximately 740°F and 750°F for the east and west side, respectively. The design at full load is near 710°F. As expected, the temperature dropped with decreasing load, averaging near 635°F at 260 MW. The design temperature at this load is near 590°F. The secondary air heater outlet temperature averaged approximately 300°F at full load -- the design value is near 282°F (Figures 8-45 and 8-46).

Fly Ash LOI

An estimate fly ash LOI is shown in Figure 8-47. Because there was no on-line carbon-in-ash measurement during this phase, the carbon-in-ash measurement is based on a correlation between LOI obtained during the performance tests and the deviation between stack oxygen for these tests and the long-term stack oxygen levels.

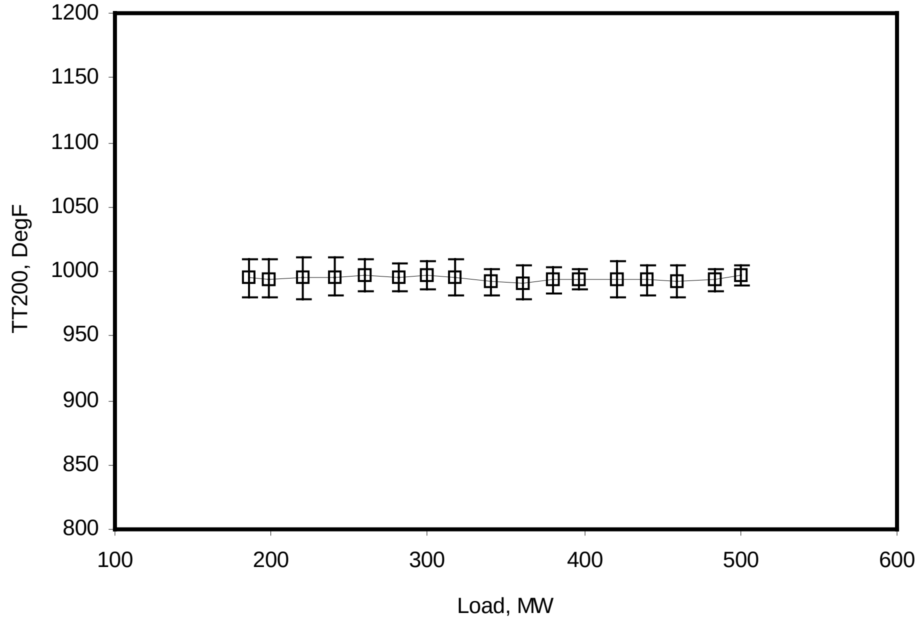


Figure 8-33 LNB / Long-Term / Main Steam at Turbine Temperature

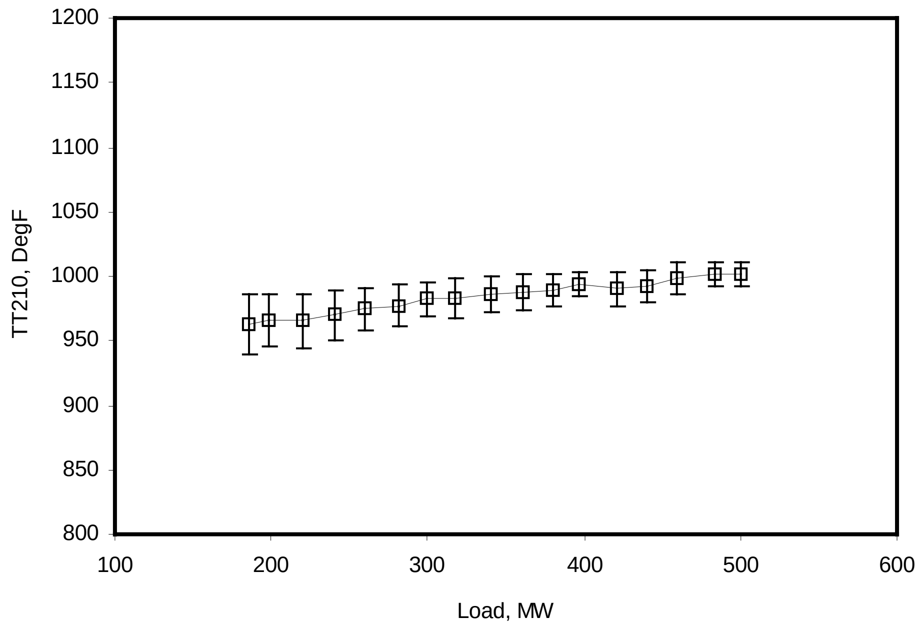


Figure 8-34 LNB / Long-Term / Reheat Steam at Turbine Temperature

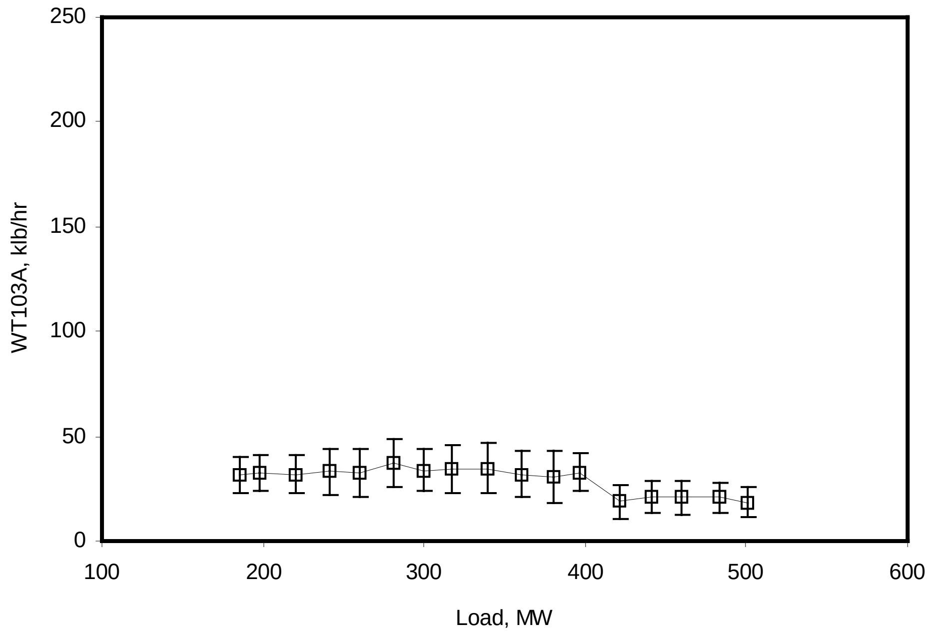


Figure 8-35 LNB / Long-Term / Superheat Spray Flow Lower

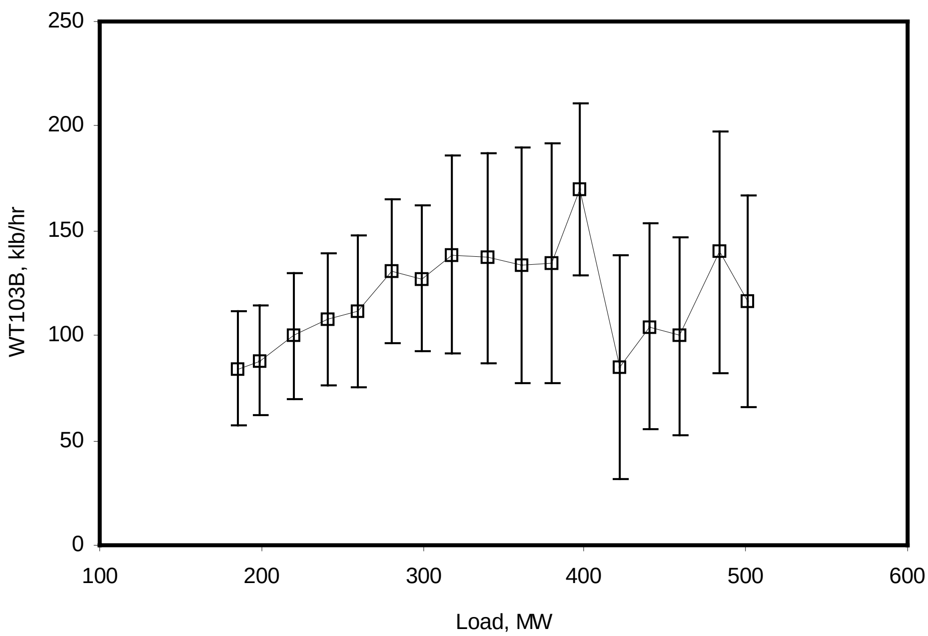


Figure 8-36 LNB / Long-Term / Superheat Spray Flow Upper

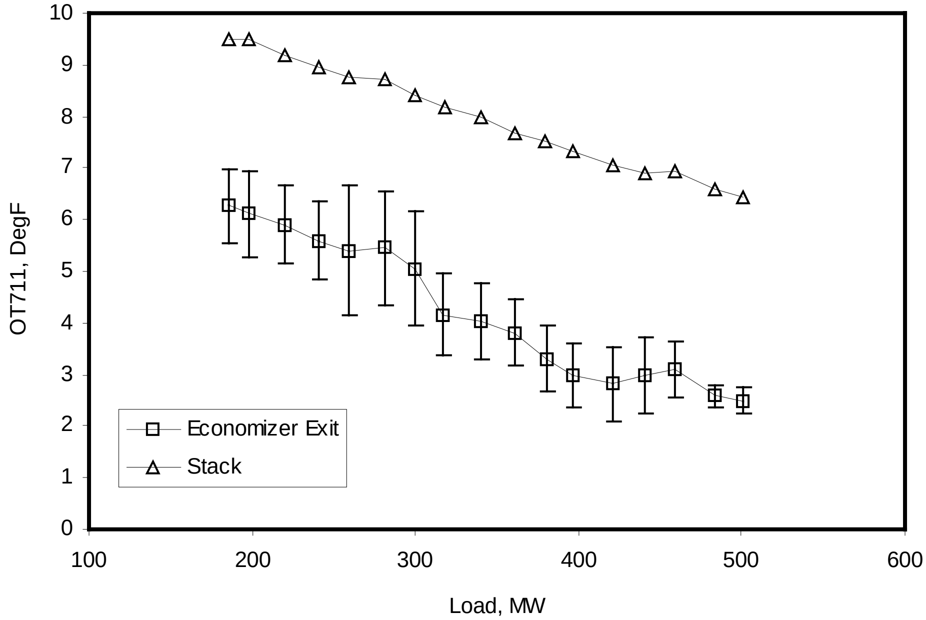


Figure 8-37 LNB / Long-Term / Excess Oxygen at Economizer Outlet / East

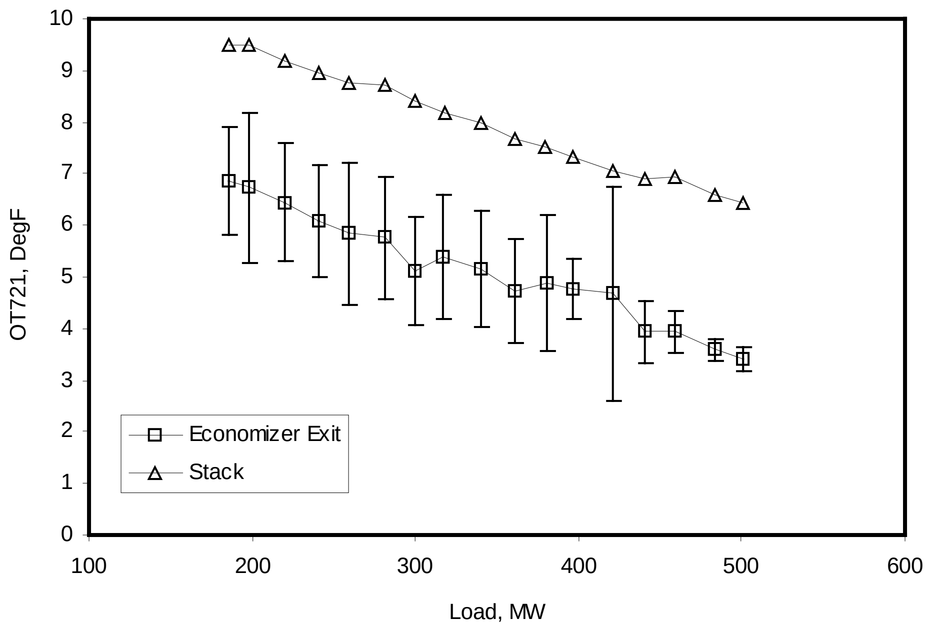


Figure 8-38 LNB / Long-Term / Excess Oxygen at Economizer Outlet / West

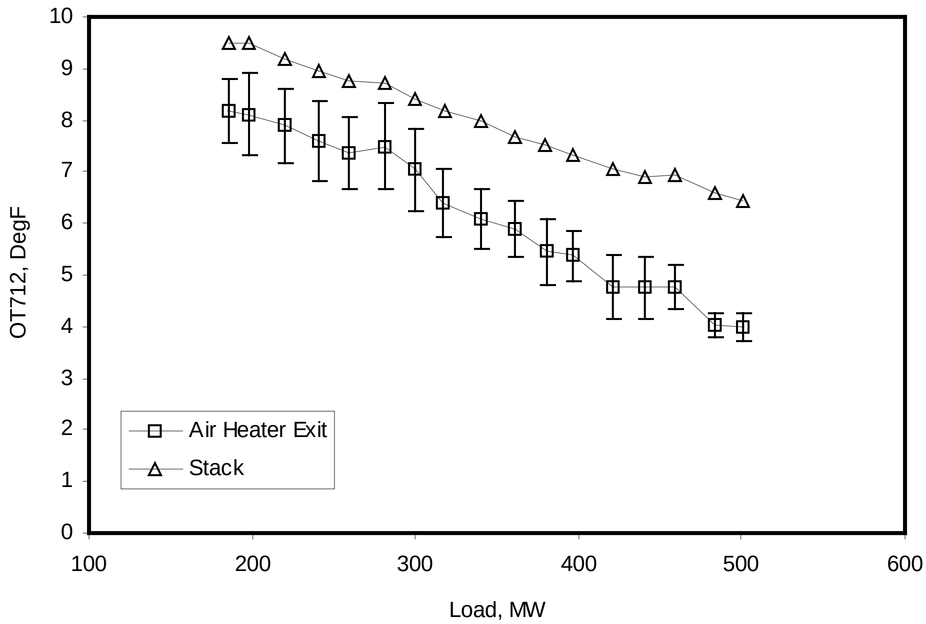


Figure 8-39 LNB / Long-Term / Excess Oxygen at Air Heater Outlet / East

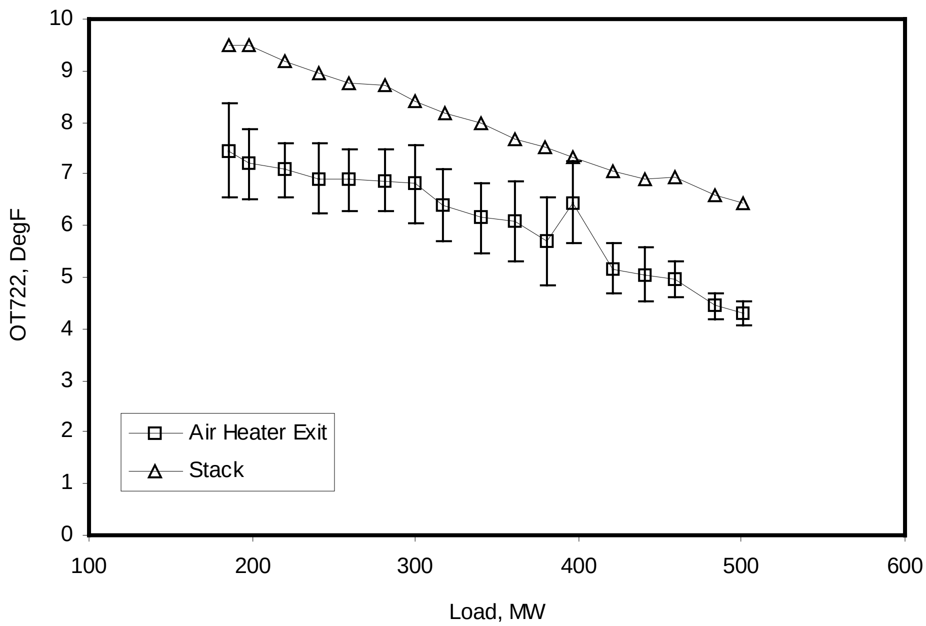


Figure 8-40 LNB / Long-Term / Excess Oxygen at Air Heater Outlet / West

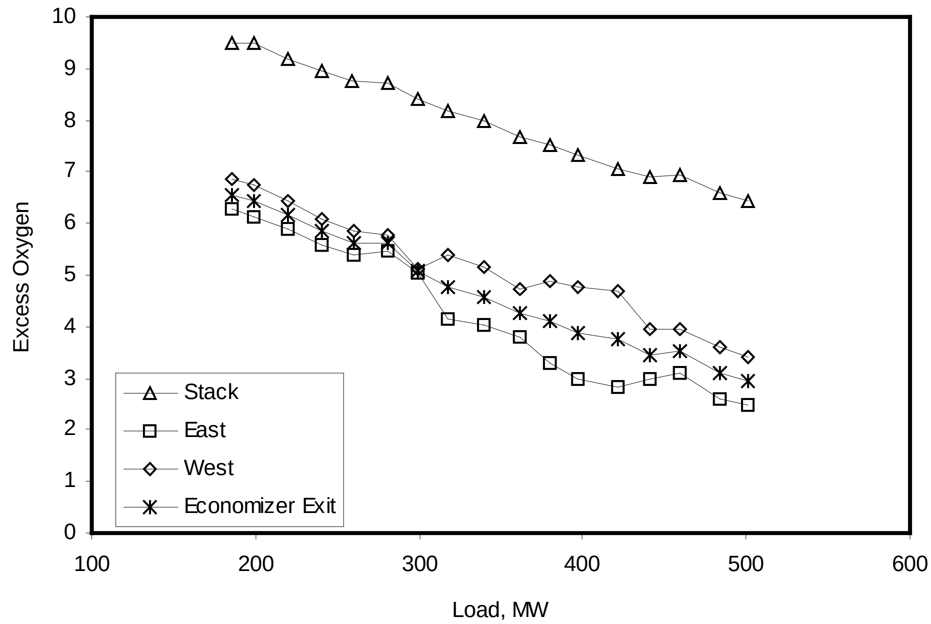


Figure 8-41 LNB / Long-Term / Excess Oxygen at Economizer Exit / Average

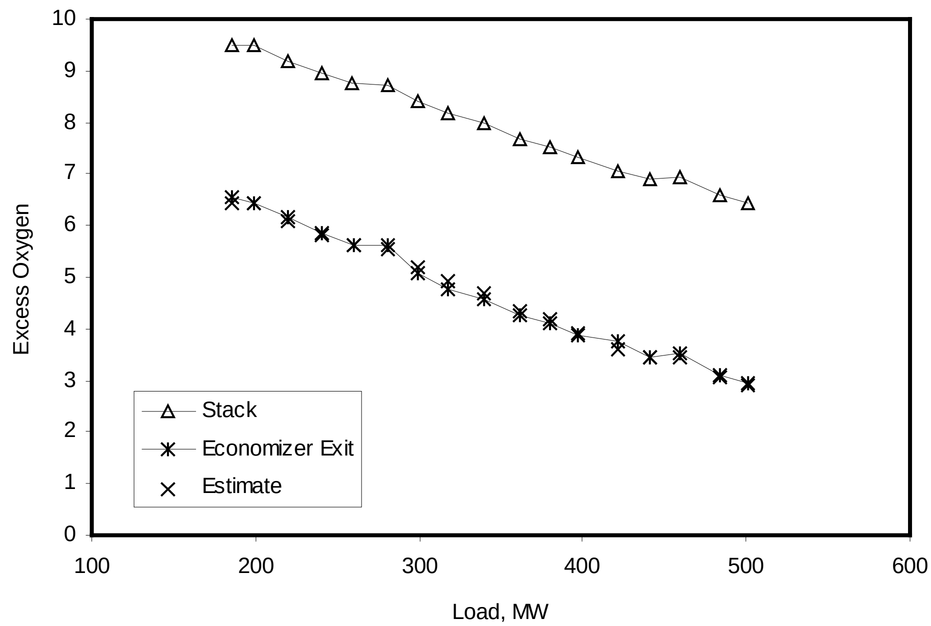


Figure 8-42 LNB / Long-Term / Excess Oxygen at Economizer Exit / Estimate

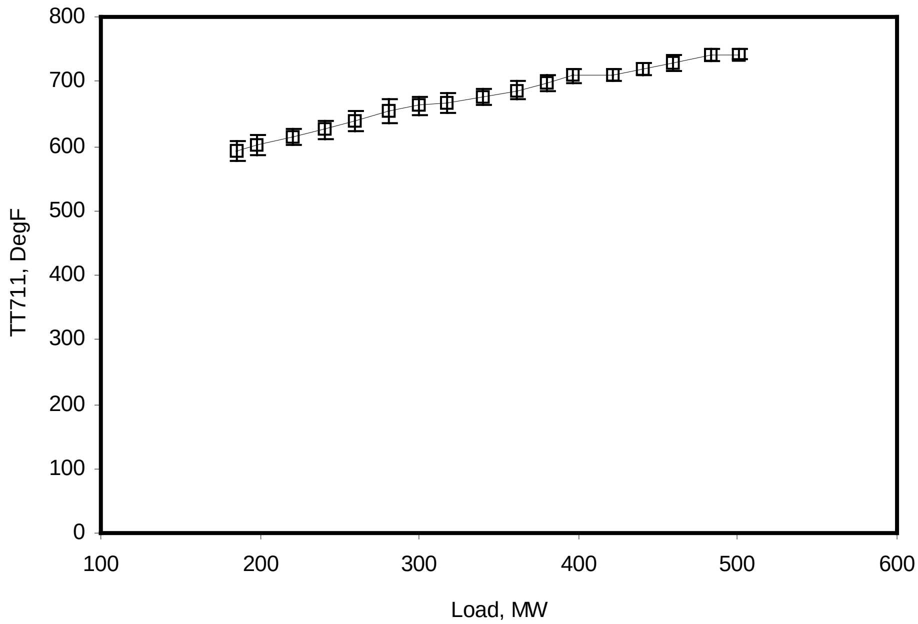


Figure 8-43 LNB / Long-Term / Flue Gas Temperature at Air Heater Inlet / East

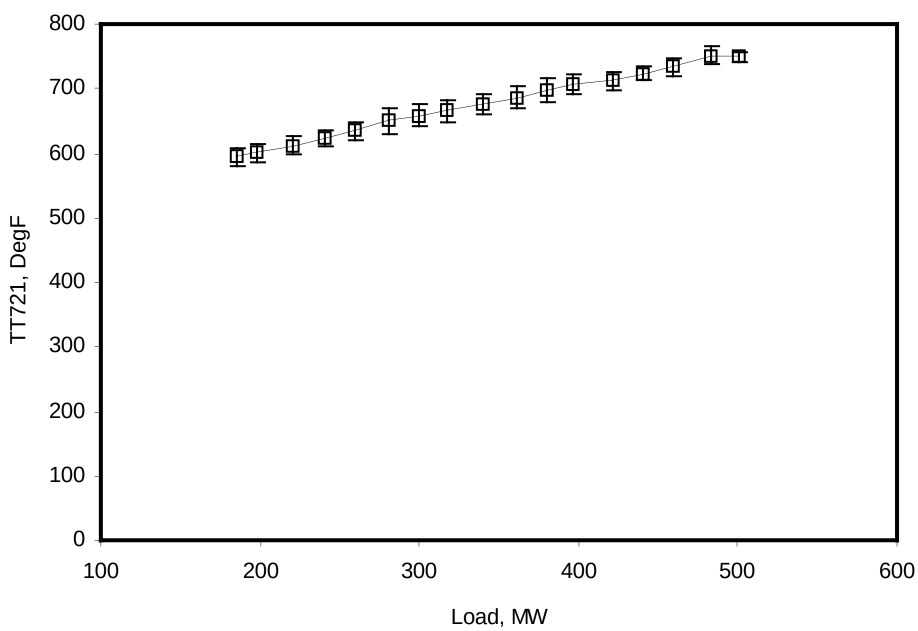


Figure 8-44 LNB / Long-Term / Flue Gas Temperature at Air Heater Inlet / West

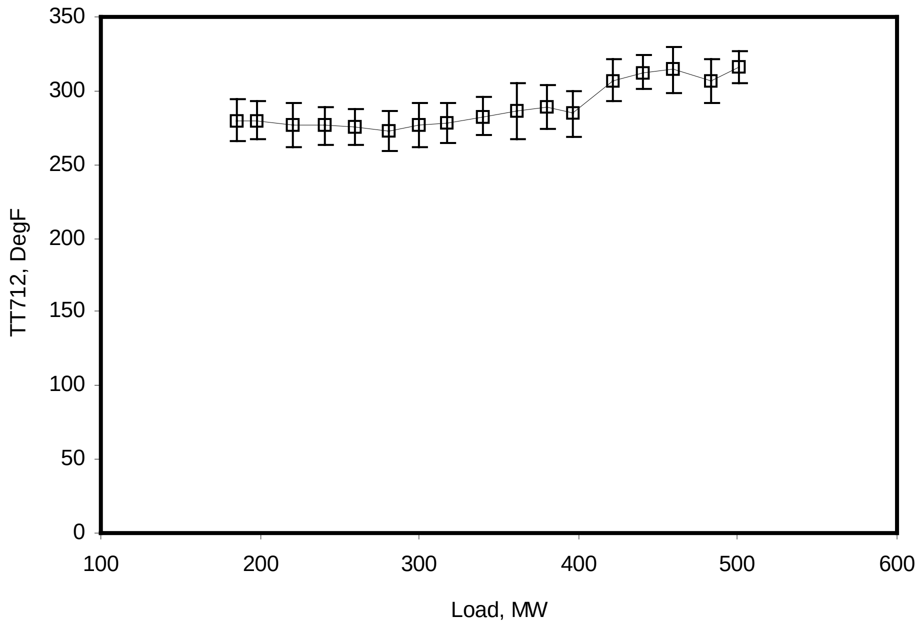


Figure 8-45 LNB / Long-Term / Flue Gas Temperature at Air Heater Outlet / East

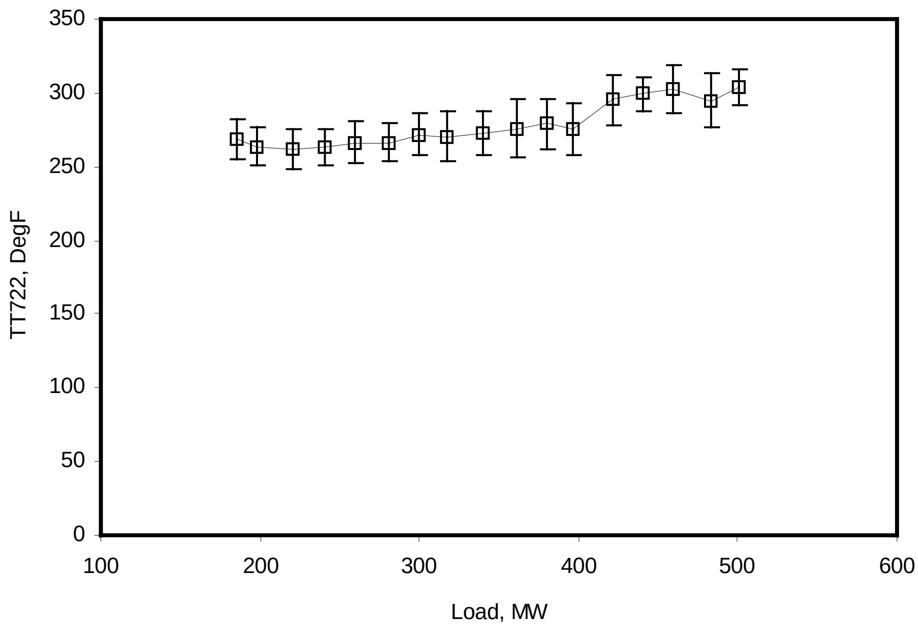


Figure 8-46 LNB / Long-Term / Flue Gas Temperature at Air Heater Outlet / West

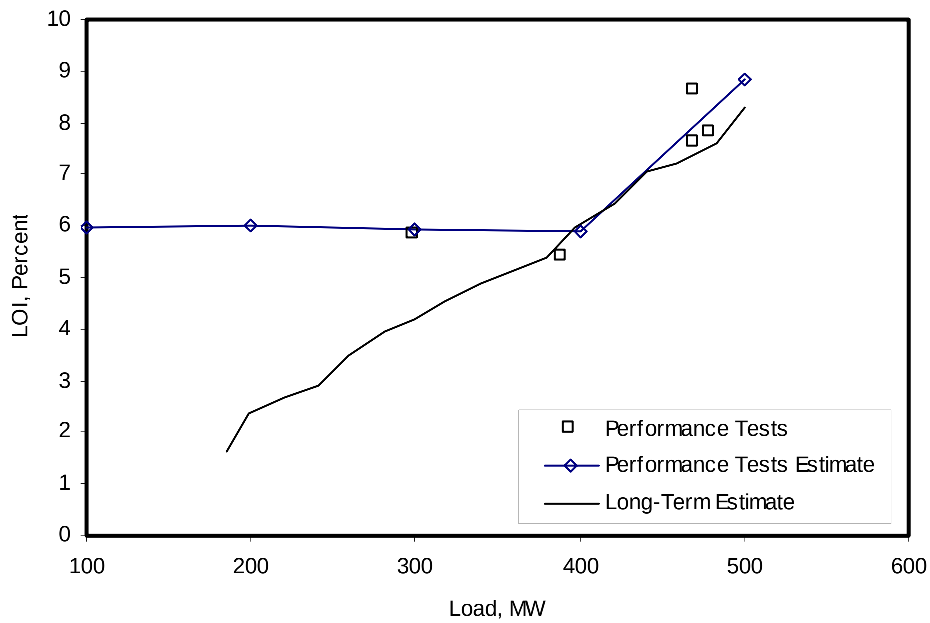


Figure 8-47 LNB / Long-Term / LOI Estimate

8.3 Operation and Reliability Impacts

System operation in the LNB configuration experienced some positive and negative changes relative to pre-retrofit. The positive changes included:

- Reduced wallblower frequency resulting from the reduced slagging.
- Better-tuned system.

The negative changes were:

- Reduction of operating flexibility, because the excess oxygen operating range was restricted to 3.5-4.5 percent.
- Increased backpass sootblower operating frequency, resulting from the reduced furnace slagging.
- The need to shut down the unit periodically to clean the air heater as a result of increased fouling.

The test program at Hammond has provided preliminary indications that the unit reliability may be impacted by the LNB system. Examples of the reliability impacts experienced during the testing include burner fires and burner tip cracking.

Several burner overheating incidents were experienced following installation of the low NOx burners. Although in most instances these failures did not force the unit out of service, they did require that the burner be removed from service, reducing the flexibility of the unit, and eventually required that the burner be replaced. In each instance, portions of the cast burner nozzle assembly melted away, especially in the vicinity of the coal nozzle. A typical example is shown in Figure 8-48. The locations of the burner fires were independent of the pulverizer supplying the burner. In one of the burner failures, the damage was not only to the burner nozzle, but included the inner and outer barrel, the secondary air registers, and two adjacent burners (Figure 8-49). These burner failures instigated the installation of an enhanced burner temperature monitoring system to provide more comprehensive alarming capabilities.

An analysis of these failures included the collection and review of all available operating data. Although there is insufficient data to conclusively identify the root cause of these burner fires, the following are observations and hypotheses that resulted from the study:

- Burner fires generally occurred at reduced operating loads and the affected pulverizer operating at the lower end of the air/fuel curve.
- All failures appear to result from layout in the burner and subsequent coking.
- Although calculated primary air velocities entering the burners were at levels that would normally be considered adequate to prevent coal layout, inadequate primary air velocity could not be discounted as a contributing factor.

- In regard to plugging and coal layout, the new low NOx burners appear to be more sensitive to air velocities and air/fuel ratios than the earlier turbulent burners.

Figure 8-48 LNB / Typical Burner Fire

Figure 8-49 LNB / Extensive Burner Fire

In addition to the burner fires, a majority of the burners have developed cracks in the burner cast tips. Some of these cracks are several inches long, especially in the upper elevation of burners. Although it appears the cracks do not impact unit operation or burner performance, if they develop further, they may force the unit out of service or require significant repairs (even replacement of the tips).

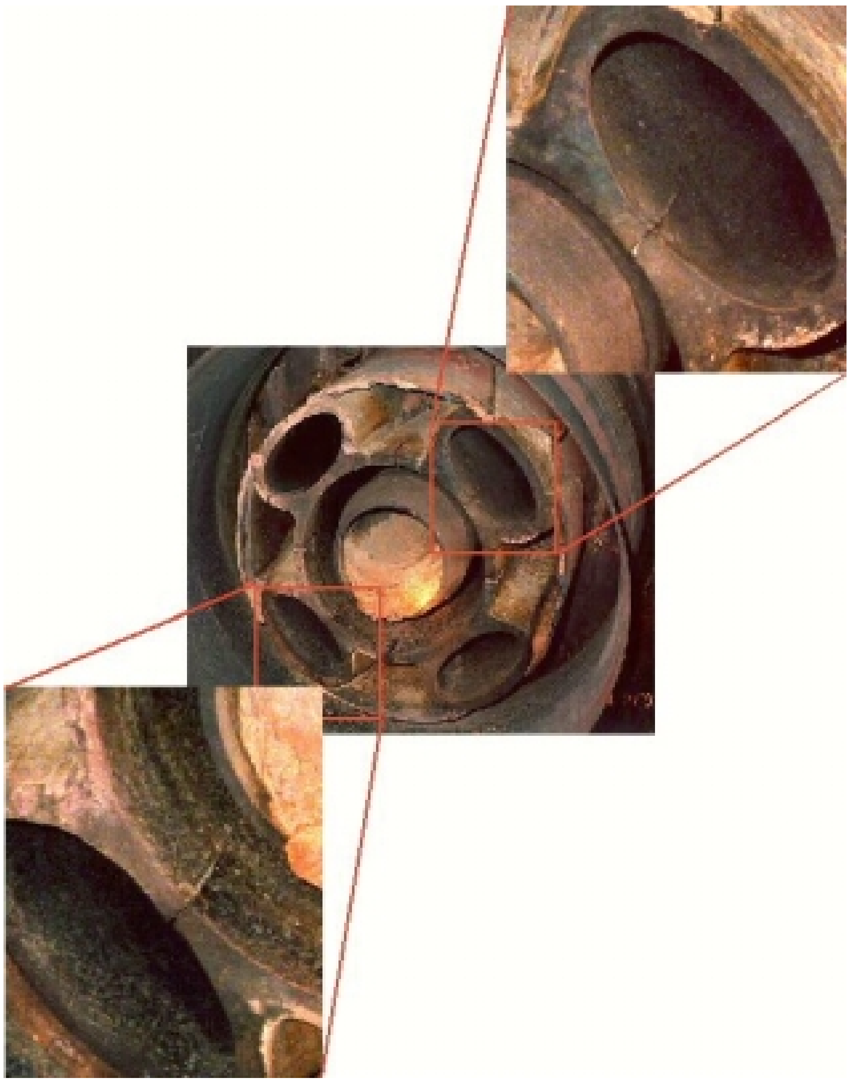


Figure 8-50 LNB / Cracked Burner Tip

9 PHASE 3B - LNB+AOFA TRIALS

Following conclusion of the LNB test phase during January 1992, testing in the low NOx burner and advanced overfire air configuration was scheduled to begin immediately and end in late March 1992. However, due to delays associated with increased stack particulate emissions following the LNB installation, it was not possible to complete testing in the LNB+AOFA configuration prior to the spring 1992 outage, during which two new pulverizers were to be installed (B and E). Abbreviated testing (designated 3B') in the LNB+AOFA configuration was performed during February and March 1992 to obtain operating data prior to this outage. To maintain stack particulate compliance, the unit ran at reduced loads (less than 450 MW) until spring 1993. During this period, long-term data was collected and the NOx vs. LOI tests in the LNB configuration (see Section 8) were performed. Hammond Unit 4 was given permission from the state to resume full-load operation on March 26, 1993. Following resumption of full load operation on March 26, 1993, FWEC personnel re-optimized the unit for LNB+AOFA operation from March 30, 1993 through May 6, 1993.

Characterization of the unit began on May 6, 1996 and was completed on August 26, 1993. All major boiler components, as well as ancillary equipment, were in the normal "as found" operating condition. The fuel burned throughout the Phase 3B short-term program was from the normal supply source and was handled according to common plant practice. For all Phase 3B testing (LNB with AOFA), the main AOFA guillotine dampers and AOFA port dampers were full open and the AOFA flow control dampers were nominally open to the settings recommended by FWEC over the load range. For some diagnostic and verification tests, the OFA flow control dampers were opened more or less than the nominal settings to determine the effects of OFA flow on NOx emissions and on operating parameters.

9.1 Abbreviated Testing Conducted First Quarter 1992

FWEC began optimization of the unit for operation with LNB with AOFA on January 17, 1992 and was completed on February 17, 1992. FWEC's initial estimate for the time required for optimization in this configuration was two weeks. The optimization schedule was adversely impacted by (1) unavailability of the unit because of problems unrelated to the LNB retrofit and (2) often, for the same burner tuning, results were not repeatable.

Using the data collected during optimization, FWEC developed operating instructions for this mode of operation. These operating instructions require that the AOFA flow be indexed to load as opposed to AOFA damper position used during Phase 2. Because the AOFA flow is manually controlled, this manner of operation can adversely impact the rate at which the unit can be dispatched.

The installation of the overfire airflow measurement system purge panels was completed on March 20, 1992. FWEC operating instructions for the LNB+AOFA configuration required that the AOFA flow measurement system be operational. During LNB+AOFA short-term testing, the flow measurement system was manually purged. Since manual purging is not feasible on an extended basis, long-term testing was delayed until the automatic purge system was operational. The operability of the AOFA flow measurement system was not a critical issue during the AOFA test phase because the operating instructions specified AOFA control damper positions as a function of load instead of AOFA flows.

Because of the extended amount of time required to optimize the LNB and LNB+AOFA configurations and the need to further evaluate the adverse impacts of the LNBs on electrostatic precipitator performance, testing could not be completed within the original schedule. Therefore, the LNB+AOFA diagnostic, performance, chemical emissions, long-term, and verification tests were rescheduled to follow the spring 1992 outage. To provide preliminary data from this configuration and to identify changes in unit operation that may have occurred as a result of modifications to the unit being made during the spring 1992 outage, abbreviated diagnostic tests for the LNB+AOFA configuration were undertaken prior to the outage.

The abbreviated diagnostic testing for the LNB combined with AOFA began February 18, 1992 and continued to February 25, 1992 (see Appendix D). Results from these tests indicated full-load NOx emissions were approximately 0.55 lb/MBtu and fly ash LOI values of approximately 11 percent. For comparison, full-load, long-term NOx emissions for the baseline, AOFA, and LNB test phases were approximately 1.24, 0.94, and 0.65 lb/MBtu, respectively. In addition to the standard regimen of diagnostic tests performed in previous phases of the project, mill performance and combustion air distribution were performed for one full-load condition. These tests, normally performed during the performance tests, were added to the diagnostic test matrix to better characterize operating parameters that have a significant impact on combustion performance. Mill performance was improved over that seen in previous test phases. The performance was especially good on the B&W mills installed during the spring 1991 outage ("C" and "F" mills). Secondary air, overfire air, and primary air accounted for 66, 17, and 16 percent, respectively, of total combustion air at full-load. For comparison, Phase 2 AOFA performance tests indicated that of the total combustion air flow, 50 percent was secondary air, 20-25 percent was overfire air, and 25 percent was primary air.

9.2 Short-Term Test Results

The short-term testing consisted of first performing diagnostic testing to establish the general NOx and operating trends followed by performance testing to establish the characteristics of the fuel/air feed systems and the solid and gaseous emissions for the most representative configuration. Following the performance testing, the NOx emissions and unit operating parameters were monitored continuously, 24 hours per day, for a period of 95 days. At the end of the long-term test period, a short series of verification tests was conducted, similar to diagnostic testing, to determine whether any change had occurred in the basic unit emission characteristics over the long-term period. All tests during the diagnostic, performance, and verification portions of the short-term test effort were conducted within the normal limits of operating parameters for the unit, with the exception of excess oxygen. Excess oxygen was exercised well above and below the plant-specified range at each load level to the potential levels that might be encountered during transients in the long-term test phase. For all tests, the OFA flow was read from the OFA flow meter readouts in the control room, which represented the air flows to the front and rear, east and west quadrants of the OFA windbox. During the performance testing, additional measurements were made of the airflow into each OFA quadrant by means of pitot traverses performed in accordance with ASME test procedures. The following paragraphs describe the diagnostic, performance and verification testing performed during Phase 3B.

9.2.1 Diagnostic Tests

The initial Phase 3B short-term characterization testing was begun on May 6, 1993 and was completed on August 26, 1993. A total of 53 diagnostic tests were performed during this period (Table 9-1). The Phase 3B diagnostic effort consisted of characterizing emissions under normal operating conditions with the LNBs installed and the AOFA flow control dampers opened to the settings recommended by FWEC, as well as greater and lesser settings. The tests were performed at nominal loads of 180, 300, 400, 450, and 480 MW. The diagnostic test efforts were interrupted to accomplish the performance testing due to scheduling conflicts. Diagnostic testing was then completed after the performance testing was completed. The initial diagnostic testing began shortly after FWEC completed start-up testing for the LNB+AOFA configuration. Each test condition (load, excess oxygen, OFA flow, and mill configuration) was held steady for a period of from one to three hours depending upon the type of test performed. During this period, data was collected from the control room, DAS, and economizer exit and air heater exit species and temperatures were recorded utilizing the sample distribution. When sufficient time permitted, furnace backpass ash grab samples were collected from the manual ash samplers and coal samples were collected from the individual mills.

9.2.1.1 Unit Operating Condition

During the diagnostic test efforts, no unusual operating conditions were encountered that placed restrictions on the test effort, except that testing at high load was at times restricted by high opacity emissions. For that reason, some 450 MW tests were conducted when the 480 MW load level could not be reached without excessive opacity. Sixteen days of testing were executed comprising the 53 various excess oxygen, mill pattern, OFA and load conditions. Because historic load profiles indicated much greater operating times at 400 MW and above, compared to lower loads, diagnostic testing was conducted more extensively at the higher load levels.

9.2.1.2 Gaseous Emissions

During both the diagnostic and performance test efforts, flue gas data and boiler operating data were collected on the data acquisition system. The gas analysis system allowed measurement of NOx, CO, O_2, and THC from 48 probe locations within the flue gas stream both upstream and downstream of the air heater. Two basic types of tests were performed: (1) overall NOx characterization and (2) economizer exit plane species distribution characterization. The overall NOx characterization tests were performed over a period of approximately one hour and were used to obtain composite average specie concentrations from the individual probes in a duct sampled as a group. The economizer exit plane species distribution characterizations were performed over a period of approximately two to three hours. These tests used data from the individual probe species concentrations in the A- and B-side economizer exit planes to establish the distribution of combustion products. Maldistributions, if present, indicate fuel and/or air non-uniformity. The range of excess oxygen and resulting NOx emissions for the four nominal load levels tested during the diagnostic portion of the Phase 3B effort are shown in Figures 9-1 and 9-2. The conditions represented in these figures include the tested ranges of excess oxygen variation, mill-out-of-service variation, mill biasing, OFA flow, etc.

Figure 9-1 illustrates that the testing was performed over a range of excess oxygen levels that were both below and above the normal levels for this unit. The solid line represents the recommended minimum excess oxygen operating level over the load range. During economic dispatch of the unit, excursions to the extreme O_2 levels are frequently experienced during transient load conditions. Thus, the range of excess O_2 levels was tested to permit a valid comparison between the short-term and long-term emission characteristics.

Figure 9-2 is a summary of all of the NOx data obtained for all test configurations. These configurations represented the range of normal configurations that were believed to be the predominant modes of operation that might be experienced during the system load dispatch mode of operation during long-term testing. The data scatter results partially from the fact that the different firing configurations are represented. The shaded area represents the range of NOx values experienced at excess O_2 levels within a ±0.5 percent O_2 variation about the recommended O_2 level and with nominal OFA flow. It should be emphasized that analyses performed for data gathered during the long-term testing, where virtually thousands of data points were used for the characterization, provide a more statistically appropriate NOx band than that presented in Figure 9-2.

Short-term characterization of the NOx emissions generally were made for trends determined on the same day of testing for a particular configuration to eliminate, to some extent, the influence of the uncontrollable parameters. Figures 9-3 through 9-6 show the diagnostic test results for the four loads tested -- 480, 400, 300, and 180 MW, respectively. Data shown in these figures are for the nominal overfire airflow recommended by FWEC at each load. The legend for each data point indicates the test day and run for the data point in the format X-Y, where X is the test day and Y is the run. In addition to the 480 MW nominal load condition, a number of 450 MW tests were conducted because of periodic difficulty in achieving the 480 MW load level. Additional data from these tests can be found in Appendix D.

Over the load range from 480 to 180 MW, the NOx sensitivity with excess oxygen excursions varied from 0.076 to 0.029 lb/MBtu per percent O_2. A trend did not exist with respect to the sensitivities -- the highest sensitivity was at 400 MW while the lowest was at the 180 MW load point. This is inconsistent with results from other test phases where the sensitivity decreased with decreasing load. The explanation for this inconsistency is unknown at this time. One possibility is that insufficient data was gathered to estimate a representative sensitivity at each load point.

Table 9-1 LNB+AOFA / Diagnostic Tests Conducted

Test No.	Date	Test Conditions	Load MW	MOOS Pattern	OFA Flow KPPH	Excess O_2 Dry (%)
101-1	05/06/93	HI-LOAD OFA VARIATION	449	AMIS	600	3.5
101-2	05/06/93	HI-LOAD OFA VARIATION	452	AMIS	455	3.6
101-3	05/06/93	HI-LOAD OFA VARIATION	446	AMIS	300	3.6
102-1	05/07/93	MID-LOAD O2 VARIATION	394	AMIS	400	4.4
102-2	05/07/93	MID-LOAD O2 VARIATION	397	AMIS	400	3.3
102-3	05/07/93	MID-LOAD O2 VARIATION	397	AMIS	400	2.7
102-4	05/07/93	HI-LOAD BASELINE	479	AMIS	763	3.1
103-1	05/08/93	MID-LOAD MILL VARIATION	407	E	310	4.1
103-2	05/08/93	MID-LOAD O2 VARIATION	402	B	320	4.6
103-3	05/08/93	MID-LOAD O2 VARIATION	398	B	300	4.0
103-4	05/08/93	MID-LOAD O2 VARIATION	399	B	303	3.1
104-1	05/09/93	LO-LOAD O2 VARIATION	305	D&F	305	5.2
104-2	05/09/93	LO-LOAD O2 VARIATION	295	D&F	295	3.9
105-1	05/10/93	MID-LOAD MILL/O2 VARIATION	395	F	300	3.9
105-2	05/10/93	MID-LOAD MILL/O2 VARIATION	396	F	344	5.1
106-1	06/08/93	HI-L0AD OFA VARIATION	450	AMIS	595	3.6
106-2	06/08/93	HI-L0AD OFA VARIATION	477	AMIS	794	3.9
106-3	06/08/93	HI-L0AD OFA VARIATION	468	AMIS	829	4.5
107-1	06/09/93	HI-LOAD NOMINAL	465	AMIS	813	4.0
108-1	06/10/93	HI-LOAD O2 VARIATION	463	AMIS	824	4.1
108-2	06/10/93	HI-LOAD O2 VARIATION	449	AMIS	792	3.8
108-3	06/10/93	HI-LOAD O2 VARIATION	472	AMIS	802	3.1
109-1	06/11/93	HI-LOAD OFA VARIATION	470	AMIS	797	3.7
109-2	06/11/93	HI-LOAD OFA VARIATION	470	AMIS	952	3.5
109-3	06/11/93	HI-LOAD OFA VARIATION	474	AMIS	611	3.6
110-1	06/12/93	LO-LOAD MILL/O2 VARIATION	302	E	314	5.3
110-2	06/12/93	LO-LOAD MILL/O2 VARIATION	305	B&E	250	4.6
110-3	06/12/93	LO-LOAD MILL/O2 VARIATION	305	B&E	326	5.5
110-4	06/12/93	LO-LOAD MILL/O2 VARIATION	302	B&E	315	6.4
110-5	06/12/93	MID-LOAD O2 VARIATION	394	B	327	5.6
110-6	06/12/93	MID-LOAD O2 VARIATION	391	B	313	4.3
110-7	06/12/93	MID-LOAD O2 VARIATION	391	B	403	4.3
111-1	06/13/93	LO-LOAD MILL/O2 VARIATION	293	B&D	310	6.3
111-2	06/13/93	LO-LOAD MILL/O2 VARIATION	295	B&D	317	5.0
111-3	06/13/93	LO-LOAD MILL/O2 VARIATION	292	B&D	306	4.3
112-1	06/14/93	MID-LOAD NOMINAL O2	400	AMIS	396	4.3
112-2	06/14/93	MID-LOAD O2 VARIATION	400	TEST ABORTED - MILL PROBLEMS		
112-3	06/14/93	MID-LOAD NOMINAL O2	404	AMIS	416	4.7
113-1	06/15/93	HI-LOAD OFA VARIATION	476	AMIS	799	3.8
113-2	06/15/93	HI-LOAD OFA VARIATION	474	AMIS	585	3.6
113-3	06/15/93	HI-LOAD OFA VARIATION	474	AMIS	276	3.4
114-1	06/16/93	MIN-LOAD O2 VARIATION	179	B,D,E	94	6.8
114-2	06/16/93	MIN-LOAD O2 VARIATION	186	B,D,E	93	5.4
114-3	06/16/93	MIN-LOAD O2 VARIATION	183	B,D,E	90	4.5
121-1	06/24/93	HI-LOAD OFA VARIATION	483	AMIS	954	3.7
121-2	06/24/93	HI-LOAD OFA VARIATION	482	AMIS	791	3.9
121-3	06/24/93	HI-LOAD OFA VARIATION	481	AMIS	603	3.8
121-4	06/24/93	HI-LOAD OFA VARIATION	495	AMIS	777	3.8
122-1	06/25/93	MID-LOAD MILL/O2 VARIATIONS	401	AMIS	409	4.0
122-2	06/25/93	MID-LOAD MILL/O2 VARIATIONS	402	AMIS	275	4.1
122-3	06/25/93	MID-LOAD MILL/O2 VARIATIONS	397	AMIS	516	4.2
122-4	06/25/93	MID-LOAD MILL/O2 VARIATIONS	396	AMIS	510	4.7
122-5	06/25/93	MID-LOAD MILL/O2 VARIATIONS	395	AMIS	401	4.7
122-6	06/25/93	MID-LOAD MILL/O2 VARIATIONS	392	AMIS	395	3.3

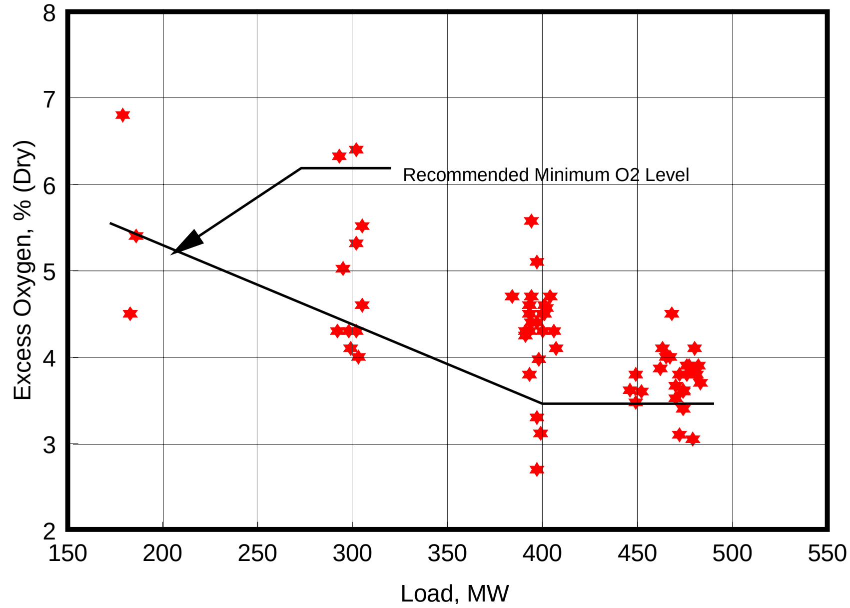


Figure 9-1 LNB+AOFA / Oxygen Levels Tested

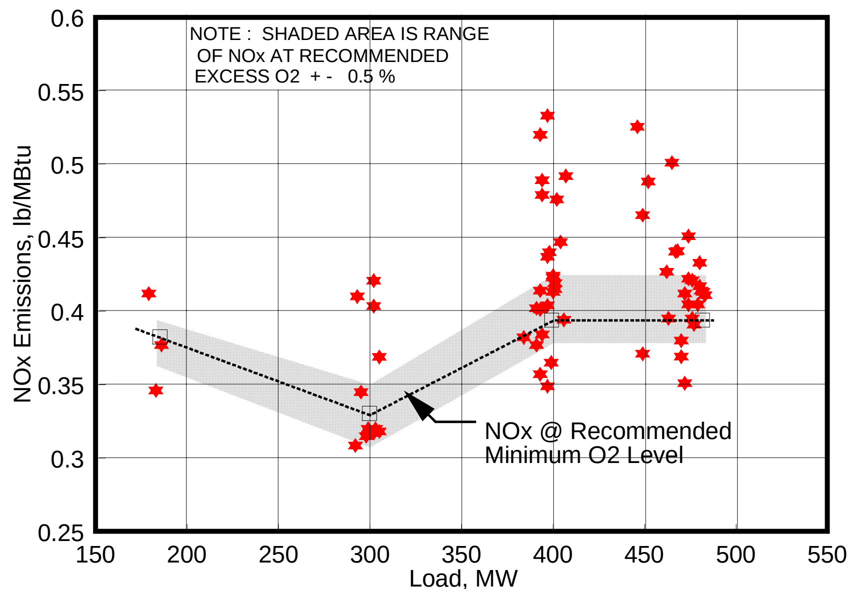


Figure 9-2 LNB+AOFA / NOx Emissions

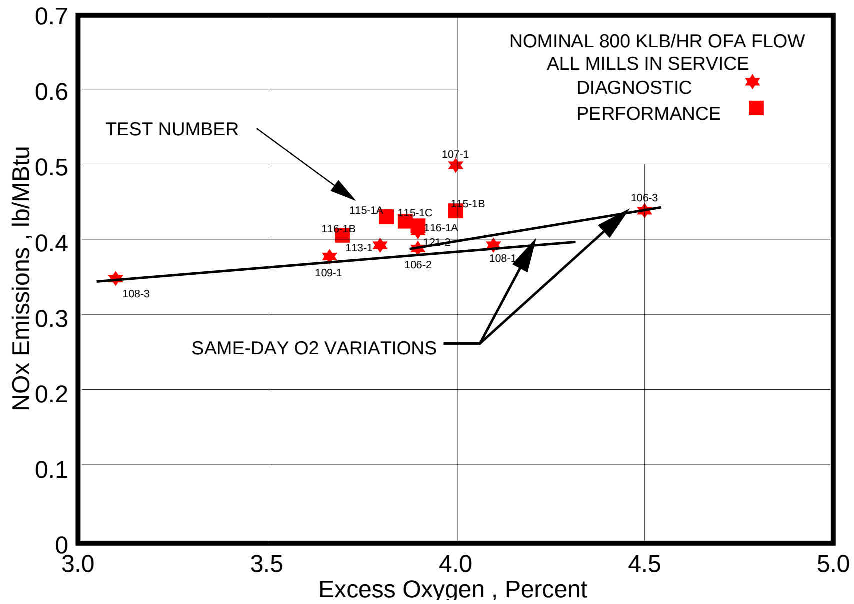


Figure 9-3 LNB+AOFA / NOx Characterization / 480 MW

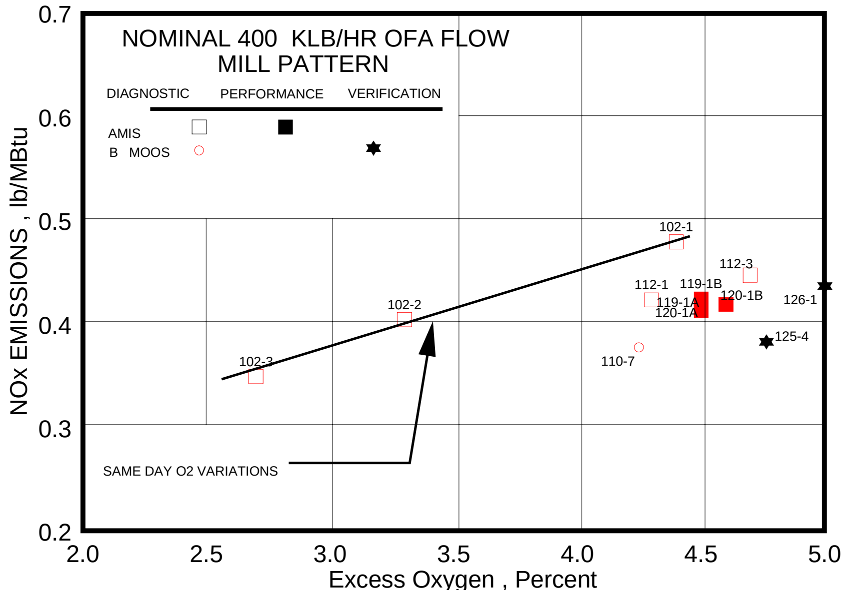


Figure 9-4 LNB+AOFA / NOx Characterization / 400 MW

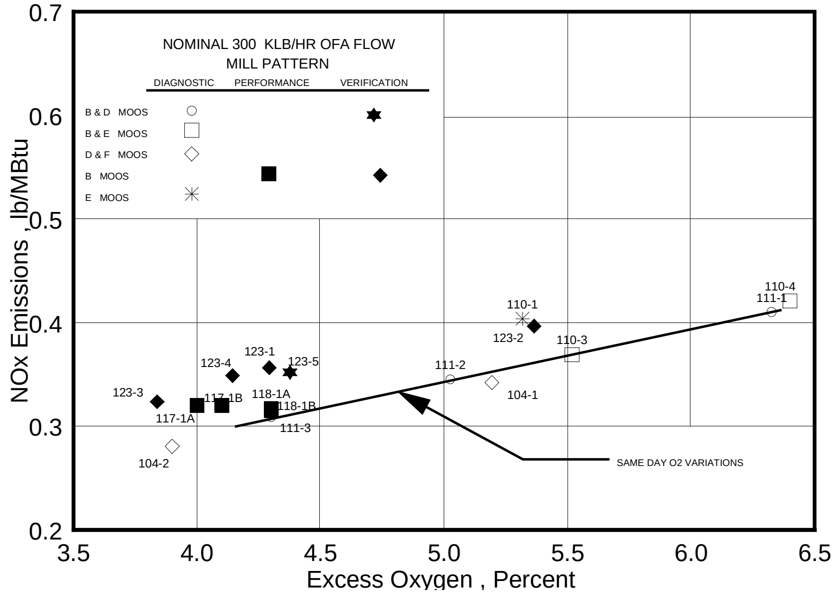


Figure 9-5 LNB+AOFA / NOx Characterization / 300 MW

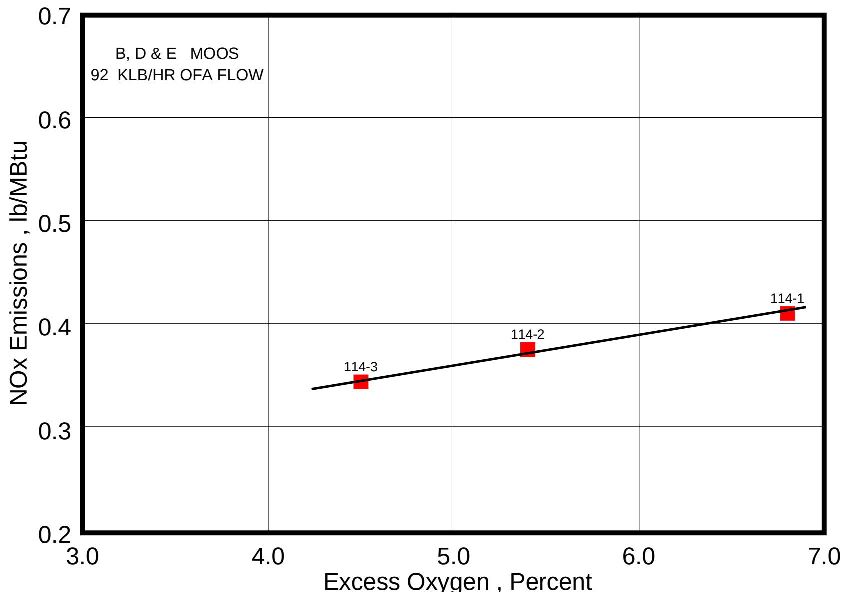


Figure 9-6 LNB+AOFA / NOx Characterization / 180 MW

During the Phase 3B test effort, a number of tests were performed to establish the sensitivity of NOx emissions with AOFA port opening. The ports could only be closed to the limit that allowed sufficient cooling air to prevent slag buildup at the AOFA opening. Figure 9-7 illustrates the sensitivity of NOx emissions to AOFA port opening for the Phase 3B effort and for the Phase 2 effort (AOFA alone) at 480 MW. In both the Phase 2 and 3B efforts, it was not possible to close the AOFA ports completely. In the case of Phase 2, the AOFA ports had some leakage air past the dampers. In the case of Phase 3B, the AOFA ports were not closed completely to prevent slag buildup. In both phases it is evident that the zero flow NOx level can be determined by extrapolation of the data to the closed damper position. The normal AOFA position at 480 MW for both phases was approximately 55 percent open.

From Figure 9-7 it is evident that the effect of AOFA was less for the Phase 3B configuration with LNB plus AOFA than for the Phase 2 configuration with AOFA alone. For the AOFA only configuration, the NOx emissions sensitivity between 0 and 55 percent damper position was approximately 0.0035 lb/MBtu per percent damper opening while in the LNB plus AOFA configuration it was 0.0014 lb/MBtu per percent damper opening position -- less than one-half the sensitivity. As may be expected, operation of AOFA with LNB results in lower effectiveness than for operation of AOFA alone. In the AOFA only configuration, the NOx reduction was approximately 21 percent (at 55 percent damper position) while in the LNB plus AOFA configuration it was approximately 16 percent. The apparent AOFA reduction between Phase 3A and 3B was on the order of 40 percent. This apparent anomaly can in part be explained by examining the mill operation in both phases and the results of the NOx. vs. LOI tests conducted in Phase 3A (see Section 8).

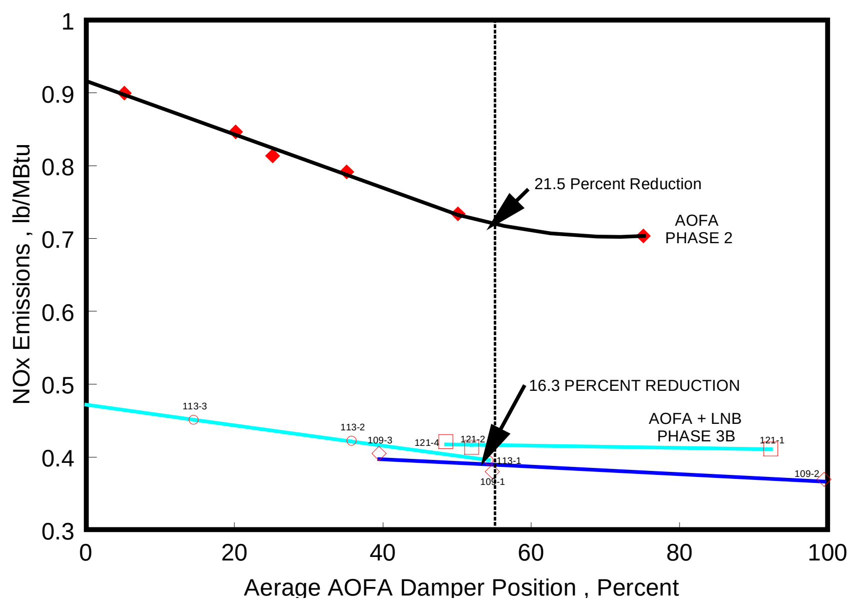


Figure 9-7 LNB+AOFA / Comparison of AOFA Effectiveness

9.2.2 Performance Tests

Six performance tests were conducted at nominal loads of 480, 400, and 300 MW (Table 9-2). Testing at each load point required two consecutive days to complete sampling of all of the parameters included in the performance matrix. At each nominal load, the coal firing rate was kept as constant as possible and the electric load allowed to swing slightly as affected by coal variations, boiler ash deposits, ambient temperature, etc. The unit excess O_2 and OFA flow rates were maintained per FWEC recommendations. The coal feed rate to all in-service pulverizers was kept as nearly equal as possible, based upon the control room readings. As described in subsequent paragraphs, after the completion of the Phase 3B long-term testing, it was discovered that the control room feeder readings did not accurately represent the actual mill coal flow rates. Each performance test day covered a period from ten to twelve hours during which time boiler operational data was recorded, fuel and ash samples acquired, gaseous and solid emission measurements made, and fly ash resistivity measured in situ.

Table 9-2 LNB+AOFA / Performance Tests Conducted

Test No.	Date	Test Conditions	LOAD MW	MOOS Pattern	OFA Flow (KPPH)	Excess O2 Dry (%)
115-1A	06/17/93	Perf. Test / Full-Load	480	AMIS	790	3.8
115-1B	06/17/93	Perf. Test / Full-Load	467	AMIS	784	4.0
115-1C	06/17/93	Perf. Test / Full-Load	462	AMIS	774	3.9
116-1A	06/18/93	Perf. Test / Full-Load	476	AMIS	787	3.9
116-1B	06/18/93	Perf. Test / Full-Load	472	AMIS	805	3.8
117-1A	06/19/93	Perf. Test / Mid-Load	303	B	311	4.0
117-1B	06/19/93	Perf. Test / Mid-Load	299	B	297	4.1
118-1A	06/20/93	Perf. Test / Mid-Load	302	B	321	4.3
118-1B	06/20/93	Perf. Test / Mid-Load	298	B	308	4.3
119-1A	06/21/93	Perf. Test / Mid-Load	400	B	427	4.5
119-1B	06/22/93	Perf. Test / Mid-Load	400	B	409	4.5
120-1A	06/22/93	Perf. Test / Mid-Load	401	B	421	4.5
120-1B	06/23/93	Perf. Test / Mid-Load	401	B	424	4.6

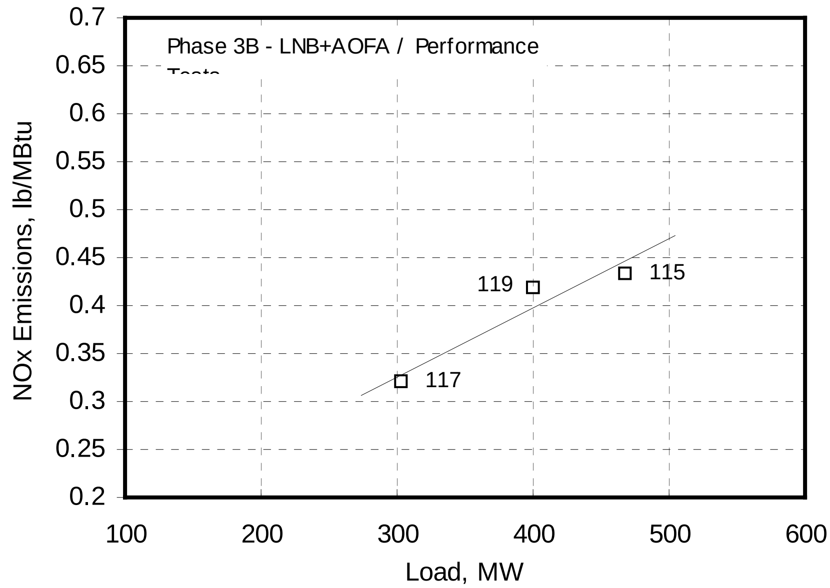
9.2.2.1 Unit Operating Data

For each performance test, the desired test conditions were established and allowed to stabilize at least one hour prior to commencement of testing. To the extent possible, the active coal mills were balanced with respect to plant instrumentation (subsequently discovered to be inaccurate). Normal primary air/coal ratios and mill outlet temperatures were maintained, within the capacity of the existing primary air system. When the desired operating conditions were established, some controls were placed in manual mode to minimize fluctuations in the fuel and airflows. This technique resulted in extremely stable operation over the test duration with only minor adjustment to the airflow over the day to maintain a near-constant stoichiometry.

Because a portion of the testing was concerned with measurement of various particulate emission characteristics, it was decided that soot blowing (both furnace and air heaters) should be suspended during the particulate sampling periods. As a result, the collected ash would include only particulate matter actually generated by the coal combustion at the time of testing (plus any normal attrition of wall or air heater deposits) and not periodic portions of ash loosened by soot blowing. When necessary for proper unit operation, air heaters were blown between repetitions in the solids emissions testing. A summary of important operating parameters recorded on the DAS during this test series can be found in Appendix D.

9.2.2.2 Gaseous Emissions

During the performance tests, gaseous emissions were measured with the ECEM operating in the manual mode. At various times during the performance tests, flue gas was sampled from selected probes or probe groups in the primary and secondary air heater inlet and outlet ducts. These groupings consisted of composites of the individual east and west economizer exit ducts and individual measurements from each probe in these ducts. Composite grouping was performed to establish the overall emission characteristics while the individual probe measurements were made to establish spatial distributions of emission species. Composite average values of NOx measured during each performance tests are shown in Figure 9-8.



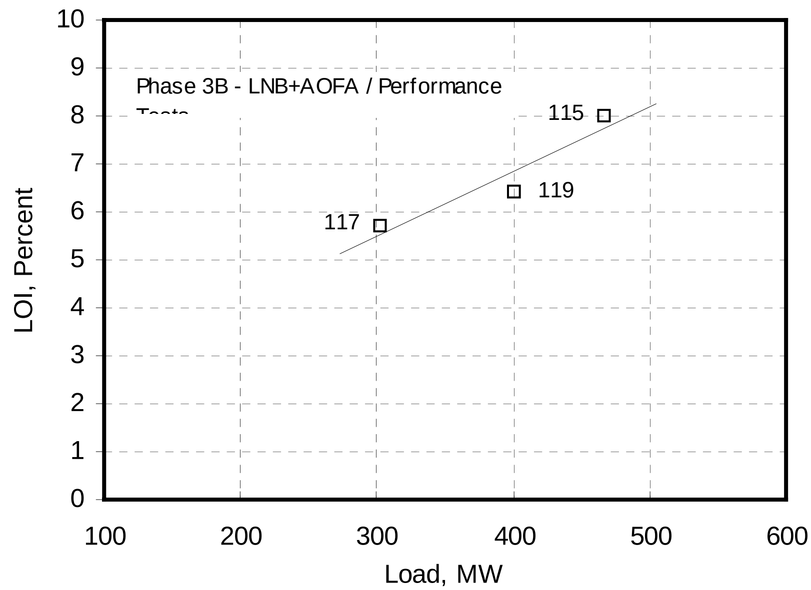


Figure 9-8 LNB+AOFA / Performance Tests / NOx Emissions and LOI

9.2.2.3 Combustion System Tests

As in prior phases, combustion performance tests were performed at each of three load levels to document the specific performance parameters related to the fuel and air combustion systems.

Mill Performance

The airflow to each mill and the particle size and mass flow distributions of coal to each burner were measured. Tests were performed at three load levels (480, 400, and 300 MW). Figures 9-9 and 9-10 summarize the results of these tests. It can be seen that, despite the mills being set to approximately equal coal flows with the boiler controls based upon control room instrumentation, the measured coal flows varied considerably from mill to mill. Also, the measured PA flow rates varied considerably, producing a wide range of fuel to primary air ratios (Figure 9-10). It should be noted that the pipe-to-pipe variations in coal mass flow rates are large (over 3:1 for Test 115) -indicating that the localized flame stoichiometry within the furnace may be highly non-uniform (see Appendix D for details).

Based upon the measured mill flows, it can be shown that the furnace was operating in a significant mill bias mode with the bulk of the fuel being delivered to the top of the furnace (Table 9-3 and Figure 9-11). As discussed previously (Section 8), this configuration was shown to have a significant effect on NOx emissions -- coal flow biased to the top row of mills than the bottom row produced the lowest NOx emission of any of the bias configuration during the Phase 3A NOx vs. LOI test program.

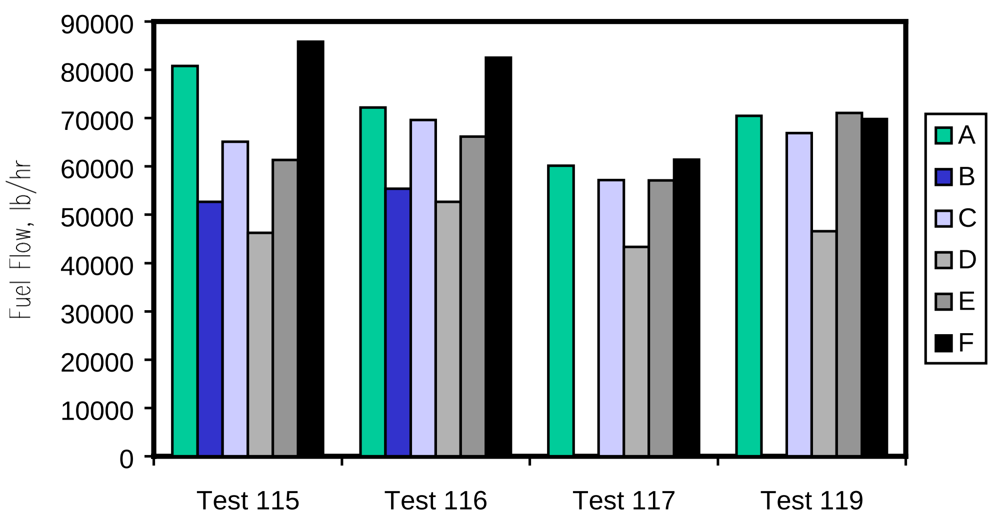


Figure 9-9 LNB+AOFA / Fuel Distribution

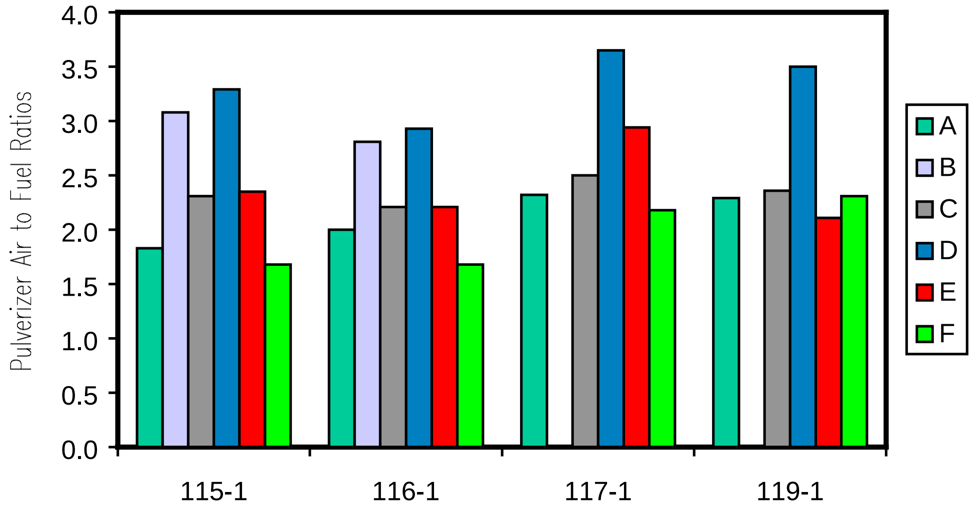


Figure 9-10 LNB+AOFA / Pulverizer Air to Fuel Ratio

Table 9-3 LNB+AOFA / Performance Tests / Indicated and Measured Mill Flows

Mill	Coal Flow (klb/hr) Indicated	Coal Flow (klb/hr) Measured	Contribution Percent
Top Mills			38
C	58	65	
F	57	85	
Middle Mills			33
A	58	81	
D	57	46	
Bottom Mills			29
B	56	53	
E	56	61	

Test 115

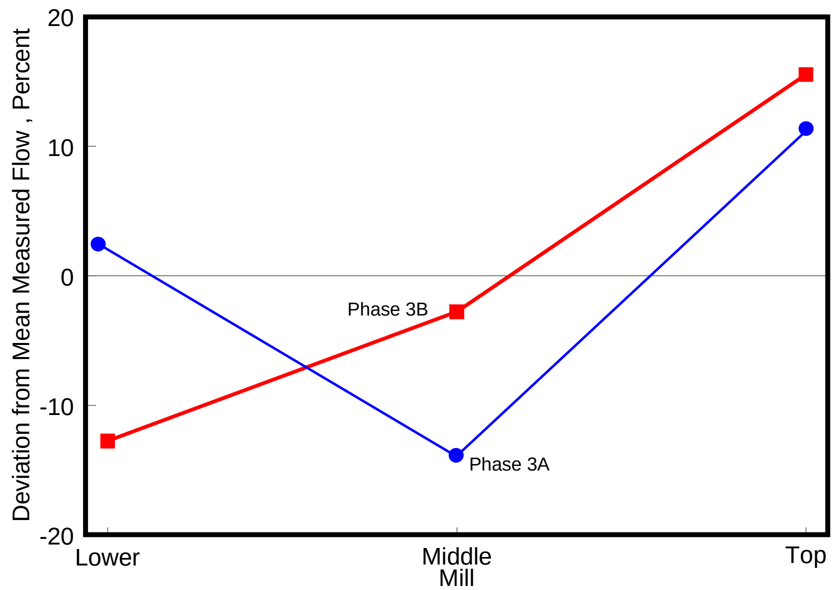


Figure 9-11 LNB+AOFA / Mill Biasing

The coal fineness (Table 9-3) was excellent for all mills except B and D, the two remaining older mills currently scheduled for replacement. Average coal fineness ranged from 73.5 percent to 76 percent passing 200 mesh and 0.43 percent to 0.98 percent remaining on 50 mesh. Mill specific data and the results from individual tests can be found in Appendix D.

Table 9-4 LNB+AOFA / Performance Tests / Average Coal Fineness

	Remaining on 50 Mesh	Passing 100 Mesh	Passing 200 Mesh
Test 115	0.79	94.69	73.50
Test 116	0.98	94.69	74.19
Test 117	0.43	96.38	75.99
Test 119	0.61	95.38	74.04

Combustion Air Flow

The total combustion airflow is the sum of the secondary air (combustion airflow to the burners including underfire air), overfire air, and primary air to the pulverizers. Total dirty airflow includes total pulverizer primary air and includes seal air introduced at the pulverizers and feeders. During low and intermediate load tests, off-line pulverizer airflow was measured at the inlet of the pulverizer and was included when tabulating total combustion airflow. Secondary and OFA air was measured at the main secondary air supply ducts and at each corner (quadrant) of the OFA windbox, respectively.

The total combustion air for each test is shown in Table 9-5 and Figures 9-12 and 9-13. Total unit airflow at full load was 6 to 10 percent higher than that observed during pervious phases. At low loads there was also increased airflow requirements. A summary of the partitioning of the combustion air between primary, secondary, and OFA air flow is shown in Figures 9-12 and 9-13. This data indicates that the overfire airflow represented approximately 20 percent of the total combustion air flow at full load, decreasing to approximately 10 percent at 300 MW. Below 300 MW, the AOFA control dampers were in the closed position per FWEC recommendations.

Table 9-5 LNB+AOFA / Performance Tests / Combustion Air Flow

Test Number	→	115	116	117	118	119	120
Unit Load (Mw)	→	480	480	300	300	400	400
Pulverizer Air		897,350	892,685	742,520	702,952	793,453	786,239
Secondary Air		2,437,598	2,490,624	1,628,886	1,589,363	2,350,423	2,349,506
Overfire Air		847,935	880,120	259,776	349,802	446,909	487,798
Air to Off-line Mills		0	0	54,343	55,054	67,359	61,591
Total Unit Air (TUA)		4,182,883	4,263,429	2,685,525	2,697,171	3,658,144	3,685,134

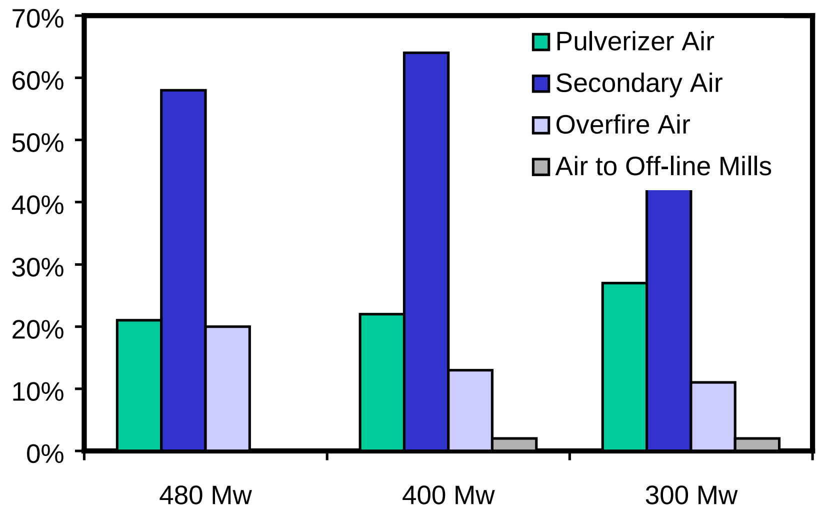


Figure 9-12 LNB+AOFA / Distribution of Unit Air Flow by Load

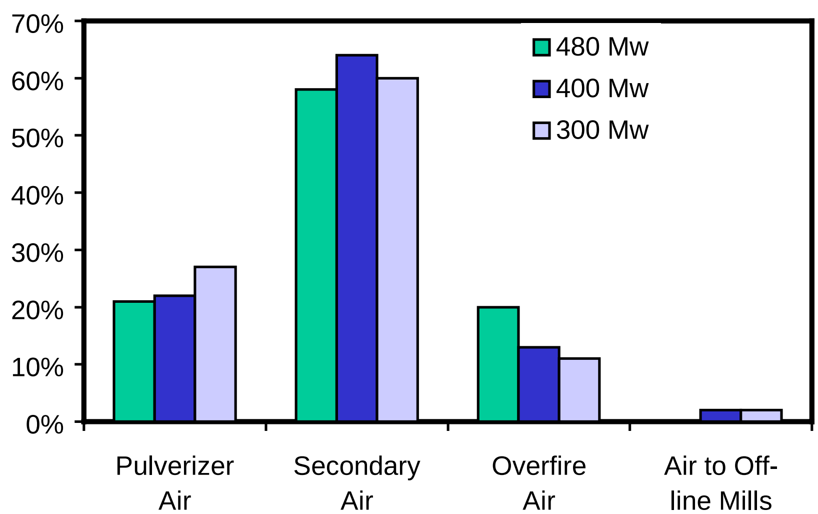


Figure 9-13 LNB+AOFA / Distribution of Unit Air Flow by Component

Furnace Measurements

Measurements were made of combustion gas temperatures and O_2 at eight locations within the boiler furnace nose and convective pass entrance at loads of 480, 400, and 300 MW. At 480 MW, average furnace gas temperature on the 8th floor ranged between 1887°F and 1907°F at full load. Oxygen level, on average, was 2.8 percent but was stratified from port to port. Large fluctuations in temperature and oxygen level were observed across the furnace. Average oxygen levels from port to port fluctuated from 0 percent (reducing) to 5.6 percent. Figure 9-14 illustrates the wide variation in furnace oxygen and gas temperature at full as observed by a HVT probe on the 8th floor. During 400 MW load tests, average oxygen level on the 8th floor observed by the HVT probe ranged from 3.3 percent to 3.4 percent with average gas temperatures ranging from 1827°F to 1853°F. During 300 MW load tests, average oxygen levels observed on the 8th floor by the HVT probe ranged from 2.4 percent to 3.3 percent with average gas temperatures ranging from 1616°F to 1650°F.

The large fluctuations in temperature and oxygen could be caused by inadequate mixing of combustion air and fuel at the burner, insufficient penetration of overfire air into the combustion zone, and/or imbalances in fuel and air.

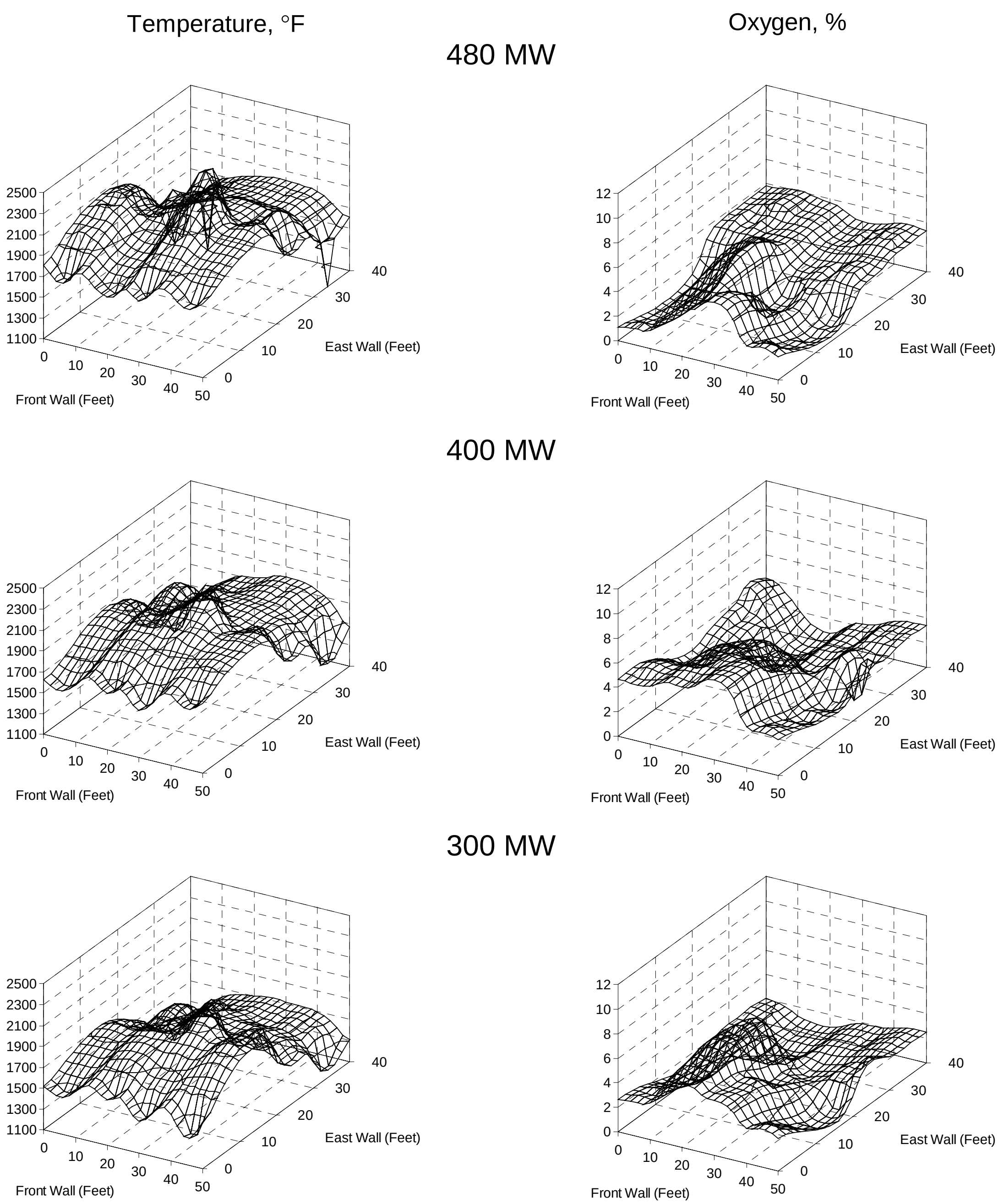


Figure 9-14 LNB+AOFA / Furnace Exit Temperatures and Oxygen

9.2.2.4 Coal Analyses

During each of the nine days of Phase 3B performance testing, samples were obtained of coal entering the active mills, and fly ash collected in the ESP (east and west sides) and bottom ash. The coal samples were analyzed for proximate and ultimate composition, heating value, grindability, and ash fusion properties. For the most part, the coal properties are consistent with the analyses obtained during the previous testing phases of the program (Table 9-6). Several exceptions are with respect to the sulfur levels and the fixed carbon (FC) to volatile matter (VM) ratio. The sulfur levels averaged 1.67 percent during Phase 3B while they were 1.53 during Phase 3A. Similarly, the FC/VM ratio was 1.50 for Phase 3B and 1.61 for Phase 3A.

Table 9-6 LNB+AOFA / Average Coal Properties

Test	Average	Standard Deviation	Variance
Ultimate			
H_2O %	6.42	0.63	0.4
C %	70.78	1.39	1.92
H %	4.66	0.05	0
N %	1.39	0.04	0
Cl %	0.04	0.02	0
S %	1.67	0.12	0.01
Ash %	9.51	0.49	0.24
O %	5.57	0.5	0.25
Total	100.05	0.02	0
Grind SU	48.8	1.59	2.53
HHV (Btu/lb)	12494	244	59515
VM %	33.66	0.55	0.31
FC %	50.44	1.22	1.48

Based upon limited data, the change in FC/VM between Phases 3A and 3B would indicate that with the same NOx control method (either LNB alone or LNB + AOFA) for both coals (Phase 3B and 3A coals), the Phase 3A coal would emit a higher level of NOx than the Phase 3B coal. This aspect of the differences in the coal could help to explain the apparent high NOx reduction of approximately 40 percent) between Phases 3A and 3B. This coal related factor coupled with the mill biasing discussed above points to the potential reason why the Phase 3B NOx levels were low and that this low level of NOx may not have been a result of burner adjustments. As discussed in the previous section, burner adjustments provide relatively small changes in NOx levels for similar operating conditions. The two factors that influenced the NOx level most were excess oxygen and mill biasing in that order of the degree of influence. Burner adjustments showed NOx influences well below these two factors.

9.2.2.5 Solid Emissions

Mass Loading, Gas Flow, and Temperature

Ash particulate emissions were measured both for total mass emissions rate and for characteristic properties related to ash collection within an ESP. The specific measurements and analyses that were performed included (1) total mass emissions; (2) particle size; (3) chemical composition; (4) ash resistivity; and (5) SO_3 concentration in the flue gas. These measurements were made immediately after the air heaters.

Total mass emissions reflect both a fraction of the total coal ash injected into the furnace (100 percent minus the ash that drops into the furnace bottom hopper or the economizer hopper), plus most, if not all, of any unburned carbon leaving the flame zone. Table 9-7 presents a summary of the results of the sampling performed at each test condition. The results shown for each test represent the average of three replicate samples. As a measure of the degree of completeness of combustion, the ash collected in the cyclone portion of the Method 17 train for each test was analyzed for carbon content and loss-on-ignition (LOI). The LOI is considered to represent carbon content along with volatile solids (sulfates, chlorides, etc.) driven off in the analysis procedure. The principal use of the performance test LOI analyses is as a reference for comparison with ash samples acquired during other phases of the program.

Table 9-7 LNB+AOFA / Summary of Solid Mass Emissions

Test No.	Load MW	O_2 Percent	Loading gr/dscf	Gas Flow ACFM	Gas Temp. °F	Carbon %	LOI %
115	472	4.0	2.98	2,123,000	312	7.2	8.0
117	301	4.0	2.92	1,324,000	295	5.2	5.7
119	400	4.2	2.96	1,816,000	282	5.6	6.4

The particulate mass loadings were essentially constant between the different test conditions, suggesting a consistent set of combustion conditions and coal supply (Table 9-7). Ideally, the particulate mass loading would be independent of boiler load, but the tendency to increase excess air with reduced loads causes a small reduction in mass loadings, when expressed in standard units.

Compared to the baseline measurements, mass loading and gas flow rates both increased during the LNB+AOFA test phase. The increase in mass loading appears to be related to an increase in fly ash relative to bottom ash. For pulverized coal boilers, this split is typically 80 percent fly ash with 20 percent becoming bottom ash or slag. An increase in the fly ash portion would indicate a reduction in slagging, which has been observed following other LNB retrofits. For the baseline tests at Hammond Unit 4, approximately 73 percent of the ash in the coal appears as fly ash. The fly ash portion increased in all subsequent test phases. For the AOFA and LNB tests, the fly ash fractions were over 100 percent, indicating some inaccuracy in the values of the coal feed rate, coal ash content, or gas volume used in this calculation. In the LNB+AOFA test, the fly ash portion was 77 percent, more nearly comparable to the baseline conditions. However, within the accuracy of the numbers, there does appear to be a general increase in the fraction of ash exiting the furnace, particularly during the Phase 2 and 3A test programs. This is consistent with other measurements and observations indicating that a decrease in furnace slagging took place following the low NOx modifications.

As with AOFA and LNB, the data in Table 9-7 also indicates that the gas volume flow rates increased in each of the low NOx tests relative to the baseline tests. Changes in gas volume flow can have the most significant effect on ESP performance associated with low NOx technologies. It is generally accepted that increased flue gas flow can result with low NOx burners because of increased excess air required to produce acceptable carbon burnout. The measurements of flue gas volume flow were made over a short period of time at the start of each evaluation period.

As with previous tests, the flue gas temperatures measured at the inlet to the precipitator decreased with decreasing load. The gas temperature also varied with sampling position. Similar to the previous tests, the temperature decreased as the sampling port got closer to the edge of each duct and increased from the top to the bottom of the duct. Most of this variation is considered to be related to the rotation of the rotary air heater (Appendix D).

Fly Ash Chemical Composition

The chemical composition of fly ash collected in the ESP hoppers was determined from proportional blends of samples taken from the hoppers. Each field was assumed to have equal collection efficiency and the individual hopper samples were proportionally combined to match the predicted amount of fly ash collected in each hopper. The blended sample should closely represent the inlet ash composition. Figure 9-15 shows the chemical composition of the blended hopper samples from each load of the LNB+AOFA tests. Only minor variations were observed between the load conditions in the elemental components known to affect dust resistivity, which include Li_2O, Na_2O, MgO, CaO, and Fe_2O_3.

The Method 17 mass loading samples were sieved into two fractions by splitting the sample with a 200-mesh (75 μm) screen. Both size fractions of each sample were analyzed for carbon content and LOI. The results of these analyses are summarized for the LNB+AOFA tests in Table 9-8. The data shows that the size fraction smaller than 200 mesh of the mass train samples typically contain about 5.4 percent carbon at the full load test conditions and somewhat less in the two reduced load tests. The vast majority of the carbon is found in the greater than 200 mesh samples, indicating that the carbon is present as large unburned char particles. As expected, the LOI values from the same samples are slightly higher than the carbon contents. The LOI from the ESP hopper samples are also shown in the table for comparison. There is generally good correspondence between the total LOI measured on the inlet mass train samples and that measured in the ESP hoppers.

Values of carbon or LOI greater than 5 to 8 percent can result in ESP performance problems. The detrimental effects are thought to be a result of preferential re-entrainment of the very low resistivity carbon particles. Many of the samples from the low NOx configuration tests have values in the range where an effect could occur. However, the relationships between LOI values, the form and size of carbon particles, and ESP performance are not well defined. Therefore, we can not conclusively determine if the fly ash carbon contents measured would affect ESP performance.

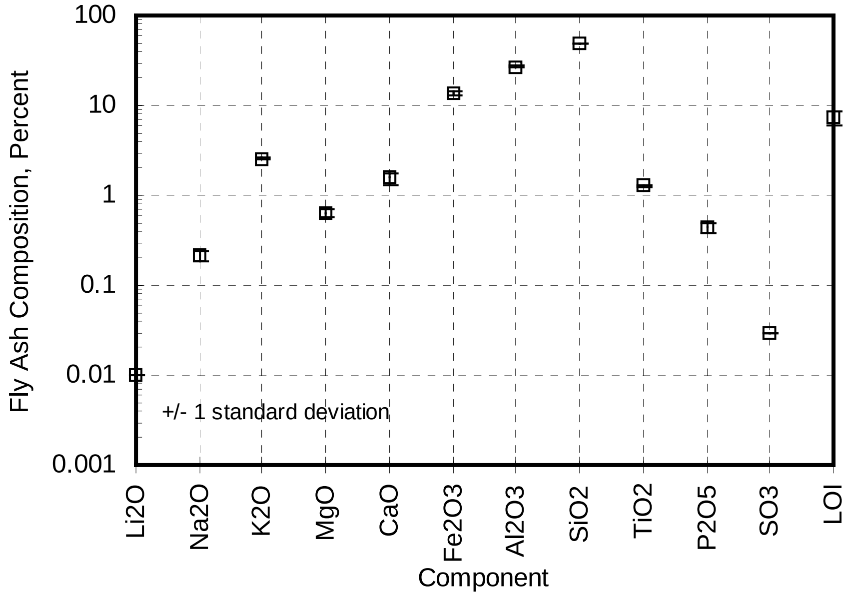


Figure 9-15 LNB+AOFA / Fly Ash Chemical Composition

Table 9-8 LNB+AOFA / Fly Ash Carbon Content by Size Fraction

			Mass Train Samples					
			Carbon, %			LOI, %		
Date	Test	Load	<200 Mesh	>200 Mesh	Total	<200 Mesh	>200 Mesh	Total
6/17/93	115	480	5.4	22.1	7.2	6	24.8	8
6/21-22/93	119	400	4.1	18.3	5.6	4.6	21	6.4
6/19/93	117	300	3.7	20.6	5.2	4.1	21.8	5.7
6/24/93	121a	483	7	30.7	9.5	7.3	33.5	10
	121b	482	7	23.6	9.1	7.4	29.1	10.1
	121c	481	7.1	27.7	9.6	7.6	29.9	10.3
	121d	495	6.9	14.7	8	7.1	27	9.8

Notes: a. Maximum overfire air at 483 MW
b. Nominal overfire air at 482 MW
c. Low overfire air at 481 MW
d. Nominal overfire air at 493 MW

Flue Gas SO_3 Concentration

The electrical resistivity of ash depends on the chemical composition of the fly ash, the temperature, and the concentrations of SO_3 and water vapor present in the flue gas. The amount of SO_3 measured at the inlet to a cold-side electrostatic precipitator is equal to the amount of SO_3 produced in the flue gas minus any condensed and deposited on cold surfaces and fly ash particles. The amount of SO_3 measured at the ESP inlet is therefore difficult to interpret with regard to other measured variables. However, the concentration must be known to accurately describe the operation of a precipitator. The results of the SO_2 and SO_3 concentration measurements made during the LNB+AOFA test are given in Figure 9-16. Tabular data can be found in Appendix D.

Fly Ash Resistivity

The electrical resistivity of fly ash is one of the main factors that determine the ability to collect ash in a precipitator. A summary of the in situ resistivity measurements is presented in Figure 9-17, with two methods of resistivity determination being reported. This figure was derived from data found in Appendix D. These measurements show some variability, but, with the exception of the June 17 data, the averages for all the boiler loads shown in the table are very consistent. (A factor of 2 is generally considered the maximum resolution of the measurement.) The 480 MW spark data collected on June 17 is an order of magnitude higher than the 480 MW spark results on June 18. This may in part be attributed to the higher gas temperature on June 17, but the lack of temperature dependency in the 400 MW data, which spanned 23°F, does not support this conclusion. Also, the V-I and spark methods agree reasonably well for the other tests but not for the June 17 data. Although the value obtained by the spark method is normally used as the true resistivity, in this case we conclude that the June 17 spark data was affected by carbon in the ash.

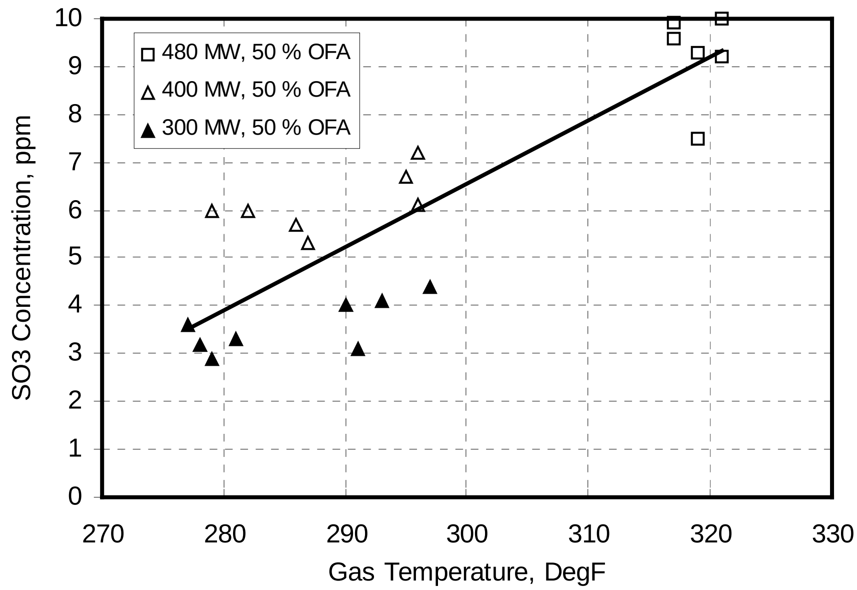


Figure 9-16 LNB+AOFA / SOx Results

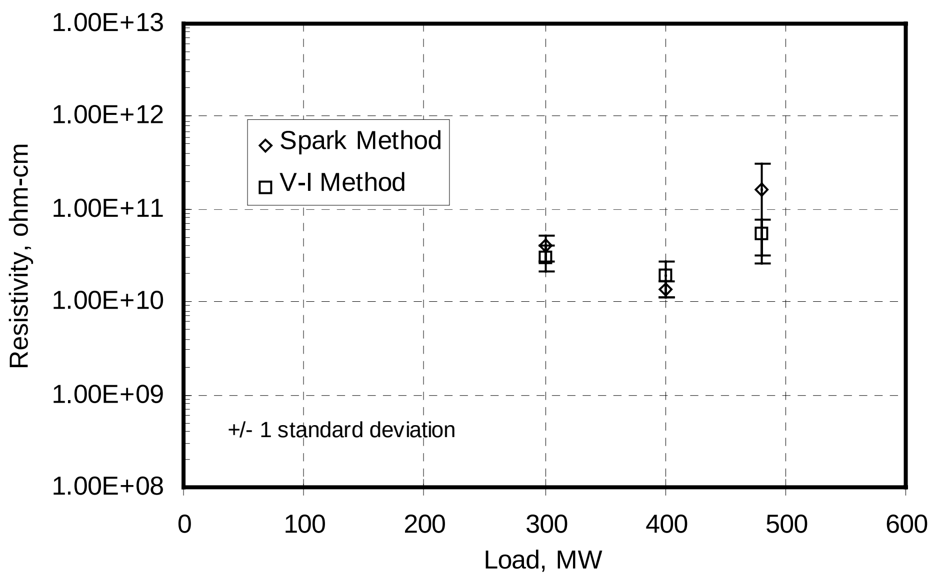


Figure 9-17 LNB+AOFA / In-Situ Ash Resistivity

Particle Size Distribution

Using a Modified Brink cascade collector, measurements were made at each of the three boiler loads tested (480, 400, and 300 MW). Cumulative mass loading as a function of particle size for all tests is shown in Figure 9-18. Each data point on this graph represents the mass concentration (mg/acm) contained in all particles smaller than the diameter at which the point is plotted. The derivative of the inlet cumulative mass size distribution for the three load conditions is shown in Figure 9-19, where, for any size interval, the area under the curve represents the amount of mass contained in that interval. This method of presenting the data illustrates the particle sizes where mass is concentrated and helps to highlight differences between distributions. The error bars on the graphs represent 90 percent confidence intervals to the average distributions. The fact that these error bars are difficult to separate from the data points reflects the consistency of the measurements. Each size distribution is typically the combination of eight impactor samples. Virtually no differences are seen in the Phase 3B size distributions for the various load conditions. This implies that the particle size distributions observed at the ESP inlet did not depend on the boiler load. The mass mean diameter, which is the particle size corresponding to 50 percent mass accumulation in Figure 9-18, is about 16.7 μm for all three data sets. Assuming a log-normal distribution, a geometric standard deviation (σ) of about 2.5 can then be computed. The EPRI data base predicts a mass mean diameter of 16.3 μm and a σ of 3.4 for bituminous coal, implying that the measured size distributions for the LNB+AOFA tests were reasonably typical of a bituminous coal.

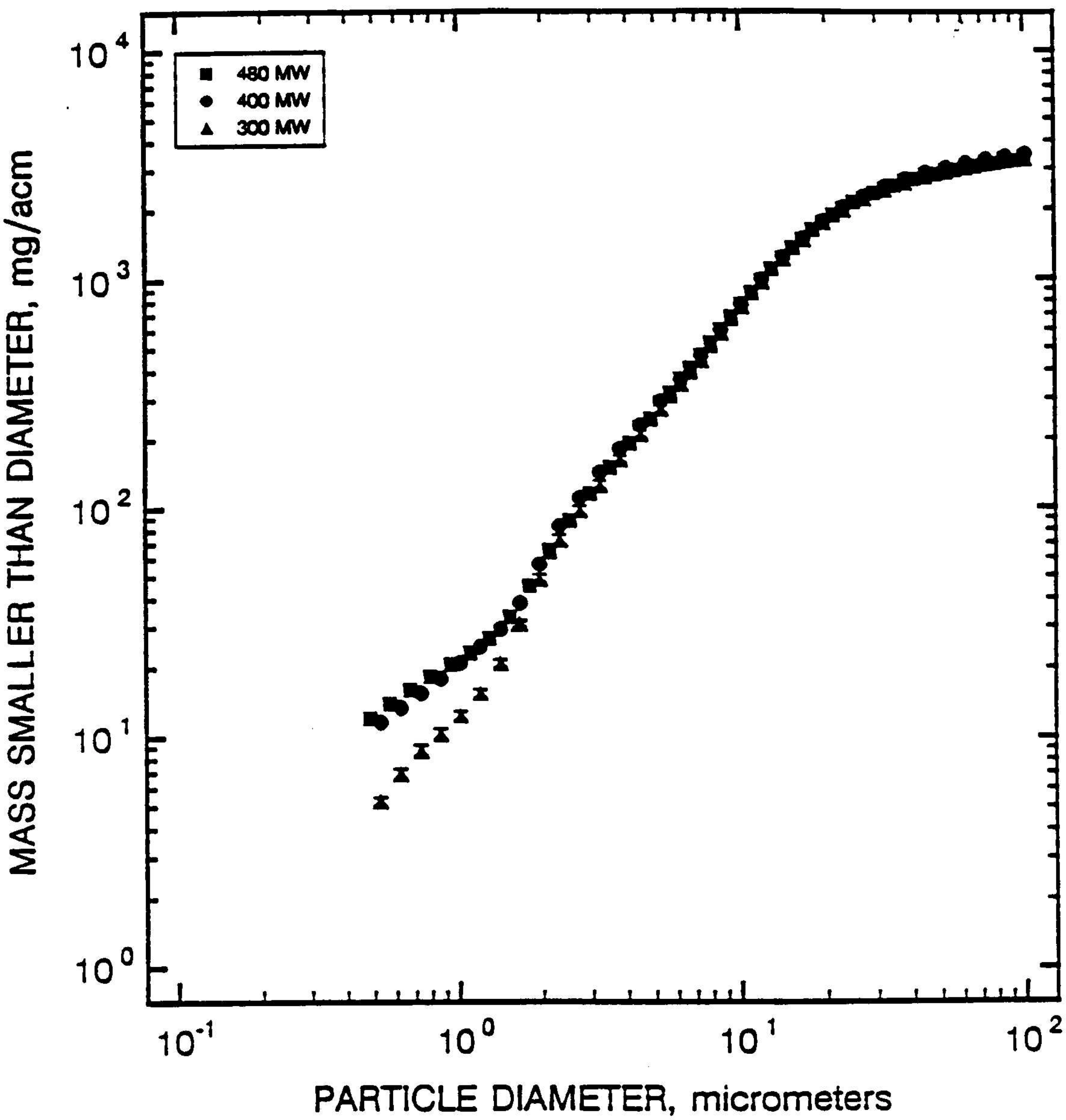


Figure 9-18 LNB+AOFA / Fly Ash Particle Size Distribution by Cumulative Mass Loading

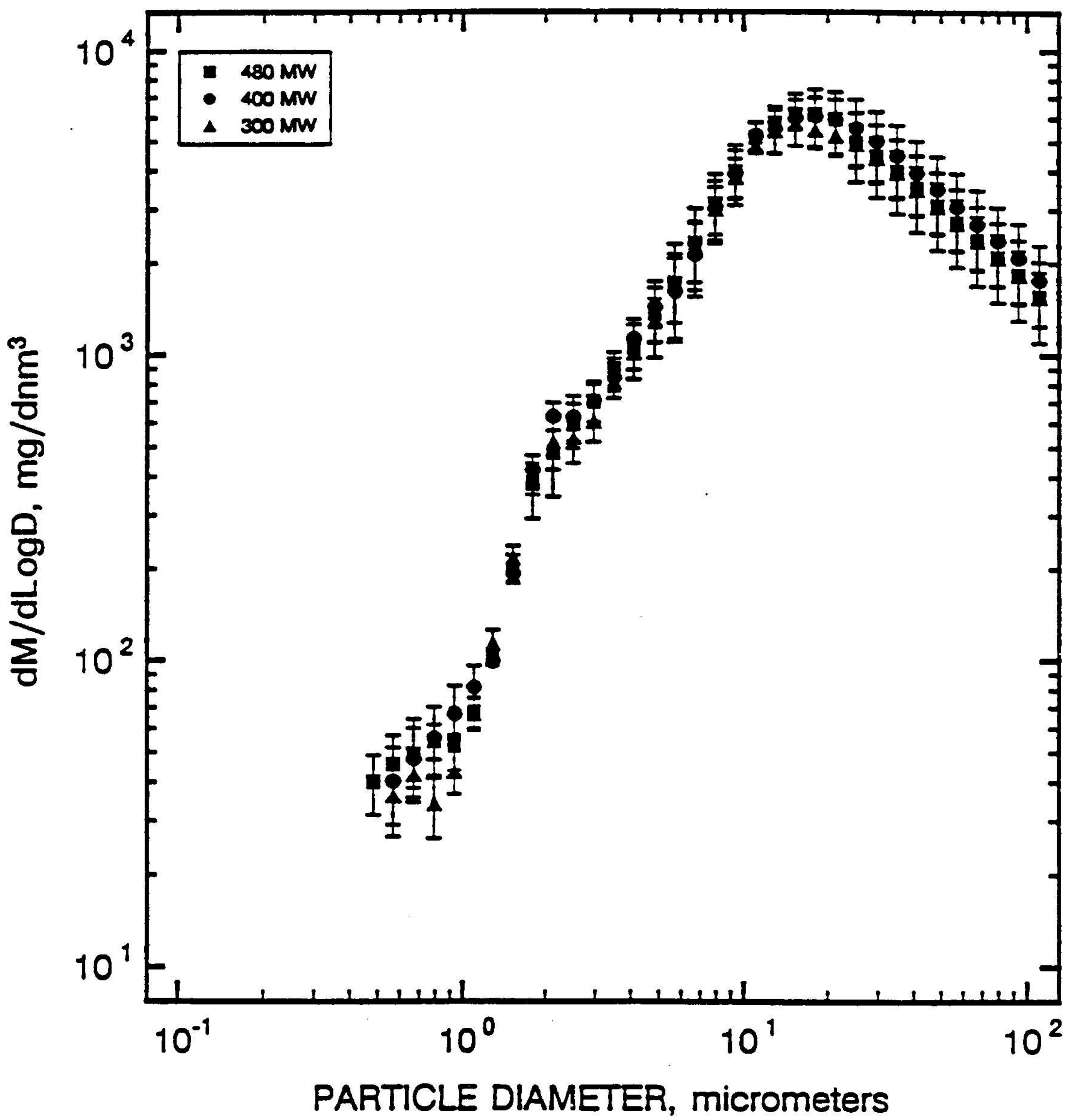


Figure 9-19 LNB+AOFA / Fly Ash Particle Size Distribution by Differential Mass Size

9.2.3 Verification Tests

A short series of verification tests were conducted to ascertain whether any significant changes had occurred in the Hammond Unit 4 NOx emission characteristics during the long-term testing that might influence the long-term data analysis. Figure 9-20 summarizes the results of those tests. As observed during the diagnostic testing, the Unit 4 precipitator could not accommodate high load operation on a regular basis without producing excessive opacity emissions. For that reason, the high load testing which could be achieved during the verification phase was substantially restricted. Also, because of system load demands, testing at loads below 300 MW was not possible. Therefore, most of the verification test results were obtained at 400 MW. These data points are included in the diagnostic test plots of NOx vs. O_2. It can be seen that the NOx emissions during the verification testing were comparable to the earlier emission levels under comparable operating conditions. It is, therefore, concluded that no fundamental changes occurred in the unit emission characteristics during the long-term testing. Additional results from the verification tests can be found in Appendix D.

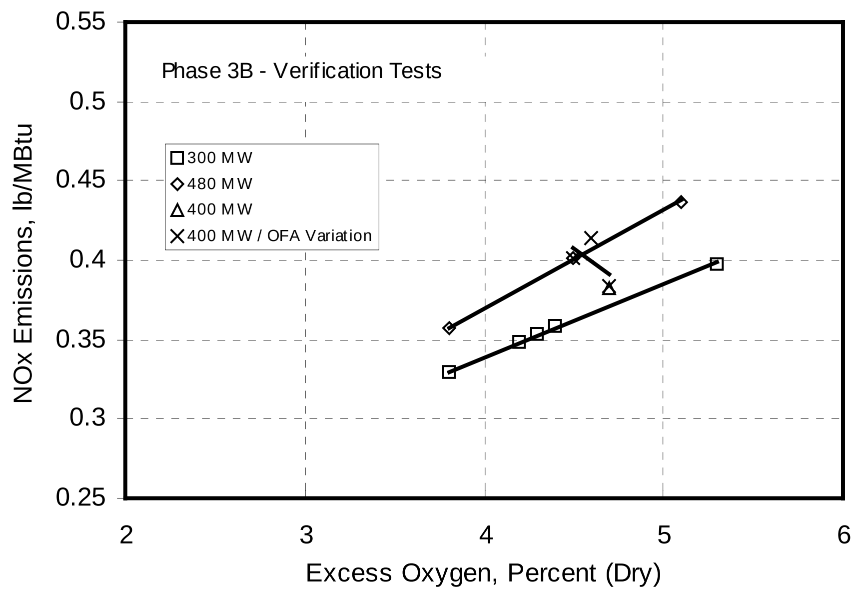


Figure 9-20 LNB+AOFA / Verification Tests

9.3 Long-Term Testing

The long-term testing consisted of continuous measurement of operating parameters while the unit was under load dispatch control. This long-term testing was performed from May 11, 1993 through August 13, 1993. During this period, unit outages and short-term tests resulted in some lost days of data capture. The data capture was, however, sufficient to fully characterize the unit both from an engineering perspective as well as a regulatory point of view. As before, the focus of the analysis of this long-term data was:

- Characterization of the daily load and NOx emissions.
- Characterization of the NOx emissions as a function of the O_2 and mill patterns.
- Determination of the thirty-day rolling average NOx emissions.
- Determination of the achievable NOx emission level based upon valid days of CEMS data.
- Comparison of long-term results to short-term results.

The following paragraphs describe the major results of these analyses.

9.3.1 Unit Operating Characteristics

From the data for the long-term testing (May 11 through August 13, 1993), the daily averages of load and NOx were determined and are shown in Figure 9-21. The daily average data was determined using the EPA criteria for valid data explained in prior sections. Only days with at least 18 hours of data are presented in this figure. For the Phase 3B long-term test period, the daily average emissions ranged from approximately 0.32 to 0.58 lb/MBtu. As shown, average load varied considerably during the test period. Also, note the unusually high NOx emission on approximately the 20 sequential day. The cause for this excursion is unknown.

One method of characterizing the boiler operating characteristics during the long-term testing is to examine the within-day variation of load and NOx. This was accomplished by segregating the data by hour of the day. For these segregated data, the mean load and NOx was computed. In addition, the hourly values representing the lower 95 percent and upper 95 percent of all values were determined. This data, shown in Figure 9-22, indicates that the unit continued to operate as a base loaded unit for the most part but spent less time at the maximum and NOx emissions over the entire long-term test period than during Phases 1 and 2. The figure illustrates that the unit was operated as a base loaded unit for most of the day (on average 12 hours were above 300 MW). This is a considerably lower base load than experienced during the Phases 1 and 2 but greater than that experienced during Phase 3A. It is evident that the NOx versus load characteristics are very flat with respect to load change. The exact relationship will be illustrated in the following paragraphs.

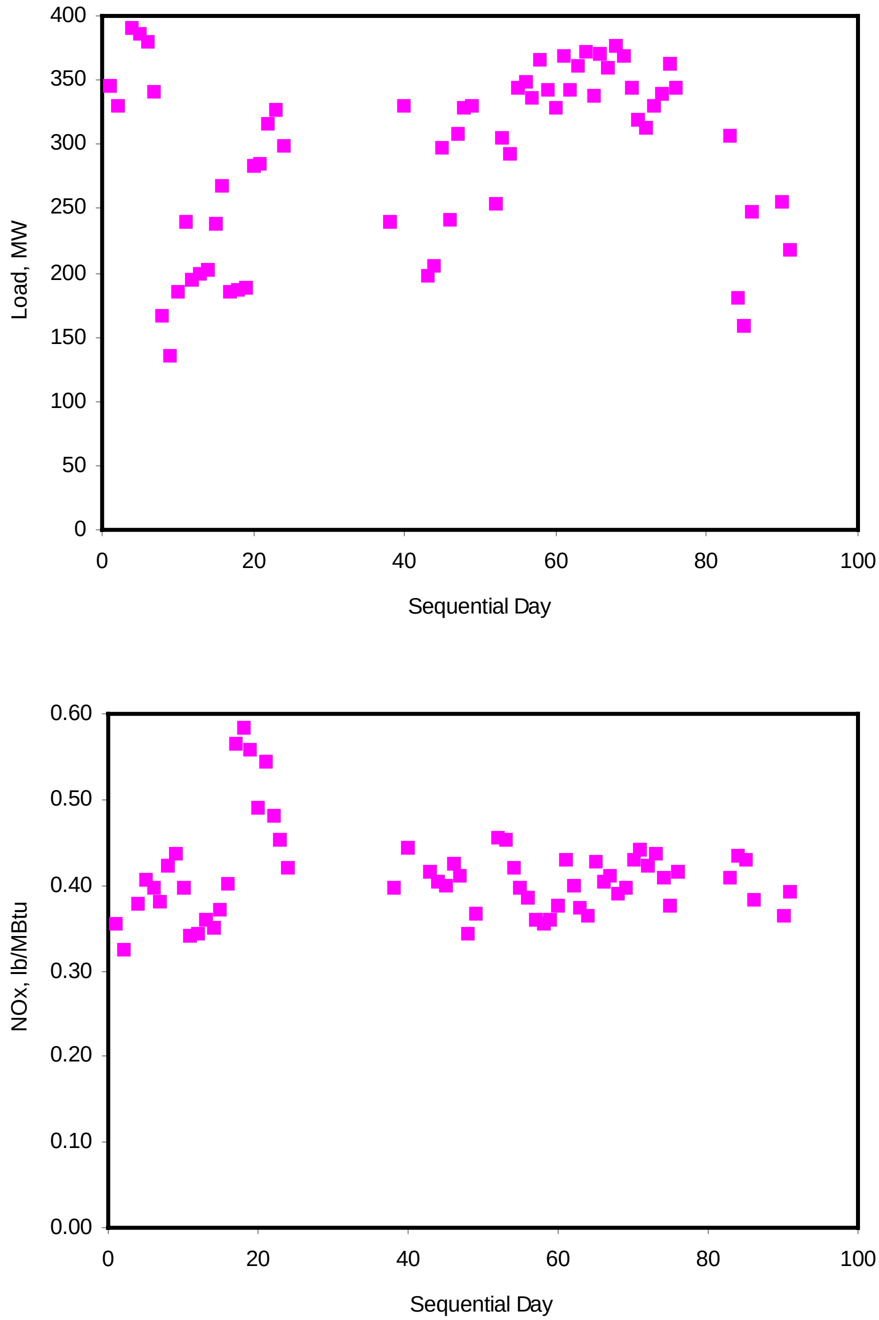


Figure 9-21 LNB+AOFA / Long-Term Daily Average Characteristics

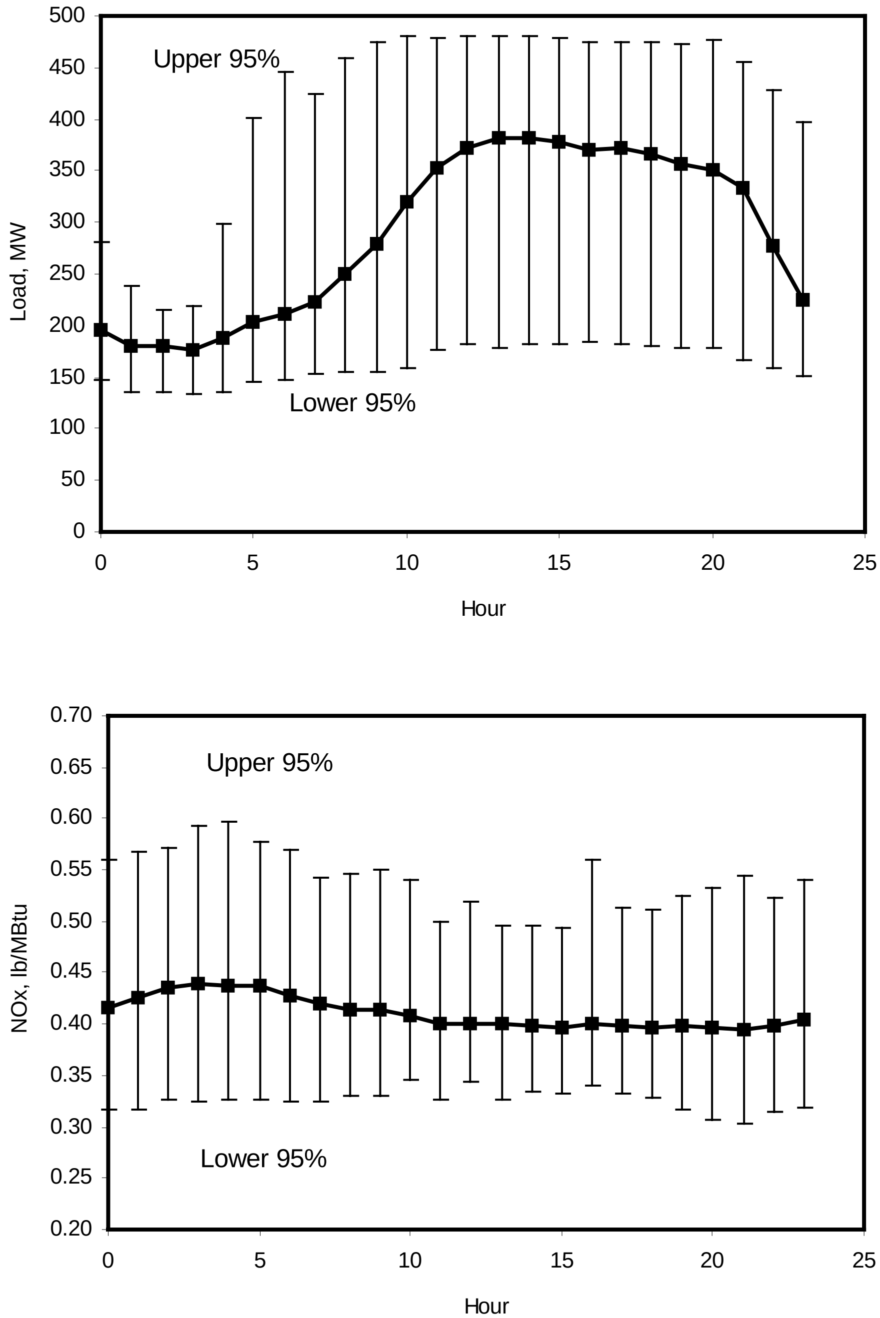


Figure 9-22 LNB+AOFA / Long-Term Diurnal Characteristics

9.3.2 Parametric Test Results

For the parametric analyses, all of the valid five-minute data was used. The 5-minute and hourly average emission data was analyzed to determine the overall relationship between NOx and load and the effect of boiler O_2 on NOx emissions for certain frequently used mill patterns. Since this data was obtained while the unit was under normal load dispatch, it represents the long-term NOx characteristics.

The NOx versus load relationship was determined by first segregating the 5-minute average load data into 20 MW wide load ranges. The population for each load range, as well as the lower 95 percentile and upper 95 percentile are shown for both load and NOx emission values. Figure 9-23 through 9-26 illustrates the excess oxygen, NOx, SOx, and CO versus load trend for this data. This figure illustrates that the NOx remained relatively constant from the 500 MW down to the 200 MW load points at an emission level of approximately 0.40 lb/MBtu. At loads below this point, the AOFA was essentially closed and the NOx emissions increased with decreasing load up to approximately 0.48 lb/MBtu. The excess oxygen downstream of the air heater shows the same trend as that for the other phases of the program -- increasing excess oxygen with decreasing load.

The effect of operating O_2 on NOx emissions for certain mill patterns was examined for load ranges that corresponded to some of the loads tested during the short-term test portion of the Phase 3B test effort. These ranges were the 180-190, 290-300, 390-400, and 470-480 MW ranges. All of the valid five-minute data for these load ranges was used to assess the impact of excess oxygen level for the most commonly used mill patterns. In order to determine the most frequently used patterns, the frequency distribution of the mills-in-service pattern was determined. Table 9-9 presents the frequency distribution for the two most used mill patterns in a particular load range. It is apparent that there are certain preferred mill patterns for each load range. These patterns are dictated by the operational requirements of the unit (i.e., slag minimization, steam temperature control, etc.). Prior to commencing the short-term testing effort, discussions with plant operations indicated that certain mill patterns were the preferred patterns. These patterns were then used during the diagnostic and performance testing with the intent of comparing the results with the same patterns during long-term testing. The mill patterns used during the short-term test effort were the AMIS and B-MOOS at 400 MW and B-MOOS at 300 MW. Referring to Table 9-10, it is evident that these patterns were not the most prevalent during this long-term test effort.

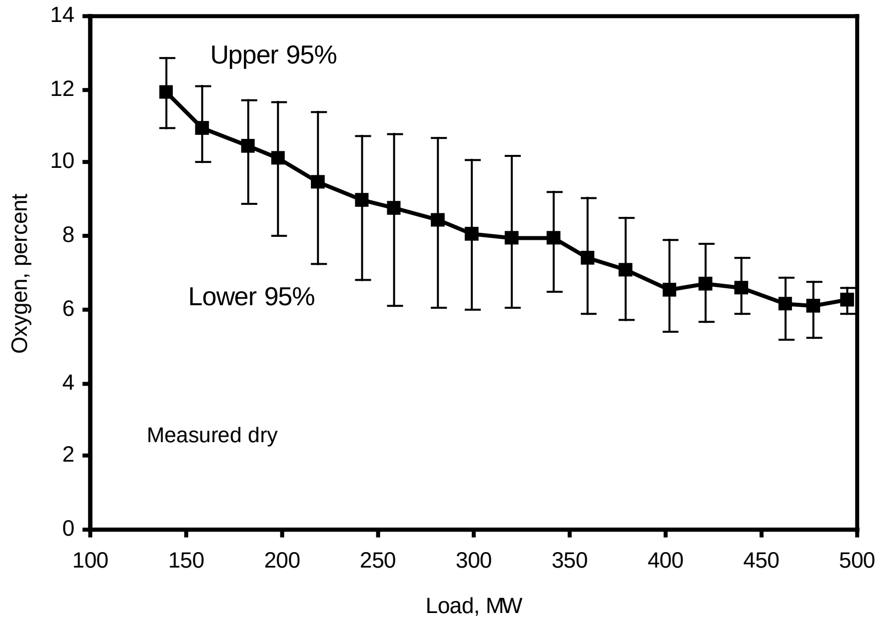


Figure 9-23 LNB+AOFA / Long-Term Stack O_2 vs. Load

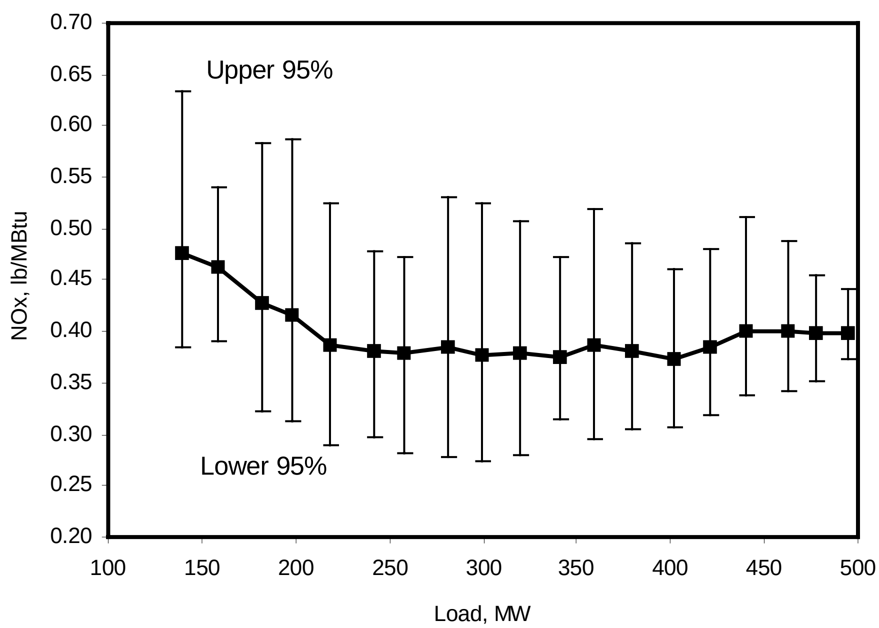


Figure 9-24 LNB+AOFA / Long-Term NOx vs. Load

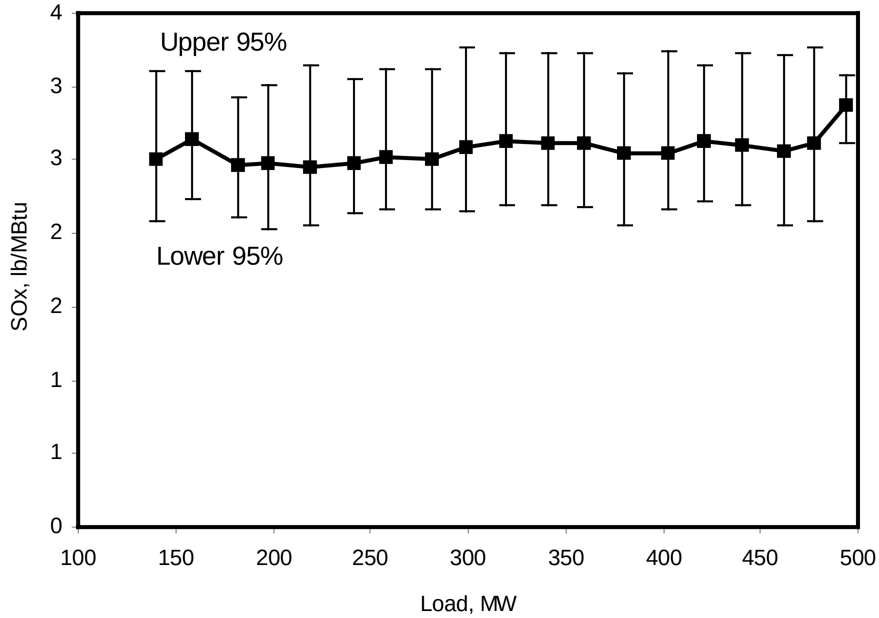


Figure 9-25 LNB+AOFA / Long-Term SOx vs. Load

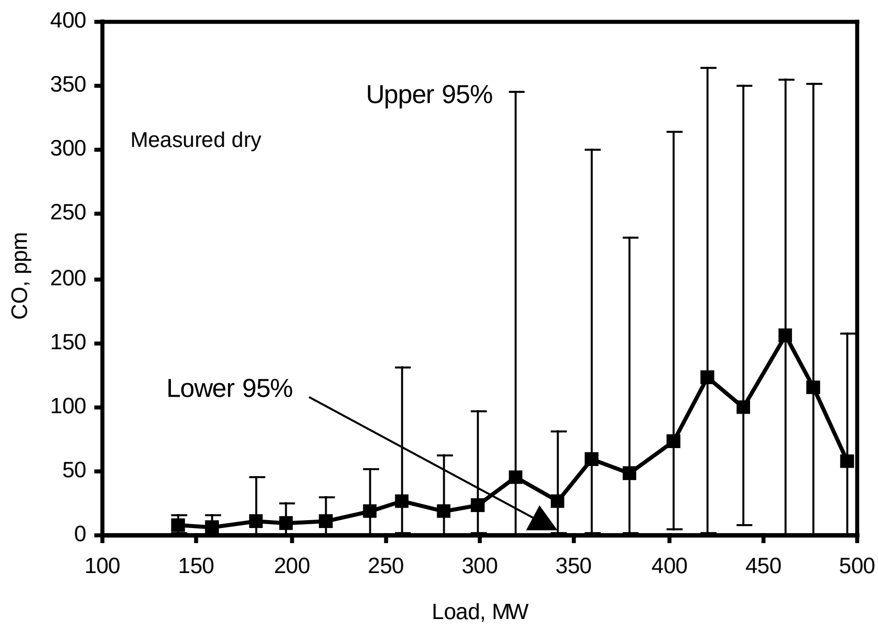


Figure 9-26 LNB+AOFA / Long-Term CO vs. Load

Table 9-9 LNB+AOFA / Long-Term Mill Pattern Use

Average Load MW	MOOS	Sample Size	Average O_2 %	Average NOx lb/MBtu
186	B,E	1070	9.6	0.69
186	C,F	379	9.2	0.63
296	B,E	1180	8.4	0.51
296	B,C	834	9.0	0.44
396	E	717	7.3	0.61
396	F	307	7.1	0.48
474	NONE	142	6	0.64

9.3.3 Thirty-Day Rolling Averages

Thirty-day rolling average load, NOx, and O_2 were computed using the valid hourly data as defined by the EPA criteria. These thirty-day rolling averages are shown in Figure 9-27 for the 87 (56 rolling averages) boiler operating days (by EPA criteria) of data. The thirty-day rolling average results shown are only representative of the load scenario that was experienced by the unit during this long-term test period. During other periods when the load might be significantly different, the rolling averages would be expected to be somewhat different. For this particular period, it can be seen that the 30-day rolling average load was generally in the 320 to 340 MW range. Over the entire daily long-term effort there was a slight increase in the daily load.

9.3.4 Achievable Emission Characterization

The achievable NOx emission limit on a 30-day rolling average basis is determined using the descriptive statistics for 24-hour average NOx emissions. The descriptive statistics for the 24-hour average NOx emissions data are presented in Table 9-10. The analysis indicated that the daily emissions were normally distributed. The analysis also indicated that the day-to-day fluctuations in NOx emissions followed a simple first order auto-regressive model. Based upon the EPA criteria, the achievable NOx emission limit should only be exceeded, on average, once per 10 years on a 30-day rolling average basis. The achievable emission depends on the long-term mean, variability, and autocorrelation level. Based on the daily values given, the 30-day and annual average NOx emissions were calculated (Table 9-11). The 30-day average achievable emission level was estimated to be 0.51 lb/MBtu. The annual average achievable NOx emission level was estimated to be 0.42 lb/MBtu. The assumption related to these achievable emission levels is that the Hammond unit will be operated in the future under similar load dispatching as that during the baseline test phase. As explained above under other load scenarios, the thirty-day rolling averages would be different and therefore, the achievable emission level would also be different.

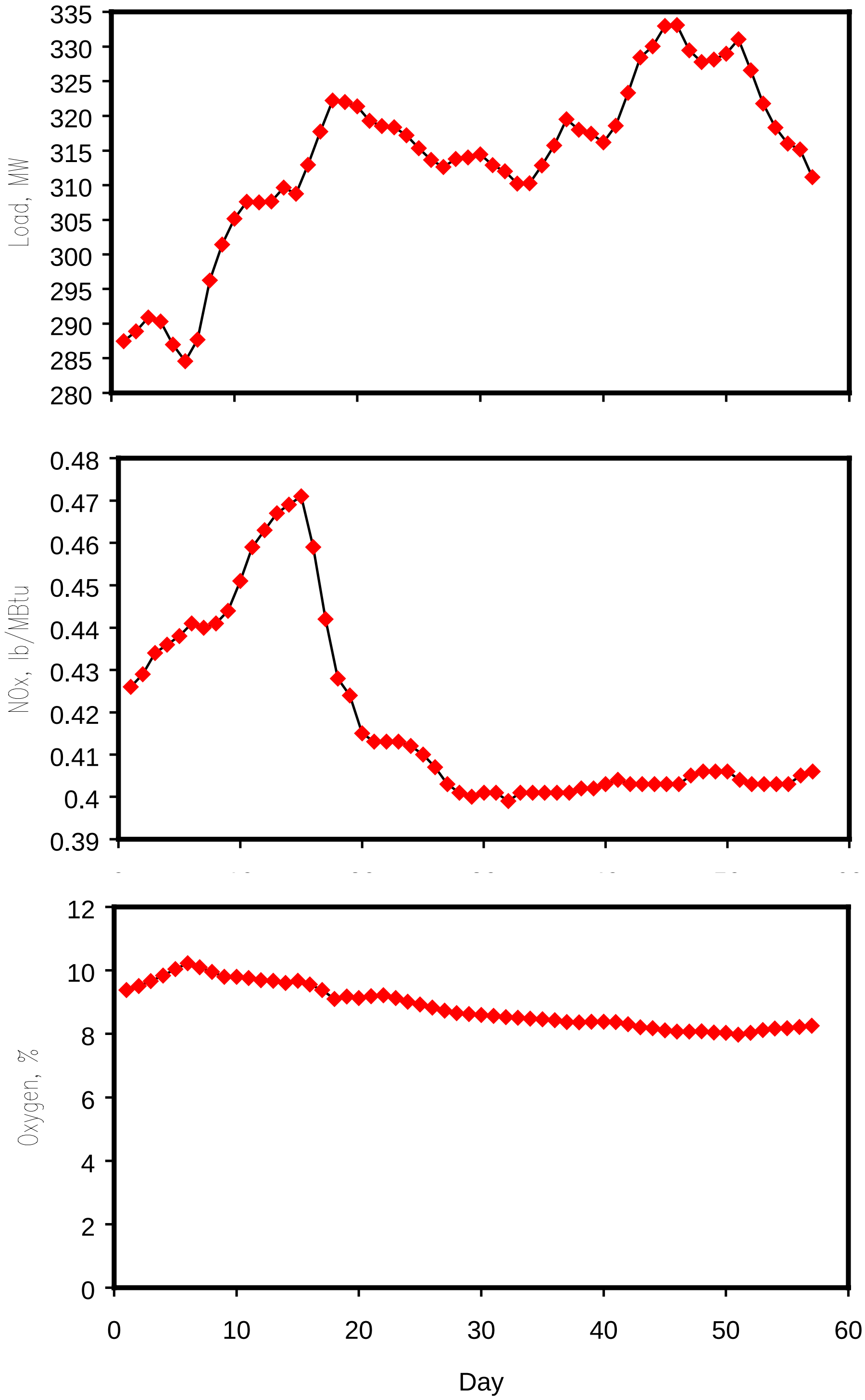


Figure 9-27 LNB+AOFA / Long-Term 30 Day Rolling Average

Table 9-10 LNB+AOFA / Descriptive Statistics for Daily Average NOx Emissions

Number of Daily Values	63
Average Emissions, (lb/MBtu)	0.41
Relative Standard Deviation, Percent	12.9
Distribution (Box-Cox Transformed)	Normal
First Order Autocorrelation (r)	0.688

Table 9-11 LNB+AOFA / Achievable NOx Emission Limit

Autocorrelation (lb/MBtu)	Achievable Emission Limit 30-Day	Achievable Emission Limit Annual
r = 0	0.51	0.42

9.3.5 Comparison of Short- and Long-Term NOx Data

The short- and long-term characteristics presented earlier included a number of mill configurations and a range of excess oxygen levels. Figures 9-28 provides a comparison of the short- and long-term data. From the comparison it is evident that the data obtained during the short-term efforts was, in many cases, within the upper 95 and lower 95 percent range. It is difficult to say if the same outcome would occur if the mix of configurations used in the short-term effort were the same as that experienced during the long-term effort. Nevertheless, the agreement between short-term and long-term data is much better than for previous phases.

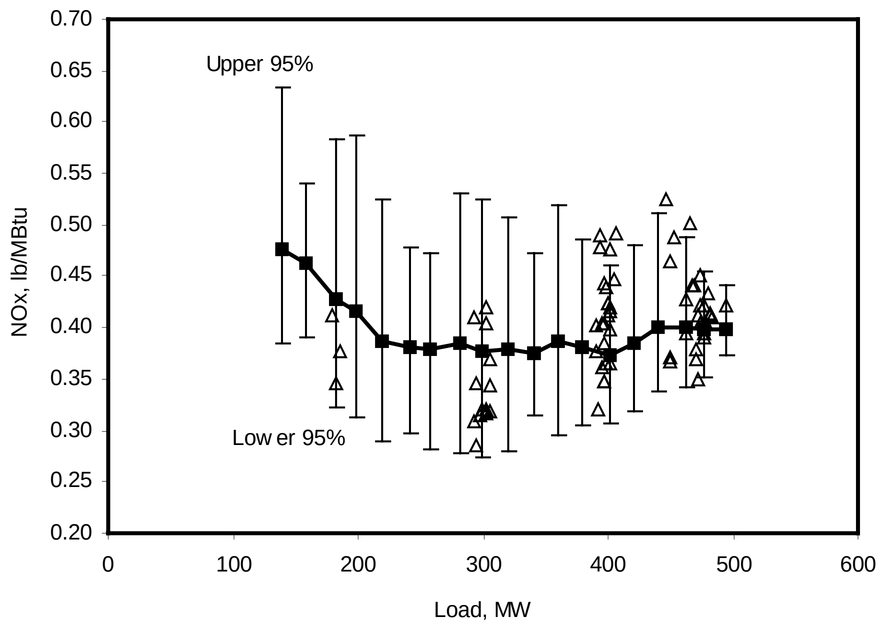


Figure 9-28 LNB+AOFA / Comparison of Short- and Long-Term NOx Emissions

9.3.6 Process Data

In addition to the emissions data described earlier, process data was collected to provide insight to changes in the boiler performance and turbine cycle heat rate as a result of the installation of the tested technologies. The most important of these variables are discussed below.

Steam Temperatures and Spray Flows

Main steam and reheat temperatures as measured at the turbine inlet are shown in Figures 9-29 and 9-30, respectively. Main steam temperature averaged approximately 1000°F over the entire load range with no appreciable degradations at any load. Reheat temperature, although near 1000°F at full load, dropped to near 975°F at lower loads. As shown in Figures 9-31 and 9-32, lower superheat spray flow averaged below 50 klbm/hr over the load range with maximum flows at lower loads while upper spray flow increased from near 80 klbm/hr to120 klbm/hr as load increased.

Excess Oxygen Levels

In addition to the ECEM excess oxygen measurement, excess oxygen was also measured at the economizer and air heater outlet using in situ instrumentation. Excess oxygen at the east and west economizer outlet is shown in Figures 9-33 through 9-34, respectively. Excess oxygen as measured at the economizer outlet is used by the control system to maintain combustion stoichiometry at prescribed levels. In all figures, the reading obtained by the in situ instrumentation is well below that obtained by the ECEM. This difference is the result of:

- The ECEM is a dry reading whereas the in situ instrumentation provides excess oxygen on a dry basis.

- The ECEM samples flue gas considerably downstream of the in situ monitors and thus there is the potential for air inleakage.

The average economizer outlet excess oxygen level is shown in Figure 9-35. The west measured value was approximately 0.5 percent above the east side value. This split was also observed with the ECEM during the short-term tests. For Phase 3A, the stack oxygen was, on average, a good estimator for economizer oxygen when these factors are taken into consideration (Figure 9-36). Excess oxygen as measured at the air heater outlet is used for determination of air heater and boiler performance and not for control and are shown in Figures 9-37 and 9-38.

Economizer Exit and Air Heater Exit Temperatures

The economizer exit and air heater exit gas temperatures are shown in Figures 9-39 through 9-42. Full load economizer exit temperatures average approximately 750°F and 740°F for the east and west side, respectively. The design at full load is near 710°F. As expected, the temperature dropped with decreasing load, averaging near 650°F at 260 MW. The design temperature at this load is near 590°F. The secondary air heater outlet temperature averaged approximately 325°F at full load -- the design value is near 282°F (Figures 9-41 and 9-42). This increased temperature represents a considerable efficiency penalty.

Fly Ash LOI

An estimate for the fly ash LOI is shown in Figure 9-43. Because there was no on-line carbon-in-ash measurement during this phase, the LOI estimate is based on performance test results and the deviation between stack oxygen for the performance and long-term tests.

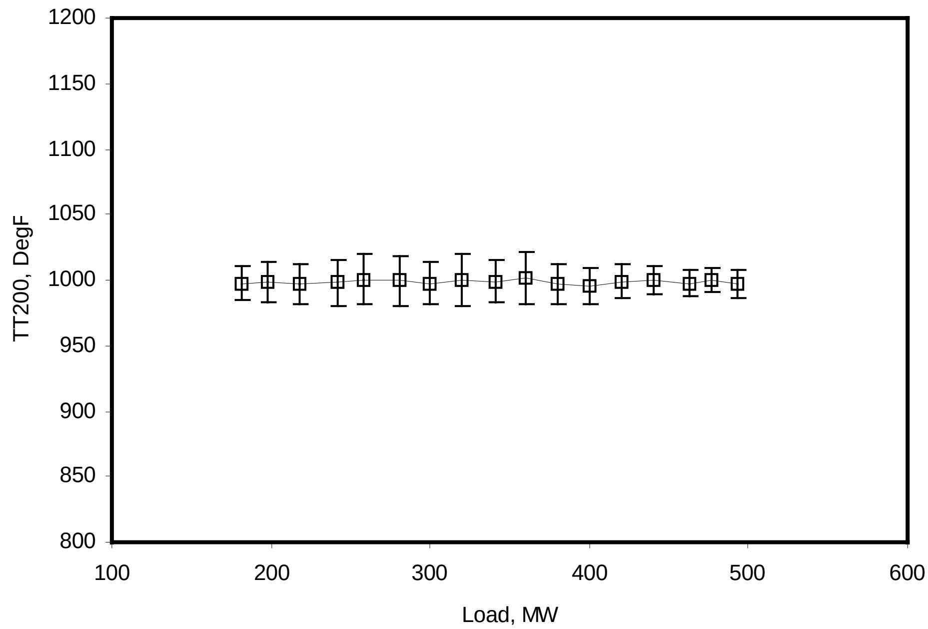


Figure 9-29 LNB+AOFA / Long-Term / Main Steam at Turbine Temperature

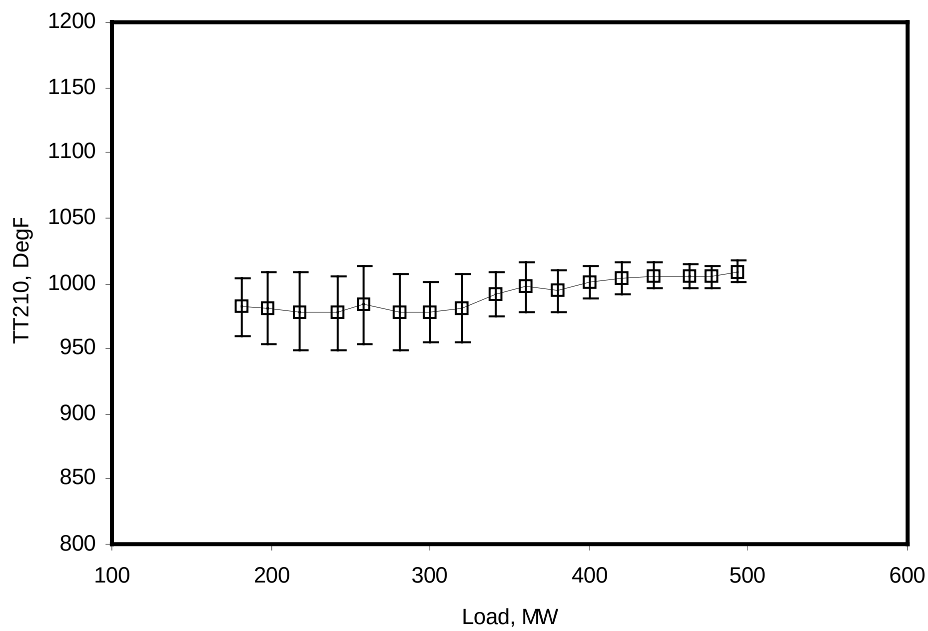


Figure 9-30 LNB+AOFA / Long-Term / Reheat Steam at Turbine Temperature

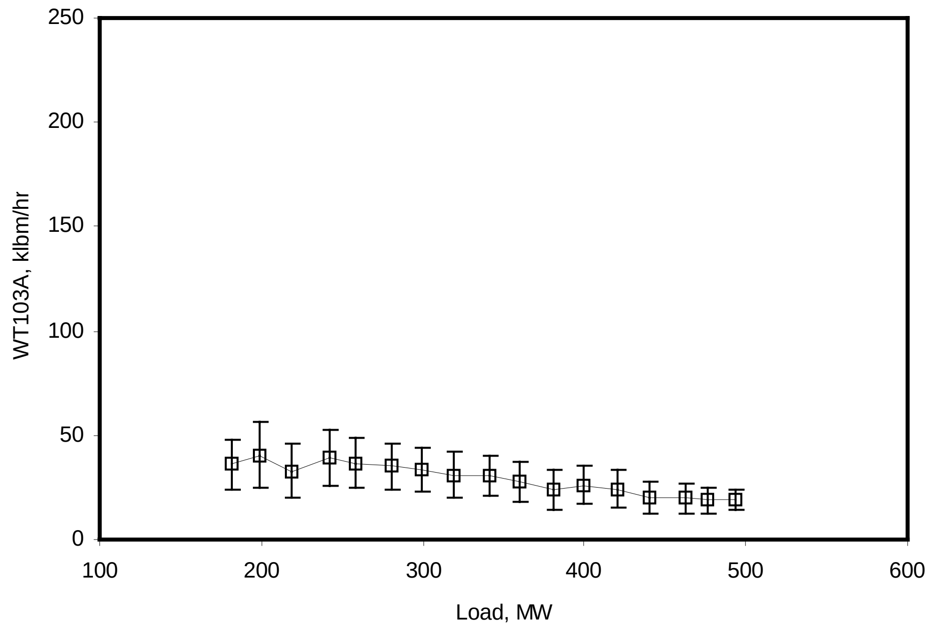


Figure 9-31 LNB+AOFA / Long-Term / Superheat Spray Flow Lower

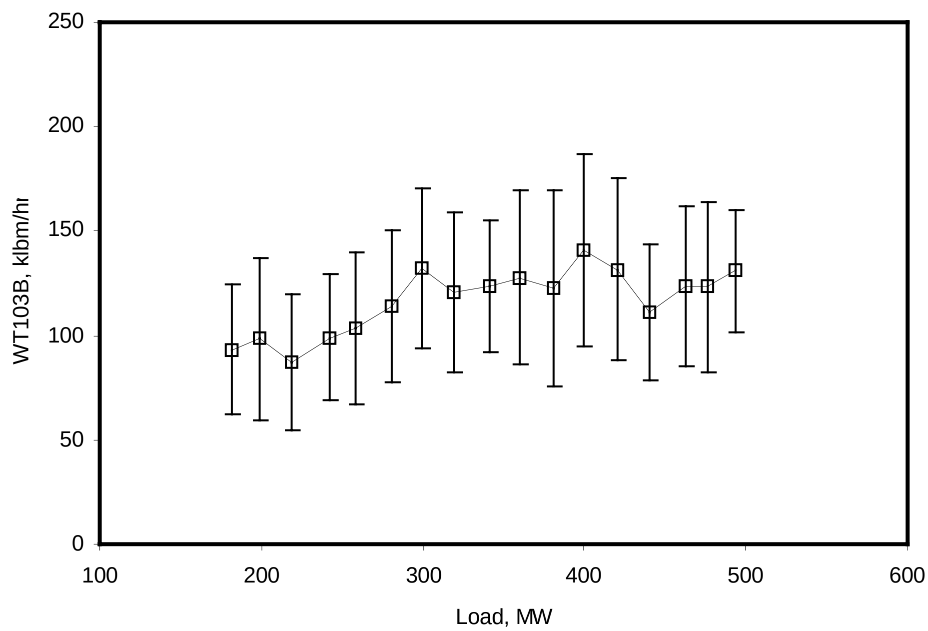


Figure 9-32 LNB+AOFA / Long-Term / Superheat Spray Flow Upper

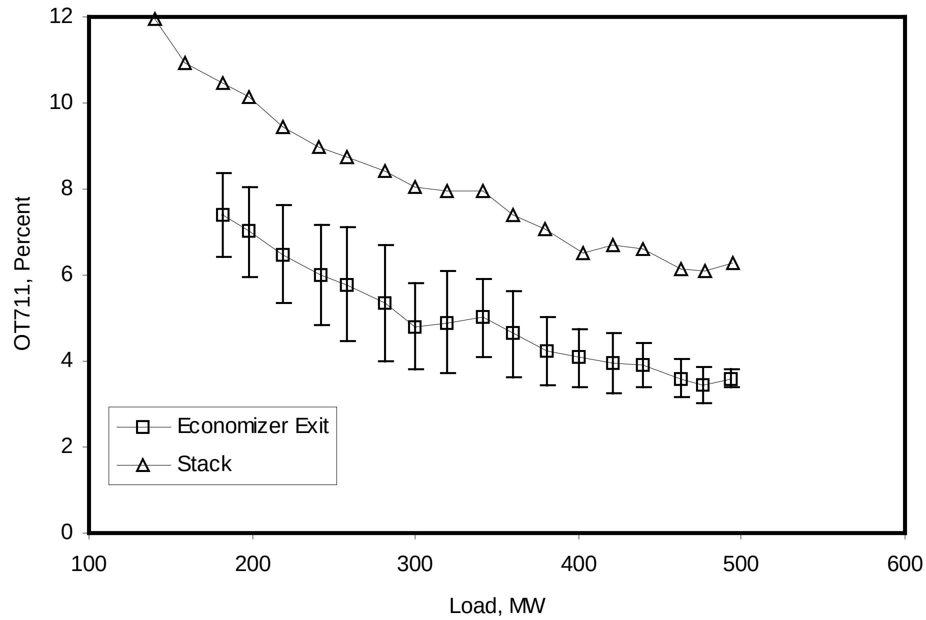


Figure 9-33 LNB+AOFA / Long-Term / Excess Oxygen at Economizer Outlet / East

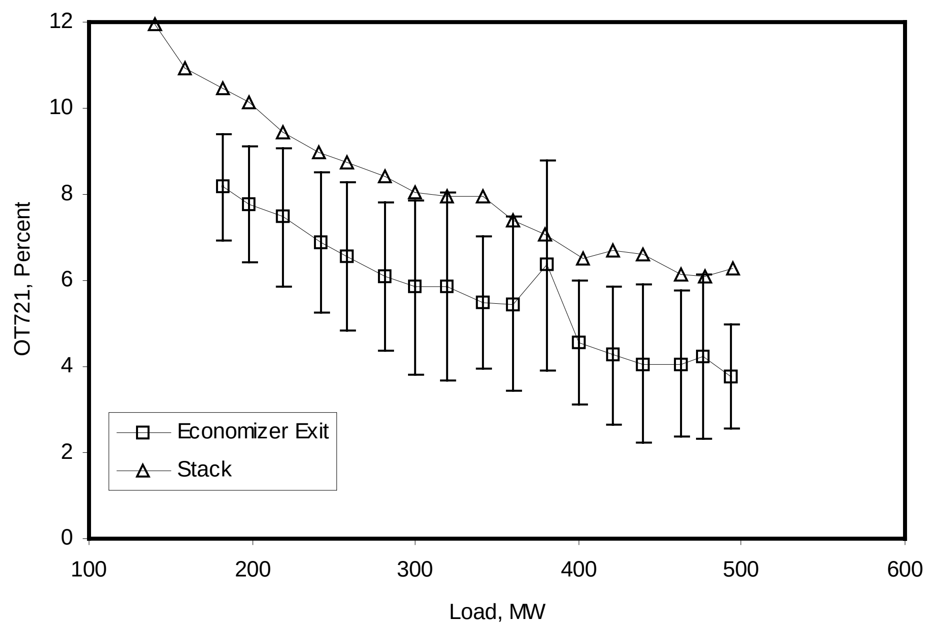


Figure 9-34 LNB+AOFA / Long-Term / Excess Oxygen at Economizer Outlet / West

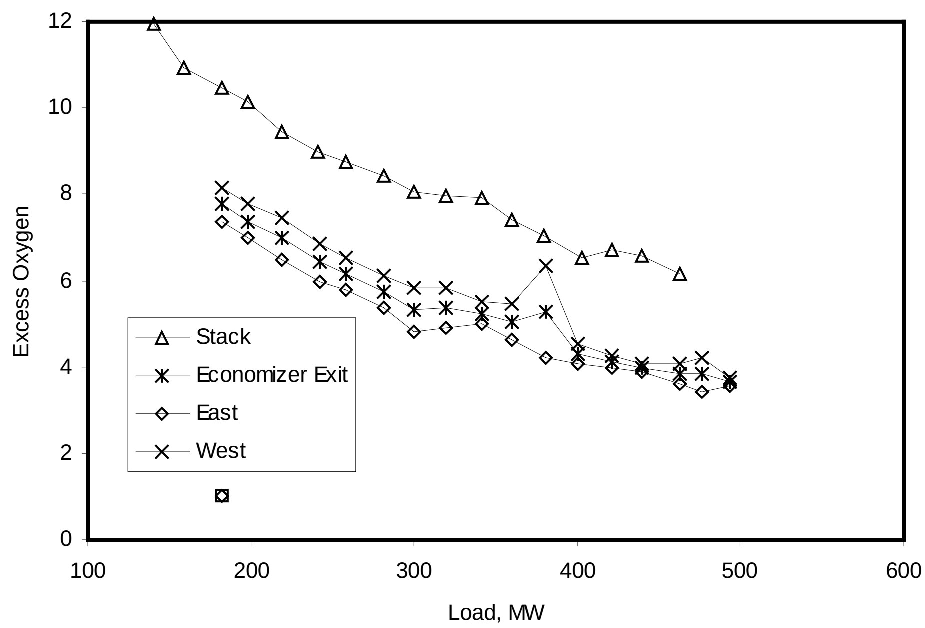


Figure 9-35 LNB+AOFA / Long-Term / Excess Oxygen at Economizer Exit / Average

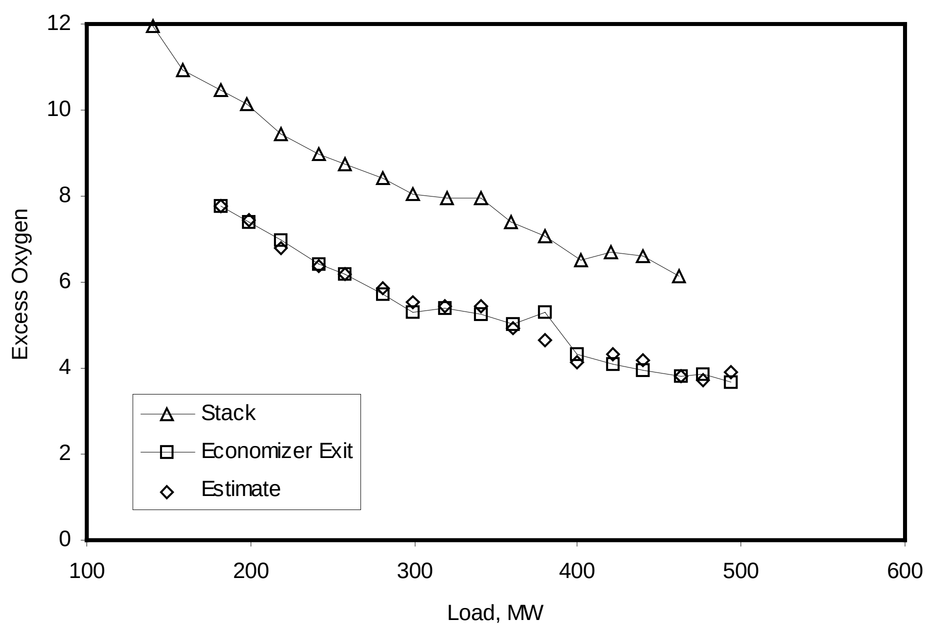


Figure 9-36 LNB+AOFA / Long-Term / Excess Oxygen at Economizer Exit / Estimate

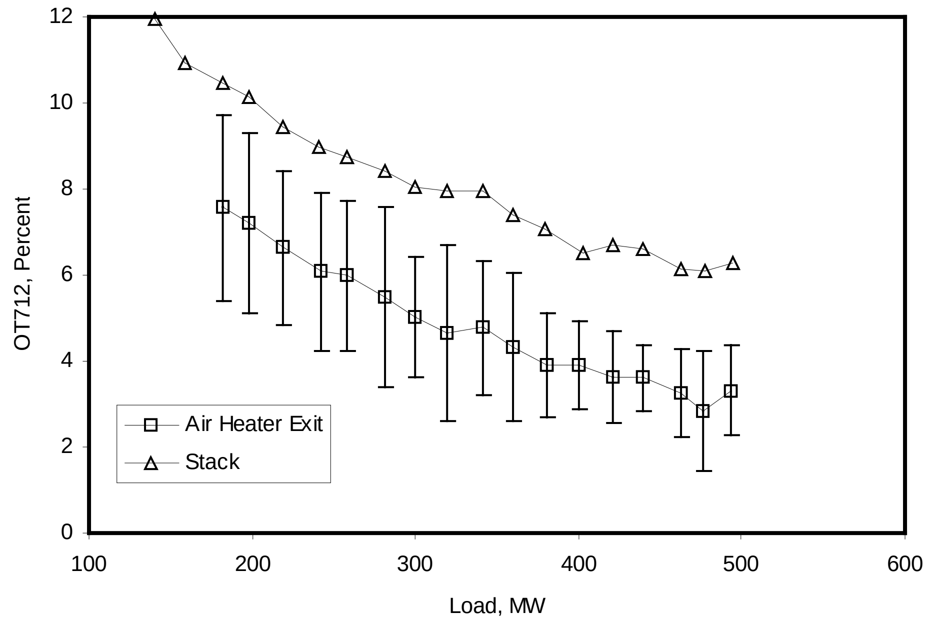


Figure 9-37 LNB+AOFA / Long-Term / Excess Oxygen at Air Heater Outlet / East

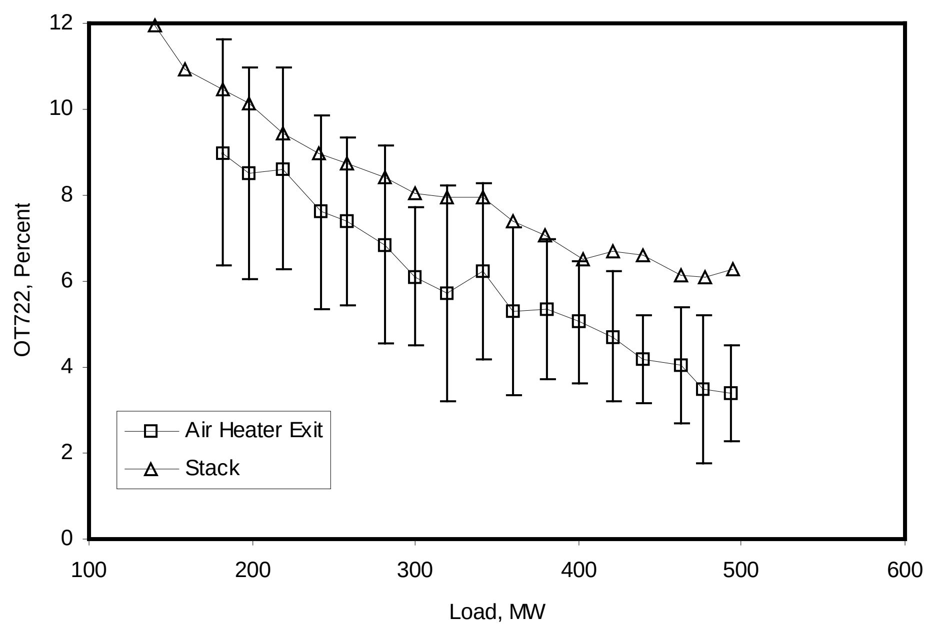


Figure 9-38 LNB+AOFA / Long-Term / Excess Oxygen at Air Heater Outlet / West

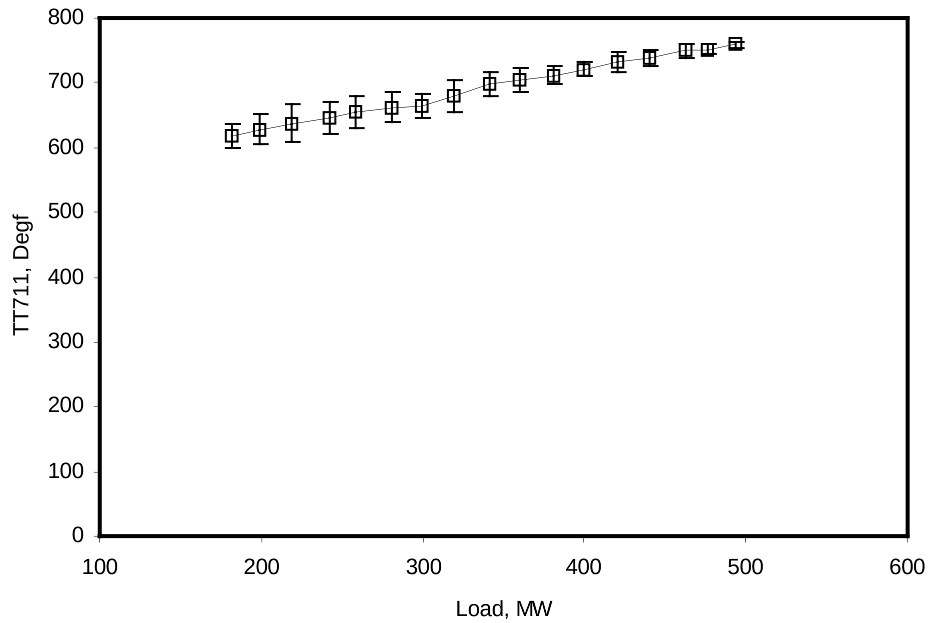


Figure 9-39 LNB+AOFA / Long-Term / Flue Gas Temperature at Air Heater Inlet / East

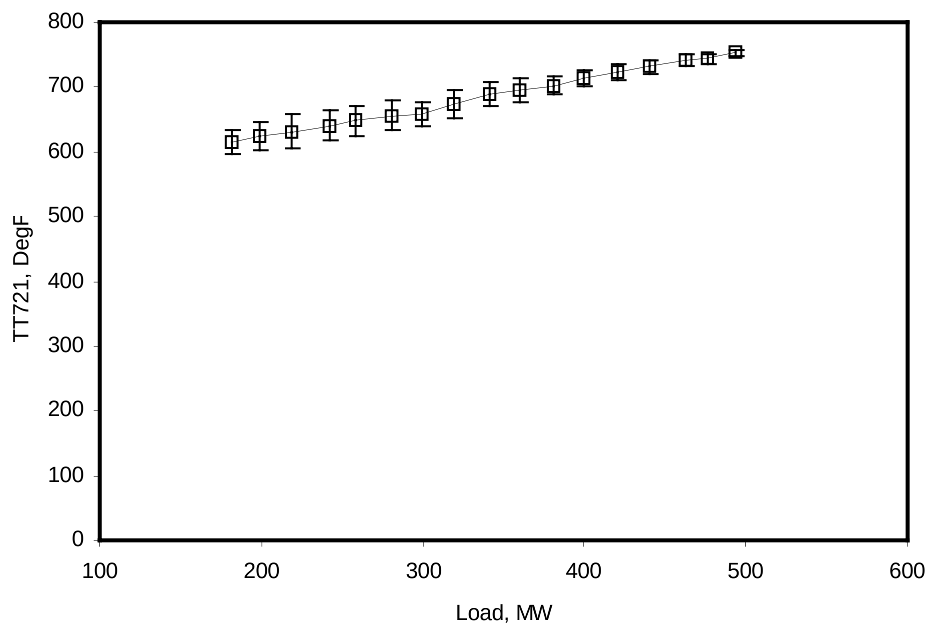


Figure 9-40 LNB+AOFA / Long-Term / Flue Gas Temperature at Air Heater Inlet / West

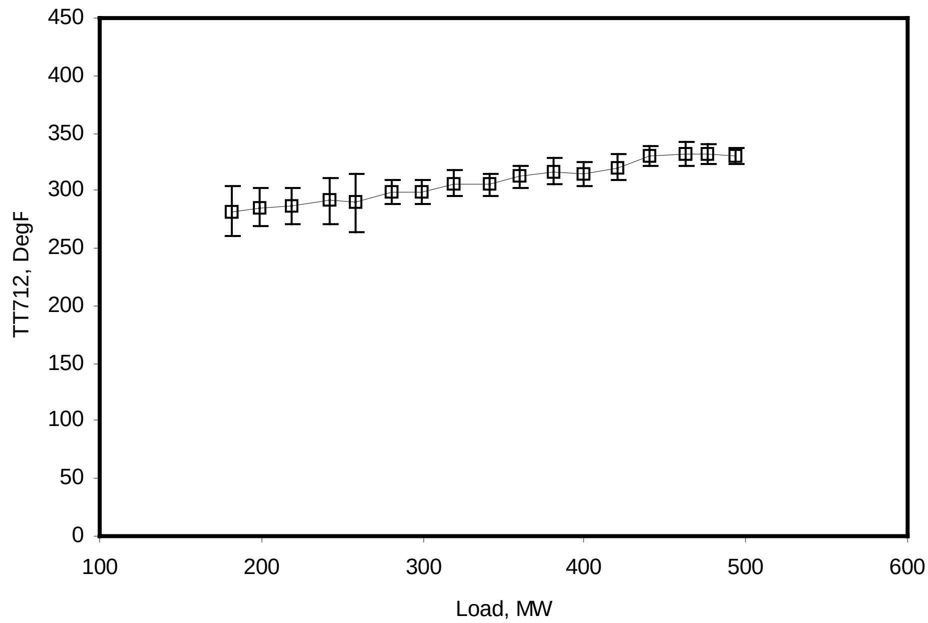


Figure 9-41 LNB+AOFA / Long-Term / Flue Gas Temperature at Air Heater Outlet / East

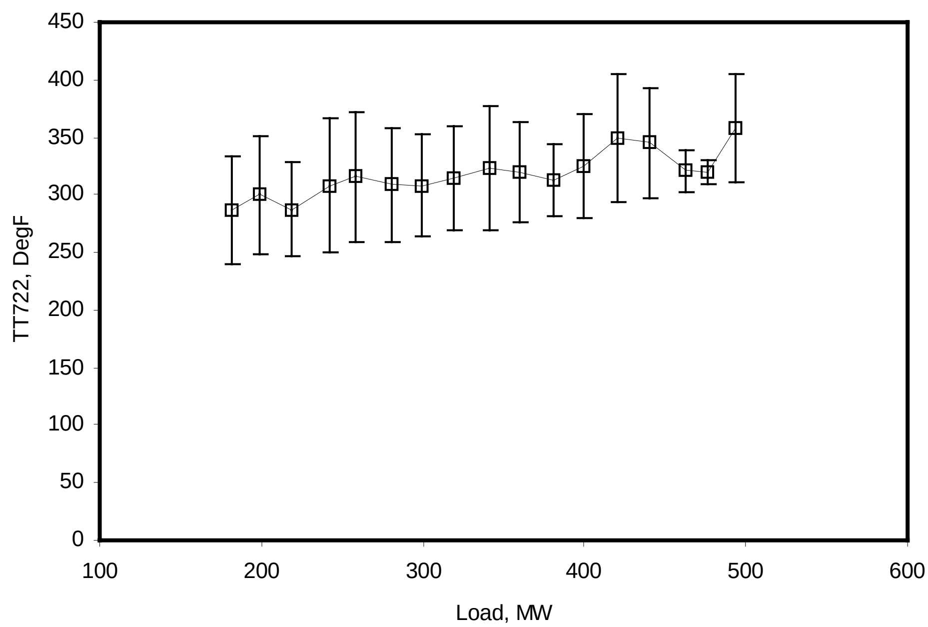


Figure 9-42 LNB+AOFA / Long-Term / Flue Gas Temperature at Air Heater Outlet / West

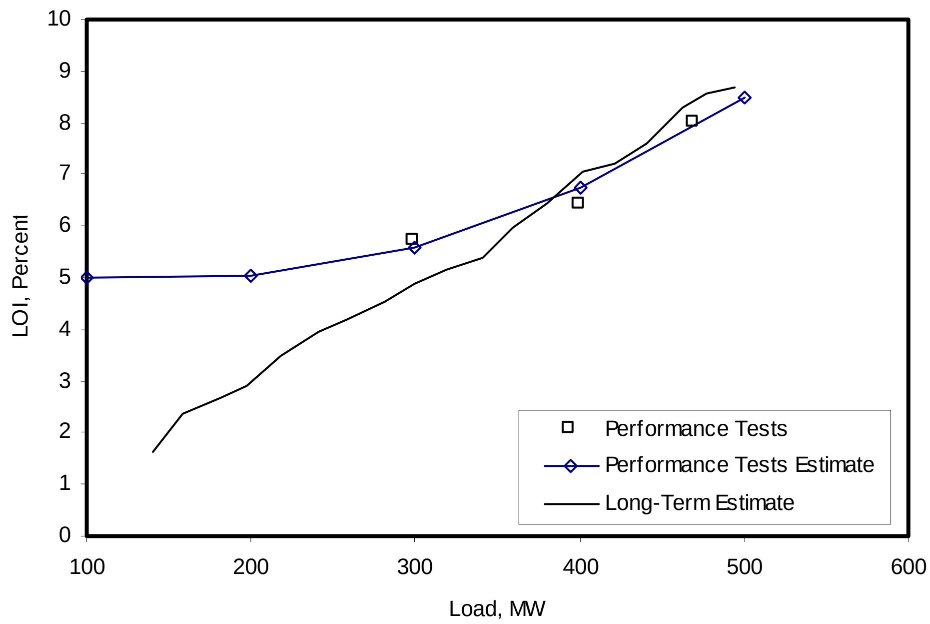


Figure 9-43 LNB+AOFA / Long-Term / LOI Estimate

10 PERFORMANCE COMPARISON

This section provides a comparison of the performance of the low NOx combustion technologies relative to baseline and each other. Factors compared include NOx emissions, fly ash unburned carbon levels, CO emissions, excess oxygen and combustion air, air heater and economizer outlet gas temperatures, steam temperatures, drum and throttle pressure, boiler efficiency and unit heat rate. When available, both short- and long-term data are used in the comparison. It should be noted that this data reflects how the technologies performed on Hammond Unit 4 and although extrapolation to other units is reasonable, consideration must be given to how close other units are to Hammond 4 in terms of boiler design, coal characteristics, and operating conditions.

10.1 NOx Emissions

The true measure of the effectiveness of a particular NOx control technology is represented by the long-term emissions characteristics. A comparison of the long-term NOx emissions for the AOFA, LNB, and LNB+AOFA test phases to that observed during baseline is shown in Figure 10-1. The band around each NOx curve represents 90 percent of all long-term data collected during the particular phase. As shown, NOx emission variations for the LNB and LNB+AOFA test phase were considerably less than the variations observed during the baseline and AOFA test phases. This reduction in variation is primarily attributable to improved condition of the low NOx burners as compared to the original, Intervane burners. Also, there was some overlap in the NOx emission characteristics of the baseline and AOFA test phases particularly at lower loads. This convergence is somewhat expected in that below 300 MW, the AOFA flow is reduced to the minimum flow necessary to provide cooling and prevent slag buildup around the AOFA ports.

Figure 10-2 compares the mean NOx emissions for the baseline, AOFA, LNB, and LNB+AOFA test phases. As shown, full-load NOx emissions were reduced from approximately 1.2 lb/Mbtu to 0.40 lb/Mbtu during the course of the project. NOx reductions as a percentage of baseline values are shown in Figure 10-3. Full-load NOx emission reductions of approximately 20, 50, and 65 percent were obtained with AOFA, LNB, and LNB+AOFA, respectively. As shown, the effectiveness of configurations utilizing AOFA exhibit a general decline in NOx reduction performance with decreasing load, whereas the NOx reduction when utilizing LNBs alone is relatively independent of load. Also, as discussed in Section 9, the NOx performance improvement between the LNB and LNB+AOFA configuration is not entirely the result of the use of AOFA but includes other favorable NOx factors including mill biasing.

As discussed in prior sections and which can be inferred from Figure 10-1, NOx emissions are highly dependent on unit operating conditions, both controlled and uncontrolled. As an example, varying excess oxygen by ±1 percent produces the NOx variation shown in Figure 10-4. In this figure, the bars represent the 90 percentile limits whereas the outer lines represent the projected mean NOx levels. The nominal sensitivity used for all plots was 0.1 lb/Mbtu per percent change in excess O_2 which is representative of the sensitivity seen in all four phases. As can be seen, not all NOx variations could be accounted for by changes of 1 percent in excess O_2, particularly for the baseline and AOFA test phases, and at lower loads for all phases. It should be noted that the excess O_2 variations during the baseline and AOFA phases were much greater than that seen during the LNB and LNB+AOFA phases. This was in part attributable to the condition of the burners during this test period. When this operating O_2 variation is considered, a large range of percent NOx reduction can result (Figure10-5).

NOx emissions for the performance tests during each phase are shown in Figure 10-6. As shown, full-load NOx reductions for these tests were greater than that obtained during long-term, normal operation. The principal cause of the increase was the higher NOx emissions during the baseline performance test (1.44 lb/Mbtu vs. 1.23 lb/Mbtu). When the performance test NOx values are corrected to stack O_2 levels (Table 10-1) observed during long-term testing, the emission reductions obtained for the performance and long-term tests are very similar.

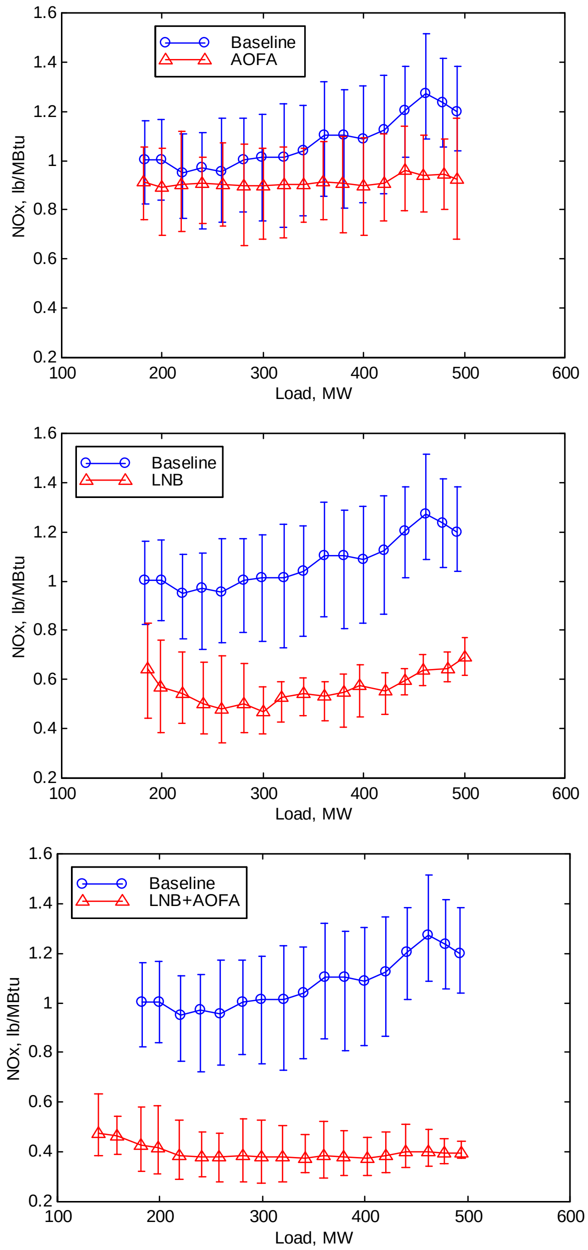


Figure 10-1 Comparison of Long-Term NOx Emissions and Variations

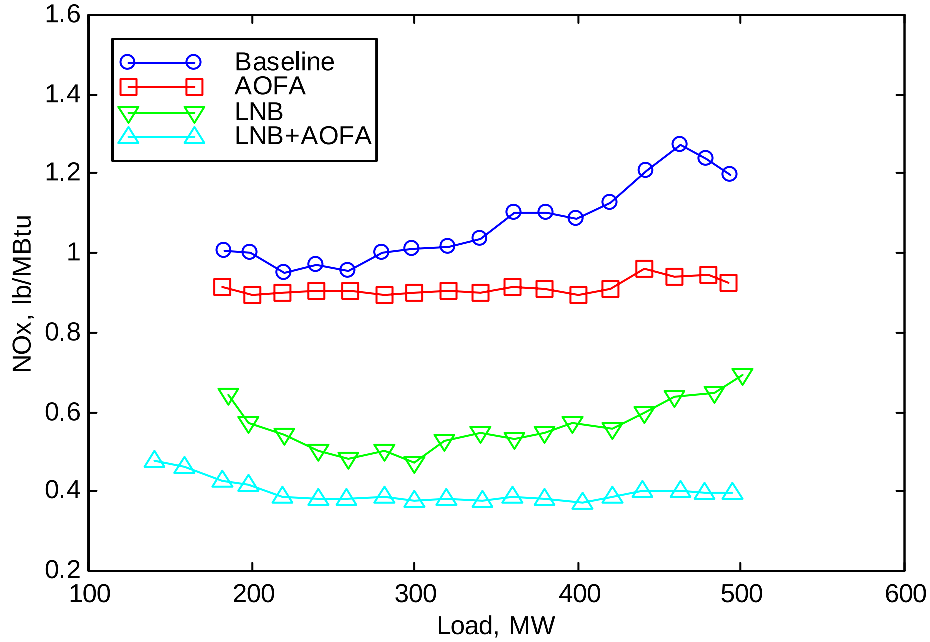


Figure 10-2 Comparison of Long-Term NOx Emissions

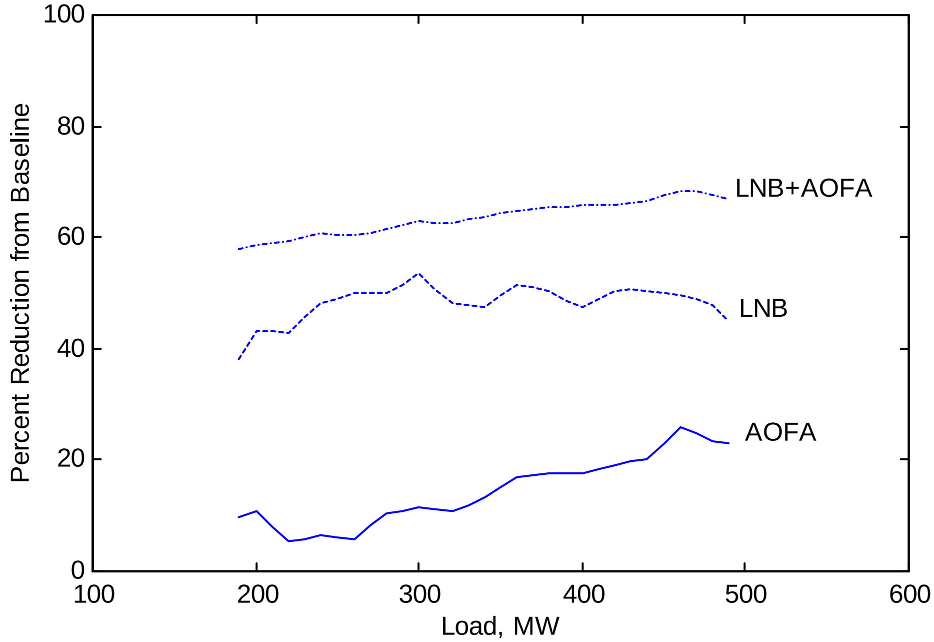


Figure 10-3 NOx Emission Reductions

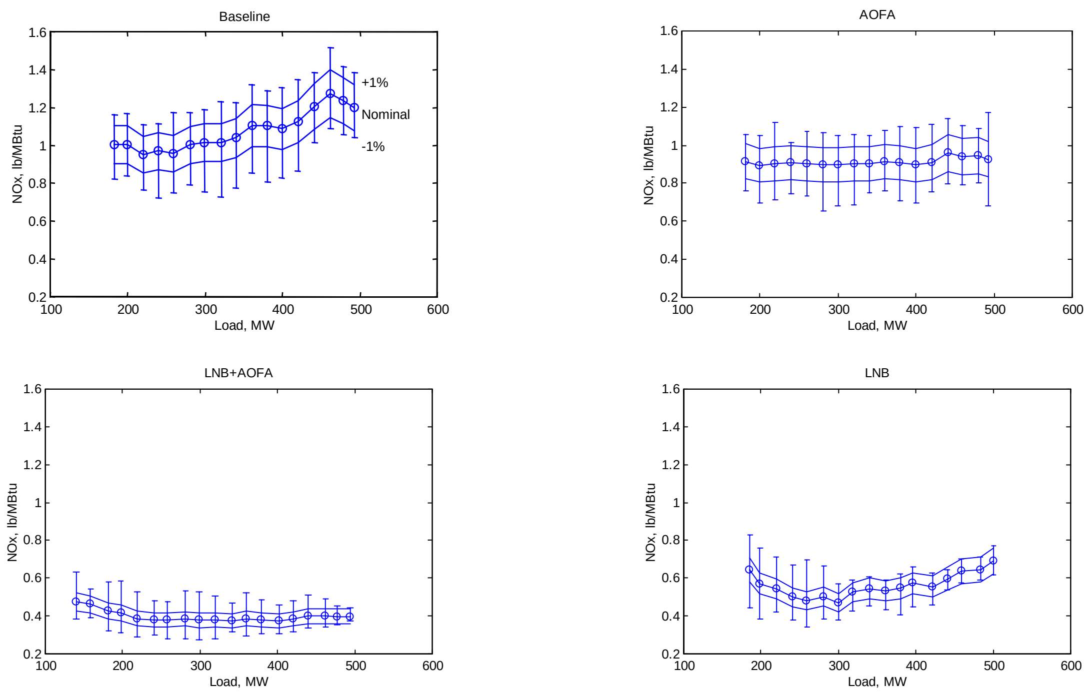


Figure 10-4 NOx Emissions Resulting from ±1 Percent Change in Excess O_2

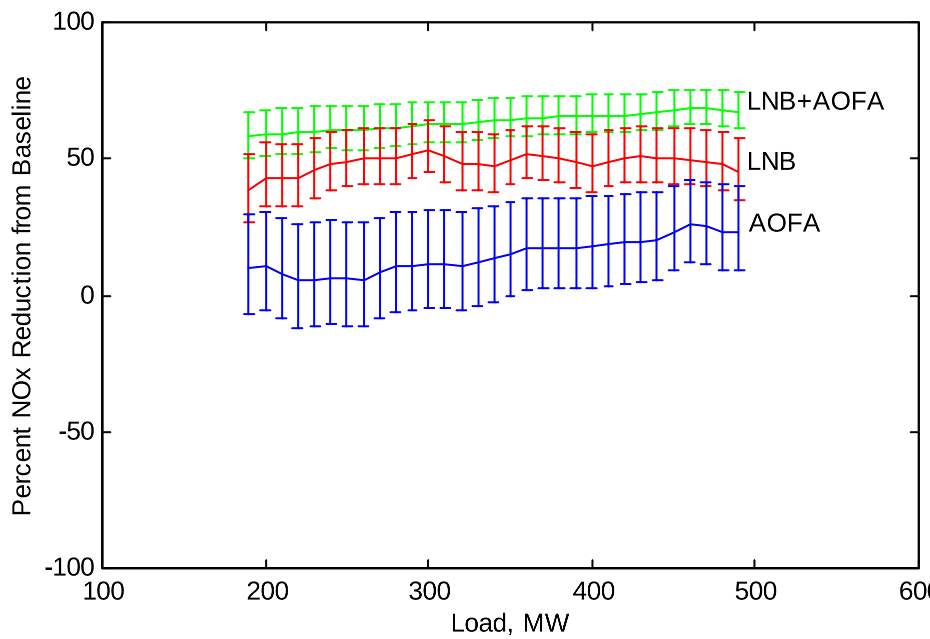


Figure 10-5 NOx Emission Reductions with ±1 Percent Change in Excess O_2

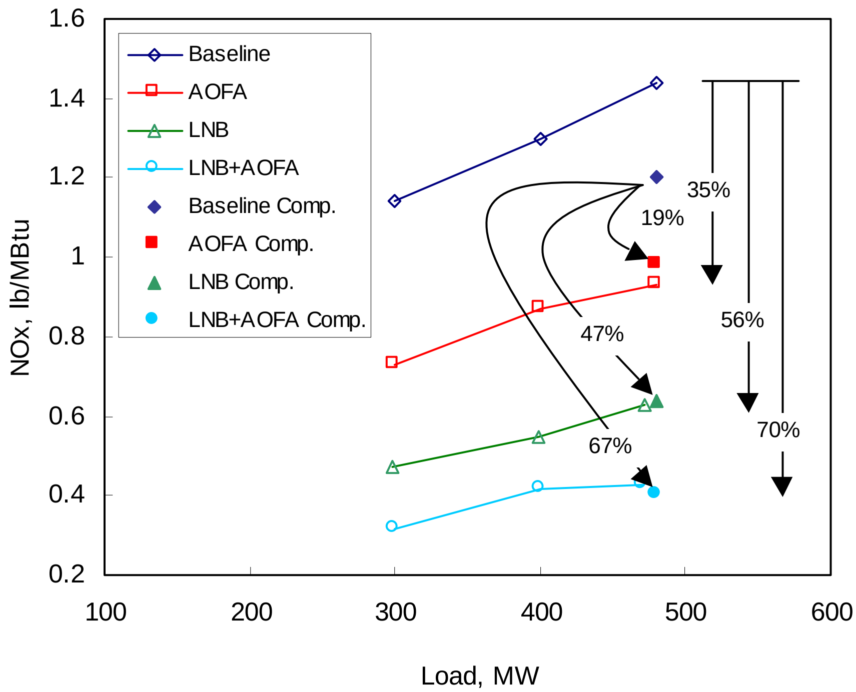


Figure 10-6 Comparison of Performance Tests NOx Levels

Table 10-1 NOx Emissions Obtained During Long-Term and Performance Test

	Long-Term NOx Emissions Lb/MBtu	Long-Term Stack O_2 Percent	Perf. Test NOx Emissions Lb/Mbtu	Perf. Test Stack O_2 Percent	Compensated[2] Perf. Test NOx Emissions Lb/Mbtu
Baseline	1.24	5.0	1.44	7.5	1.19
AOFA	0.94	6.5	0.93	6.3	0.94
LNB	0.65	6.6	0.63	6.4	0.64
LNB+AOFA	0.40	6.1	0.43	6.6	0.40

[1]Full-load (480 MW)
[2]NOx emissions compensated to stack O_2 levels observed during the corresponding long-term test period.

10.2 Fly Ash LOI

A comparison of the LOI levels for the four phases as determined during the performance tests is shown in Figure 10-7. Full-load LOI levels during the performance test were 5.4 percent, 9.6 percent, 8.6 percent, and 8.0 percent for the baseline, AOFA, LNB, and LNB+AOFA test phases, respectively. These values are the average of the performance test conducted during the test period. As a percent of baseline level, at full-load, LOI increased from 48 percent (LNB phase) to 78 percent (AOFA). Similar increases were obtained at all load levels tested. This increase occurred despite the replacement of four of six pulverizers during the course of the test program and the resultant improvement of coal fineness (Baseline – Pass 200 Mesh = 63% / Remain 50 Mesh = 2.7%, AOFA = 67% / 2.3%, LNB = 66% / 1.6 %, LNB+AOFA = 74% / 0.6%).

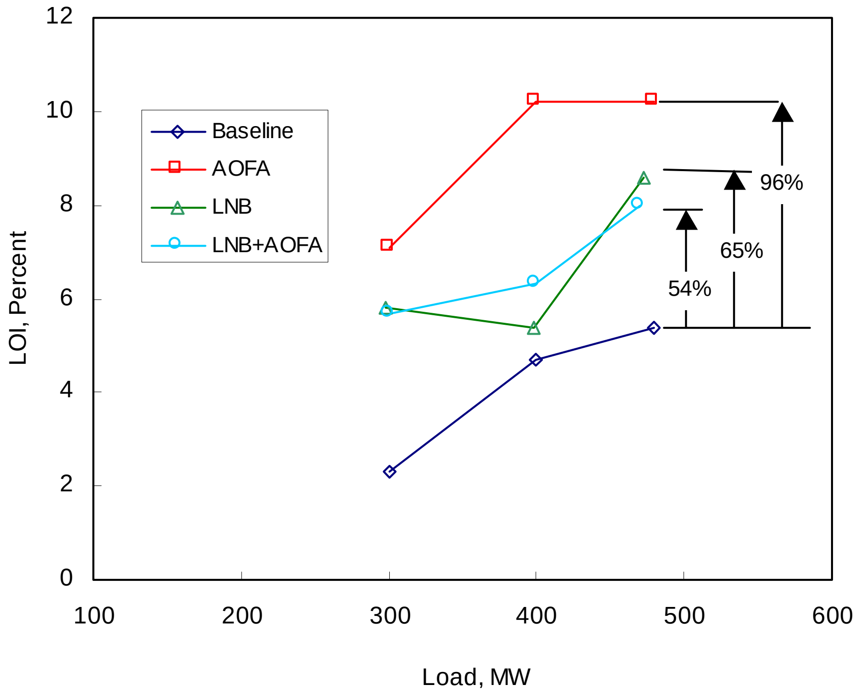


Figure 10-7 Comparison of Performance Tests LOI Levels

As stated previously, the performance tests conditions were selected based on predicted long-term operating factors including excess oxygen and mill patterns. Because the unit was not necessarily operated at these selected conditions, short-term performance tests do not necessarily match that obtained during long-term tests. To partially compensate for differences in the long-term and short-term operating conditions, the LOI can be adjusted to the stack oxygen levels observed during the long-term data collection. The full-load estimate is shown in Table 10-2 with that for all loads in Figure 10-8. Because the difference between short- and long-term stack oxygen was the greatest during the baseline test phase, the change in LOI was the greatest for this phase, going from near 5.4 percent to 7.0 percent. The projected long-term, full-load LOI changes for the other phases were relatively small. Using the projected long-term, full-load LOI, the percent increase in LOI was 31, 21, and 19 percent for the AOFA, LNB, and LNB+AOFA test phase, respectively. Again, this increase was observed despite significant improvement in coal fineness.

Table 10-2 Full-Load LOI Levels

	Perf. Test Stack O_2 Percent	Perf. Test LOI Percent	Perf. Test Percent Increase	Long-Term Stack O_2 Percent	Long-Term LOI Percent[1]	Long-Term Percent Increase[2]
Baseline	7.5	5.2	na	5.0	7.1	na
AOFA	6.3	10.2	96	6.5	10.1	42
LNB	6.4	8.6	65	6.6	8.2	16
LNB+AOFA	6.6	8	54	6.1	8.4	18

[1]LOI compensated to stack O_2 levels obtained during long-term test using a sensitivity of 0.75 LOI percent per percent change in excess O_2.
[2]Relative to baseline.

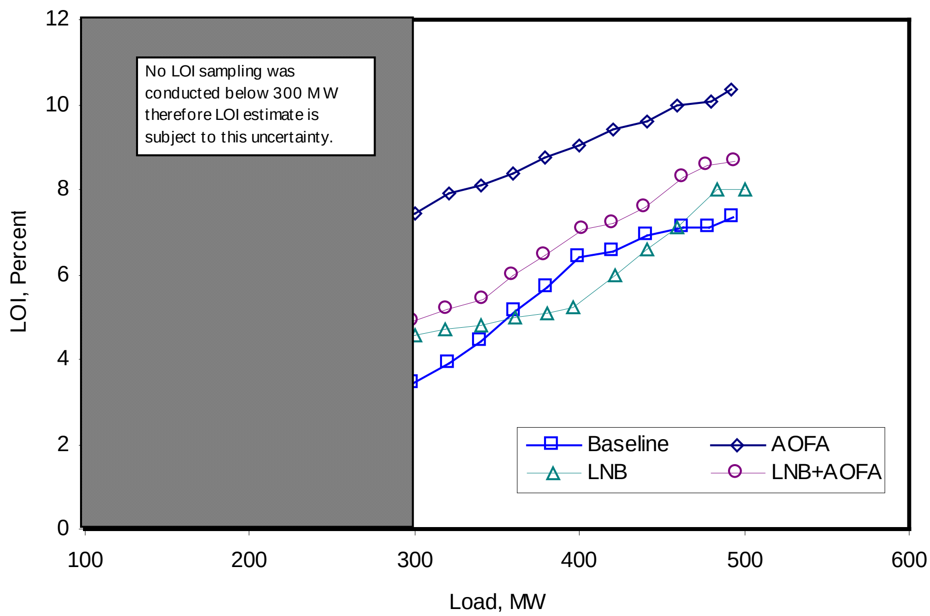


Figure 10-8 Estimate of Long-Term LOI

10.3 CO Emissions

Whereas CO emissions for the AOFA and LNB phases were less than that observed during baseline (Figure 10-9), the CO emissions for the LNB+AOFA test phase was greater at most load levels. Factors that can affect CO emissions include overall boiler stoichiometric level, individual burner stoichiometric level, burner register settings, and burner condition. Another factor is starting with the AOFA test phase, the operators had available a display of CO emissions in the control room that was used to some degree to limit CO emissions. Based on the general increase in CO emissions in the LNB+AOFA configuration, a lower effective furnace O_2 level appears to have contributed to the more than anticipated reduction in NOx emissions between the LNB and LNB+AOFA test phases.

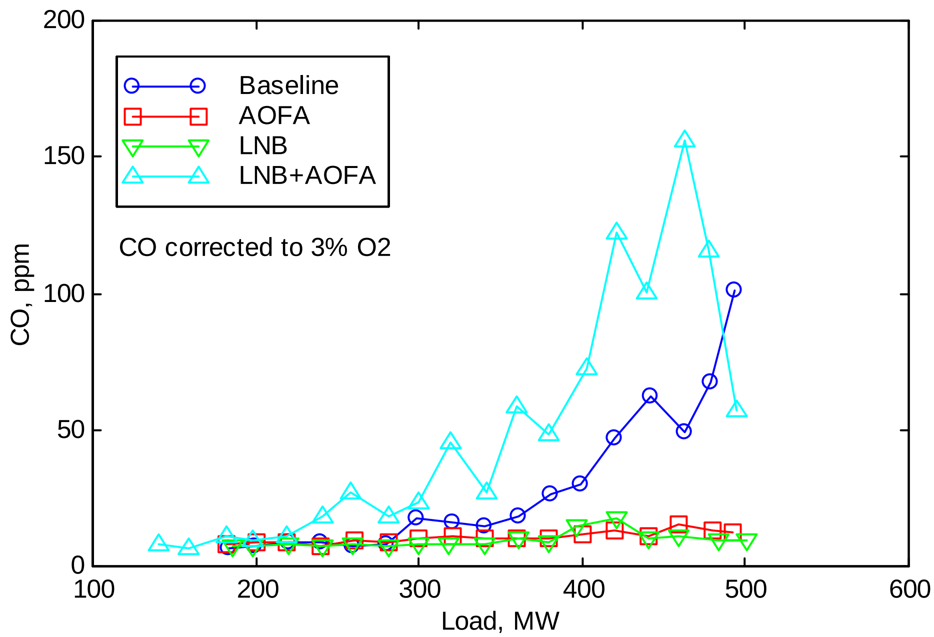


Figure 10-9 Comparison of Long-Term CO Emissions

10.4 Excess Oxygen and Combustion Air

The long-term stack oxygen levels for the baseline, AOFA, LNB, and LNB+AOFA phases are shown in Figure 10-10. As shown, the baseline stack oxygen level is substantially lower than that observed for the subsequent phases. The increase in stack oxygen levels could be the result of increased (1) combustion air requirements or (2) backpass, air heater, or precipitator air infiltration. Because of the latter, stack oxygen is not always a good indicator of the combustion air requirements for the low NOx combustion technology.

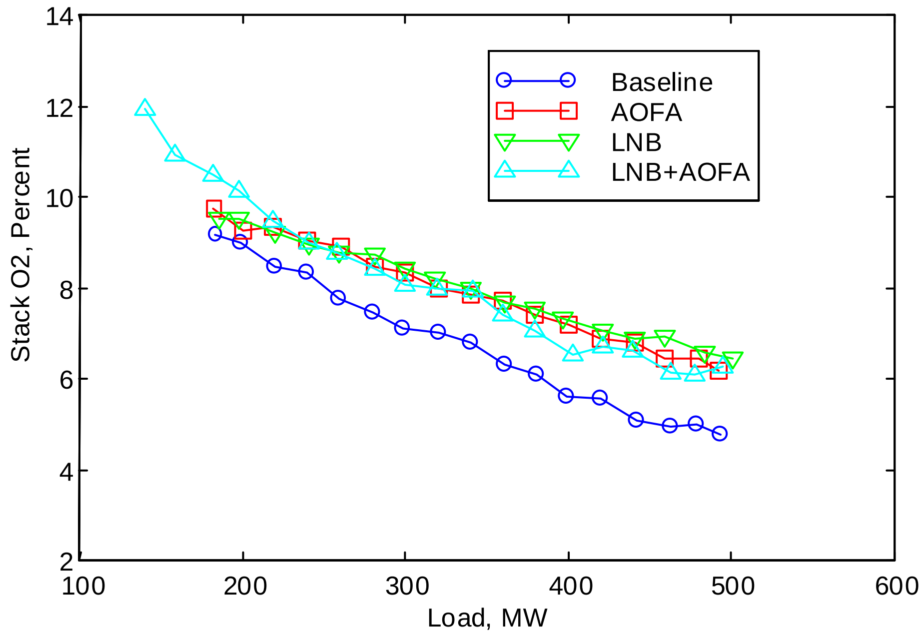


Figure 10-10 Comparison of Long-Term Stack O_2 Levels

Another indicator of the combustion air during the four test phases is the economizer outlet oxygen level (Figure 10-11). These wet measurements are from the plant's six in situ oxygen probes. As shown, at full load, the baseline excess oxygen level, averaging 2.3 percent during the data collection period, was considerably below the values observed during subsequent phases (AOFA = 3.4, LNB = 3.1, and LNB+AOFA = 3.8 percent). Also, the baseline levels remained below the other levels for all loads. The observed values are consistent with the oxygen levels observed at the stack. As with the stack oxygen measurement, as an indicator of combustion air, the economizer readings can suffer from air infiltration in the furnace backpass; however, the infiltration in this section of the furnace should be less than that obtained downstream of this point (air heater and precipitator).

During some of the performance tests, oxygen levels were measured at the top of the furnace using HVT probes (Figure 10-12). The x-y plane in these figures represents the horizontal cross section of the furnace at the 8^{th} floor. These plots clearly illustrate the non-uniform combustion within the furnace. The non-uniform combustion is likely the result of maldistribution of fuel and air within the furnace. Note that for the baseline example, there appears to be areas within the furnace with excess oxygen levels near zero. Because baseline, long-term oxygen levels were less than that seen during the performance tests, this near zero condition would have been exacerbated.

The full-load, total combustion airflow as determined during the performance tests are shown in Table 10-3. As shown, combustion airflow tended to be greater during the LNB and LNB+AOFA performance tests than during baseline. Combustion airflow during the AOFA performance tests was comparable with that observed during baseline. As mentioned previously, the baseline performance tests were conducted at significantly higher excess oxygen than that run during the long-term tests. The other phases (AOFA, LNB, and LNB+AOFA) showed much less variation between the performance and long-term tests. Together, this further strengthens the proposition that there was greater combustion air during the low NOx combustion technology test phases than during baseline.

Using the measured air flows and stack oxygen levels obtained during the performance tests, the baseline airflow can be adjusted to reflect the 5 percent stack oxygen level that the unit ran during long-term testing, yielding a total combustion airflow of 3.3×10^6 lb/hr (Table 10-3). Using this flow as the baseline, the combustion air increased by 16, 21, and 30 percent for the AOFA, LNB, and LNB+AOFA tests phases, respectively. It should be noted that for the 480 MW load tests, coal flow averaged approximately 360,000 lb/hr (HHV = 12,900 Btu/lb) yielding a stoichiometric airflow of near 3.5×10^6 lb/hr – a value above the projected airflow at 5 percent stack oxygen levels.

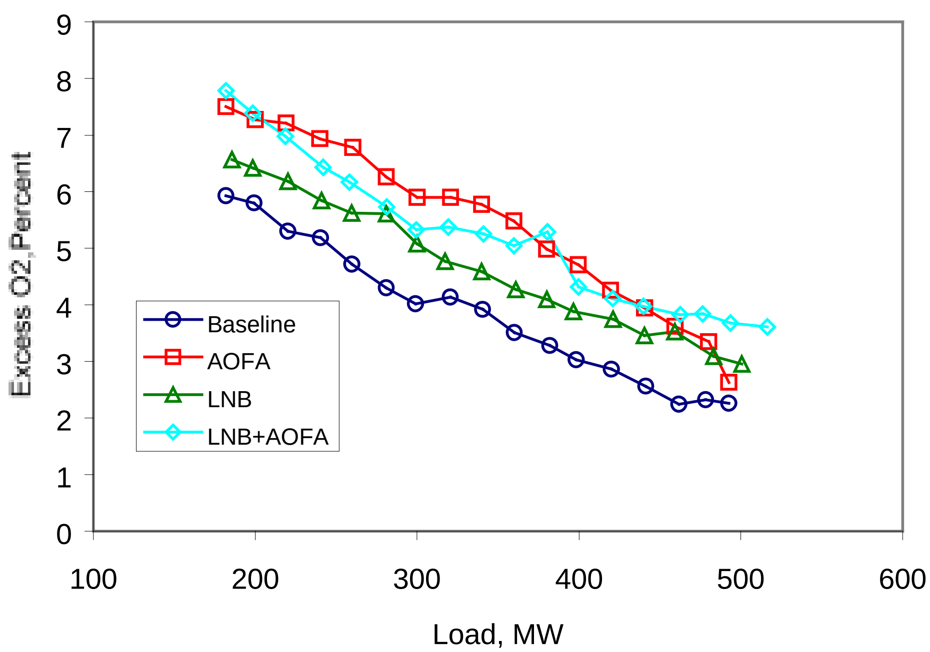


Figure 10-11 Comparison of Long-Term Economizer Outlet O_2 Levels

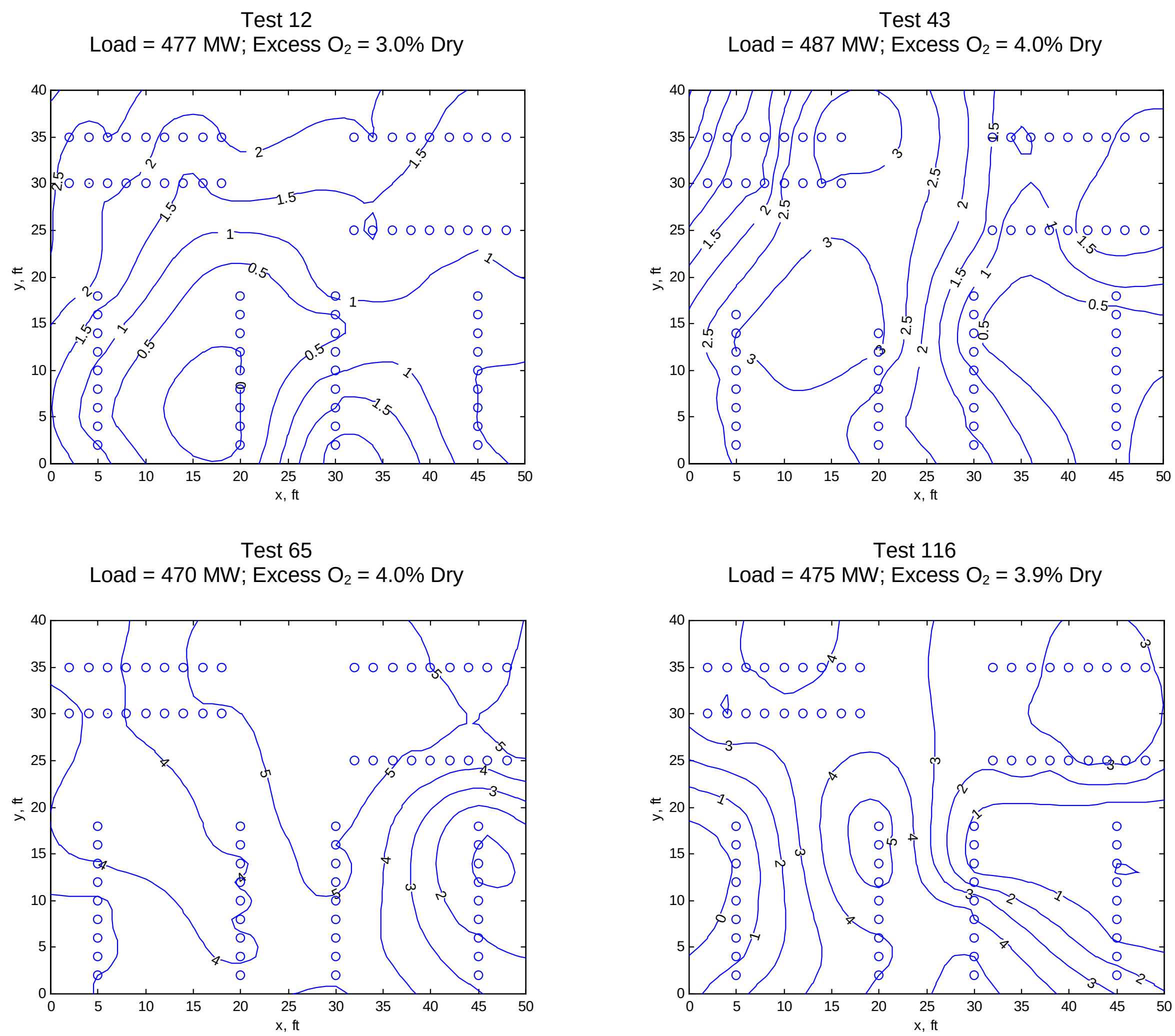


Figure 10-12 Comparison of Upper Furnace Oxygen Levels

Table 10-3 Comparison of Full-Load Combustion Airflows

Phase	Test	Air Flow lb/hr	% Increase from Baseline	Air Flow Adjusted lb/hr	% Increase from Baseline
Baseline	Average	3,746,943	na	$3.3*10^6$	na
	13-1	3,888,690			
	17-1	3,605,196			
AOFA	Average	3,764,118	0%	--	16%
	37-1	3,447,972			
	38-1	3,684,285			
	43-1	3,849,933			
	44-1	3,988,251			
	45-1	3,850,147			
LNB	Average	3,932,143	5%	--	21%
	65-1	3,957,904			
	66-1	3,933,419			
	70-1	4,133,784			
	71-2	3,889,088			
	72-1	3,746,518			
LNB+AOFA	Average	4,223,156	13%	--	30%
	115-1	4,182,883			
	116-1	4,263,429			

10.5 Air Heater and Economizer Gas Outlet Temperatures

As measured during the performance tests, air heater air outlet temperatures showed an increase in temperature with the installation of the low NOx combustion technologies (Figures 10-13, 10-14, and 10-15). The temperature values shown are averaged values from multi-point sampling at the precipitator inlet just downstream of the air heater. All else being the same, each 10°F increase in exit temperature, results in approximately 0.25 percent decrease in boiler efficiency, a substantial performance penalty. These temperatures can be impacted not only by the combustion technology, but also the controllable operating parameters (in particular, excess oxygen) and air heater leakage. Also, note that during the baseline 300 MW and 400 MW tests, the duct temperature was close to the sulfuric acid dewpoint (approximately 230°F to 260°F at the SO_3 concentrations in the flue gas stream).

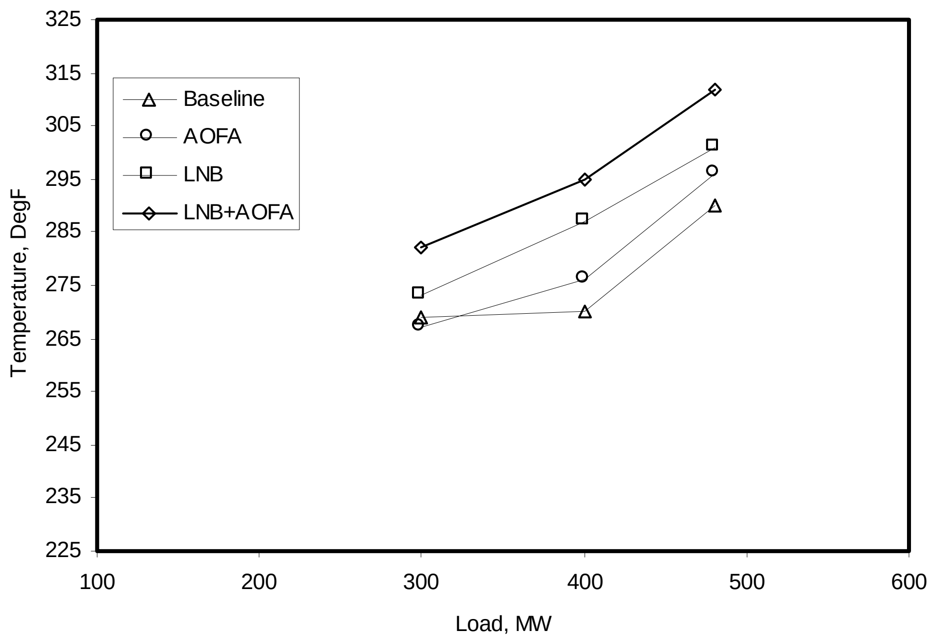


Figure 10-13 Comparison of Air Heater Gas Outlet Temperatures (Performance Tests)

As stated earlier, the performance tests were not necessarily conducted at the conditions seen over the long-term test periods. In particular, the baseline performance tests were run at substantially higher excess oxygen levels than the levels the unit operated with during the same long-term test period. Note that the long-term LNB+AOFA temperatures were much higher than those recorded during the performance tests.

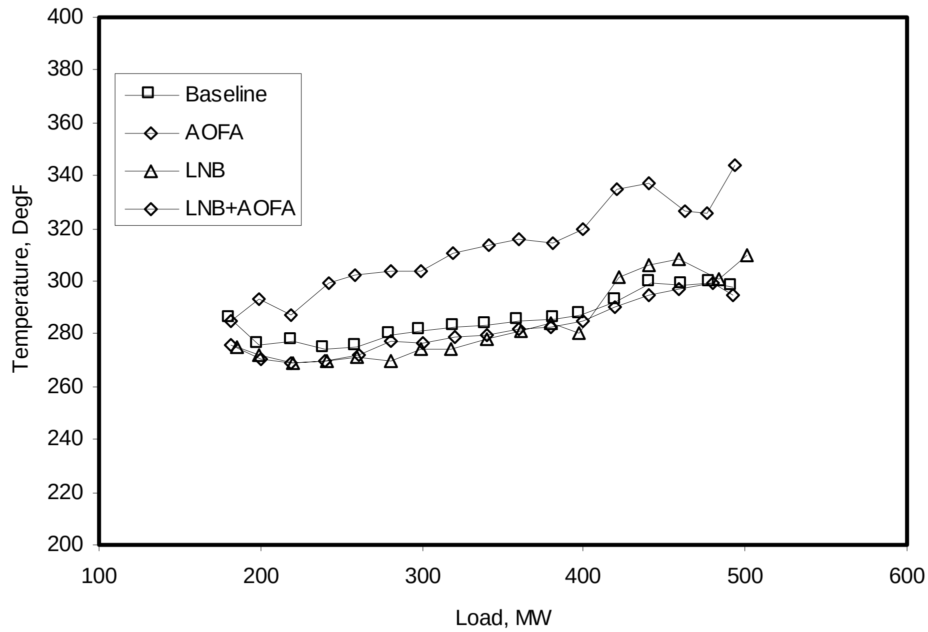


Figure 10-14 Comparison of Air Heater Gas Outlet Temperature (Long-Term)

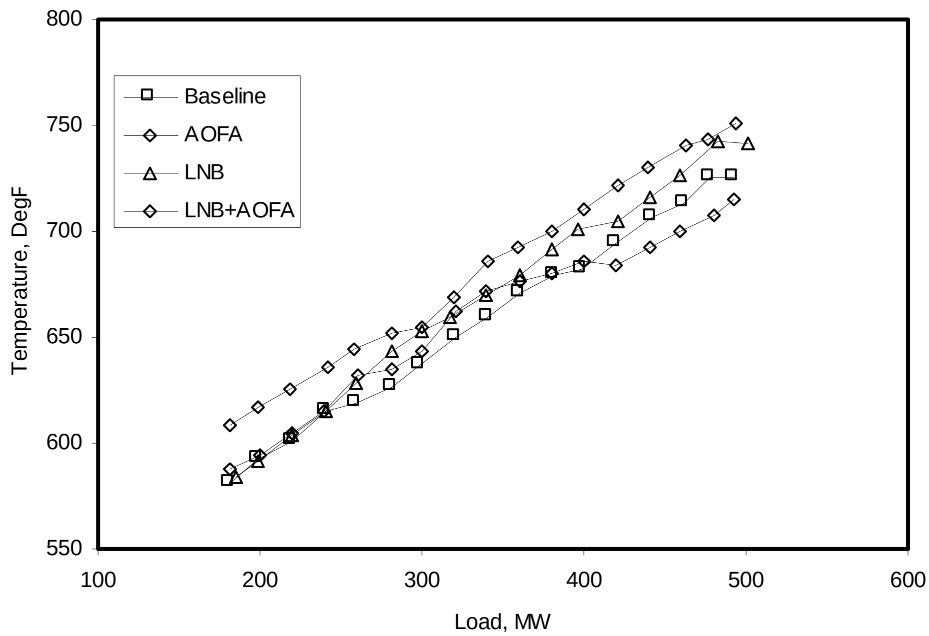


Figure 10-15 Comparison of Economizer Gas Outlet Temperature (Long-Term)

10.6 Steam Temperatures

Superheat and reheat temperatures for the four phases are shown in Figures 10-16 through 10-19. Temperatures below design steam temperatures (1000°F for both superheat and reheat on Hammond 4) result in significant heat rate penalties (approximately 20 Btu/ kWh per 10°F deviation in steam temperature). Temperatures above design, although beneficial to heat rate, can accelerate unit degradation. The primary control mechanisms for steam temperature control are the superheat and reheat pass dampers in the furnace backpass. Based on the performance tests (Figures 10-16 and 10-17), at full-load, steam temperatures were improved during the AOFA, LNB, and LNB+AOFA as compared to baseline. Operation factors that can affect the steam temperatures include combustion air levels, slagging properties of the fuel, and distribution of the combustion air and fuel within the furnace. In general, increased combustion air has a propensity to increase steam temperatures. As noted previously, the combustion air tended to increase with the installation of the low NOx combustion technologies. Long-term superheat temperatures were also generally improved over that observed during baseline (Figure 10-18). Long-term reheat temperatures were generally improved at full-load while deteriorated at loads below 300 MW. As shown, in Figure 10-19, the difference in performance and long-term results can in part be contributed to differences in operating excess O_2 levels between the short- and long-term test segments.

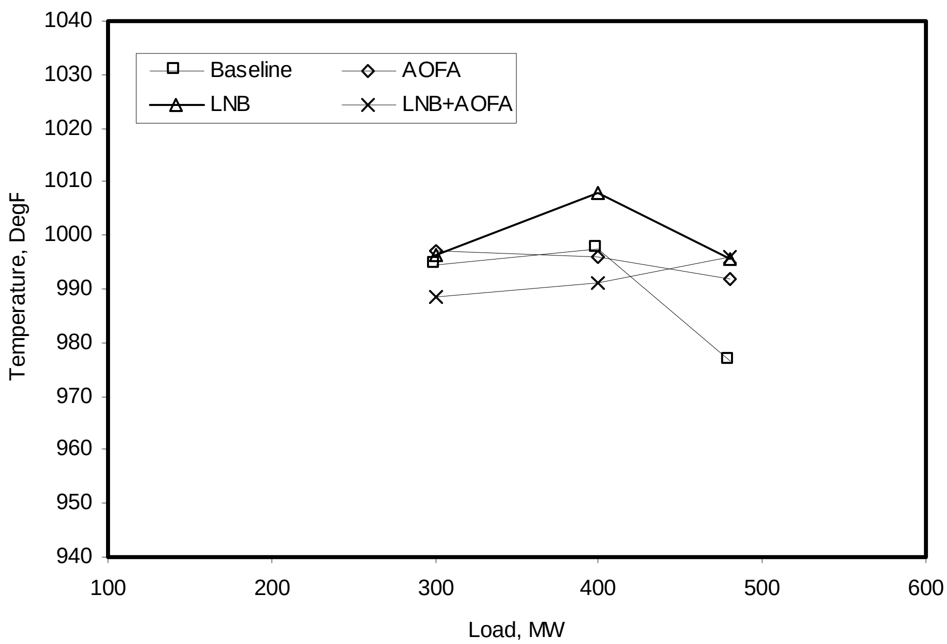


Figure 10-16 Comparison of Superheat Temperature (Performance Tests)

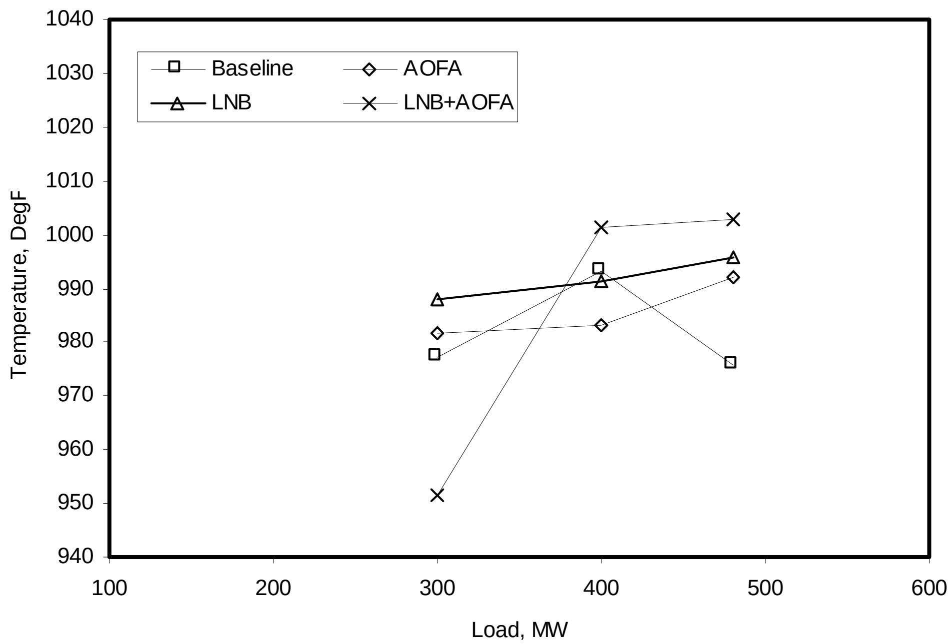


Figure 10-17 Comparison of Reheat Temperature (Performance Tests)

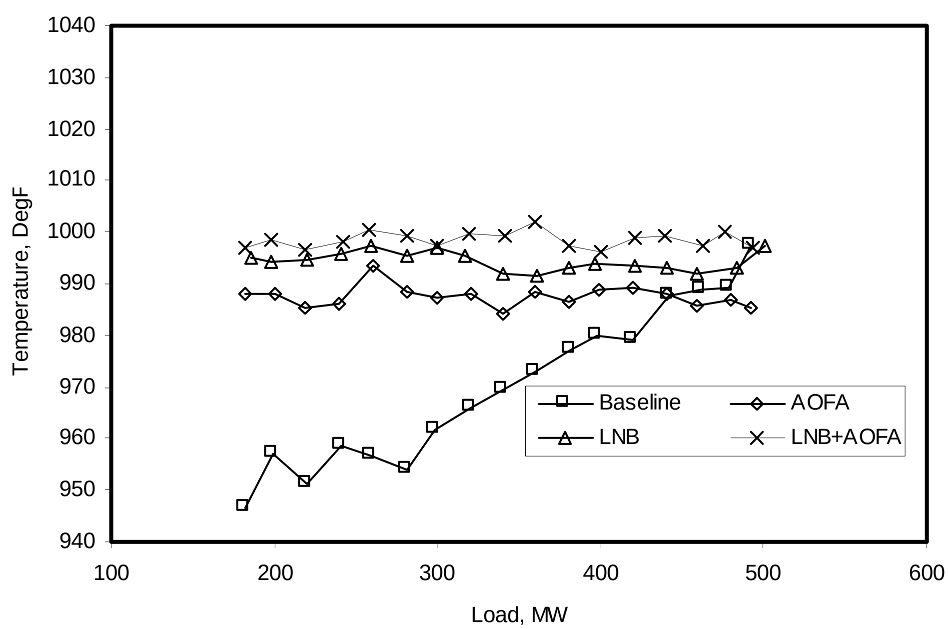


Figure 10-18 Comparison of Superheat Temperature (Long-Term)

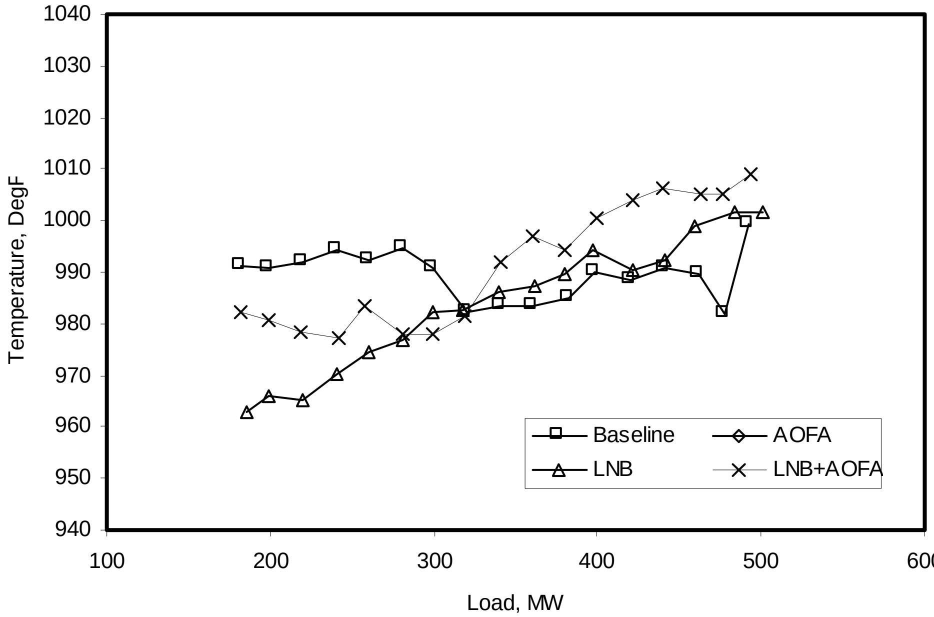


Figure 10-19 Comparison of Reheat Temperature (Long-Term)

10.7 Drum and Throttle Pressure

Throttle pressure deviations from design (2400 psig) impact unit heat rate by approximately 45 Btu/kWh per every 100 psi deviation from design. The throttle pressure characteristic for each phase is shown in Figure 10-20. Design pressure for the unit is 2400 psig. As shown, the unit operated at considerably lower pressures than design for all four phases. It is doubtful that the retrofits were responsible for the deviations between the phases but more likely may have been the result of boiler control system performance or changes in operator setpoints.

As shown in Figure 10-21, drum pressure was similar for all four phases and slightly below the design pressure. The cause of the mid-load droop in drum pressure during the baseline phase is unknown, but is unlikely to be the result of the low NOx technology retrofits.

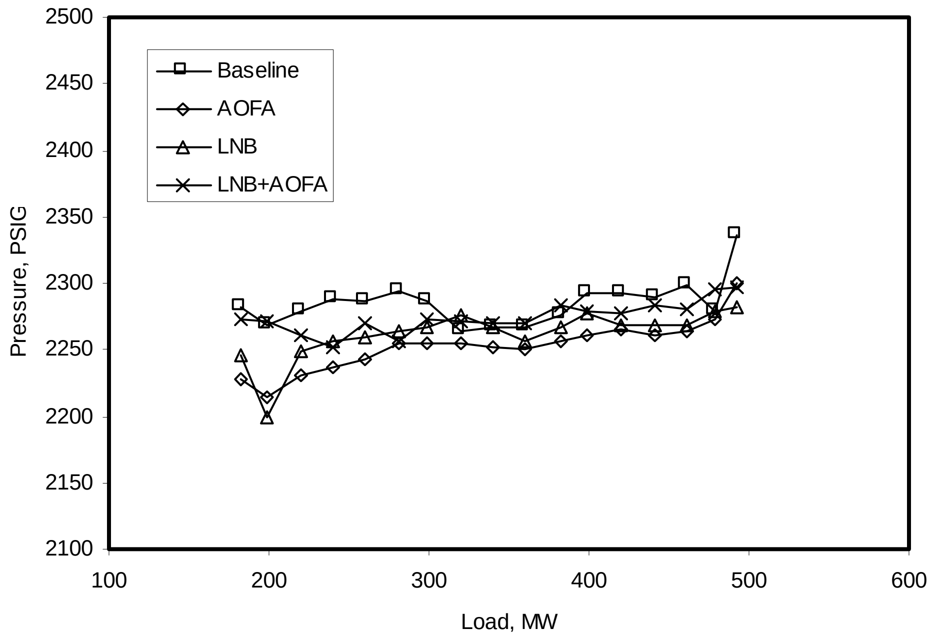


Figure 10-20 Comparison of Throttle Pressure (Long-Term)

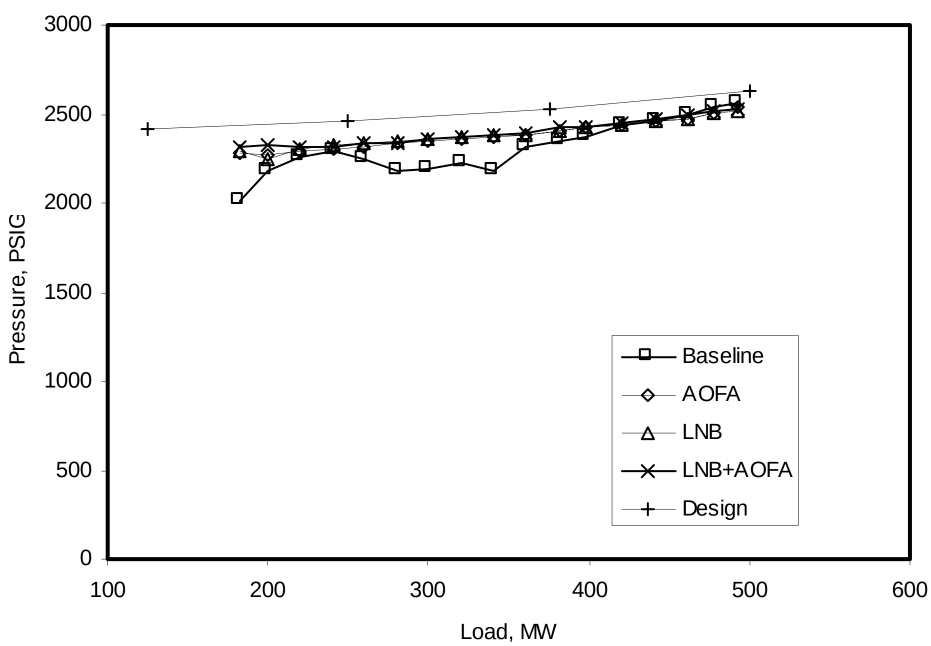


Figure 10-21 Comparison of Drum Pressure (Long-Term)

10.8 Boiler Efficiency and Unit Heat Rate Impacts

The impacts described in the previous paragraphs affect the boiler efficiency and turbine heat rate, which in turn affect the unit's net heat rate (Figure 10-22). Factors included in this analysis include fly ash unburned carbon levels, flue gas temperature leaving the air heaters, excess oxygen levels, and steam (superheat and reheat) temperatures. Factors excluded from the analysis include the impact of superheat spray flows, steam pressure deviations, and station service. Superheat spray flow has little impact on overall unit heat rate. Although station service has a direct impact on net unit heat rate, it was felt that its influence was secondary to the other factors considered. Steam pressure deviations, although having an impact on turbine cycle heat rate, are less influential than steam temperatures (at least at the pressure deviations seen during the duration of the project) and could not be clearly associated with changes in the combustion technologies.

The effects at full load (both short- and long-term) are shown in Table 10-4. In this table, all performance impacts were determined using baseline as a reference. Baseline boiler efficiency and turbine cycle heat rate are taken to be 90 percent and 9000 Btu/kWh, respectively. Several conclusions can be made from this table. Although the performance test boiler efficiency was greater during the baseline phase than the other phases, this improved performance appears to have come at the expense of steam temperatures and consequently, turbine cycle heat rate. Overall, considering the boiler and turbine cycle penalties, unit heat rate increased with each technology over that observed during baseline. Note that although the steam temperature improved with the installation of the technologies, the improvement did not compensate for the degradation in boiler efficiency. This increase is consistent with the plant staff's determination that the unit heat rate has increased during the period from 1989 through 1993. The effects at other loads as determined from the short-term tests are shown in Figures 10-23 through 10-24.

This performance degradation was also observed during the long-term data collection periods (Figures 10-25 and 10-26). As noted previously, the performance tests were not necessarily conducted at the same operating conditions as observed during long-term testing. Again, baseline boiler efficiency and turbine cycle heat rate are taken to be 90 percent and 9000 Btu/kWh, respectively. As shown, boiler efficiency decreased with installation of the low NOx technologies primarily as the result of increased furnace exit gas temperatures. As in the performance test, the steam conditions appeared to improve and somewhat compensated for the poorer boiler performance.

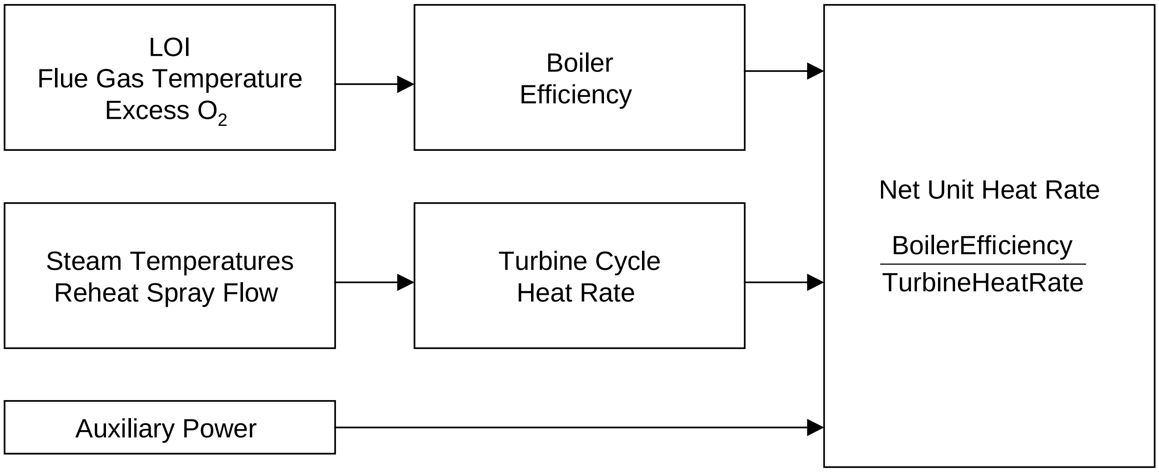


Figure 10-22 Impacts on Unit Heat Rate

Table 10-4 Impacts on Boiler Performance and Unit Heat Rate (480 MW)

Full-Load Performance Tests	Baseline	AOFA	LNB	LNB+AOFA
Boiler Efficiency	90.0%	89.5%	89.7%	89.3%
Dry Flue Gas	--	-4	-11	47
Unburned Carbon	--	60	45	30
Turbine Cycle Heat Rate	9000	8994	8992	8961
Superheat Penalty	--	-2	-4	-23
Reheat Penalty	--	-4	-4	-15
Unit Heat Rate (Btu/kWh)	10000	10050	10027	10038

Full-Load Long-Term	Baseline	AOFA	LNB	LNB+AOFA
Boiler Efficiency	90.0%	89.2%	89.3%	88.7%
Dry Flue Gas	--	49	63	128
Unburned Carbon	--	37	11	18
Turbine Cycle Heat Rate	9000	8999	8975	8960
Superheat Penalty	--	3.6	-7.2	-20
Reheat Penalty	--	-5	-18	-21
Unit Heat Rate (Btu/kWh)	10000	10085	10049	10105

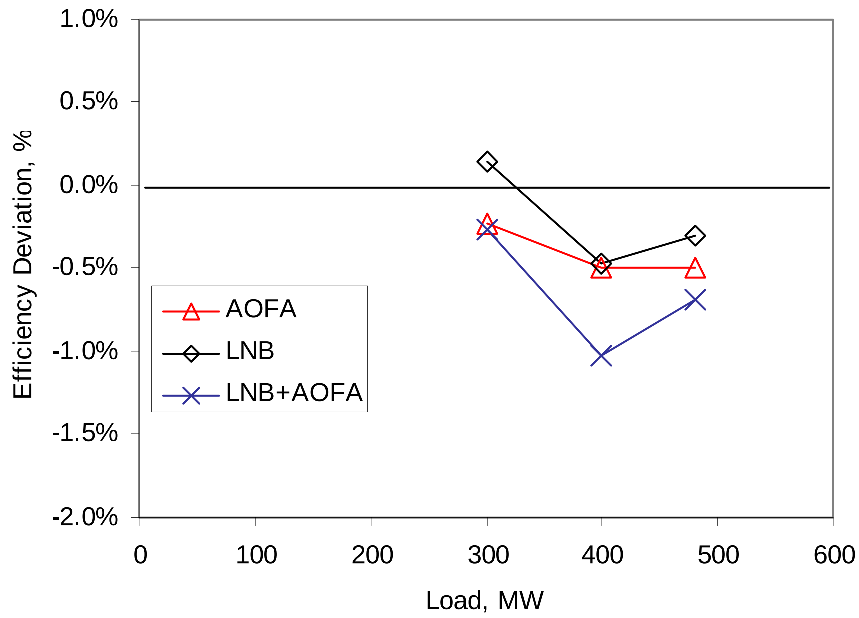


Figure 10-23 Boiler Efficiency Deviation (Performance Tests)

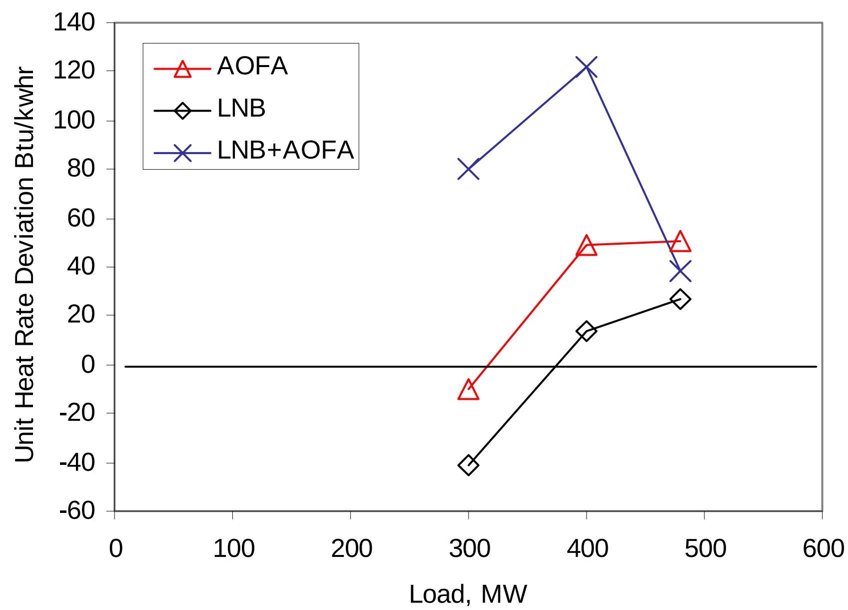


Figure 10-24 Unit Heat Rate Deviation (Performance Tests)

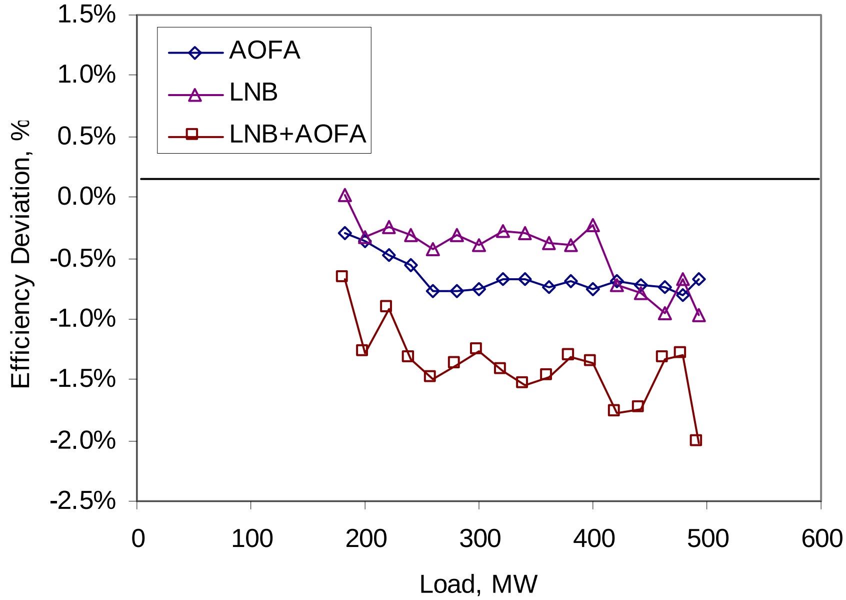


Figure 10-25 Boiler Efficiency Deviation (Long-Term)

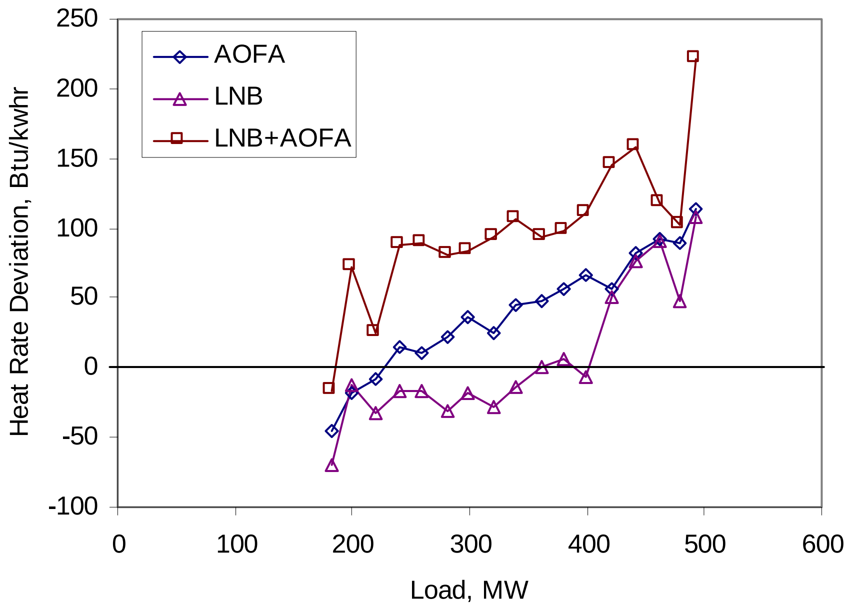


Figure 10-26 Unit Heat Rate Deviation (Long-Term)

11 ECONOMIC EVALUATION

The economic impacts of the wall-fired combustion techniques for NOx reduction consist of capital costs for the retrofits, lost revenue as a result of unit outages, and changes in operating and maintenance costs, both fuel and non-fuel related. For the purposes of this report, it is assumed that the non-fuel related costs and the lost revenue due to the outages are similar for the considered NOx reduction technologies. Therefore, the main economic impacts are attributed to the capital costs and fuel related (heat rate related) O&M costs.

The average cost effectiveness of each NOx reduction technology (expressed in $/ton of NOx removed) is estimated in this section by taking into account the capital cost, O&M impacts, and the NOx emission reduction on an annual basis.

11.1 Estimated Capital Costs

Although the demonstration nature of the Hammond retrofit had an impact on the total project costs, the capital costs are within the expected range for wall-fired installations (6 - 15 $/kW for the LNB and 10 - 20 $/kW for the LNB + AOFA).[1] For the purposes of this report, the following estimates of the actual Hammond capital costs were developed excluding the demonstration related cost adders (e.g., testing, data analysis, and reporting). However, the estimates do include a certain amount of cost sharing by project participants:

AOFA	$3.8 million or 7.6 $/kW
LNB	$4.5 million or 9.0 $/kW
LNB+AOFA	$8.3 million or 16.6 $/kW

For a 500 MW wall-fired commercial installation, with a scope of supply similar to the Hammond retrofit, it is anticipated that the following estimated costs could be utilized for planning purposes:

AOFA	$4.4 million or 8.8 $/kW
LNB	$5.0 million or 10.0 $/kW
LNB+AOFA	$9.4 million or 18.8 $/kW

These estimates are based upon the actual Hammond Unit 4 costs and other available cost data from EPRI and additional sources.

The scope of supply and associated capital costs for a specific commercial installation may vary greatly depending on a number of site specific factors including boiler size, boiler age, furnace configuration, windbox design and condition, physical interferences, number of burners/elevations, auxiliary systems, asbestos removal, and other factors.

[1] All costs are in 1995 dollars.

11.2 Cost Effectiveness at Full-Load

The annual O&M cost and NOx reductions for the installed technologies relative to baseline depend to a large degree on the load profile of the unit. However as a first step, it is informative to perform the analysis for full-load conditions. The annual fuel related O&M cost changes relative to baseline were estimated based on the changes of the unit net heat rate and the following assumptions:

- Base loaded unit (i.e., full-load operation)
- 65 percent capacity factor; and
- $1.2 per MBtu coal cost.

The capital and O&M cost impacts, along with the annual NOx emission reduction (based on long-term, full-load operation), were used for estimating the average cost-effectiveness of the low NOx technologies tested at Hammond Unit 4. A levelization factor of 0.08 was used. The results are summarized in Table 11-1. As shown, given the assumptions given above and performance and cost of the technologies as shown in the table, the annual operating O & M costs increased for each of the technologies tested and ranged from approximately $165,000 (LNB) to $333,000 (LNB+AOFA). The cost effectiveness of the technologies ranged from $65 (LNB) to $144 (AOFA) per ton of NOx removed. Also shown in this table is the cost effectiveness of AOFA when LNB is the base. In this case, the cost effectiveness of AOFA is near $136 per ton NOx removed. However, as discussed in prior sections, the NOx performance in the LNB+AOFA phase was in part the result of factors other than the AOFA. When these other factors are considered, the cost effectiveness of the AOFA added to the LNB system is near $310 per ton NOx removed. This increase may be expected because: (1) the NOx reduction from baseline to AOFA and LNB to LNB+AOFA (adjusted) were similar (24 vs. 22 percent) and (2) the LNB levels of NOx were approximately 50 percent of that of baseline. The cost effectiveness for a range of fuel cost and levelization factors is shown in Figure 11-1.

Table 11-1 Cost Effectiveness of Low NOx Technologies

	Baseline	Baseline -> AOFA	Baseline -> LNB	Baseline -> LNB+AOFA	LNB -> LNB+AOFA	LNB (Adj.) -> LNB+AOFA
O&M						
Boiler Efficiency	90	89.2	89.3	88.7	88.7	88.7
Efficiency Change	Base	-0.8	-0.7	-1.3	-0.6	-0.6
Turbine Heat Rate - Btu/kWh	9,000	8,999	8,975	8,960	8,960	8,960
Unit Net Heat Rate - Btu/kWh	10,000	10,089	10,050	10,101	10,101	10,101
% NHR Change	Base	0.89	0.50	1.01	0.51	-0.51
Annual O & M	Base	$290,968	$165,556	$333,351	$167,795	$167,795
Cost Effectiveness						
NOx Full Load	1.24	0.94	0.65	0.4	0.4	0.4
% NOx Reduction	Base	24	48	68	38	22
Annual NOx Reduction - Tons/yr	Base	4,143	8,117	11,615	3,457	1,521
Capital Costs - $ millions	Base	3.8	4.5	8.3	3.8	3.8
Cost Effectiveness - $/ton removed	Base	$144	$65	$86	$136	$310

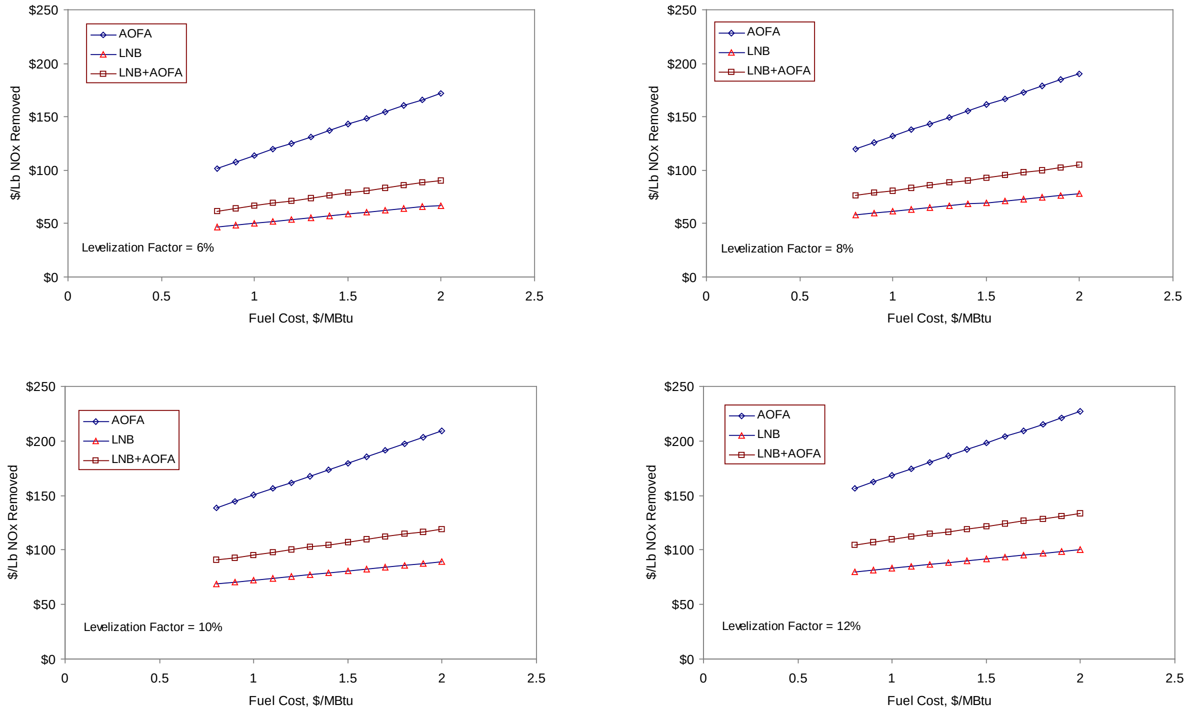


Figure 11-1 Full-Load Cost Effectiveness as a Function of Fuel Cost and Capital Costs

11.3 Load Profile Impact on Cost Effectiveness

The previous analysis was based on NOx and heat rate performance at full load. Because both of these operating parameters are potentially dependent on load, it is important to consider the effect of load profiles on the cost effectiveness of the technologies. Four load scenarios, shown in Figure 11- 2 were considered for this analysis. The *baseline* scenario was the actual load profile for the baseline test phase. The *base load*, *peaking*, *cycling*, and *flat* profiles are hypothetical load profiles. As shown in Table 11- 2, for the baseline load profile, NOx emission reductions of 20, 48, and 66 percent were obtained for AOFA, LNB, and LNB+AOFA, respectively. The percent NOx reduction for LNBs were relatively constant for all load profiles (46 to 49 percent). AOFA effectiveness varied from 10 percent to 20 percent according to the load profile. Because the effectiveness of AOFA is the greatest at full load while that of LNBs if relatively flat over the load range, the yearly mass of NOx reduced varies greatly with the technology and load profile.

The load average impact on heat rate is shown in Table 11- 3. As shown, with one exception the low NOx technologies adversely impacted unit heat rate. For LNBs under the peaking load scenario, performance would actually improve. The heat rate impact for AOFA ranged from 11 to 71 Btu/kWh while that of LNBs ranged from –6 to 39 Btu/kWh. The LNB+AOFA impact ranged from 42 to 93 Btu/kWh. The fuel cost implications are shown in Table 11- 4. Using these costs as a basis, the cost effectiveness of the LNB configuration ranged from $51 to $59 per ton NOx removed while that of AOFA ranged from $130 to $270 per ton NOx removed.

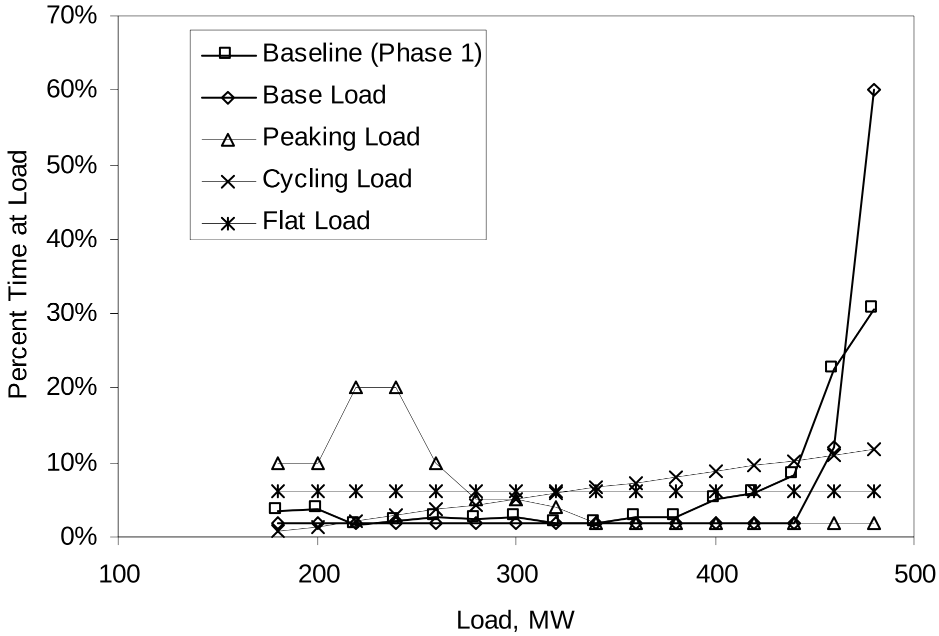


Figure 11-2 Load Profiles

Table 11-2 NOx and NOx Reduction as a Function of Load Profile

		Phase		
Load Profile	Baseline	AOFA	LNB	LNB+AOFA
Baseline (lb/Mbtu)	1.17	0.93	0.60	0.39
percent reduction	--	20%	48%	66%
tons reduced/year	--	4610	10390	14312
Base Load (lb/Mbtu)	1.19	0.93	0.62	0.40
percent reduction	--	21%	48%	67%
tons reduced/year	--	5082	10977	15379
Peaking Load (lb/Mbtu)	1.00	0.91	0.54	0.39
percent reduction	--	10%	46%	61%
tons reduced/year	--	1324	5543	7358
Cycling Load (lb/Mbtu)	1.11	0.92	0.57	0.39
percent reduction	--	18%	49%	65%
tons reduced/year	--	3559	9340	12545
Flat Load (lb/Mbtu)	1.07	0.91	0.55	0.39
percent reduction	--	15%	48%	64%
tons reduced/year	--	2570	7694	10271

Table 11-3 Average Heat Rate Deviation as a Function of Load Profile and Technology

	Phase			
	Baseline	AOFA	LNB	LNB+AOFA
Baseline	--	62	39	93
Base Load	--	71	39	92
Peaking Load	--	11	-6	42
Cycling Load	--	49	22	88
Flat Load	--	32	8	68

Table 11-4 Fuel Cost Deviation as a Function of Load Profile and Technology

	Phase			
	Baseline	AOFA	LNB	LNB+AOFA
Baseline	--	$313,969	$198,068	$469,113
Base Load	--	$355,744	$194,716	$465,677
Peaking Load	--	$53,592	-$31,048	$210,394
Cycling Load	--	$245,708	$112,122	$445,184
Flat Load	--	$159,470	$39,912	$344,053

Table 11-5 Cost Effectiveness as a Function of Load Profile and Technology

	Phase			
	Baseline	AOFA	LNB	LNB+AOFA
Baseline	--	$134	$54	$79
Base Load	--	$130	$51	$73
Peaking Load	--	$270	$59	$119
Cycling Load	--	$154	$51	$88
Flat Load	--	$180	$52	$98

12 CONCLUSIONS

The primary objective of the demonstration at Hammond Unit 4 was to determine the long-term effects of commercially available wall-fired low NOx combustion technologies on NOx emissions and boiler performance. Short-term tests of each technology were also performed to provide engineering information about emissions and performance trends. A target of achieving fifty percent NOx reduction using combustion modifications was established for the project.

Specifically, the original objectives of the project were:

- Demonstrate in a logical stepwise fashion the short-term NOx reduction capabilities of the following advanced low NOx combustion technologies:

    FWEC's Advanced Overfire Air (AOFA)

    FWEC's Controlled Flow / Split Flame Low NOx burners (LNB)

    LNB with AOFA

- Determine the dynamic, long-term emissions characteristics of each of these combustion NOx reduction methods using statistical techniques.
- Evaluate the progressive cost effectiveness (i.e., dollars per ton NOx removed) of the low NOx combustion techniques tested.
- Determine the effects on other combustion parameters (e.g., CO production, carbon carryover, particulate characteristics) of applying the NOx reduction methods listed above.

12.1 Baseline Performance

To assess the impact of the low NOx technologies on NOx emissions and unit performance, the unit was tested before the retrofit (baseline testing). The baseline testing reflected normal operating conditions; no additional tuning of the burners was performed. The main results of the baseline tests are:

- Long-term NOx emissions at full load of 1.24 lb/MBtu with an excess oxygen of 2.6 percent.
- NOx emissions decreased slightly with decreasing load.
- Short-term NOx emissions at full load of 1.44 lb/MBtu, which is 14 percent higher than the long-term NOx emissions. The main difference between long- and short-term results were that the latter had higher excess oxygen levels. During the short-term tests, the LOI was approximately 5 percent.
- Moderate to high furnace slagging occurred.
- Significant air and coal flow imbalance was measured.

12.2 NOx Emissions and Unit Performance with the Low NOx Technologies

The project demonstrated that 50-70 percent NOx reduction can be achieved with LNB and LNB+AOFA. However, this NOx reduction is accompanied by adverse impacts such as:

- Increase in excess oxygen.
- Higher unburned carbon loss (LOI).
- The dust loading and volumetric gas flow rate entering the ESP increased for both LNB and LNB+AOFA adversely impacting precipitator performance.

A positive impact of the LNB and LNB+AOFA, in addition to the NOx emission reduction, was the reduction in furnace slagging.

12.2.1 NOx Emission Reduction

The three low NOx technologies tested at Hammond -- AOFA, LNB (CF/SF burners), and LNB+AOFA, achieved 24, 48-59, and 68 percent average long-term NOx emission reduction at full load, respectively (Table 12-1). NOx emissions at low loads did not vary significantly. Long-term NOx emissions for all the low NOx technologies tested declined slightly within the control range (300-500 MW) and increased below 300 MW, especially with the LNB and LNB+AOFA systems.

NOx emissions reduction up to 40 percent was achieved with the AOFA under controlled (short-term) conditions. This difference between short- and long-term NOx reduction is attributable mainly to the difference in excess oxygen levels in the two test components.

Table 12-1 Full-Load NOx Emissions (Long-Term)

	Baseline	AOFA	LNB	LNB+AOFA
Load (MW)	490	480	483	495
Average Long-term NOx (lb/MBtu)	1.24	0.94	051-0.65	0.40
% NOx Reduction	Base	24	48-59	68

12.2.2 Performance and Operational Impacts

Both adverse and beneficial impacts on the unit operation were experienced after the low NOx retrofits. The adverse impacts were: (1) higher excess oxygen, (2) higher LOI, and (3) increased dust loading and gas flow rate into the marginally sized ESP, which resulted in temporary unit derating. The main beneficial impact, in addition to NOx emission reduction, was the significant reduction in waterwall slagging with the utilization of the LNB and LNB+AOFA systems. Table 12-2 summarizes the performance impacts resulting from the low NOx technologies.

Table 12-2 Full-Load Performance Impacts

	Baseline	AOFA	LNB	LNB+AOFA
Average Excess oxygen (%)	2.6	2.6	4.1	3.8
LOI (%)	5	10	8	8
Slagging	Moderate to high	Slightly reduced	Substantially reduced	Substantially reduced
Steam Temperatures	Base	Superheat improved Reheat improved at upper loads	Superheat improved Reheat improved at upper loads	Superheat improved Reheat improved at upper loads
ESP Performance	Marginal	Marginal	Derating to 300 MWs due to increased dust loading; load re-established w/ammonia injection	Derating to 450 MW even with use of ammonia injection system

Required Excess Oxygen

The excess oxygen increased by an average of 1.5 percent for the LNB and 1.2 percent for the LNB+AOFA systems. This oxygen increase was needed for good flame stability and maintaining CO emissions below 100 ppm. In particular, for the LNB+AOFA, a minimum oxygen level of 3.8 percent was recommended by FWEC. The increased oxygen reduces the boiler efficiency and increases the unit net heat rate. Another adverse impact of increased excess oxygen is the reduction in the operating excess oxygen range, which reduces the operating flexibility of the unit. The lower limit of the excess oxygen was increased to maintain low CO emissions, while the upper limit was reduced owing to increased dust loading and resulting ESP limitations. As a result, the excess oxygen operating range changed from 2.0 - 5.0 percent for the baseline system, to:

- 3.0 - 4.5 percent for the LNB; and
- 3.8 - 4.5 percent for the LNB+AOFA.

During the AOFA testing, the excess oxygen is estimated to be similar to baseline.

Impact on LOI

The LOI increased from the baseline 5 percent level to 10 percent for the AOFA, and 8 percent for the LNB and LNB+AOFA systems. Short-term testing showed that reduction of LOI to pre-retrofit levels is possible, but at the expense of NOx emission reduction. For example, testing at 450 MW with the LNB system indicated that LOI could be reduced from 8 percent to 5 percent, but NOx will increase by approximately 5 percent. A similar trade-off is expected for the AOFA and LNB+AOFA systems. Such NOx - LOI trade-off is possible through adjustments in excess oxygen, mill biasing, and burner tip position. It should be noted that the LOI deterioration occurred despite significant improvements in coal fineness.

Steam Outlet Temperatures and Furnace Slagging

The furnace slagging (medium-high during baseline) was reduced significantly with the LNB and the LNB+AOFA systems. This improvement reduced the operating frequency of the furnace wall blowers from once per shift to once per day. However, the backpass fouling increased and required more frequent sootblowing and occasional unit outage to clean the air heater. Although the benefits from reduced furnace cleaning were counter-balanced by the increased sootblowing of the backpass, the slagging reduction was perceived by the plant operators as an overall improvement because it is more difficult to clean the furnace than the backpass. In addition, slagging reduction may reduce the long-term boiler tube failures and unit forced outage rate.

Overall, superheat temperatures appeared to improve with the installation of the AOFA and LNBs, particularly at low loads. Reheat temperatures showed improvement at upper loads but degraded a lower loads.

Air Heater and Furnace Exit Gas Temperatures

In general, it appears that that the air heater air outlet temperatures increased with the installation of the low NOx combustion technologies. Performance tests indicated an increase of 30°F between the baseline and LNB+AOFA test phase. During the long-term test periods, the increase was evident only in the LNB+AOFA configuration. The LNB and LNB+AOFA economizer air outlet temperatures were also substantially higher than the baseline and AOFA test phases.

Impacts on ESP Performance

The higher oxygen and reduced furnace slagging with the LNB and LNB+AOFA systems increased the dust loading and gas flow rate to the ESP. These factors adversely impact the unit's ability to meet the stack particulate limits. ESP performance modeling was performed on the assumption that the only differences between the test phases were the increased gas volume and the mass loading at the ESP inlet. These modeling studies showed increased emissions and opacity for each of the low NOx technologies. The amount of degradation was small but could push a small, marginal ESP into an unacceptable performance range as it did at Hammond. For larger ESPs, the small increase could easily be unnoticeable.

Impacts on Unit Operation

Unit operation with the LNB system was similar to baseline. However, the addition of the AOFA system, which was operated manually, required greater attention and created an additional task for the plant operators; a task that was compromised by other priorities. As a result, the AOFA dampers could not be adjusted as frequently as they should have been resulting in sub-optimum AOFA flow rate during load transitions. Also, the operating flexibility of the unit was reduced with the LNB and LNB+AOFA because of the constriction of the oxygen operating range. This limited the operators' flexibility to increase the oxygen temporarily during load transients to avoid CO and NOx emission spikes.

Impacts on Unit Reliability

Since the low NOx burner installation, several burners have been damaged from overheating. In most cases, the damage included only the outer barrel/tip assembly; however, in at least one instance, the damage was much more extensive and included the inner and outer barrels, burner register assembly, two adjacent burner registers, and the windbox. It appears that the current burners are more sensitive to coal layout, coking, and subsequent overheating than the Intervane burners that they replaced.

Also, numerous cast burner tips have developed cracks some several inches long. According to FWEC, these cracks do not affect burner performance and FWEC has recommended that no corrective action is needed.

Impacts on Boiler Performance and Unit Heat Rate

The effects of the above unit performance impacts on boiler efficiency, turbine heat rate, and unit net heat rate are summarized in Table 12-3.

Table 12-3 Full-Load Heat Rate Impacts

Full-Load Long-Term	Baseline	AOFA	LNB	LNB+AOFA
Boiler Efficiency	90.0%	89.2%	89.3%	88.7%
Turbine Cycle Heat Rate	9000	8999	8975	8960
Unit Heat Rate	10000	10089	10050	10101
Net Heat Rate Change	--	0.9%	0.5%	1.0%

12.3 Economics

The economic impact of the low NOx technologies includes the capital cost of the technologies plus the change in O&M costs resulting from the technologies. Using the baseline load profile as a reference, the annual reduction in NOx emissions would be 4610 tons for the AOFA configuration, 10390 tons for LNB configuration, and 14312 tons for LNB+AOFA configuration (Table 12-4).

The total cost in terms of dollars per ton NOx removed was calculated by dividing the total levelized cost by the total tons NOx removed per year. For a 500 MW wall-fired commercial installation, with a scope of supply similar to the Hammond retrofit, it is estimated that the capital costs would be approximately:

AOFA	$4.4 million or 8.8 $/kW
LNB	$5.0 million or 10.0 $/kW
LNB+AOFA	$9.4 million or 18.8 $/kW

These estimates are based upon the actual Hammond Unit 4 costs and other available cost data from EPRI and additional sources. Using the estimated capital costs and O&M costs and performance as observed at Hammond, the cost effectiveness of the tested technologies was $134, $54, and $79 for AOFA, LNB, and LNB+AOFA configurations, respectively, for the load profile exhibited during the baseline test phase. The cost effectiveness is dependent not only on the performance of the technology but also on the load profile during the evaluation period.

Table 12-4 Cost Effectiveness

Full-Load Long-Term	Tons NOx Removed	Cost Effectiveness ($/ton removed)
AOFA	4610	$134
LNB	10390	$54
LNB+AOFA	14312	$79

12.4 Lessons Learned

The lessons learned from this demonstration are summarized below:

- AOFA provided a full-load NOx reduction of approximately 20 percent when added to the baseline configuration or LNB configuration.
- The AOFA system is less effective (in terms of percent NOx reduction from baseline) at reduced loads than at full-load.
- The LNB burners provided approximately 50 percent NOx reduction over the load range.
- Performance degradation should be expected when installing the low NOx technologies. At Hammond, performance degradations included increased fly ash LOI, increased combustion air requirements, and higher furnace exit gas temperatures. These adverse impacts were somewhat mitigated by improvement in steam temperatures.
- The low NOx burners appear to be less forgiving to operating conditions than the turbulent burners they replaced.
- Optimization of the low NOx combustion systems is more time consuming and complicated than originally anticipated. Plans should be made for optimization times of several weeks.
- Serious consideration must be given to the potential impacts of the low NOx technologies on plant systems other than the boiler, such as the ESP.
- On-line continuous optimization methodologies have the potential to improve the low NOx technologies performance and mitigate their adverse impacts.

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APPENDIX A
BASELINE TEST DATA

Table A-1 Baseline / Diagnostic Test Summary

Test	Date	Test Conditions	Load MW	MOOS Pattern	Excess O_2 %	NOx lb/MBtu
1-1	11/2/89	OPERATIONAL RANGE	480	NONE	HIGH	na
1-2	11/2/89	OPERATIONAL RANGE	480	NONE	LOW	na
1-3	11/2/89	HI LOAD O2 VARIATION	480	NONE	3.1	1.36
2-1	11/3/89	HI LOAD O2 VARIATION	480	NONE	2.5	1.27
2-2	11/3/89	HI LOAD MILL BIAS	480	NONE	2.7	1.36
2-3	11/3/89	MID LOAD O2 VARIATION	400	E	3.3	1.35
3-1	11/4/89	LOW LOAD O2 VARIATION	185	B&E	7.2	1.19
3-2	11/4/89	"	185	B&E	6.2	1.07
4-1	11/5/89	HI LOAD O2 VARIATION	480	NONE	2.5	1.25
4-2	11/5/89	"	480	NONE	2.2	1.19
5-1	11/6/89	HI LOAD MILL BIAS	480	NONE	2.4	1.17
5-2	11/6/89	MID LOAD O2 VARIATION	400	E	2.4	1.09
6-1	11/7/89	MID LOAD O2 VARIATION	300	E	3.8	0.95
6-2	11/7/89	"	300	E	5.2	1.06
6-3	11/7/89	MID LOAD MILL VARIATION	400	NONE	3.5	1.04
7-1	11/8/89	MID LOAD O2 VARIATION	300	E	4.3	1.09
7-2	11/8/89	MID LOAD MILL VARIATION	300	B	4.2	1.02
7-3	11/8/89	MID LOAD O2 VARIATION	400	E	4.3	1.16
7-4	11/8/89	"	400	B	3.2	1.10
7-5	11/8/89	HI LOAD O2 VARIATION	480	NONE	2.9	1.21
8-1	11/9/89	MID LOAD MILL VARIATION	300	B&E	4.0	0.97
8-2	11/9/89	MID LOAD O2 VARIATION	479	NONE	3.0	1.32
8-3	11/9/89	"	478	NONE	2.7	1.33
8-4	11/9/89	HI LOAD O2 VARIATION	478	NONE	2.2	1.30
9-1	11/10/89	MID LOAD O2 VARIATION	400	B	2.3	1.15
9-2	11/10/89	"	400	B	3.5	1.30
9-3	11/10/89	"	400	B	5.1	1.42
9-4	11/10/89	HIGH LOAD O2 VARIATION	480	NONE	3.3	1.46
9-5	11/10/89	"	480	NONE	2.9	1.42
10-1	11/11/89	MID LOAD O2 VARIATION	405	E	2.0	0.96
10-2	11/11/89	"	403	E	3.1	1.10
10-3	11/11/89	"	400	E	4.5	1.21
10-4	11/11/89	"	305	E	2.8	0.97
10-5	11/11/89	"	315	E	4.8	1.14
11-1	11/13/89	HIGH LOAD O2 VARIATION	478	NONE	2.9	1.30
11-2	11/13/89	"	480	NONE	2.9	1.32

Notes: 1. Dry excess O_2 at economizer outlet.

Table A-2 Baseline / Diagnostic Tests / Operating Summary

Test No.	Date	Load MW	East Econ Out* O2 %	West Econ Out* O2 %	Avg. Econ Out O2 %	CEM NOx Avg*** PPM	Opacity %	Mill A klb/hr	Mill B klb/hr	Mill C klb/hr	Mill D klb/hr	Mill E klb/hr	Mill F klb/hr
1-1	11/02/89	480	2.2	2.3	RANGE	-	11.7	58	66	53	62	63	53
1-2	11/02/89	480	1.8	1.9	RANGE	-	11.8	56	64	51	60	62	52
1-3	11/02/89	480	2.7	2.5	3.1	999	15.8	56	64	52	60	62	52
2-1	11/03/89	480	2.4	2.0	2.5	933	9.4	57	65	52	61	63	53
2-2	11/03/89	480	2.4	2.4	2.7	1000	-	58	58	58	58	58	58
2-3	11/03/89	400	3.5	2.2	3.3	992	-	55	64	55	60	0	53
3-1	11/04/89	185	6.2	6.7	7.2	872	3.8	37	0	37	43	0	37
3-2	11/04/89	185	5.6	6.1	6.2	786	2.6	39	0	40	46	0	39
4-1	11/05/89	480	2.3	2.5	2.5	917	29.7	57	63	60	58	62	60
4-2	11/05/89	480	2.0	2.2	2.2	876	26.2	57	64	60	58	62	61
5-1	11/06/89	480	2.2	2.4	2.4	858	23.0	60	66	54	60	65	55
5-2	11/06/89	400	2.3	2.4	2.4	803	12.1	56	64	56	62	0	56
6-1	11/07/89	300	3.7	4.1	3.8	694	8.6	45	51	43	50	0	50
6-2	11/07/89	300	4.5	5.5	5.2	780	16.6	47	53	44	51	0	50
6-3	11/07/89	400	3.0	3.1	3.5	764	11.6	54	50	45	51	50	47
7-1	11/08/89	300	3.7	4.7	4.3	799	9.4	43	45	48	48	0	48
7-2	11/08/89	300	3.7	4.0	4.2	752	7.3	44	0	49	48	45	48
7-3	11/08/89	400	3.8	4.0	4.3	853	19.0	57	63	57	59	0	58
7-4	11/08/89	400	3.1	2.8	3.2	808	9.4	57	0	58	60	58	58
7-5	11/08/89	480	2.7	2.6	2.9	885	10.2	57	64	57	59	60	58
8-1	11/09/89	300	3.6	4.3	4.0	713	5.1	58	0	55	57	0	55
8-2	11/09/89	479	2.6	2.8	3.0	970	25.8	62	62	58	63	63	62
8-3	11/09/89	478	2.3	2.5	2.7	974	21.6	62	61	47	62	62	61
8-4	11/09/89	478	1.7	2.0	2.2	957	22.6	60	60	46	62	61	60
9-1	11/10/89	400	2.2	2.2	2.3	842	7.5	62	0	56	63	61	61
9-2	11/10/89	400	3.5	3.0	3.5	954	14.2	63	0	58	64	63	62
9-3	11/10/89	400	4.8	4.7	5.1	1041	18.1	64	0	59	65	64	63
9-4	11/10/89	480	3.0	2.6	3.3	1072	31.8	62	61	57	62	62	61
9-5	11/10/89	480	2.7	2.2	2.9	1042	29.2	61	63	70	71	66	78
10-1	11/11/89	405	2.1	2.2	2.0	701	6.4	60	62	58	61	0	57
10-2	11/11/89	403	2.8	3.3	3.1	805	9.0	60	61	58	61	0	58
10-3	11/11/89	400	4.1	4.3	4.5	888	13.9	59	62	58	60	0	57
10-4	11/11/89	305	3.1	2.7	2.8	714	4.1	44	48	45	58	0	43
10-5	11/11/89	315	4.3	4.6	4.8	838	10.0	44	48	45	52	0	45
11-1	11/13/89	478	2.7	2.3	2.9	953	17.9	55	61	57	59	62	58
11-2	11/13/89	480	2.9	2.7	2.9	970	22.6	55	60	57	59	63	58

Table A-2 Baseline / Diagnostic Tests / Operating Summary (cont)

Test No.	Date	Load MW	Sec APH Temp A Gas Outlet Deg F	Sec APH Temp B Gas Outlet Deg F	Steam Flow MLB/HR	SH Temp DegF	SH Spray Flow Lower klb/hr	SH Spray Flow Upper klb/hr	RH Temp DegF
1-1	11/02/89	480	-	-	3.2	1002	7.9	8.6	1002
1-2	11/02/89	480	-	-	3.2	993	7.8	11.3	982
1-3	11/02/89	480	-	-	3.2	997	9.5	11.5	993
2-1	11/03/89	480	274	189	-	1010	7.5	16.0	980
2-2	11/03/89	480	-	-	3.2	1011	8.9	13.0	990
2-3	11/03/89	400	-	-	2.7	1011	9.5	13.4	989
3-1	11/04/89	185	241	574	1.2	1006	6.5	7.0	970
3-2	11/04/89	185	250	305	1.3	1000	6.5	8.0	970
4-1	11/05/89	480	220	300	3.2	1000	12.2	13.5	988
4-2	11/05/89	480	290	370	3.2	1006	12.0	11.7	989
5-1	11/06/89	480	310	325	3.2	1003	12.5	13.8	987
5-2	11/06/89	400	303	310	2.6	1003	11.6	15.8	980
6-1	11/07/89	300	280	300	2.0	1001	5.2	12.0	925
6-2	11/07/89	300	280	290	2.0	1000	7.3	12.3	960
6-3	11/07/89	400	310	293	2.5	996	8.0	9.2	965
7-1	11/08/89	300	267	310	1.9	994	6.7	10.7	940
7-2	11/08/89	300	270	320	1.9	1001	6.6	10.9	945
7-3	11/08/89	400	275	310	2.5	1004	9.8	12.5	978
7-4	11/08/89	400	280	310	2.5	1005	9.2	11.3	980
7-5	11/08/89	480	290	340	3.2	994	9.8	10.5	985
8-1	11/09/89	300	250	323	1.9	1009	7.7	12.2	953
8-2	11/09/89	479	270	350	3.2	979	11.3	13.0	976
8-3	11/09/89	478	280	345	3.2	973	12.2	12.0	962
8-4	11/09/89	478	290	340	3.2	985	11.8	8.8	970
9-1	11/10/89	400	280	315	2.6	1006	9.9	3.0	974
9-2	11/10/89	400	270	317	2.6	994	11.5	14.4	991
9-3	11/10/89	400	277	315	2.6	995	13.7	13.5	1004
9-4	11/10/89	480	295	350	3.2	990	13.7	9.3	1000
9-5	11/10/89	480	295	377	3.2	986	13.4	10.0	997
10-1	11/11/89	405	278	310	2.7	994	6.8	9.8	935
10-2	11/11/89	403	260	342	2.6	995	7.9	8.9	963
10-3	11/11/89	400	260	350	2.6	998	9.9	10.3	985
10-4	11/11/89	305	270	345	2.0	985	6.4	8.5	911
10-5	11/11/89	315	250	357	2.0	982	8.3	10.6	960
11-1	11/13/89	478	288	330	3.2	990	11.6	12.0	987
11-2	11/13/89	480	295	345	3.2	982	12.8	12.0	992

Table A-3 Baseline / Performance Tests Summary

Test	Date	Conditions	Load MW	MOOS Pattern	Excess O_2 Dry	NOx 3% O_2 ppm	NOx lb/MBtu	CO ppm	LOI %	Carbon %
12	11/29/89	High Load Med O2	477	NONE	3.0	973	1.33	18	5.4	4.9
13	11/30/89	High Load High O2	476	NONE	3.3	1117	1.53	11	NA	NA
14	12/01/89	Med Load	298	E	4.7	839	1.14	9	2.3	2.3
15	12/02/89	Med Load	301	E	4.5	801	1.09	9	NA	NA
16	12/03/89	Med Load	389	E	3.7	949	1.29	12	4.7	4.1
17	12/04/89	High Load Low O2	469	NONE	2.5	1070	1.46	14	4.9	4.5
18	12/05/89	Med Load	390	E	3.3	1049	1.43	12	NA	NA

Notes: 1. Dry excess O_2 at economizer outlet.

Table A-4 Baseline / Performance Tests / Operating Summary

Test No.	Date	Load MW	East Econ Out* O2 %	West Econ Out* O2 %	East Econ Out** O2 %	West Econ Out** O2 %	Avg. Econ Out O2 %	CEM NOx Avg*** PPM	Opacity %	Mill A klb/hr	Mill B klb/hr	Mill C klb/hr	Mill D klb/hr	Mill E klb/hr	Mill F klb/hr
12-1	11/29/89	470	2.2	2.6	3.4	2.8	3.1	973	14	61.3	60.5	51.7	61.1	62.8	59.2
12-2		482	1.8	2.1	3.1	2.5	2.8		13	61.4	60.6	51.3	61.3	62.3	59.4
13-1	11/30/89	474	2.3	2.8	3.8	3.1	3.5	1117	15	57.7	55.6	57.8	56.8	58.0	59.0
13-2		477	2.2	2.6	3.4	2.8	3.1		15	58.0	56.8	57.9	57.2	57.9	59.4
14-1	12/01/89	295	3.9	4.4	5.3	4.8	5.1	839	4	44.7	44.8	43.6	44.6	0	45.5
14-2		300	3.5	4.1	4.9	4.4	4.7		4	44.8	45.0	43.6	44.6	0	45.5
15-1	12/02/89	300	3.7	4.1	4.9	4.4	4.7	801	4	44.5	43.3	43.1	42.4	0	44.2
15-2		303	3.4	3.7	4.5	4.0	4.3		4	44.6	43.6	43.1	42.4	0	44.5
16-1	12/03/89	389	3.2	3.4	4.0	3.3	3.7	949	12	57.1	55.6	57.6	56.0	0	56.8
16-2		388	3.0	3.4	3.8	3.3	3.6		9	57.1	55.6	56.9	56.1	0	56.9
17-1	12/04/89	470	2.2	2.6	2.5	2.4	2.5	1070	23	59.5	57.8	52.6	58.6	60.0	60.0
17-2		468	2.1	2.3	2.3	2.4	2.4		24	59.6	57.9	52.7	58.7	59.9	60.5
18-1	12/05/89	388	2.5	3.1	3.6	3.0	3.3	1049	-	57.7	55.9	56.7	56.3	0	58.3
18-2		391	2.5	3.1	3.5	3.1	3.3		13	57.8	56.1	56.6	56.6	0	58.6
18-3		390	2.7	3.2	3.7	3.1	3.4		15	58.0	56.1	56.7	56.5	0	58.7

* Plant O2, wet
** ECEM O2, dry
*** DRY,3% O2

Table A-4 Baseline / Performance Tests / Operating Summary (cont)

Test No.	Date	Load MW	Sec APH Temp A Gas Outlet Deg F	Sec APH Temp B Gas Outlet Deg F	Steam Flow MLB/HR	SH Temp DegF	SH Spray Flow Lower klb/hr	SH Spray Flow Upper klb/hr	RH Temp DegF
12-1	11/29/89	470	279	304	3342	988	161	146	989
12-2		482	283	311	3453	977	157	150	982
13-1	11/30/89	474	293	305	3262	932	143	150	922
13-2		477	295	307	3393	989	174	174	986
14-1	12/01/89	295	270	286	2041	998	92	138	975
14-2		300	278	293	2065	994	102	139	975
15-1	12/02/89	300	265	306	2076	998	107	151	979
15-2		303	272	313	2098	988	110	153	980
16-1	12/03/89	389	247	304	2683	993	147	201	1000
16-2		388	252	310	2661	994	156	198	N/A
17-1	12/04/89	470	264	323	3336	986	169	159	988
17-2		468	273	331	3328	987	177	142	988
18-1	12/05/89	388	260	328	2664	999	167	200	988
18-2		391	266	335	2686	998	175	208	991
18-3		390	262	334	2679	995	183	207	994

Table A-5 Baseline / Performance Tests / Summary of Mill Performance

Test No.	Load MW	Parameter	Mill A	Mill B	Mill C	Mill D	Mill E	Mill F	Test Average
12-1	480	Measured Coal Flow, Klb/hr	63.3	57.1	57.8	63.8	60.2	48.2	58.4
		Measured PA Flow, Klb/hr	162.9	152.0	147.8	150.2	145.6	144.1	150.4
		A/F Ratio	2.6	2.9	2.7	2.5	2.6	3.0	2.72
		Control Room Fuel Flow, Klb/hr	62.0	63.0	54.0	63.0	62.0	59.5	60.6
		Avg. Burner Pipe Velocity, FPM	8241	8527	8513	8232	8206	7470	8198
		High Pipe Coal Flow, Klb/hr	22.8	16.7	12.3	19.0	17.5	15.3	17.3
		Low Pipe Coal Flow, Klb/hr	12.8	13.0	9.7	13.2	13.9	8.7	11.9
		Avg. Passing 200 Mesh, PCT	56.2	57.6	63.7	60.4	67.0	68.3	62.2
		Avg. Remaining 50 Mesh, PCT	4.58	3.52	2.54	3.45	2.6	2.13	3.14
13-1	475	Measured Coal Flow, Klb/hr	59.0	63.8	53.3	61.8	56.6	66.6	60.2
		Measured PA Flow, Klb/hr	153.9	149.3	146.5	148.8	159.9	141.9	150.1
		A/F Ratio	2.7	2.4	2.7	2.4	2.7	2.1	2.50
		Control Room Fuel Flow, Klb/hr	59.0	58.8	59.0	58.3	58.8	58.5	58.7
		Avg. Burner Pipe Velocity, FPM	8309	7928	7488	7482	7766	7244	7703
		High Pipe Coal Flow, Klb/hr	22.8	16.7	12.4	19.0	17.5	15.3	17.3
		Low Pipe Coal Flow, Klb/hr	12.8	13.0	9.7	13.2	13.9	8.7	11.9
		Avg. Passing 200 mesh, PCT	61.7	58.7	66.9	63.0	67.8	65.9	64
		Avg. Remaining 50 Mesh, PCT	3.08	2.76	2.39	2.95	1.48	1.5	2.36
14-1	300	Measured Coal Flow, Klb/hr	43.2	48.4	38.6	45.3		41.6	43.4
		Measure PA Flow, Klb/hr	148.7	139.8	146.2	142.4		139.9	143.4
		A/F Ratio	3.64	2.95	3.77	3.16		3.50	3.40
		Control Room Fuel Flow, Klb/hr	44.8	46.5	45.0	47.0		45.5	45.8
		Avg. Burner Pipe Velocity, FPM	8030	7290	7339	7298		7188	7429
		High Pipe Coal Flow, Klh/hr	14.2	14.8	10.8	13.4		14.6	13.6
		Low Pipe Coal Flow, Klb/hr	8.02	10.9	8.6	8.8		7.9	8.8
		Avg. Passing 200 Mesh, PCT	66.8	62.7	69.41	65.8		72.8	67.5
		Avg. Remaining 50 Mesh, PCT	2.00	1.53	2.16	2.18		0.94	1.76
15-1	306	Measured Coal Flow, Klb/hr	43.9	41.5	37.7	45.8		37.9	41.4
		Measure PA Flow, Klb/hr	156.1	136.7	146.5	145.5		141.0	145.2
		A/F Ratio	3.5	3.4	3.6	3.0		3.6	3.42
		Control Room Fuel Flow, Klb/hr	44.5	45.0	44.5	45.0		44.0	44.6
		Avg. Burner Pipe Velocity, FPM	7837	7132	6956	7101		6892	7184
		High Pipe Coal Flow, Klh/hr	14.0	11.3	11.5	13.3		10.8	12.2
		Low Pipe Coal Flow, Klb/hr	9.7	8.4	8.4	9.2		8.4	8.8
		Avg. Passing 200 Mesh, PCT	68.4	67.8	72.7	68.9		74.9	70.5
		Avg. Remaining 50 Mesh, PCT	1.73	0.82	1.34	1.18		0.72	1.16
16-1	400	Measured Coal Flow, Klb/hr	MNT	MNT	53.7	60.5		MNT	
		Measured PA Flow, Klb/hr	153.4	136.6	156.8	148.7		138.1	146.7
		A/F Ratio			2.7	2.4			
		Control Room Fuel Flow, Klb/hr	58.0	58.0	58.0	58.0		58.0	58.0
		Avg. Burner Pipe Velocity, Klb/hr			7454	7519			
		High Pipe Coal Flow, Klb/hr			14.4	20.0			
		Low Pipe Coal Flow, Klb/hr			11.9	12.3			
		Avg. Passing 200 Mesh, PCT							
		Avg. Remaining 50 Mesh, PCT							
17-1	480	Control Room Fuel Flow, Klb/hr	60.5	60.5	54.5	60.5	60.5	60.5	59.5
		Measured PA Flow, Klb/hr	165.6	152.1	156.9	160.8	161.2	145.0	156.9

MNT - Mill not tested
MOOS - Mill Out of Service

Table A-6 Baseline / Performance Tests / Combustion Air Flow Distribution

Test	Load	Total Combustion Air lb/hr	Total Secondary Air lb/hr	Secondary Air to Burners %	Primary Air to Burners lb/hr	Primary Air to Burners %
12	477	na	na	na	902,790	na
13	480	3,888,690	2,988,424	77%	900,266	23%
14	300	2,538,957	1,822,025	72%	716,932	28%
15	300	2,253,325	1,528,560	68%	724,765	32%
16	400	3,118,711	2,385,146	76%	733,565	24%
17	480	3,605,196	2,661,583	74%	943,613	26%
18	400	2,975,622	2,218,796	75%	756,826	25%

Table A-7 Baseline / Performance Tests / Coal Analysis

Date	H2O %	C %	H %	N %	Cl %	S %	Ash %	O %	TOTAL %	HHV BTU/lb	VM %	FC %
11/29/89	3.70	71.0	4.63	1.53	0.030	1.82	10.8	6.53	100.03	12693	34.2	51.3
11/29/89	3.48	72.4	4.68	1.56	0.020	1.77	9.9	6.19	100.00	12930	34.3	52.3
11/29/89	4.18	72.2	4.77	1.49	0.031	1.78	9.9	5.67	100.02	12847	34.0	54.1
11/29/89	4.49	71.4	4.57	1.50	0.031	1.75	10.0	6.34	100.02	12827	34.1	51.5
11/30/89	5.42	71.2	4.72	1.47	0.027	1.79	9.9	5.50	100.03	12706	33.6	54.0
11/30/89	4.55	72.1	4.61	1.44	0.031	1.69	10.1	5.57	100.02	12933	33.9	51.5
11/30/89	3.95	72.9	4.73	1.29	0.032	1.58	10.4	5.11	100.03	12963	33.1	52.5
12/01/89	3.22	73.2	4.70	1.39	0.037	1.70	10.1	5.68	100.03	13137	33.4	53.3
12/01/89	3.12	74.2	4.76	1.52	0.030	1.65	10.2	4.58	100.03	13210	33.6	53.1
12/01/89	3.77	73.3	4.75	1.40	0.031	1.66	9.9	5.21	100.02	13043	34.1	52.2
12/01/89	3.98	72.9	4.80	1.38	0.033	2.01	9.7	5.26	100.03	12986	33.8	52.6
12/01/89	3.96	72.2	4.64	1.45	0.020	1.96	10.0	5.79	100.00	12988	33.6	52.5
12/02/89	4.37	71.9	4.71	1.44	0.035	1.66	9.8	6.15	100.03	12865	33.9	52.0
12/02/89	3.89	72.5	4.82	1.40	0.033	1.73	9.9	5.77	100.03	12934	33.7	52.5
12/02/89	4.18	72.7	4.66	1.38	0.031	1.72	9.7	5.72	100.03	12942	32.6	55.9
12/03/89	4.83	71.4	4.54	1.38	0.033	1.77	10.0	6.02	100.03	12793	32.7	52.4
12/03/89	5.58	72.0	4.63	1.29	0.030	1.51	9.1	5.91	100.03	12793	32.7	52.6
12/03/89	4.94	72.8	4.66	1.43	0.030	1.62	9.4	5.21	100.04	12975	33.2	52.5
12/04/89	5.03	72.9	4.74	1.42	0.031	1.61	9.6	4.73	100.02	12925	33.1	52.3
12/04/89	5.07	72.6	4.77	1.42	0.031	1.76	9.0	5.41	100.02	12946	33.8	52.2
12/05/89	4.62	71.6	4.68	1.48	0.030	1.83	9.9	5.93	100.02	12810	32.8	52.7
12/05/89	4.14	72.7	4.77	1.47	0.034	1.64	9.4	5.89	100.03	12978	33.9	52.6
12/05/89	4.23	72.3	4.60	1.48	0.030	1.60	9.5	6.23	100.00	12989	33.0	53.3
12/05/89	4.04	72.7	4.68	1.39	0.031	1.76	10.1	5.30	100.03	12900	33.1	52.7
Average	4.28	72.4	4.69	1.43	0.031	1.72	9.8	5.65	100.02	12921	33.5	52.7
Std. Dev.	0.63	0.7	0.07	0.07	0.004	0.11	0.4	0.48	0.01	117	0.5	0.9
Var.	0.39	0.5	0.01	0.00	0.000	0.01	0.1	0.23	0.00	13708	0.3	0.9

Table A-8 Baseline / Performance Tests / Boiler Emissions Summary

	MASS LOADING		GAS VOLUME FLOW		GAS TEMP., °F	WATER VAPOR, %	ISOKINETIC AGREEMENT, %
	gr/acf	gr/scf	acfm	dscfm			
480 MW, 11/29/89, TEST 12							
RUN 1	1.66	2.63	1974000	1243000	287	6.6	97.5
RUN 2	1.70	2.73	1967000	1223000	290	6.9	97.4
RUN 3	1.57	2.54	1971000	1223000	293	6.8	97.5
AVERAGE	1.64	2.63	1970667	1229667	290	6.8	97.5
±1s	0.05	0.08	2867	9428	2	0.1	0.0
COV	0.03	0.03	0.0	0.01	0.01	0.02	0.00
480 MW, 12/04/89, TEST 17							
RUN 1	1.51	2.38	2029000	1286000	284	5.8	98.5
RUN 2	1.45	2.38	1992000	1238000	290	6.9	103.6
RUN 3	1.56	2.51	1991000	1232000	296	6.6	101.9
AVERAGE	1.51	2.42	2004000	1252000	290	6.4	101.3
±1s	0.04	0.06	17682	24166	5	0.5	2.1
COV	0.03	0.03	0.01	0.02	0.02	0.07	0.02
400 MW, 12/03/89, Test 16							
Run 1	1.58	2.33	1728000	1137000	262	---[a]	100.6
Run 2	1.40	2.17	1697000	1096000	274	6.6	101.6
Run 3	1.43	2.20	1703000	1105000	273	6.2	101.3
AVERAGE	1.47	2.23	1709333	1112667	270	6.4	101.2
±1s	0.08	0.07	13425	17594	5	0.2	0.4
COV	0.05	0.03	0.01	0.02	0.02	0.03	0.00
300 MW, 12/01/89, TEST 14							
RUN 1	1.75	2.63	1394000	926000	263	6.1	99.3
RUN 2	1.68	2.57	1383000	903000	270	6.9	99.2
RUN 3	1.70	2.61	1402000	911000	275	6.7	100.8
AVERAGE	1.71	2.60	1393000	913333	269	6.6	99.8
±1s	0.03	0.02	7789	9534	5	0.3	0.7
COV	0.02	0.01	0.01	0.01	0.02	0.05	0.01

[a]Value discarded due to water freezing in sample lines resulting in incomplete recovery. 3.2% actual measured value.

Table A-9 Baseline / Performance Tests / Fly Ash Chemical Composition

Oxide	480 MW, 11/29/89 Test 12		480 MW, 12/04/89 Test 17		400 MW, 12/03/89 Test 16		300 MW, 12/01/89 Test 14	
	East	West	East	West	East	West	East	West
Li_2O	0.05	0.05	0.06	0.06	0.04	0.04	0.05	0.05
Na_2O	0.49	0.47	0.56	0.52	0.42	0.42	0.44	0.44
K_2O	2.8	2.8	3.0	3.1	3.1	3.3	2.9	2.9
MgO	1.2	1.1	1.4	1.3	1.2	1.2	1.1	1.1
CaO	2.4	1.8	3.7	2.9	1.2	1.0	2.0	1.7
Fe_2O_3	17.1	17.1	16.1	16.1	15.0	15.0	15.7	15.0
Al_2O_3	26.5	26.7	27.0	27.2	27.2	27.0	26.7	26.8
SiO_2	47.7	48.0	45.7	47.3	49.6	50.5	48.9	49.5
TiO_2	1.2	1.3	1.1	1.1	1.2	1.1	1.2	1.2
P_2O_5	0.48	0.39	0.48	0.41	0.28	0.25	0.39	0.39
SO_3	0.14	0.12	0.17	0.14	0.06	0.05	0.14	0.07
LOI	8.1	5.1	6.7	3.8	4.8	14.9	5.5	2.3

Table A-10 Baseline / Performance Tests / Carbon and LOI Results

DATE	TEST	LOAD, MW	MASS TRAIN SAMPLES		ESP HOPPER LOI, %	
			CARBON, %	LOI, %	EAST DUCT	WEST DUCT
11/29/89	12	480	4.92	5.4	8.1	5.1
12/04/89	17	480	4.53	4.9	6.7	3.8
12/03/89	16	400	4.11	4.7	4.8	14.9
12/01/89	14	300	1.92	2.3	5.5	2.3

Table A-11 Baseline / Performance Tests / SOx Results

Date	Duct	TEST CONDITION	GAS TEMPERATURE, °F	CONCENTRATION, ppm	
				SO_3	SO_2
480 MW					
11/29/89 (Test 12)	East	480 MW	246	1.7	1347
	East	480 MW	247	1.9	1337
	East	480 MW	248	2.1	1349
	East	480 MW	248	2.0	1362
11/30/89 (Test 13)	East	480 MW	265	2.7	1025
	East	480 MW	262	2.5	1031
	East	480 MW	260	2.3	1042
	East	480 MW	261	2.3	1048
12/04/89 (Test 17)	West	480 MW	276	2.6	1073
	West	480 MW	277	2.7	1092
	West	480 MW	282	2.4	1108
	West	480 MW	286	2.5	1131
Average of 480 MW Data			263	2.3	1162
400 MW					
12/03/89 (Test 16)	West	400 MW	260	3.0	899
	West	400 MW	262	3.3	886
	West	400 MW	264	3.2	890
	West	400 MW	264	3.4	891
12/05/89 (Test 18)	East	400 MW	225	1.1	1005
	East	400 MW	229	1.2	1008
	East	400 MW	230	1.3	999
	East	400 MW	231	1.2	1008
Average of 400 MW Data			246	2.2	948
300 MW					
12/01/89 (Test 14)	East	300 MW	220	2.1	960
	East	300 MW	224	2.3	947
	East	300 MW	229	2.4	971
	East	300 MW	229	2.4	978
12/02/89 (Test 15)	West	300 MW	255	3.7	902
	West	300 MW	260	4.4	915
	West	300 MW	263	4.4	921
	West	300 MW	263	4.6	929
Average of 300 MW Data			243	3.3	940

Table A-12 Baseline / Performance Tests / In Situ Ash Resistivity Results

Date	Duct	Gas Temp, °F	Dust Layer, mm	Spark Method		V-I Method	
				Field, kV/cm	Resistivity, ohm-cm	Field, kV/cm	Resistivity, ohm-cm
----- 480 MW -----							
11/29/89 (Test 12)	East	277	0.92	13.0	5.0E+11	6.6	3.3E+10
		279	1.60	14.1	7.9E+10	2.6	1.3E+10
	West	296	1.26	17.9	3.1E+11	3.2	1.6E+10
		296	1.29	17.4	5.8E+11	5.8	2.9E+10
11/30/89 (Test 13)	East	285	1.19	15.1	2.1E+12	5.4	2.7E+10
		289	1.66	16.3	4.1E+11	5.2	2.6E+10
		289	1.42	15.8	6.9E+10	13.6	6.8E+10
Average of Tests 12-13		287			5.8E+11		3.0E+10
12/04/89 (Test 17)	West	300	0.96	20.3	1.8E+10	20.4	1.0E+11
		304	0.99	21.2	6.6E+10	16.4	8.2E+10
	East	269	1.52	16.8	1.2E+10	4.6	2.3E+10
		272	1.85	13.8	1.3E+10	5.4	2.7E+10
Average of Test 17		286			2.7E+10		5.8E+10
----- 400 MW -----							
12/03/89 (Test 16)	East	244	0.53	17.0	1.6E+09	8.6	4.3E+10
		247	0.55	19.1	1.2E+09	9.2	4.6E+10
	West	288	0.71	23.2	9.4E+09	15.6	7.8E+10
		289	1.02	17.6	1.9E+10	15.2	7.6E+10
12/05/89 (Test 18)	East	257	1.89	12.7	8.7E+09	2.2	1.1E+10
		263	2.04	14.7	9.9E+09	1.2	6.1E+09
		266	1.64	15.5	7.6E+09	0.6	3.0E+09
400 MW Average		265			8.2E+09		3.8E+10
----- 300 MW -----							
12/01/89 (Test 14)	East	260	1.34	16.8	2.6E+09	0.7	3.7E+09
		266	1.36	16.5	3.1E+09	1.1	5.5E+09
	West	268	0.82	22.0	4.3E+09	6.2	3.1E+10
		268	0.87	19.0	5.6E+09	8.4	4.2E+10
12/02/89 (Test 15)	West	272	0.74	18.2	7.3E+09	14.8	7.4E+10
		279	0.92	19.6	7.1E+09	12.6	6.3E+10
	East	264	1.38	17.4	3.0E+09	2.2	1.1E+10
		265	1.19	16.4	2.4E+09	1.3	6.3E+09
300 MW Average		268			4.4E+09		3.0E+10

Table A-13 Baseline / Verification Tests Summary

Test	Date	Conditions	Load MW	MOOS Pattern	Excess O_2 Dry	NOx 3% O_2 ppm	NOx lb/MBtu
19-1	4/02/89	HI LOAD O2 VARIATION	470	NONE	2.3	863	1.18
19-2	4/02/89	HI LOAD O2 VARIATION	470	NONE	2.6	939	1.28
19-3	4/02/89	HI LOAD O2 VARIATION	475	NONE	3.7	1063	1.45
20-1	4/03/89	MID LOAD O2 VARIATION	404	E	2.4	734	1.00
20-2	4/03/89	MID LOAD O2 VARIATION	403	E	3.5	876	1.19
20-3	4/03/89	MID LOAD O2 VARIATION	403	E	4.8	960	1.31
21-1	4/04/89	MID LOAD O2 VARIATION	400	B	2.3	785	1.07
21-2	4/04/89	MID LOAD O2 VARIATION	402	B	3.1	921	1.26
21-3	4/04/89	MID LOAD O2 VARIATION	402	B	4.3	974	1.33
22-1	4/05/89	HI LOAD O2 VARIATION	475	NONE	2.8	950	1.30
22-2	4/05/89	HI LOAD O2 VARIATION	475	NONE	2.4	961	1.31

Notes: 1. Dry excess O_2 at economizer outlet.

Table A-14 Baseline / Long-Term / Emissions by Load

LOAD CAT	N	PCT LOAD	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX	L5% KCO3	AVG KCO3	U95% KCO3	L5% KTHC3	AVG KTHC3	U95% KTHC3
170-190	592	3.5%	173	183	189	7.3	9.2	10.4	0.82	1.00	1.16	1.89	2.47	2.90	0	6	14	-4	0	2
190-210	651	3.8%	191	199	208	7.7	9.0	10.3	0.84	1.00	1.17	1.73	2.36	2.92	0	7	13	-1	0	2
210-230	299	1.7%	211	220	229	7.1	8.5	9.7	0.77	0.95	1.11	2.11	2.51	3.05	0	9	14	-1	0	2
230-250	379	2.2%	231	240	249	6.6	8.3	9.6	0.72	0.97	1.11	1.84	2.43	3.03	0	9	17	-1	0	2
250-270	442	2.6%	251	259	268	6.3	7.8	9.4	0.75	0.96	1.17	1.96	2.49	3.08	0	8	14	-1	0	1
270-290	401	2.3%	272	281	289	5.9	7.4	8.8	0.79	1.00	1.17	2.05	2.50	3.05	0	8	13	-1	0	1
290-310	460	2.7%	291	299	309	5.6	7.1	8.6	0.76	1.01	1.19	0.98	2.31	3.09	0	17	98	-1	0	1
310-330	332	1.9%	311	321	329	5.2	7.0	8.8	0.73	1.01	1.23	1.81	2.41	3.11	0	16	59	-1	0	1
330-350	314	1.8%	331	340	349	5.1	6.8	8.2	0.78	1.04	1.22	1.83	2.42	3.05	0	15	53	-1	0	1
350-370	459	2.7%	351	361	369	5.0	6.3	7.9	0.85	1.10	1.32	1.83	2.33	2.96	1	18	63	-1	0	1
370-390	450	2.6%	371	381	389	4.8	6.1	7.5	0.81	1.10	1.29	1.86	2.39	3.00	0	27	136	-1	0	1
390-410	851	5.0%	391	399	409	4.4	5.6	7.7	0.83	1.09	1.30	1.80	2.40	3.00	1	30	177	-1	0	1
410-430	1030	6.0%	411	420	429	4.5	5.5	7.2	0.87	1.13	1.35	1.87	2.42	2.97	1	47	328	-1	0	1
430-450	1408	8.2%	431	441	449	4.0	5.1	6.0	1.01	1.21	1.39	1.85	2.39	2.98	6	62	319	-1	0	1
450-470	3855	22.5%	452	462	469	4.1	4.9	5.7	1.09	1.27	1.52	1.01	2.19	2.94	7	49	301	0	0	1
470-490	5126	30.0%	471	479	486	4.1	5.0	5.7	1.06	1.24	1.41	1.89	2.46	3.02	6	67	325	-1	1	2
490-510	57	0.3%	490	493	498	4.1	4.7	5.5	1.04	1.20	1.38	1.85	2.39	2.89	6	101	335	0	0	1

EDITED HAMMOND PHASE 1 TEST DATA
FIVE MINUTE DATA
ALL DATA
PROCESSING FOR LOAD CATEGORIES
COMMON LOAD O2 NOX SOX CO3% THC3%

Table A-15 Baseline / Long-Term / Within-Day Averages

HOUR	N	LOWER 5%	LOAD AVG	UPPER 95%	LOWER 5%	O2 AVG	UPPER 95%	LOWER 5%	NOX AVG	UPPER 95%	LOWER 5%	SOX AVG	UPPER 95%
0	64	185.81	289.66	453.19	4.942	7.502	9.517	0.853	1.061	1.286	1.720	2.369	2.990
1	64	183.42	277.85	446.17	5.350	7.659	9.551	0.861	1.051	1.303	1.763	2.361	2.996
2	64	181.92	272.74	444.70	5.056	7.804	9.760	0.863	1.052	1.292	1.816	2.355	2.964
3	63	187.12	293.55	446.98	5.056	7.556	9.789	0.862	1.064	1.321	1.820	2.352	2.974
4	64	197.57	340.30	463.92	4.924	6.832	9.670	0.842	1.091	1.332	1.840	2.355	2.942
5	63	267.33	405.25	481.29	4.476	5.838	8.866	0.874	1.123	1.339	1.843	2.379	2.935
6	61	307.54	440.74	482.86	4.272	5.402	6.898	0.928	1.147	1.354	1.886	2.393	2.969
7	58	261.74	442.94	483.41	4.263	5.322	7.929	0.774	1.144	1.410	1.871	2.402	2.960
8	52	264.73	437.68	483.77	4.264	5.433	7.870	0.904	1.161	1.414	1.841	2.428	3.040
9	49	276.51	438.68	484.46	4.138	5.376	7.730	0.969	1.172	1.346	1.764	2.399	3.001
10	55	323.64	447.51	482.87	3.936	5.131	7.061	0.970	1.187	1.401	1.840	2.415	3.047
11	60	307.26	447.87	483.19	4.287	5.348	7.528	0.942	1.208	1.395	1.861	2.446	3.059
12	65	389.81	453.61	482.22	4.156	5.244	7.050	0.967	1.209	1.391	1.892	2.425	3.026
13	66	396.12	451.14	482.29	4.384	5.305	7.050	0.970	1.213	1.393	1.853	2.441	3.034
14	62	364.92	448.86	481.60	4.295	5.231	6.250	1.006	1.217	1.363	1.821	2.399	2.991
15	62	351.89	446.17	481.55	4.247	5.248	7.483	0.953	1.222	1.388	1.830	2.393	2.974
16	64	345.61	446.49	483.47	4.087	5.266	7.517	0.991	1.228	1.412	1.849	2.374	2.990
17	64	368.72	447.98	483.87	4.228	5.257	6.250	0.980	1.229	1.421	1.838	2.347	3.019
18	64	357.97	451.18	483.30	4.132	5.217	6.250	1.011	1.239	1.434	1.715	2.332	3.006
19	64	344.24	453.29	482.57	4.114	5.135	6.250	0.990	1.238	1.439	1.758	2.338	3.012
20	64	412.29	455.36	483.12	4.231	5.108	6.250	0.992	1.242	1.430	1.743	2.343	2.987
21	64	369.88	447.10	480.80	4.116	5.152	6.450	0.991	1.225	1.422	1.755	2.355	3.027
22	64	231.34	415.07	477.82	4.149	5.580	8.134	0.854	1.184	1.394	1.743	2.371	3.016
23	64	185.93	339.42	463.99	4.659	6.626	9.059	0.858	1.105	1.350	1.769	2.395	3.079

PLANT HAMMOND BASELINE TESTING
DECEMBER 1989 - APRIL 1990
WITHIN-DAY AVERAGES

Table A-16 Baseline / Long-Term / Daily Averages

SEQ	DID	NHOURS	LOAD	O2	NOX	SO2
1	891226	4	453.61	5.669	1.307	2.480
2	891227	6	454.20	5.633	1.334	3.025
3	891228	12	446.67	6.260	1.308	2.441
4	891229	20	446.90	5.868	1.337	2.505
5	891230	10	354.06	6.962	1.201	2.498
6	891231	0				
7	900101	0				
8	900102	12	359.24	7.647	0.954	2.625
9	900103	13	370.00	7.786	0.997	2.395
10	900104	6	411.94	7.085	0.976	2.783
11	900105	1	477.77	5.650	1.278	2.249
12	900106	0				
13	900107	0				
14	900108	14	471.41	5.531	1.292	3.011
15	900109	22	420.01	5.971	1.317	3.025
16	900110	21	379.92	6.622	1.250	2.391
17	900111	21	434.66	5.920	1.305	2.522
18	900112	22	417.71	5.985	1.198	2.747
19	900113	23	407.44	6.489	1.232	2.328
20	900114	23	454.56	5.177	1.260	2.791
21	900115	20	420.62	5.764	1.240	2.881
22	900116	8	297.33	7.387	1.079	2.717
23	900117	0				
24	900118	17	414.46	5.906	1.065	2.837
25	900119	15	402.29	6.220	1.121	2.485
26	900120	0				
27	900121	0				
28	900122	14	453.76	5.354	1.298	2.639
29	900123	24	414.96	6.010	1.129	2.592
30	900124	21	413.93	6.090	1.165	2.576
31	900125	22	423.75	6.108	1.150	2.602
32	900126	14	457.55	5.579	1.304	2.262
33	900127	0				
34	900128	0				
35	900129	13	447.04	5.899	1.241	2.648
36	900130	21	410.61	6.043	1.081	2.852
37	900131	7	294.70	7.781	1.052	2.801
38	900201	0				
39	900202	0				
40	900203	0				
41	900204	0				
42	900205	0				
43	900206	0				
44	900207	10	446.47	5.617	1.268	2.443
45	900208	21	396.72	6.155	1.126	2.764
46	900209	13	367.80	6.749	1.045	2.749
47	900210	0				
48	900211	0				
49	900212	14	438.93	5.424	1.250	3.022
50	900213	23	395.84	6.172	1.214	2.621
51	900214	22	378.73	6.061	1.143	1.974
52	900215	21	381.44	6.521	1.219	2.097
53	900216	22	403.53	6.099	1.250	2.276
54	900217	10	262.58	8.747	1.029	2.201
55	900218	0				
56	900219	14	443.32	5.725	1.336	1.942
57	900220	23	409.86	5.834	1.262	2.645
58	900221	22	395.88	5.947	1.203	2.267
59	900222	9	328.65	6.940	0.977	2.538

Table A-16 Baseline / Long-Term / Daily Averages (continued)

SEQ	DID	NHOURS	LOAD	O2	NOX	SO2
60	900223	0				
61	900224	0				
62	900225	0				
63	900226	15	473.96	5.469	1.272	2.433
64	900227	22	393.37	6.513	1.090	2.336
65	900228	24	449.30	5.618	1.243	1.835
66	900301	22	439.66	5.711	1.313	2.178
67	900302	19	403.12	6.266	1.115	2.079
68	900303	24	401.08	6.269	1.164	2.064
69	900304	24	374.68	6.255	1.044	1.980
70	900305	22	405.57	5.531	1.089	2.064
71	900306	24	435.67	4.643	1.109	2.306
72	900307	0				
73	900308	24	421.20	5.445	1.202	2.098
74	900309	23	398.20	5.698	1.215	2.071
75	900310	24	396.21	5.242	1.055	2.444
76	900311	24	361.06	6.003	1.051	2.378
77	900312	23	457.68	4.457	1.155	2.692
78	900313	24	382.53	5.632	0.980	2.322
79	900314	23	454.73	4.549	1.040	2.410
80	900315	22	445.23	4.993	1.184	2.210
81	900316	24	415.24	5.247	1.123	2.369
82	900317	24	231.14	8.644	0.934	2.612
83	900318	24	288.37	6.533	0.843	3.005
84	900319	24	396.61	5.340	1.065	2.928
85	900320	23	440.54	4.708	1.200	2.898
86	900321	24	387.35	5.349	1.078	2.461
87	900322	24	423.39	5.375	1.143	2.383
88	900323	22	394.02	5.589	1.043	2.492
89	900324	24	411.08	5.584	1.072	2.061
90	900325	24	360.04	5.806	1.068	2.200
91	900326	24	436.61	5.133	1.231	2.392
92	900327	24	424.79	4.871	1.215	2.654
93	900328	20	404.73	5.433	1.127	1.927
94	900329	24	429.67	5.533	1.397	0.772
95	900330	24	433.15	5.227	1.358	1.811
96	900331	24	430.85	5.301	1.360	1.890
97	900401	24	415.38	5.493	1.239	1.943
98	900402	7	347.87	6.822	1.143	1.990
99	900403	13	426.87	5.082	1.163	2.190
100	900404	17	423.57	5.125	1.225	1.834
101	900405	13	413.30	5.752	1.207	1.976

Table A-17 Baseline / Long-Term / Rolling Averages

30 DAY LOAD	NLOAD	30 DAY NOX	NNOX	30 DAY O2	NO2
413.96	709	1.217	379	6.06	379
413.46	708	1.216	375	6.06	375
413.50	708	1.214	369	6.07	369
414.27	708	1.211	357	6.06	357
412.25	709	1.204	337	6.08	337
413.36	713	1.212	324	6.01	324
415.52	714	1.216	318	5.99	318
415.35	716	1.218	327	5.98	327
414.33	715	1.212	348	5.99	348
413.83	715	1.206	361	6.02	361
413.14	715	1.203	347	6.03	347
412.31	715	1.195	325	6.04	325
412.23	714	1.194	318	5.97	318
410.77	714	1.188	320	5.99	320
409.63	714	1.184	320	6.00	320
408.89	714	1.183	318	6.00	318
407.27	714	1.182	317	6.06	317
405.33	714	1.178	297	6.08	297
405.16	715	1.189	296	6.06	296
405.40	715	1.194	319	6.04	319
407.41	714	1.194	341	6.04	341
404.86	714	1.190	327	6.07	327
403.23	714	1.195	303	6.07	303
404.25	714	1.201	297	6.04	297
403.24	714	1.196	297	6.07	297
402.97	715	1.195	307	6.05	307
404.09	713	1.203	329	6.03	329
406.40	713	1.198	348	6.04	348
406.38	713	1.194	359	6.06	359
404.87	713	1.191	362	6.08	362
405.27	714	1.187	377	6.02	377
405.45	715	1.183	401	5.93	401
404.17	715	1.183	401	5.93	401
404.48	715	1.184	425	5.91	425
405.01	715	1.185	448	5.89	448
404.39	715	1.179	472	5.86	472
402.02	715	1.173	496	5.87	496
403.47	715	1.170	509	5.81	509
402.76	716	1.163	512	5.79	512
404.08	715	1.160	522	5.71	522
406.02	715	1.161	544	5.68	544
406.52	715	1.160	568	5.66	568
401.29	716	1.148	578	5.79	578
397.63	716	1.133	579	5.81	579
397.97	716	1.130	581	5.78	581
399.73	716	1.129	583	5.71	583
399.07	716	1.123	585	5.68	585
400.77	716	1.123	609	5.67	609
400.02	716	1.116	617	5.66	617
400.03	716	1.109	618	5.65	618
398.70	717	1.104	620	5.65	620
401.68	717	1.108	644	5.63	644
403.64	717	1.112	668	5.60	668
402.18	713	1.109	673	5.60	673
403.23	713	1.120	675	5.57	675
402.69	713	1.124	675	5.55	675
402.50	715	1.126	677	5.54	677
402.46	715	1.131	682	5.52	682
403.25	713	1.129	665	5.51	665
403.88	713	1.133	654	5.47	654
404.00	713	1.137	649	5.46	649
403.92	713	1.140	638	5.50	638

Table A-18 Baseline / Long-Term / Hourly Average Stats

Load >	Load <	N	Load Avg MW	Load Std.Dev. MW	Load Max MW	Load Min MW	O2 Avg %	O2 Std. Dev. %	O2 Max %	O2 Min %	NOx Avg lb/MBtu	NOx Std. Dev. lb/MBtu	NOx Max lb/MBtu	NOx Min lb/MBtu
170	190	46	184.2	4.292	189.9	172.3	9.245	0.7281	10.368	7.264	1.0155	0.0976	1.17	0.836
190	210	48	199.9	4.797	208.5	190.5	8.992	0.6627	10.450	6.912	1.0046	0.0766	1.211	0.802
210	230	26	219.2	5.158	229.5	210.1	8.376	0.6245	9.788	7.261	0.9375	0.1045	1.082	0.659
230	250	40	238.1	6.073	248.6	230.2	8.251	0.7168	9.779	6.885	0.9662	0.1188	1.184	0.499
250	270	37	259.3	5.391	269.5	250.3	7.848	0.8226	9.203	6.489	0.9709	0.1197	1.173	0.573
270	290	31	280.4	5.271	289.8	270.3	7.518	0.8014	9.225	5.601	1.0229	0.1171	1.205	0.732
290	310	44	298.3	6.266	309.8	290.0	6.916	0.7888	8.133	4.821	0.9799	0.1309	1.172	0.479
310	330	29	322.0	5.204	329.7	310.7	7.159	1.0747	9.133	5.419	1.0367	0.1406	1.261	0.74
330	350	29	339.0	5.496	349.4	330.2	6.844	0.7395	7.950	5.025	1.0699	0.1183	1.266	0.823
350	370	44	361.5	5.270	369.9	350.8	6.361	0.7354	7.951	4.993	1.1048	0.1258	1.332	0.716
370	390	37	380.0	4.714	389.8	370.5	6.214	0.6136	7.717	5.056	1.1019	0.1407	1.315	0.746
390	410	69	399.6	5.787	410.0	390.0	5.541	0.9132	7.800	3.284	1.0927	0.1400	1.343	0.828
410	430	90	419.8	6.308	429.9	410.1	5.539	0.7785	7.483	4.231	1.1213	0.1342	1.409	0.846
430	450	139	442.2	5.383	449.9	430.1	5.299	0.6257	6.700	3.700	1.2296	0.1168	1.513	0.948
450	470	351	461.7	5.558	469.7	450.0	4.952	0.4362	6.250	3.887	1.2663	0.1174	1.641	0.971
470	490	418	478.9	4.054	487.1	470.0	4.990	0.4388	5.767	3.651	1.2331	0.1014	1.501	0.945
490	510	0												
510	530	0												

APPENDIX B
AOFA TEST DATA

Table B-1 AOFA / Diagnostic Test Summary

TEST NO.	DATE	TEST CONDITIONS	LOAD (MW)	MOOS	OFA DAMPER (%)	Ex O2 DRY (%)	NOx at 3% O2 (ppm)	NOx (lb/MBtu)
23-1	05/23/90	START-UP TEST	478	NONE	0	2.7	1027	1.40
24-1	06/11/90	HI LOAD O2 VARIATION	482	NONE	0	2.1	899	1.23
24-2	06/11/90	"	480	NONE	0	3.0	945	1.29
25-1	06/12/90	HI LOAD NORMAL O2	475	NONE	0	2.8	801	1.09
25-2	06/12/90	"	478	NONE	0	2.5	809	1.10
25-3	06/12/90	HI LOAD 02 VARIATION	478	NONE	0	2.5	883	1.20
25-4	06/12/90	"	479	NONE	0	2.5	825	1.12
25-5	06/12/90	"	476	NONE	25	2.4	783	1.07
25-6	06/12/90	"	475	NONE	100	2.4	665	0.91
26-1	06/13/90	HI LOAD OFA VARIATION	478	NONE	0	2.1	794	1.08
26-2	06/13/90	"	478	NONE	50	2.8	635	0.87
27-1	06/15/90	HI LOAD REGISTER MALDISTR	480	NONE	6	2.8	796	1.09
27-2	06/15/90	HI LOAD REGISTER ADJ	478	NONE	6	5.3	656	0.89
27-3	06/15/90	"	478	NONE	7			
27-4	06/16/90	"	475	NONE	7			
27-5	06/16/90	"	476	NONE	7	2.6	742	1.01
28-1	06/16/90	HI LOAD OFA VARIATION	482	NONE	7	2.6	742	1.01
28-2	06/16/90	"	483	NONE	20	2.7	700	0.95
28-3	06/16/90	"	483	NONE	35	2.9	650	0.89
28-4	06/16/90	"	480	NONE	51	2.8	583	0.79
28-5	06/16/90	HI LOAD OFA/O2 VARIATION	482	NONE	51	2.3	551	0.75
29-1	06/17/90	MID LOAD OFA VARIATION	405	NONE	5	4.4	785	1.07
29-2	06/17/90	"	405	NONE	14	4.3	772	1.05
29-3	06/18/90	"	408	NONE	30	4.2	696	0.95
29-4	06/18/90	"	408	NONE	39	4.4	648	0.88
30-1	06/19/90	HI LOAD 02 VARIATION	487	NONE	5	2.5	812	1.11
30-2	06/19/90	"	487	NONE	4	2.7	877	1.20
30-3	06/19/90	HI LOAD 02/0FA VARIATION	487	NONE	30	2.5	717	0.98
31-1	06/20/90	HI LOAD REGIST ADJ	482	NONE	5	2.4	802	1.09
31-2	06/20/90	"	487	NONE	5	2.0	763	1.04
31-3	06/20/90	"	490	NONE	5	2.1	795	1.08
31-4	06/20/90	HI LOAD OFA VARIATION	490	NONE	30	2.2	705	0.96
32-1	06/21/90	HI LOAD OFA VARIATION	485	NONE	4	2.5	714	0.97
32-2	06/21/90	"	485	NONE	20	2.6	685	0.93
32-3	06/21/90	"	482	NONE	50	2.9	587	0.80
33-1	06/25/90	LOW LOAD OFA VARIATION	308	E	5	4.6	723	0.99
33-2	06/26/90	"	300	E	25	4.1	695	0.95
33-3	06/26/90	"	302	E	50	5.1	626	0.85
33-4	06/26/90	"	310	E	75	4.0	643	0.88
33-5	06/26/90	LOW LOAD OFA/O2 VARIATION	302	E	75	3.3	576	0.79
34-1	06/26/90	LOW LOAD NORMAL	290	E	5	3.2	609	0.83
34-2	06/26/90	LOW LOAD O2 VARIATION	305	E	50	4.2	557	0.76
34-3	06/27/90	"	295	E	50	3.2	480	0.65
34-4	06/27/90	"	295	E	50	3.5	507	0.69
34-5	06/27/90	MID LOAD OFA VARIATION	390	E	50	3.4	527	0.72
34-6	06/27/90	"	390	E	35	3.4	531	0.72
34-7	06/27/90	"	390	E	20	3.3	553	0.75
34-8	06/27/90	"	390	E	5	3.0	564	0.77

Notes: 1. Dry excess O2 at economizer outlet.

Table B-1 AOFA / Diagnostic Test Summary (continued)

TEST NO.	DATE	TEST CONDITIONS	LOAD (MW)	MOOS	OFA DAMPER (%)	Ex O2 DRY (%)	NOx AT 3% O2 (ppm)	NOx (lb/MBtu)
35-1	06/26/90	MID LOAD OFA VARIATION	405	E	5	3.4	630	0.86
35-2	06/27/90	"	405	E	25	3.4	587	0.80
35-3	06/28/90	"	402	E	50	3.5	546	0.74
35-4	06/28/90	MID LOAD OFA/O2 VARIATION	407	E	50	3.2	530	0.72
35-5	06/28/90	"	410	E	50	4.0	568	0.77
35-6	06/28/90	MID LOAD OFA VARIATION	407	E	75			
35-7	06/28/90	"	410	E	5			
36-1	06/29/90	HI LOAD OFA VARIATION	475	NONE	5	2.9	659	0.90
36-2	06/29/90	"	475	NONE	25	2.9	596	0.81
36-3	06/29/90	"	480	NONE	50	3.1	538	0.73
36-4	06/29/90	"	480	NONE	75	2.9	516	0.70
46-1	08/14/90	LOW LOAD O2 VARIATION	300	E	50	3.5	472	0.64
46-2	08/14/90	"	300	E	50	4.4	556	0.76
46-3	08/14/90	"	300	E	50	5.1	624	0.85
46-4	08/14/90	"	300	E	50	5.6	675	0.92
47-1	08/14/90	MID LOAD	400	NONE	50	3.4	569	0.78
47-2	08/14/90	MID LOAD REPEAT	400	NONE	50	3.4	570	0.78
47-3	08/15/90	MID LOAD O2 VARIATION	400	NONE	50	3.5	581	0.79
47-4	08/15/90	"	400	NONE	50	4.0	607	0.83
47-5	08/15/90	"	400	NONE	50	4.6	637	0.87
48-1	08/15/90	HI LOAD O2 VARIATION	455	NONE	50	2.5	502	0.68
48-2	08/15/90	"	455	NONE	50	3.2	559	0.76
48-3	08/15/90	"	455	NONE	50	3.9	604	0.82
48-4	08/15/90	HI LOAD 02/OFA VARIATION	455	NONE	50	4.3	628	0.86
48-5	08/15/90	"	450	NONE	35	4.2	662	0.90
48-6	08/15/90	"	450	NONE	20	4.4	731	1.00
48-7	08/15/90	"	450	NONE	5	4.6	774	1.06
48-8	08/15/90	"	450	NONE	0	4.2	774	1.06
49-1	08/16/90	HI LOAD OFA VARIATION	475	NONE	5	3.8	675	0.92
49-2	08/16/90	"	480	NONE	20	2.9	620	0.85
49-3	08/16/90	"	482	NONE	35	3.1	580	0.79
49-4	08/16/90		482	NONE	50	3.2	553	0.75
49-5	08/16/90		480	NONE	50	3.6	568	0.77
49-6	08/16/90		485	NONE	50	4.3	619	0.84

Notes: 1. Dry excess O2 at economizer outlet.

Table B-2 AOFA / Diagnostic Tests / Operating Summary

Test No.	Date	Load (MW)	O2 E Econ Outlet (DRY %)	O2 W Econ Outlet (DRY %)	CEM O2 Outlet (DRY %)	CEM NOx 3% O2 (PPM)	Stack Opacity (PCT)	Mill A klb/hr	Mill B klb/hr	Mill C klb/hr	Mill D klb/hr	Mill E klb/hr	Mill F klb/hr
23-1	05/23/90	478	3.0	2.9	2.7	1027		58	66	56	63	63	56
24-1	06/11/90	482	2.5	2.6	2.1	889		57	48	57	57	57	56
24-2	06/11/90	480	3.1	3.0	3.0	945		57	49	57	57	57	56
25-1	06/12/90	475	3.1	3.4	2.8	801	8.9	56	50	56	57	58	56
25-2	06/12/90	478	3.2	3.5	2.5	809	10.6	56	50	56	57	58	57
25-3	06/12/90	478	3.2	3.2	2.5	883	10.0	56	49	56	59	58	56
25-4	06/12/90	479	2.9	3.2	2.5	825	11.8	56	50	56	59	58	56
25-5	06/12/90	476	2.8	3.2	2.4	783	12.6	56	50	56	58	58	56
25-6	06/12/90	475	2.7	3.0	2.4	665	8.8	56	50	56	59	58	56
26-1	06/13/90	478	2.8	3.1	2.1	794	18.1	66	44	58	59	56	57
26-2	06/13/90	478	3.0	3.2	2.8	635	9.5	65	43	57	59	55	56
27-1	06/15/90	480	3.1	3.0	2.8	796	9.6	58	58	54	59	59	58
27-2	06/15/90	478	2.9	3.0	5.3	656	13.1	64	57	56	58	54	54
27-3	06/15/90	478	2.9	2.8			7.6	64	58	57	58	56	54
27-4	06/15/90	475	2.8	2.8			14.6	64	58	56	58	54	54
27-5	06/15/90	476	3.2	3.4	2.6	742	15.9	64	58	56	58	54	54
28-1	06/16/90	482	3.4	3.5	2.6	742	9.9	63	56	56	57	54	54
28-2	06/16/90	483	3.5	3.6	2.7	700	10.6	63	56	56	57	54	54
28-3	06/16/90	483	3.6	3.9	2.9	650	14.7	63	56	56	56	54	54
28-4	06/16/90	480	3.4	3.9	2.8	583	10.8	63	56	56	57	54	54
28-5	06/16/90	482	3.1	3.4	2.3	551	9.8	64	57	56	57	54	54
29-1	06/17/90	405	4.6	5.1	4.4	785	4.7	54	46	46	49	46	46
29-2	06/17/90	405	4.6	5.0	4.3	772	5.6	54	46	46	48	46	46
29-3	06/18/90	408	4.6	5.0	4.2	696	6.9	53	47	46	49	46	46
29-4	06/18/90	408	4.4	5.4	4.4	648	5.9	54	47	46	49	46	46
30-1	06/19/90	487	2.7	2.9	2.5	812	9.1	79	65	52	63	50	56
30-2	06/19/90	487	3.2	3.0	2.7	877	14.0	59	63	58	63	50	56
30-3	06/19/90	487	3.3	3.0	2.5	717	17.3	59	66	58	63	49	56
31-1	06/20/90	482	2.9	2.7	2.4	802	11.4	63	60	60	61	50	55
31-2	06/20/90	487	2.5	2.5	2.0	763	10.2	63	59	60	61	50	56
31-3	06/20/90	490	2.6	2.8	2.1	795	13.3	63	58	60	61	50	56
31-4	06/20/90	490	2.8	3.0	2.2	705	12.8	62	58	60	60	50	55
31-5	06/20/90	491	2.9	3.4			10.7	62	58	60	60	50	45
32-1	06/21/90	485	3.0	3.2	2.5	714	10.0	59	61	56	62	50	54
32-2	06/21/90	485	3.0	3.2	2.6	685	12.2	59	60	56	62	50	54
32-3	06/21/90	482	3.2	3.6	2.9	587	10.6	59	61	56	62	50	54
33-1	06/25/90	308	3.2	4.9	4.6	723	1.9	43	43	43	42	0	43
33-2	06/26/90	300	3.2	5.0	4.1	695	1.9	43	43	43	42	0	43
33-3	06/26/90	302	3.2	4.9	5.1	626	1.0	49	44	42	44	0	42
33-4	06/26/90	310	3.1	4.8	4.0	643	1.2	49	44	42	44	0	42
33-5	06/26/90	302	2.6	4.4	3.3	576	0.6	49	44	42	44	0	42
34-1	06/26/90	290	3.0	4.7	3.2	609	3.5	46	44	42	44	0	44
34-2	06/26/90	305	3.6	4.8	4.2	557	1.5	46	45	42	44	0	44
34-3	06/27/90	295	2.5	3.9	3.2	480	0.2	46	45	42	44	0	44
34-4	06/27/90	295	2.8	4.2	3.5	507	0.1	46	45	42	44	0	44
34-5	06/27/90	390	2.8	4.6	3.4	527	3.9	59	57	54	56	0	56
34-6	06/27/90	390	2.7	4.6	3.4	531	5.7	59	57	54	56	0	56
34-7	06/27/90	390	2.8	4.5	3.3	553	7.9	59	57	54	56	0	56
34-8	06/27/90	390	2.7	4.3	3.0	564	4.0	59	57	54	56	0	56

Table B-2 AOFA / Diagnostic Tests / Operating Summary (continued)

Test No.	Date	Load (MW)	O2 E Econ Outlet (DRY %)	O2 W Econ Outlet (DRY %)	CEM O2 Outlet (DRY %)	CEM NOx 3% O2 (PPM)	Stack Opacity (PCT)	Mill A klb/hr	Mill B klb/hr	Mill C klb/hr	Mill D klb/hr	Mill E klb/hr	Mill F klb/hr
35-1	06/27/90	405	3.0	4.2	3.4	630	6.2	60	57	57	54	0	56
35-2	06/27/90	405	3.0	4.2	3.4	587	5.7	74	61	69	62	0	73
35-3	06/27/90	402	2.8	4.4	3.5	546	4.7	60	57	57	54	0	56
35-4	06/27/90	407	2.6	4.1	3.2	530	3.8	60	60	55	54	0	56
35-5	06/28/90	410	3.4	4.8	50.0	4	9.0	60	60	55	54	0	56
35-6	06/28/90	407	2.9	4.6			9.7	60	61	55	54	0	56
35-7	06/28/90	410	2.8	4.1			5.2	60	61	55	54	0	73
36-1	06/29/90	475	3.0	3.2	2.9	659	10.2	63	60	50	59	49	56
36-2	06/29/90	475	2.9	3.2	2.9	596	10.3	63	60	50	59	49	56
36-3	06/29/90	480	2.8	3.6	3.1	538	12.2	64	60	50	59	49	56
36-4	06/29/90	480	2.8	3.5	2.9	516	13.4	63	60	50	59	49	56
46-1	08/14/90	300	3.3	4.1	3.5	472		44	45	42	49	0	43
46-2	08/14/90	300	4.1	4.4	4.4	556	2.3	44	45	42	49	0	44
46-3	08/14/90	300	4.6	5.2	5.1	624	3.0	44	45	42	49	0	44
46-4	08/14/90	305	5.0	5.6	5.6	675	4.0	44	45	43	49	0	44
47-1	08/14/90	402			3.4	569	22.8	46	51	45	53	55	47
47-2	08/14/90	402	3.2	3.6	3.4	570	29.4	46	51	45	52	55	46
47-3	08/14/90	405	3.0	3.6	3.5	581	19.2	46	51	46	52	55	46
47-4	08/14/90	410	4.0	4.6	4.0	607	18.3	46	51	46	52	55	46
47-5	08/14/90	410	4.2	5.0	4.6	637	19.4	46	52	46	52	54	47
48-1	08/15/90	455	2.9	2.6	2.5	502	20.0	54	58	58	45	60	53
48-2	08/15/90	455	3.1	3.3	3.2	559	24.9	51	55	55	55	58	52
48-3	08/15/90	455	3.6	4.0	3.9	604	27.4	51	56	56	55	58	52
48-4	08/15/90	455	3.9	4.4	4.3	628	19.4	51	56	55	55	57	53
48-5	08/15/90	450	4.2	4.5	4.2	662	17.7	54	57	48	56	59	54
48-6	08/15/90	450	4.2	4.4	4.4	731	18.3						
48-7	08/15/90	450	4.1	4.3	4.6	774	21.5						
48-8	08/15/90	450	4.0	4.2	4.2	774	20.5						
49-1	08/16/90	475	3.0	2.5	3.8	675	18.2	63	64	62	65	49	58
49-2	08/16/90	480	3.2	2.7	2.9	620	15.2						
49-3	08/16/90	482	3.2	2.8	3.1	580	15.1						
49-4	08/16/90	482	3.6	3.0	3.2	553	21.7	63	64	53	64	50	57
49-5	08/16/90	470	3.6	3.4	3.6	568	20.1	63	64	52	64	49	57
49-6	08/16/90	485	4.5	4.0	4.3	619	19.9	63	64	52	64	49	57
50-1	10/24/90	487	4.2	3.2			50.1	64	64	64	70	50	56
51-1	10/26/90	489	3.2	2.6			20.5	64	65	62	66	53	59

Table B-2 AOFA / Diagnostic Tests / Operating Summary (continued)

Test No.	Date	Load (MWe)	Stack Opacity (PCT)	SAPH A Out Temp (° F)	SAPH B Out Temp (° F)	Steam Flow MLB/HR	SH Temp (° F)	SH Lower Spray (kLB/HR)	SH Upper Spray (kLB/HR)	Hot RH Temp (° F)
23-1	05/23/90	478		230	250	3.2	990	15.3	13.2	10
24-1	06/11/90	482		200	240	3.2	995	15.4	11.7	992
24-2	06/11/90	480		190	240	3.2	995	17.0	11.3	995
25-1	06/12/90	475	8.9	190	230		999	11.5	7.0	940
25-2	06/12/90	478	10.6	200	240	3.2	997	13.0	15.0	994
25-3	06/12/90	478	10.0	200	230	3.2	1002	13.7	6.7	950
25-4	06/12/90	479	11.8	200	240	3.2	1000	14.3	6.7	950
25-5	06/12/90	476	12.6	190	230	3.2	1005	14.2	6.5	950
25-6	06/12/90	475	8.8	190	230	3.2	999	14.5	6.6	
26-1	06/13/90	478	18.1	190	230	3.2	1006	12.8	12.5	930
26-2	06/13/90	478	9.5	200	230	3.2	1011	15.5	11.0	900
27-1	06/15/90	480	9.6	220	230	3.2	977	14.4	11.2	980
27-2	06/15/90	478	13.1	220	230	3.2	994	15.2	9.2	950
27-3	06/15/90	478	7.6	210	230	3.2	995	15.5	9.2	940
27-4	06/15/90	475	14.6	210	220	3.2	995	15.3	9.2	960
27-5	06/15/90	476	15.9	220	230	3.2	992	15.7	9.2	960
28-1	06/16/90	482	9.9	220	230	3.3	992	15.4	10.6	960
28-2	06/16/90	483	10.6	220	230		990	15.6	10.6	960
28-3	06/16/90	483	14.7	210	230	3.2		15.5	10.0	980
28-4	06/16/90	480	10.8	210	220	3.2	987	16.5	10.5	980
28-5	06/16/90	482	9.8	210	210	3.2	993	16.3	10.4	960
29-1	06/17/90	405	4.7	200	240	2.6	985	16.5	11.5	1004
29-2	06/17/90	405	5.6	200	240	2.7	998	16.0	10.0	1002
29-3	06/18/90	408	6.9	190	240	2.6	993	16.2	9.2	1000
29-4	06/18/90	408	5.9	190	240	2.6	993	16.0	9.6	1000
30-1	06/19/90	487	9.1	205	250	3.3	985	16.5	14.3	1000
30-2	06/19/90	487	14.0	210	260	3.3	978	17.5	14.2	950
30-3	06/19/90	487	17.3	200	260	3.3	975	17.3	14.2	920
31-1	06/20/90	482	11.4	200	240	3.3	1006	15.7	14.4	960
31-2	06/20/90	487	10.2	200	230	3.3	998	16.3	14.6	930
31-3	06/20/90	490	13.3	210	240	3.3	986	16.6	14.8	920
31-4	06/20/90	490	12.8	210	250	3.7	979	17.0	14.8	980
31-5	06/20/90	491	10.7	205	250	3.3	976	17.2	15.8	910
32-1	06/21/90	485	10.0	210	240	3.3	973	12.3	15.5	920
32-2	06/21/90	485	12.2	210	240	3.3	973	13.7	15.2	950
32-3	06/21/90	482	10.6	210	240	3.3	965	14.5	15.0	940
33-1	06/25/90	308	1.9	185	185	2.0	988	8.0	10.0	935
33-2	06/26/90	300	1.9	190	170	2.0	1007	7.8	10.0	960
33-3	06/26/90	302	1.0	190	170	2.0	1009	8.5	9.5	965
33-4	06/26/90	310	1.2	185	180	2.0	982	9.3	13.3	950
33-5	06/26/90	302	0.6	180	175	2.0	996	8.5	12.5	950
34-1	06/26/90	290	3.5	185	185	2.0	1013	7.5	7.5	930
34-2	06/26/90	305	1.5	190	180	2.0	987	7.8	7.0	930
34-3	06/27/90	295	0.2	180	170	2.0	993	5.5	5.7	920
34-4	06/27/90	295	0.1	180	170	2.0	1001	7.5	8.5	925
34-5	06/27/90	390	3.9	190	200	2.6	1004	11.0	10.7	955
34-6	06/27/90	390	5.7	185	205	2.6	1002	12.0	11.0	955
34-7	06/27/90	390	7.9	175	195	2.6	989	12.0	13.0	950
34-8	06/27/90	390	4.0	180	205	2.6	992	12.0	12.0	950
35-1	06/27/90	405	6.2	205	225	2.7	982	12.2	15.0	950
35-2	06/27/90	405	5.7	200	230	2.7	995	13.5	13.5	950
35-3	06/27/90	402	4.7	200	230	2.7	997	13.5	13.5	950

Table B-2 AOFA / Diagnostic Tests / Operating Summary (continued)

Test No.	Date	Load (MWe)	Stack Opacity (PCT)	SAPH A Out Temp (° F)	SAPH B Out Temp (° F)	Steam Flow MLB/HR	SH Temp (° F)	SH Lower Spray (kLB/HR)	SH Upper Spray (kLB/HR)	Hot RH Temp (° F)
35-4	06/27/90	407	3.8	200	225	2.7	1003	13.5	13.5	950
35-5	06/28/90	410	9.0	202	230	2.6	993	14.2	13.5	952
35-6	06/28/90	407	9.7	195	235	2.6	995	14.0	13.5	950
35-7	06/28/90	410	5.2	195	225	2.7	999	13.8	13.5	950
36-1	06/29/90	475	10.2	190	220	3.3	982	15.2	10.0	980
36-2	06/29/90	475	10.3	190	230	3.2	986	12.2	10.0	990
36-3	06/29/90	480	12.2	190	240	3.2	982	13.8	10.0	990
36-4	06/29/90	480	13.4	195	245	3.2	981	13.0	10.0	985
46-1	08/14/90	300		200	200	2.0	991	5.0	5.8	950
46-2	08/14/90	300	2.3	200	210	2.0	998	5.8	5.8	970
46-3	08/14/90	300	3.0	200	210		997	6.3	5.8	982
46-4	08/14/90	305	4.0	190	210		987	6.2	5.7	992
47-1	08/14/90	402	22.8				986			
47-2	08/14/90	402	29.4	200	210	2.7	983	11.6	6.7	990
47-3	08/14/90	405	19.2	220	210	2.7	997	10.3	6.7	993
47-4	08/14/90	410	18.3	210	220	2.7	994	11.0	6.7	995
47-5	08/14/90	410	19.4	210	230	2.7	990	11.8	6.7	995
48-1	08/15/90	455	20.0	200	260	31.2	992	6.6	8.2	995
48-2	08/15/90	455	24.9	200	260	3.1	993	6.6	8.2	997
48-3	08/15/90	455	27.4	200	270	3.1	992	6.6	8.1	999
48-4	08/15/90	455	19.4	200	280		993	6.5	8.0	1000
48-5	08/15/90	450	17.7			3.0	989	6.5	8.0	1000
48-6	08/15/90	450	18.3				1006	6.3	8.0	1004
48-7	08/15/90	450	21.5				1016	6.3	7.8	1004
48-8	08/15/90	450	20.5				1015	6.4	8.0	1003
49-1	08/16/90	475	18.2	200	230	3.5	1006	5.0	9.0	995
49-2	08/16/90	480	15.2			3.4	998	5.0	9.0	995
49-3	08/16/90	482	15.1			3.4	989	5.0	8.8	995
49-4	08/16/90	482	21.7	200	240	3.4	983	5.0	8.0	995
49-5	08/16/90	470	20.1	220	230	3.4	1009	4.0	8.8	1000
49-6	08/16/90	485	19.9	200	240	3.4	979	2.5	8.0	997
50-1	10/24/90	487	50.1	230	280	3.3	991	165.0	10.0	1000
51-1	10/26/90	489	20.5	230	250	3.3	1001	130.0	5.0	1000

Table B-3 AOFA / Performance Tests Summary

Test	Date	Conditions	Load MW	MOOS Pattern	OFA Damper	Ex O_2 Dry %	NOx 3% O_2 ppm	NOx lb/MBtu
37-1	07/10/90	HI LOAD PERFORMANCE	480	NONE	75	3	523	0.71
37-2	07/10/90	"	480	NONE	75	2.9	537	0.73
37-3	07/10/90	"	480	NONE	75	3	538	0.73
38-1	07/11/90	HI LOAD PERFORMANCE	485	NONE	75	4.1	616	0.84
38-2	07/11/90	"	488	NONE	75	3.8	605	0.82
38-3	07/11/90	"	488	NONE	75	4.1	598	0.82
39-1	07/12/90	MID LOAD PERFORMANCE	400	E	50	3.9	505	0.69
39-2	07/13/90	"	400	E	50	4.2	559	0.76
40-1	07/13/90	MID LOAD PERFORMANCE	405	E	50	3.8	587	0.80
40-2	07/14/90	"	408	E	50	3.7	534	0.73
40-3	07/14/90	"	405	E	50	3.7	538	0.73
41-1	07/14/90	LOW LOAD PERFORMANCE	298	E	50	4.8	624	0.85
41-2	07/15/90	"	297	E	50	5.8	648	0.88
42-1	07/15/90	LOW LOAD PERFORMANCE	300	E	50	5.4	606	0.83
42-2	07/16/90	"	300	E	50	5.4	611	0.83
42-3	07/16/90	"	300	E	50	5.3	611	0.83
43-1	07/17/90	HI LOAD PERFORMANCE	487	NONE	50	4	701	0.96
43-2	07/17/90	"	487	NONE	50	4	698	0.95
43-3	07/17/90	"	487	NONE	50	3.9	687	0.94
44-1	07/18/90	HI LOAD PERFORMANCE	487	NONE	50	3.6	653	0.89
44-2	07/18/90	"	487	NONE	50	3.8	658	0.90
45-1	07/18/90	HI LOAD PERFORMANCE	489	NONE	1	3.8	902	1.23

Notes: 1. Dry excess O2 at economizer outlet.

Table B-4 AOFA / Performance Tests / Operating Data

Test No.	Date	Load MW	O2 East Econ Outlet Dry %	O2 West Econ Outlet Dry %	O_2 Outlet DRY %	NOx 3% O2 PPM	Opacity PCT	Mill A kLB/HR	Mill B kLB/HR	Mill C kLB/HR	Mill D kLB/HR	Mill E kLB/HR	Mill F kLB/HR
37-1	07/10/90	480	2.6	3.4	3.0	523	15.1	57	60	59	60	50	58
37-2	07/10/90	480	2.6	3.4	2.9	537	16.2	57	60	59	60	50	58
37-3	07/10/90	480	2.8	3.6	3.0	538	13.7	60	62	55	62	50	60
38-1	07/11/90	485	4.0	4.6	4.1	616	19.4	60	64	53	61	46	59
38-2	07/11/90	488	3.6	4.4	3.8	605	17.0	60	64	53	60	46	59
38-3	07/11/90	488	3.6	4.3	4.1	598	10.4	60	64	53	60	46	59
39-1	07/12/90	400	3.5	4.8	3.9	505	6.1	56	60	57	56	0	56
39-2	07/13/90	400	3.7	4.8	4.2	559	8.4	56	60	57	56	0	56
40-1	07/13/90	405	3.4	4.4	3.8	587	11.8	56	60	57	60	0	56
40-2	07/14/90	408	3.4	4.5	3.7	534	10.8	56	61	58	61	0	56
40-3	07/14/90	405	3.3	4.5	3.7	538	7.7	56	61	58	61	0	56
41-1	07/14/90	298	4.8	6.5	4.8	624	3.5	41	49	44	44	0	42
41-2	07/15/90	297	4.8	6.4	5.8	648	4.4	41	49	44	44	0	42
42-1	07/15/90	300	4.5	5.6	5.4	606	4.3	42	48	42	46	0	43
42-2	07/16/90	300	4.5	5.8	5.4	611	2.7	42	49	42	46	0	43
42-3	07/16/90	300	4.2	5.6	5.3	611	2.4	42	49	42	46	0	43
43-1	07/17/90	487	3.9	4.2	4.0	701	10.3	57	64	57	59	48	55
43-2	07/17/90	487	3.8	4.3	4.0	698	7.2	57	64	57	59	48	55
43-3	07/17/90	487	3.8	4.2	3.9	687	9.7	57	64	57	59	48	55
44-1	07/18/90	487	3.9	4.1	3.6	653	9.4	61	66	57	61	51	61
44-2	07/18/90	487	3.8	4.1	3.8	658	15.8	60	66	57	61	51	61
45-1	07/18/90	489	3.7	4.1	3.8	902	24.8	61	66	57	60	51	60

Table B-5 AOFA / Performance Tests / Operating Data

Test	Date	Load MW	SAPH A Out Temp °F	SAPH B Out Temp °F	Steam Flow klbm/hr	SH Temp °F	SH Spray Upper klbm/hr	SH Spray Lower klbm/hr	Hot RH Temp °F
37-1	07/10/90	480	207	200	3.1	997	16.0	12.7	988
37-2	07/10/90	480	205	212	3.1	995	17.0	12.0	986
37-3	07/10/90	480	205	210	3.2	984	19.0	10.2	987
38-1	07/11/90	485	205	235	3.1	989	17.5	7.3	1000
38-2	07/11/90	488	205	242	3.1	1000	16.8	5.6	1000
38-3	07/11/90	488	200	235	3.1	1002	18.0	5.6	993
39-1	07/12/90	400	202	180	2.5	997	13.5	15.0	990
39-2	07/13/90	400	200	180	2.5	995	14.0	14.0	985
40-1	07/13/90	405	210	195	2.5	995	13.0	14.9	980
40-2	07/14/90	408	210	185	2.5	996	13.8	14.5	980
40-3	07/14/90	405	210	192	2.5	997	14.3	14.7	980
41-1	07/14/90	298	185	180	1.8	1003	9.3	10.5	988
41-2	07/15/90	297	185	175	1.8	1011	19.5	10.2	998
42-1	07/15/90	300	177	168	1.8	1001	8.5	6.8	980
42-2	07/16/90	300	175	170	1.8	983	7.9	10.5	970
42-3	07/16/90	300	170	175	NA	987	8.5	10.5	972
43-1	07/17/90	487	220	270	3.1	993	17.5	10.5	992
43-2	07/17/90	487	210	275	3.1	984	18.6	10.5	990
43-3	07/17/90	487	210	280	NA	983	19.8	10.0	993
44-1	07/18/90	487	215	260	3.1	987	15.0	13.3	992
44-2	07/18/90	487	212	265	NA	996	15.6	10.5	998
45-1	07/18/90	489	210	265	3.1	982	17.0	10.5	1002

Table B-6 AOFA / Performance Tests / Summary of Mill Performance

Test No.	UNIT LOAD MW	PARAMETER	MILL A	MILL B	MILL C	MILL D	MILL E	MILL F
37-1	480	Measured Coal Flow, KLb/hr	53.4	64.9	64.3	68.7	50.2	56.7
		Measured PA Flow, Klb/hr	149.1	167.8	128.1	150.1	136.3	154.9
		A/F Ratio	2.57	2.75	2.17	2.50	2.72	2.50
		Avg. Burner Pipe Velocity, FPM	7174	7689	7022	7889	8726	7321
		High Pipe Coal Flow, Klb/hr	16.9	17.9	19.5	23.9	20.4	20.9
		Low Pipe Coal Flow, Klb/hr	10.1	14.6	13.1	8.0	Plugged	9.8
		Avg. Passing 200 mesh, PCT	61.5	68.4	69.7	65.9	73.5	59.1
		Avg. Passing 50 mesh, PCT	96.3	97.3	98.0	97.1	98.8	95.8
39-1	400	Measured Coal Flow, KLb/hr	47.5	64.2	55.2	49.0	0	58.4
		Measured PA Flow, Klb/hr	148.6	137.5	139.1	152.1	0	155.7
		A/F Ratio	2.65	2.31	2.48	2.72	0	2.78
		Avg. Burner Pipe Velocity, FPM	6906	7233	7575	8478	0	8186
		High Pipe Coal Flow, Klb/hr	14.1	17.7	16.5	14.9	0	19.4
		Low Pipe Coal Flow, Klb/hr	8.5	14.0	11.2	9.0	0	11.2
		Avg. Passing 200 mesh, PCT	62.3	64.9	69.4	67.9	NA	63.1
		Avg. Passing 50 mesh, PCT	96.6	97.7	97.7	98.0	NA	97.3
41-1	300	Measured Coal Flow, KLb/hr	42.4	50.6	42.8	45.6	0	49.3
		Measured PA Flow, Klb/hr	136.7	136.6	143.3	143.7	0	153.0
		A/F Ratio	3.42	2.79	3.26	3.27	0	3.73
		Avg. Burner Pipe Velocity, FPM	6746	7101	7951	7482	0	8019
		High Pipe Coal Flow, Klb/hr	13.4	15.0	12.6	15.7	0	17.5
		Low Pipe Coal Flow, Klb/hr	7.1	10.3	8.7	8.6	0	9.1
		Avg. Passing 200 mesh, PCT	68.1	68.6	73.7	71.3	NA	64.8
		Avg. Passing 50 mesh, PCT	98.1	98.9	97.2	98.2	NA	98.5

Table B-7 AOFA / Performance Tests / Combustion Air Flow Distribution

Test	Load	Total Combustion Air lb/hr	Total Secondary Air lb/hr	Secondary Air to Burners lb/hr	Secondary Air to Burners %	Primary Air to Burners lb/hr	Primary Air to Burners %	Overfire Air lb/hr	Overfire Air lb/hr
37	480	3,447,000	2,561,000	NA	NA	886,000	26%	NA	NA
38	480	4,291,000	3,377,000	2,582,000	60%	914,000	21%	795,000	19%
39	400	2,849,000	2,116,000	1,321,000	46%	733,000	26%	795,000	28%
40	405	2,808,000	2,107,000	1,431,000	51%	701,000	25%	676,000	24%
41	298	2,636,000	1,921,000	1,293,000	49%	715,000	27%	628,000	24%
42	300	2,411,000	1,681,000	1,183,000	49%	730,000	30%	498,000	21%
43	487	3,850,000	3,002,000	2,121,000	55%	848,000	22%	881,000	23%
44	487	3,988,000	3,128,000	2,328,000	58%	860,000	22%	800,000	20%
45	489	3,850,000	2,995,000	2,755,000	72%	855,000	22%	240,000	6%

Table B-8 AOFA / Performance Tests / Coal Analysis

Date	H2O	C	H	N	Cl	S	Ash	O	TOTAL	Ind., SU	HHV BTU/lb	VM %	FC %
07/10/90	4.44	73.77	4.79	1.33	0.088	1.72	9.58	4.38	100.10	44.0	13050	34.55	51.43
07/10/90	4.46	73.25	4.73	1.43	0.058	1.73	10.02	4.38	100.06	43.0	12933	34.27	51.25
07/10/90	5.07	72.74	4.74	1.38	0.068	1.77	9.75	4.57	100.09	44.0	12895	34.28	50.9
07/10/90	4.95	72.16	4.54	1.49	0.040	1.71	9.76	5.39	100.04	44.0	12914	33.47	51.82
07/11/90	5	74.2	4.7	1.42	0.058	1.75	8.82	4.11	100.06	48.0	13177	34.16	52.02
07/11/90	5.4	73.75	4.65	1.35	0.087	1.72	8.94	4.18	100.08	45.5	13065	32.20	53.46
07/11/90	5.15	74.76	4.69	1.21	0.087	1.71	8.46	4.02	100.09	45.0	13224	33.40	52.99
07/12/90	5.31	73.44	4.69	1.34	0.077	1.71	8.97	4.54	100.08	43.5	12990	33.32	52.40
07/13/90	5.08	74.19	4.79	1.43	0.087	1.57	8.65	4.29	100.09	43.5	13119	32.83	53.44
07/13/90	5.12	72.46	4.79	1.47	0.078	1.82	9.46	4.88	100.08	45.0	12832	33.30	52.12
07/13/90	6.29	72.75	4.75	1.42	0.086	1.64	8.62	4.54	100.10	47.0	12925	32.91	52.18
07/14/90	5.82	73.19	4.77	1.38	0.058	1.65	8.80	4.40	100.07	43.5	12936	32.79	52.59
07/14/90	5.81	73.18	4.85	1.43	0.048	1.67	8.38	4.68	100.05	47.0	12994	33.82	51.98
07/14/90	6.63	73.3	4.8	1.39	0.047	1.59	8.24	4.06	100.06	47.5	13039	33.31	51.82
07/14/90	6.16	72.85	4.53	1.44	0.030	1.6	8.3	5.12	100.03	43.0	13088	32.87	52.67
07/15/90	7.34	72.83	4.78	1.39	0.047	1.61	7.85	4.2	100.05	50.0	12944	33.13	51.69
07/15/90	7.45	72.36	4.73	1.39	0.028	1.58	7.97	4.53	100.04	48.5	12851	32.58	52
07/15/90	6.23	73.03	4.78	1.43	0.038	1.62	8.27	4.64	100.04	45.5	13010	34.06	51.44
07/16/90	6.04	72.59	4.79	1.49	0.048	1.63	8.7	4.74	100.03	44.5	12939	33.98	51.28
07/16/90	6.62	72.37	4.75	1.48	0.066	1.65	8.38	4.74	100.06	43.5	12907	33.5	51.51
07/17/90	5.99	72.89	4.78	1.51	0.057	1.59	8.53	4.72	100.07	42.0	12966	32.88	52.6
07/17/90	6.84	72.53	4.63	1.51	0.057	1.44	8.05	5	100.06	48.0	12832	32.26	52.85
07/17/90	4.93	75.38	4.83	1.42	0.048	1.55	7.53	4.36	100.05	43.0	13435	33.29	54.25
07/18/90	5.3	72.24	4.63	1.44	0.038	1.55	10.2	4.3	99.70	44.5	12864	32.12	52.05
07/18/90	4.11	73.37	4.72	1.49	0.029	1.55	10.01	4.76	100.04	42.5	13096	33.22	52.66
07/18/90	4.17	73.46	4.58	1.52	0.020	1.56	9.86	4.85	100.02	45.0	13112	33.13	52.84
07/18/90	5.4	72.48	4.65	1.46	0.038	1.5	10.15	4.35	100.03	45.0	12867	32.69	51.76
AVERAGE	*5.66*	*73.18*	*4.73*	*1.42*	*0.058*	*1.65*	*8.81*	*4.54*	*100.05*	*45.0*	*13001*	*33.30*	*52.22*
STD	*0.87*	*0.79*	*0.08*	*0.07*	*0.019*	*0.08*	*0.72*	*0.33*	*0.07*	*2.1*	*135*	*0.66*	*0.77*
VAR	*0.76*	*0.62*	*0.01*	*0.00*	*0.000*	*0.01*	*0.52*	*0.11*	*0.01*	*4.4*	*18270*	*0.43*	*0.60*

Table B-9 AOFA / Performance Tests / Boiler Emissions Summary

	MASS LOADING		GAS VOLUME FLOW		GAS TEMP., °F	WATER VAPOR, %	ISOKINETIC AGREEMENT, %
	gr/acf	gr/scf	acfm	dscfm			
480 MW, 7/10/90, TEST 37, 75% OFA DAMPER SETTING							
RUN 1	1.65	2.75	2225000	1337000	301	8.0	97.3
RUN 2	1.69	2.86	2165000	1280000	306	8.9	100.5
RUN 3	1.55	2.61	2251000	1336000	310	8.1	99.3
AVERAGE	1.63	2.74	2214000	1318000	306	8.3	99.0
±1s	0.06	0.10	36000	26600	4	0.4	1.3
COV	0.04	0.04	0.02	0.02	0.01	0.05	0.01
480 MW, 7/17-18/90, TEST 43-44, 50% OFA DAMPER SETTING							
RUN 1	1.20	1.94	2290000	1418000	298	5.8	94.0
RUN 2	1.75	2.87	2291000	1397000	292	7.9	96.7
RUN 3	1.92	3.16	2299000	1394000	298	7.6	96.2
AVERAGE	1.62	2.66	2293000	1403000	296	7.1	95.6
±1s	0.31	0.52	4000	11000	3	0.9	1.2
COV	0.19	0.20	0.00	0.01	0.01	0.13	0.01
480 MW, 7/18/90, Test 45, 0% OFA DAMPER SETTING							
RUN 1	1.57	2.64	2358000	1405000	308	8.0	97.3
RUN 2	1.84	3.00	2337000	1435000	309	5.1	94.6
AVERAGE	1.71	2.82	2348000	1420000	309	6.6	96.0
±1s	0.13	0.18	11000	15000	1	1.4	1.3
COV	0.08	0.06	0.00	0.01	0.00	0.22	0.01
400 MW, 7/12/90, Test 39, 50% OFA DAMPER SETTING							
RUN 1	1.75	2.75	1628000	1034000	273	7.1	96.4
RUN 2	1.93	3.08	1648000	1034000	276	8.0	97.8
RUN 3	1.71	2.74	1685000	1053000	278	8.1	98.0
AVERAGE	1.80	2.86	1654000	1040000	276	7.7	97.4
±1s	0.10	0.16	24000	9000	2	0.4	0.7
COV	0.05	0.06	0.01	0.01	0.01	0.06	0.01
300 MW, 7/14/90, TEST 41, 50% OFA DAMPER SETTING							
RUN 1	1.12	1.74	1566000	1008000	266	7.2	97.6
RUN 2	1.23	1.93	1560000	995000	268	7.4	99.4
RUN 3	1.14	1.75	1573000	1021000	268	6.1	99.0
AVERAGE	1.16	1.81	1566000	1008000	267	6.9	98.7
±1s	0.05	0.09	5000	11000	1	0.6	0.8
COV	0.04	0.05	0.00	0.01	0.00	0.08	0.01

Table B-10 AOFA / Performance Tests / Fly Ash Chemical Composition

Oxide	Test 37, 480 MW 75% OFA Setting		Test 43, 480 MW 50% OFA Setting		Test 44, 480 MW 50% OFA Setting		Test 45, 480 MW 0% OFA Setting		Test 39, 400 MW 50% OFA Setting		Test 41, 300 MW 50% OFA Setting	
	East	West	East	West	East	West	East	West	East	West	East	West
Li_2O	0.04	0.04	0.03	0.04	0.05	0.05	0.05	0.05	0.04	0.01	0.03	0.03
Na_2O	0.32	0.34	0.42	0.43	0.37	0.35	0.35	0.44	0.32	0.33	0.36	0.30
K_2O	2.66	2.69	2.54	2.56	2.49	2.49	2.55	2.54	2.58	2.68	2.66	2.63
MgO	0.98	1.00	0.81	0.85	0.94	0.94	0.89	0.86	0.92	0.99	0.87	0.86
CaO	1.52	1.63	1.06	0.99	1.82	1.85	1.85	1.85	1.13	1.34	1.15	0.82
Fe_2O_3	16.5	15.1	18.3	17.5	13.8	12.7	13.4	12.7	14.2	14.8	16.9	15.9
Al_2O_3	26.4	26.7	26.2	26.6	26.8	27.4	27.1	27.4	26.2	26.7	26.6	26.3
SiO_2	49.2	50.3	48.3	48.8	49.7	51.5	51.1	51.4	52.6	51.0	48.7	51.4
TiO_2	1.27	1.25	1.28	1.25	1.41	1.36	1.34	1.33	1.12	1.19	1.29	1.20
P_2O_5	0.48	0.40	0.47	0.41	0.69	0.68	0.72	0.66	0.30	0.33	0.36	0.28
SO_3	0.31	0.24	0.21	0.23	0.25	0.30	0.29	0.23	0.36	0.27	0.30	0.23
LOI	26.5	7.7	14.2	4.7	11.3	5.9	12.0	5.2	48.7	11.5	11.8	9.0

Table B-11 AOFA / Performance Tests / Carbon and LOI Results

				MASS TRAIN SAMPLES				ESP Hopper	
				CARBON, %		LOI, %		LOI, %	
DATE	TEST	Boiler Load, MW	OFA Damper Setting, %	<200 mesh	>200 mesh	<200 mesh	>200 mesh	East Duct	West Duct
7/10/90	37	480	75	5.3	35.2	6.0	36.2	26.5	7.7
7/17/90	43	480	50	5.4	39.0	6.4	40.9	14.2	4.7
7/18/90	44	480	50	5.0	22.6	4.2	20.8	11.3	5.9
7/18/90	45	480	0	2.8	18.5	3.3	17.4	12.0	5.2
7/12/90	39	400	50	4.7	27.1	4.3	32.1	48.7	11.5
7/14/90	41	300	50	1.9	23.8	2.8	22.4	11.8	9.0

Table B-12 AOFA / Performance Tests / SOx Results

Date	Duct	Gas Temperature, °F	Concentration, ppm		SO_3-to-SO_2 Ratio, %
			SO_3	SO_2	
480 MW, 75% OFA Damper Setting					
7/10/90 Test 37	East	271	1.2	1035	0.116
		284	1.4	1050	0.133
		282	1.5	1050	0.143
		286	1.8	1056	0.170
7/11/90 Test 38	West	266	2.1	855	0.246
		266	2.9	868	0.334
		267	3.2	871	0.367
		268	3.4	883	0.385
Average of 75% OFA Data		274	2.2	959	0.237
480 MW, 50% OFA Damper Setting					
7/17/90 Test 43	East	265	1.8	764	0.236
		267	2.2	768	0.286
		269	2.4	763	0.315
		272	2.5	762	0.328
7/18/90 Test 44	West	266	1.9	792	0.240
		266	2.5	797	0.314
		268	2.6	786	0.331
		268	2.7	791	0.341
Average of 50% OFA Data		268	2.3	778	0.299
400 MW, 50% OFA Damper Setting					
7/12/90 Test 39	West	242	1.7	800	0.213
		242	2.0	810	0.247
		243	2.1	818	0.257
		242	2.4	817	0.294
7/13/90 Test 40	East	225	1.1	943	0.117
		229	1.2	931	0.129
		230	1.3	924	0.141
		231	1.2	934	0.128
Average of 400 MW Data		236	1.6	872	0.191

Table B-13 AOFA / Performance Tests / In Situ Ash Resitivity Results

Date	Duct	Gas Temp, °F	Dust Layer, mm	Spark Method		V-I Method	
				Field, kV/cm	Resistivity, ohm-cm	Field, kV/cm	Resistivity, ohm-cm
480 MW, 75% OFA Damper Setting							
7/10/90 Test 37	East	303 306 307 305	1.28 1.01 0.67 1.14	9.4 14.9 17.9 13.2	9.1E+09 4.9E+09 8.4E+09 7.6E+09	2.9 9.1 11.2 7.7	1.4E+10 4.6E+10 5.6E+10 3.9E+10
7/11/90 Test 38	West	271 274 277 273	0.51 0.66 0.60 0.62	17.6 15.9 15.0 29.0	5.7E+09 4.9E+09 1.0E+10 6.9E+09	6.9 6.5 6.2 3.1	3.4E+10 3.3E+10 3.1E+10 1.5E+10
Average of 75% OFA Data		290			7.2E+09		3.3E+10
480 MW, 50% OFA Damper Setting							
7/17/90 Test 43	West	274 277 280 280	0.82 0.75 0.80 0.75	14.6 18.0 13.1 16.0	5.5E+10 2.3E+10 7.9E+10 6.2E+10	20.7 11.1 15.4 16.8	1.0E+11 5.5E+10 7.7E+10 8.4E+10
7/18/90 Test 44	East	299 301	1.18 1.11	12.7 14.9	2.2E+10 2.4E+10	6.8 3.5	3.4E+10 1.8E+10
Average of 50% OFA Data		285			4.4E+10		6.1E+10
480 MW, 0% OFA Damper Setting							
7/18/90 Test 45	East	302 302	0.84 0.98	19.6 15.3	2.0E+10 8.6E+10	1.5 4.3	7.7E+09 2.1E+10
Average of 0% OFA Data		302			5.3E+10		1.4E+10
400 MW, 50% OFA Damper Setting							
7/12/90 Test 39	West	251 251 252	1.00 0.47 0.67	16.5 19.1 22.4	1.9E+09 2.4E+09 1.2E+09	1.8 4.5 8.1	9.0E+09 2.2E+10 4.0E+10
7/13/90 Test 40	East	284 285 285 286	0.95 1.78 0.66 0.55	6.3 13.5 9.1 8.2	4.4E+10 3.8E+09 9.1E+09 3.8E+09	3.2 1.5 5.9 7.3	1.6E+10 7.5E+09 3.0E+10 3.6E+10
400 MW Average		274			9.5E+09		2.3E+10
300 MW, 50% OFA Damper Setting							
7/14/90 Test 41	East	285 286 284	0.81 0.94 1.43	16.7 16.0 11.5	3.3E+09 3.7E+09 2.9E+09	4.2 1.0 1.0	2.1E+10 4.8E+09 5.2E+09
7/15/90 Test 42	West	247 246 245 247	0.88 1.05 0.96 0.98	17.0 14.3 15.6 12.2	1.0E+09 3.9E+09 2.6E+09 4.9E+09	3.6 6.6 5.7 5.1	1.8E+10 3.3E+10 2.9E+10 2.6E+10
300 MW Average		263			3.2E+09		2.0E+10

Table B-14 AOFA / Verification Test Summary

TEST NO.	DATE	TEST CONDITIONS	LOAD (MW)	MOOS	OFA DAMPER (%)	Ex O2 DRY (%)	NOx at 3% O2 (ppm)	NOx (lb/MBtu)
52-1	02/22/91	400 MW NOMINAL O2	395	E	50	5.6	591	0.81
52-2	02/22/91	400 MW LOW O2	398	E	50	5.0	543	0.74
52-3	02/22/91	400 MW HIGH O2	398	E	50	6.2	657	0.90
53-1	02/23/91	400 MW NOMINAL O2	402	E	50	5.2	579	0.79
53-2	02/23/91	400 MW LOW O2	401	E	50	4.7	542	0.74
53-3	02/23/91	400 MW HIGH O2	401	E	50	5.7	620	0.85
54-1	02/25/91	480 MW NOMINAL O2 (LOI)	480	NONE	50	3.8	613	0.84
54-2	02/25/91	480 MW LOW O2 (LOI)	480	NONE	50	2.7	530	0.72
54-3	02/25/91	480 MW LOW O2	480	NONE	50	3.2	566	0.77
54-4	02/25/91	480 MW HIGH O2 (LOI)	481	NONE	50	4.3	691	0.94
54-5	02/25/91	480 MW NOMINAL O2	481	NONE	50	3.8	630	0.86
55-1	02/26/91	480 MW NOMINAL O2 (LOI)	481	NONE	50	3.8	620	0.85
55-2	02/26/91	480 MW MID OFA	481	NONE	25	3.8	758	1.03
55-3	02/26/91	480 MW LOW OFA	482	NONE	5	4.0	856	1.17
56-1	02/27/91	480 MW NOMINAL O2 (HVT)	480	NONE	50	4.0	695	0.95
57-1	02/28/91	480 MW LOW O2 (HVT)	480	NONE	50	3.3	638	0.87

Notes: 1. Dry excess O2 at economizer outlet.

Table B-15 AOFA / Long-Term / Emissions by Load

LOAD CATEGORY	N	PCT LOAD	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX	L5% KCO3	AVG KCO3	U95% KCO3	L5% KTHC3	AVG KTHC3	U95% KTHC3
170-190	1314	5.2%	175	182	189	8.2	9.7	11.3	0.76	0.91	1.06	1.82	2.21	2.63	3	8	12	1	3	5
190-210	760	3.0%	191	200	209	7.4	9.3	11.1	0.70	0.89	1.05	1.65	2.15	2.60	3	9	18	0	3	12
210-230	694	2.7%	211	219	229	7.5	9.4	11.4	0.71	0.90	1.12	1.53	2.15	2.63	3	8	19	0	3	10
230-250	821	3.2%	231	240	249	7.2	9.0	10.5	0.74	0.91	1.01	1.67	2.23	2.68	4	8	13	0	3	9
250-270	676	2.7%	251	260	269	7.3	8.9	10.6	0.73	0.90	1.07	1.57	2.09	2.62	3	9	15	0	2	6
270-290	974	3.9%	271	281	289	7.0	8.5	10.1	0.65	0.90	1.07	1.50	2.06	2.62	4	9	16	0	2	6
290-310	1145	4.5%	291	300	309	7.1	8.3	9.7	0.68	0.90	1.05	1.52	2.04	2.59	4	10	26	0	3	6
310-330	1167	4.6%	311	321	329	6.5	8.0	9.6	0.69	0.90	1.05	1.45	2.07	2.47	4	11	32	0	3	5
330-350	1252	4.9%	331	340	349	6.3	7.9	9.3	0.75	0.90	1.05	1.31	2.05	2.45	4	10	20	0	3	5
350-370	961	3.8%	351	360	369	6.2	7.7	9.2	0.76	0.91	1.08	1.41	2.08	2.53	4	10	20	0	2	5
370-390	1285	5.1%	371	380	389	6.1	7.4	8.7	0.71	0.91	1.10	1.46	2.09	2.52	4	11	21	0	2	5
390-410	1054	4.2%	391	400	409	6.0	7.2	8.8	0.70	0.89	1.10	1.56	2.14	2.67	4	12	28	0	2	7
410-430	1316	5.2%	411	420	429	5.8	6.9	8.2	0.75	0.91	1.11	1.56	2.07	2.56	5	13	34	0	2	5
430-450	1950	7.7%	432	441	449	5.8	6.8	7.8	0.80	0.96	1.14	1.46	2.01	2.53	5	11	21	0	1	4
450-470	1989	7.9%	451	459	469	5.4	6.4	7.5	0.79	0.94	1.10	1.34	1.99	2.57	4	15	48	0	2	7
470-490	7918	31.3%	473	480	486	5.3	6.5	7.8	0.80	0.94	1.09	1.57	2.08	2.67	5	13	27	0	2	6
490-510	19	0.1%	490	493	500	5.5	6.2	7.4	0.68	0.93	1.17	1.43	1.88	2.77	8	13	23	0	3	13

ALL DATA
PROCESSING FOR LOAD CATEGORIES
COMMON LOAD O2 NOX SOX CO3% THC3%

Table B-16 AOFA / Long-Term / Within-Day Averages

HOUR	N	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX
0	94	179.35	295.76	467.73	6.11	8.28	10.76	0.751	0.909	1.066	1.37	2.08	2.62
1	94	179.67	280.30	461.13	6.34	8.51	10.48	0.753	0.917	1.068	1.34	2.06	2.58
2	94	180.27	281.04	459.28	6.35	8.57	10.65	0.795	0.923	1.071	1.30	2.06	2.60
3	95	182.17	286.37	458.12	6.30	8.55	10.72	0.732	0.919	1.063	1.39	2.07	2.60
4	93	189.99	321.10	472.28	6.26	8.15	10.35	0.728	0.925	1.089	1.51	2.08	2.58
5	96	199.17	374.99	482.07	5.46	7.47	9.65	0.751	0.924	1.066	1.49	2.10	2.63
6	97	243.32	405.78	483.98	5.66	7.12	9.26	0.745	0.913	1.062	1.47	2.13	2.66
7	84	253.30	417.53	482.94	5.76	7.04	8.84	0.755	0.916	1.073	1.50	2.11	2.60
8	86	285.05	420.76	484.76	5.57	6.95	8.80	0.736	0.919	1.100	1.52	2.12	2.66
9	81	308.58	422.84	484.70	5.47	6.88	8.42	0.789	0.908	1.042	1.59	2.12	2.67
10	82	258.57	418.24	484.37	5.52	7.02	8.67	0.749	0.913	1.101	1.60	2.13	2.62
11	84	243.08	415.32	484.49	5.59	6.96	9.25	0.744	0.907	1.092	1.64	2.12	2.59
12	85	284.42	416.90	484.60	5.74	6.94	8.77	0.758	0.916	1.084	1.61	2.09	2.65
13	85	267.60	416.87	484.09	5.75	6.94	8.61	0.754	0.912	1.085	1.59	2.09	2.65
14	87	258.85	410.54	483.09	5.58	6.95	8.76	0.776	0.910	1.081	1.55	2.08	2.66
15	90	244.18	411.57	483.42	5.70	7.04	9.14	0.741	0.917	1.099	1.52	2.09	2.62
16	96	267.64	413.23	484.42	5.63	7.14	9.17	0.719	0.927	1.098	1.49	2.08	2.65
17	97	296.56	419.96	483.87	5.64	7.10	9.44	0.727	0.928	1.081	1.49	2.08	2.61
18	97	292.51	424.30	482.82	5.66	7.03	9.15	0.704	0.930	1.089	1.51	2.07	2.64
19	97	285.65	418.19	483.64	5.67	7.09	9.30	0.788	0.932	1.117	1.51	2.07	2.59
20	97	252.97	408.30	483.67	5.77	7.17	9.55	0.690	0.920	1.122	1.46	2.08	2.62
21	95	254.33	399.18	483.18	5.77	7.22	9.69	0.730	0.921	1.093	1.47	2.08	2.57
22	93	221.48	376.58	480.62	5.96	7.44	10.56	0.793	0.924	1.105	1.56	2.08	2.56
23	93	182.67	335.49	478.85	6.16	7.78	10.38	0.757	0.907	1.097	1.47	2.09	2.61

Table B-17 AOFA / Long-Term / Daily Averages

DAY	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
901014	0				
901015	0				
901016	11				
901017	24	463.13	6.86	0.990	1.72
901018	23	448.27	6.87	1.008	1.73
901019	14				
901020	0				
901021	0				
901022	14				
901023	22	446.63	7.07	0.973	1.82
901024	19	410.71	7.77	0.964	1.75
901025	23	425.92	7.13	0.920	1.85
901026	18	388.55	7.26	0.926	1.74
901027	24	433.71	6.87	0.937	1.89
901028	24	447.27	6.59	0.946	2.33
901029	24	466.65	6.19	1.009	2.31
901030	22	472.09	6.42	1.040	1.56
901031	0				
901101	0				
901102	23	443.86	6.99	0.847	1.74
901103	13				
901104	0				
901105	11				
901106	24	445.68	6.40	0.880	1.77
901107	24	430.63	6.34	0.866	1.93
901108	24	424.85	6.39	0.871	1.67
901109	24	427.36	6.54	0.891	1.62
901110	21	410.16	6.32	0.777	2.34
901111	0				
901112	18	452.27	6.51	0.780	2.53
901113	20	451.84	6.59	0.874	2.05
901114	24	438.87	6.67	0.875	2.05
901115	24	460.66	6.63	0.918	1.86
901116	21	454.70	6.33	0.861	2.02
901117	24	410.86	7.01	0.860	1.94
901118	24	438.74	6.41	0.879	2.28
901119	23	455.06	6.22	0.940	2.04
901120	24	426.70	6.71	0.922	2.01
901121	24	445.44	6.33	0.899	2.13
901122	24	370.37	7.17	0.888	1.70
901123	24	403.93	6.66	0.865	1.38
901124	23	438.51	6.39	0.885	1.57
901125	24	453.81	6.36	0.941	1.73
901126	22	463.05	6.36	0.950	1.69
901127	20	448.27	6.85	0.858	2.04
901128	23	463.79	6.39	0.811	2.57
901129	24	434.25	7.88	0.971	2.61
901130	24	457.38	7.77	0.965	2.86
901201	24	457.27	8.06	1.050	2.32
901202	24	425.02	8.09	1.027	1.53
901203	21	394.75	7.03	0.884	1.58
901204	24	360.14	6.55	0.803	2.03
901205	24	447.75	5.93	0.871	1.95
901206	24	470.59	5.11	0.845	2.23
901207	21	404.60	6.55	0.906	2.19
901208	24	422.73	7.22	0.982	2.32
901209	24	460.43	6.77	1.083	2.51
901210	18	449.61	6.82	1.069	2.30
901211	24	454.56	6.39	1.045	2.09
901212	24	416.57	7.25	1.023	2.11

Table B-17 AOFA / Long-Term / Daily Averages (Continued)

DAY	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
901213	23	434.04	7.31	1.092	2.16
901214	9				
901215	0				
901216	0				
901217	2				
901218	22	248.41	9.37	0.916	2.53
901219	17				
901220	0				
901221	4				
901222	24	358.35	7.63	0.839	2.62
901223	24	366.44	8.03	0.948	2.38
901224	19	376.10	8.11	0.948	2.55
901225	5				
901226	0				
901227	0				
901228	0				
901229	0				
901230	0				
901231	0				
910101	0				
910102	0				
910103	0				
910104	0				
910105	0				
910106	0				
910107	0				
910108	0				
910109	13				
910110	22	290.71	6.98	0.706	1.58
910111	0				
910112	0				
910113	0				
910114	0				
910115	0				
910116	24	275.26	6.52	0.672	2.55
910117	23	279.94	7.32	0.750	2.32
910118	23	310.50	7.70	0.854	2.09
910119	24	262.09	7.64	0.848	2.13
910120	24	221.41	8.21	0.871	2.12
910121	24	308.62	7.32	0.878	2.10
910122	24	346.03	7.57	0.926	2.00
910123	21	356.02	7.83	1.035	2.15
910124	24	373.44	7.31	0.948	2.25
910125	23	351.18	7.02	0.863	2.25
910126	14				
910127	0				
910128	0				
910129	0				
910130	0				
910131	0				
910201	0				
910202	0				
910203	0				
910204	0				
910205	8				
910206	24	358.25	6.98	0.883	2.14
910207	23	310.37	7.40	0.904	2.21

Table B-17 AOFA / Long-Term / Daily Averages (Continued)

DAY	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
910208	23	302.72	7.53	0.921	2.19
910209	24	286.33	7.11	0.885	2.15
910210	24	252.59	8.23	0.957	2.07
910211	23	347.74	8.02	0.983	2.19
910212	24	346.30	8.65	0.946	2.20
910213	24	315.15	8.49	0.971	1.94
910214	24	304.09	8.71	0.911	1.97
910215	20	327.71	9.05	1.036	2.10
910216	12				
910217	24	282.95	9.47	0.945	1.77
910218	4				
910219	0				
910220	19	318.15	8.73	0.861	2.22
910221	24	299.25	8.82	0.818	2.04
910222	15				
910223	18	263.92	9.25	0.878	2.46
910224	24	259.65	8.92	0.913	2.40
910225	14				
910226	15				
910227	14				
910228	16				
910301	24	305.78	8.63	0.854	2.41
910302	24	242.17	9.73	0.936	2.58
910303	24	388.95	8.42	0.982	2.17
910304	23	398.45	8.09	0.994	1.83
910305	24	387.87	7.54	0.933	2.10
910306	24	387.09	7.15	0.867	2.09
910307	23	395.15	7.34	0.935	2.31
910308	18	395.93	8.22	0.975	2.36

PLANT HAMMOND PHASE 2 TESTING
FIVE MINUTE DATA
DAILY AVGS (DAYS WITH AT LEAST 18 HRS DATA)
VALID HOURS ONLY - USES COMMON VARIABLE

Table B-18 AOFA / Long-Term / Rolling 30 Day Averages

30DAY#	MLOAD30	MKO230	MKNOX30	MKSOX30
1	434.95	6.69	0.913	1.87
2	434.93	6.68	0.911	1.87
3	435.43	6.66	0.904	1.90
4	434.91	6.69	0.904	1.93
5	436.03	6.70	0.905	1.97
6	437.08	6.73	0.909	1.99
7	437.51	6.77	0.913	1.98
8	436.27	6.77	0.911	1.97
9	433.34	6.77	0.906	1.96
10	432.71	6.76	0.901	1.95
11	433.62	6.69	0.901	1.96
12	434.25	6.68	0.900	1.98
13	434.15	6.69	0.903	1.99
14	435.06	6.70	0.909	2.00
15	434.90	6.72	0.915	2.02
16	435.71	6.72	0.921	2.03
17	435.43	6.75	0.926	2.04
18	435.66	6.77	0.933	2.06
19	432.58	6.81	0.931	2.08
20	430.16	6.85	0.934	2.09
21	427.46	6.90	0.934	2.11
22	421.41	6.90	0.928	2.13
23	417.13	6.91	0.924	2.14
24	412.87	6.95	0.923	2.14
25	406.38	7.00	0.920	2.14
26	399.50	7.05	0.918	2.14
27	394.93	7.09	0.918	2.14
28	394.10	7.10	0.919	2.15
29	392.41	7.14	0.924	2.18
30	390.30	7.17	0.927	2.20
31	386.87	7.19	0.924	2.22
32	382.18	7.22	0.923	2.24
33	379.16	7.25	0.927	2.23
34	373.42	7.22	0.925	2.21
35	369.81	7.20	0.924	2.18
36	366.24	7.16	0.919	2.18
37	364.23	7.12	0.914	2.21
38	357.50	7.13	0.915	2.23
39	354.38	7.15	0.920	2.24
40	349.02	7.22	0.922	2.25
41	345.26	7.31	0.924	2.25
42	341.88	7.35	0.923	2.25
43	337.93	7.36	0.921	2.24
44	332.11	7.38	0.911	2.23
45	325.81	7.44	0.907	2.22
46	322.33	7.52	0.904	2.22
47	319.98	7.59	0.901	2.23
48	316.17	7.64	0.895	2.22
49	314.35	7.70	0.899	2.18

Table B-22 AOFA / Long-Term / Rolling 30 Day Averages (Continued)

30DAY#	MLOAD30	MKO230	MKNOX30	MKSOX30
50	313.30	7.73	0.902	2.17
51	312.42	7.77	0.904	2.14
52	312.68	7.91	0.918	2.10
53	313.23	7.99	0.921	2.09
54	313.15	8.04	0.922	2.09
55	314.35	8.11	0.924	2.10
56	315.63	8.14	0.926	2.12
57	317.74	8.20	0.928	2.13
58	317.61	8.27	0.929	2.15
59	318.37	8.29	0.923	2.15
60	318.02	8.37	0.922	2.15
61	316.51	8.46	0.921	2.16
62	313.90	8.52	0.922	2.18
63	314.41	8.52	0.925	2.18
64	319.06	8.50	0.928	2.16
65	320.36	8.46	0.928	2.16
66	321.59	8.40	0.926	2.16
67	322.71	8.36	0.926	2.16

PLANT HAMMOND PHASE 2 TEST DATA
DAILY AVERAGES FROM EDITED 5 MINUTE DATA
PROCESS FOR ROLLING AVERAGES
VALID HOURLY AVERAGES: EACH WITH AT LEAST 1/2 DATA
EACH PARAMETER SET SEPARATELY (NO COMMON)
NON-BOD'S DELETED

APPENDIX C
LNB TEST DATA

Table C-1 LNB / Diagnostic Test Summary

Test	Date	Test Conditions	Load MW	MOOS	Econ O_2 Dry %	Econ NOx ppm	Econ NOx lb/MBtu	CO ppm	LOI E %	LOI W %
58-1	7/9/91	HIGH LOAD, AMIS, HIGH O2-LOI TEST	477	NONE	4.6	508	0.69	11	6.9	5.8
58-2	7/9/91	HIGH LOAD, AMIS, NORM O2-LOI TEST	475	NONE	4.1	480	0.65	11	8.1	9.3
58-3	7/9/91	HIGH LOAD, AMIS, LOW O2-LOI TEST	473	NONE	2.9	426	0.58	67	11.0	16.7
59-1	7/10/91	HIGH LOAD, AMIS, HIGH O2-LOI TEST	471	NONE	5.0	483	0.66	12	4.9	7.8
59-2	7/10/91	HIGH LOAD, AMIS, NORM O2-LOI TEST	473	NONE	4.0	441	0.60	13	11.0	7.9
59-3	7/10/91	HIGH LOAD, AMIS, LOW O2-LOI TEST	475	NONE	3.1	418	0.57	26	12.3	9.7
59-4	7/10/91	HIGH LOAD, AMIS, MIN O2-LOI TEST	474	NONE	2.6	401	0.55	127	16.3	11.2
59-5	7/10/91	HIGH LOAD, AMIS, LO NORM O2-HVT TEST	474	NONE	3.7	448	0.61	31		
60-1	7/11/91	MID LOAD, AMIS, HIGH O2	393	NONE	4.6	408	0.56	11		
60-2	7/11/91	MID LOAD, AMIS, NORM O2	398	NONE	3.9	377	0.51	13		
60-3	7/11/91	MID LOAD, AMIS, LOW O2	397	NONE	3.5	360	0.49	119		
60-4	7/11/91	MAX LOAD, AMIS, NORM O2, GPC HEAT RATE	502	NONE	4.0	503	0.69	4		
61-1	7/12/91	MID LOAD, AMIS, REPEAT HIGH O2	392	NONE	4.7	401	0.55	6		
61-2	7/12/91	MID LOAD, AMIS, REPEAT NORM O2	392	NONE	4.1	377	0.51	6		
61-3	7/12/91	MID LOAD, AMIS, REPEAT LOW O2	390	NONE	3.2	340	0.46	81		
61-4	7/12/91	MAX LOAD, AMIS, NORM O2, GPC HEAT RATE	498	NONE	3.9	480	0.65	15		
62-1	7/13/91	MID/LOW LOAD, E MOOS, HIGH O2	289	E	7.1	458	0.62	7		
62-2	7/13/91	MID/LOW LOAD, E MOOS, MEDIUM O2	291	E	5.9	424	0.58	7		
62-3	7/13/91	MID/LOW LOAD, E MOOS, NORM O2	290	E	4.8	398	0.54	9		
62-4	7/13/91	MID/LOW LOAD, E MOOS, LOW O2-ABBREV.	289	E	4.0	375	0.51	14		
62-5	7/13/91	HIGH LOAD, AMIS, NORM O2	474	NONE	4.3	471	0.64	18		
63-1	7/14/91	MID/LOW LOAD, BE MOOS, HIGH O2	302	B&E	5.8	366	0.50	13		
63-2	7/14/91	MID/LOW LOAD, BE MOOS, HIGH O2	305	E	5.7	425	0.58	10		
63-3	7/14/91	MID/LOW LOAD, BE MOOS, NORM O2	303	E	4.8	402	0.55	26		
64-1	7/15/91	HI LOAD, HI/MID O2, AMIS, BALANCED MILLS	467	NONE	4.6	487	0.66	13		
64-2	7/15/91	HI LOAD, LOW O2, AMIS, BALANCED MILLS	470	NONE	3.3	426	0.58	56		
67-1	7/18/91	HI LOAD, AMIS, HI O2-LOI TEST, OPEN INNER REG	472	NONE	4.3	443	0.60	16	12.7	7.5
67-2	7/18/91	HI LOAD, AMIS, MID O2-LOI TEST,	471	NONE	3.6	422	0.58	171		
67-3	7/18/91	HI LOAD, AMIS, LOW 02-LOI TEST, OPEN OUT. REG	470	NONE	3.5	425	0.58	22	13.1	10.5
67-4	7/18/91	HI LOAD, LOW O2, LOI TEST, UF AIR AT 25%	465	NONE	3.5	430	0.59	16	8.7	9.6
68-1	7/19/91	HI LOAD, AMIS-LOI TEST, LOWER PRIM AIR FLOW	460	NONE	3.5	442	0.60	37	6.2	11.2
69-1	7/20/91	HI LOAD, AMIS-LOI TEST, MILL FINENESS A-MILL	473	NONE	3.2	413	0.56	19		
69-2	7/20/91	HI LOAD, AMIS-LOI TEST, MILL FINENESS F-MILL	469	NONE	3.3	448	0.61	15		
77-1	11/16/91	LOW LOAD, BC-MOOS, HI O2	180	BC	8.7	413	0.56	6		
77-2	11/16/91	LOW LOAD, BC-MOOS, HI O2, REPEAT TEST	180	BC	8.5	428	0.58	6		
77-3	11/16/91	LOW LOAD, BC-MOOS, MID O2	182	BC	7.4	416	0.57	6		
77-4	11/16/91	LOW LOAD, BC-MOOS, LOW O2	185	BC	6.4	444	0.61	5		
78-1	11/17/91	LOW LOAD, BE-MOOS, HI O2	181	BE	8.3	556	0.76	5		
78-2	11/17/91	LOW LOAD, BE-MOOS, MID O2	183	BE	7.2	543	0.74	5		
78-3	11/17/91	LOW LOAD, BE-MOOS, LOW O2	180	BE	5.8	507	0.69	5		
79-1	11/18/91	MID/LOW LOAD, BE-MOOS, HI O2	305	BE	7.1	476	0.65	9		
79-2	11/18/91	MID/LOW LOAD, BE-MOOS, MID O2	305	BE	6.1	487	0.66	9		
79-3	11/18/91	MID/LOW LOAD, BE-MOOS, LOW O2	305	BE	5.3	399	0.54	49		
80-1	11/18/91	MID/LOW LOAD, EF-MOOS, LOW O2	310	EF	4.8	333	0.45	101		
80-2	11/18/91	MID/LOW LOAD, EF-MOOS, MID O2	308	EF	6.3	405	0.55	11		
80-3	11/18/91	MID/LOW LOAD, EF-MOOS, MID O2, SLEEVES 50%	310	EF	6.2	342	0.47	14		
81-1	1/14/92	MID/LOW LOAD, BE-MOOS, LOW O2	302	BE	5.0	369	0.50	49		
81-2	1/14/92	MID/LOW LOAD, BE-MOOS, MID O2	299	BE	6.5	438	0.60	10		
81-3	1/14/92	MID/LOW LOAD, BE-MOOS, HI O2	301	BE	7.0	445	0.61	10		
82-1	1/15/92	MID LOAD, AMIS, LOW O2	395	NONE	3.8	395	0.54	74		
82-2	1/15/92	MID LOAD, AMIS, MID O2	395	NONE	4.5	427	0.58	5		
82-3	1/15/92	MID LOAD, AMIS, HI O2	395	NONE	5.4	464	0.63	4		

Note: 1. Dry O2 at economizer outlet.

Table C-2 LNB / Diagnostic Tests / Operating Summary

Test Number	Date	Gross Load MW	O2 Econ. East (Plant) %	O2 Econ. West (Plant) %	CEM O2 %	CEM NOx lb/MBtu	Opacity %	Mill A Flow klb/hr	Mill B Flow klb/hr	Mill C Flow klb/hr	Mill D Flow klb/hr	Mill E Flow klb/hr	Mill F Flow klb/hr
58-1	7/9/91	477	3.8	4.1	4.6	0.69	-	54	64	57	55	58	53
58-2	7/9/91	475	3.4	3.7	4.1	0.65	-	64	67	70	62	62	66
58-3	7/9/91	473	2.1	2.7	2.9	0.58	-	53	62	57	54	57	52
59-1	7/10/91	471	3.9	4.7	5.0	0.66	-	52	62	57	54	58	52
59-2	7/10/91	473	2.9	3.7	4.0	0.60	-	52	62	57	54	58	52
59-3	7/10/91	475	2.1	3.1	3.1	0.57	-	52	62	56	54	58	52
59-4	7/10/91	474	1.7	2.6	2.6	0.55	-	52	62	57	54	58	52
59-5	7/10/91	474	2.4	3.7	3.7	0.61	-	52	62	56	54	58	52
60-1	7/11/91	393	3.6	4.6	4.6	0.56	-	45	53	48	47	46	44
60-2	7/11/91	398	3.0	3.8	3.9	0.51	-	44	52	47	47	46	44
60-3	7/11/91	397	2.7	3.2	3.5	0.49	-	44	52	47	47	46	43
60-4	7/11/91	502	3.7	2.6	4.0	0.69	-	58	63	57	57	61	53
61-1	7/12/91	392	3.7	2.5	4.7	0.55	-	45	49	44	47	48	44
61-2	7/12/91	392	3.1	2.9	4.1	0.51	-	45	48	44	48	48	44
61-3	7/12/91	390	2.1	2.1	3.2	0.46	-	45	48	44	47	48	44
61-4	7/12/91	498	3.5	2.6	3.9	0.65	-	55	57	53	59	63	60
62-1	7/13/91	289	4.8	4.2	7.1	0.62	-	42	43	43	44	0	43
62-2	7/13/91	291	4.8	4.2	5.9	0.58	-	42	43	43	44	0	43
62-3	7/13/91	290	3.9	3.5	4.8	0.54	-	42	43	43	44	0	43
62-4	7/13/91	289	3.9	3.5	4.8	0.54	-	42	43	43	44	0	43
62-5	7/13/91	474	3.7	3.1	4.3	0.64	-	54	56	53	57	56	54
63-1	7/14/91	302	4.5	5.3	5.8	0.50	-	54	0	55	58	0	54
63-2	7/14/91	305	4.2	5.4	5.7	0.58	-	40	47	44	47	0	44
63-3	7/14/91	303	3.6	4.7	4.8	0.55	-	-	-	-	-	-	-
64-1	7/15/91	467	4.1	3.0	4.6	0.66	26.9	57	54	53	55	58	54
64-2	7/15/91	470	2.8	2.1	3.3	0.58	18.4	57	53	53	54	58	53
67-1	7/18/91	472	3.2	3.0	4.3	0.60	23.5	55	57	56	56	56	56
67-2	7/18/91	471	2.6	2.3	3.6	0.57	27.0	57	57	57	56	56	56
67-3	7/18/91	470	3.0	2.0	3.5	0.58	24.1	55	57	57	56	57	56
67-4	7/18/91	465	3.3	2.3	3.5	0.59	20.2	67	64	65	68	65	67
68-1	7/19/91	460	3.7	2.3	3.5	0.60	22.3	56	56	45	55	56	55
69-1	7/20/91	473	2.4	2.4	3.2	0.56	22.4	56	56	55	55	56	55
69-2	7/20/91	469	3.0	2.3	3.3	0.61	23.9	55	56	56	55	56	55
77-1	11/16/91	180	8.6	7.8	8.7	0.56	1.4	34	0	0	37	35	38
77-2	11/16/91	180	8.4	7.8	8.5	0.58	NA	33	0	0	36	35	38
77-3	11/16/91	182	7.2	7.1	7.4	0.57	1.2	35	0	0	32	28	32
77-4	11/16/91	185	5.7	7.2	6.4	0.61	1.0	34	0	0	36	35	38
78-1	11/17/91	181	7.7	8.3	8.3	0.76	2.2	35	0	33	39	0	37
78-2	11/17/91	183	6.6	7.7	7.2	0.74	1.5	35	0	35	39	0	27
78-3	11/17/91	180	5.8	6.1	5.8	0.69	1.7	35	0	35	39	0	37
79-1	11/18/91	305	6.4	6.7	7.1	0.65	4.7	59	0	55	57	0	55
79-2	11/18/91	305	4.8	6.0	6.1	0.66	3.7	58	0	55	57	0	55
79-3	11/18/91	305	4.0	5.2	5.3	0.54	3.7	58	0	55	57	0	55
80-1	11/18/91	310	3.3	5.7	4.8	0.45	4.6	59	57	53	57	0	0
80-2	11/18/91	308	4.8	6.5	6.3	0.55	6.2	59	57	53	57	0	0
80-3	11/18/91	310	4.2	6.5	6.2	0.47	6.0	59	57	53	57	0	0
81-1	1/14/92	302	3.4	3.2	5.0	0.50	16.6	57	0	57	58	0	58
81-2	1/14/92	299	4.8	4.8	6.5	0.60	22.6	56	0	57	58	0	57
81-3	1/14/92	301	5.3	5.1	7.0	0.61	25.5	56	0	57	58	0	57
82-1	1/15/92	395	3.2	2.2	3.8	0.54	16.9	45	49	45	50	51	47
82-2	1/15/92	395	3.7	3.1	4.5	0.58	21.3	45	49	44	50	52	47
82-3	1/15/92	395	4.3	3.9	5.4	0.63	24.8	45	49	45	50	52	57

Table C-2 LNB / Diagnostic Tests / Operating Summary (continued)

Test Number	Date	Gross Load MW	SAPH A Outlet Temp. Deg. F	SAPH B Outlet Temp. Deg. F	Steam Flow Mlb/hr	SH Temp. Deg. F	SH Lower Spray klb/hr	SH Upper Spray klb/hr	Hot RH Temp Deg. F.
58-1	7/9/91	477	340	350	3.17	996	0.0	8.0	1022
58-2	7/9/91	475	340	350	3.15	983	0.0	8.0	997
58-3	7/9/91	473	320	350	3.15	1023	0.0	8.0	988
59-1	7/10/91	471	340	340	3.15	994	0.0	11.0	1000
59-2	7/10/91	473	330	340	3.17	986	0.0	10.2	986
59-3	7/10/91	475	330	350	3.16	992	0.0	10.2	983
59-4	7/10/91	474	330	350	3.17	993	0.0	10.2	977
59-5	7/10/91	474	340	350	3.15	979	0.0	10.1	992
60-1	7/11/91	393	300	330	2.60	1000	0.0	8.5	972
60-2	7/11/91	398	310	340	2.60	1007	0.0	8.8	969
60-3	7/11/91	397	300	360	2.60	991	0.0	10.5	967
60-4	7/11/91	502	350	360	3.32	969	0.0	10.2	1000
61-1	7/12/91	392	320	330	2.56	983	0.0	10.2	977
61-2	7/12/91	392	320	330	2.54	965	0.0	10.3	978
61-3	7/12/91	390	320	330	-	993	0.0	10.8	973
61-4	7/12/91	498	350	350	-	965	0.0	11.3	1000
62-1	7/13/91	289	310	310	1.90	989	0.0	8.4	979
62-2	7/13/91	291	310	310	1.90	989	0.0	8.4	979
62-3	7/13/91	290	310	320	1.92	1009	0.0	7.8	978
62-4	7/13/91	289	310	320	1.92	1009	0.0	7.8	978
62-5	7/13/91	474	340	350	3.08	979	0.0	6.7	1008
63-1	7/14/91	302	290	320	2.00	1026	0.0	8.0	992
63-2	7/14/91	305	300	330	2.00	985	0.0	8.0	986
63-3	7/14/91	303	310	330	2.00	1000	0.0	8.0	886
64-1	7/15/91	467	336	349	3.13	962	0.0	13.2	997
64-2	7/15/91	470	335	351	3.16	985	0.0	11.3	985
67-1	7/18/91	472	325	331	3.17	987	0.0	0.1	986
67-2	7/18/91	471	325	333	3.19	1017	0.0	0.1	982
67-3	7/18/91	470	330	341	3.15	1012	0.0	0.1	987
67-4	7/18/91	465	330	340	3.10	983	0.0	0.1	981
68-1	7/19/91	460	320	333	3.07	1012	0.0	0.1	999
69-1	7/20/91	473	315	328	3.15	959	0.0	0.1	987
69-2	7/20/91	469	318	330	3.13	986	0.0	0.1	987
77-1	11/16/91	180	286	280	1.10	993	0.0	6.5	996
77-2	11/16/91	180	290	283	1.08	994	0.0	6.9	995
77-3	11/16/91	182	300	289	1.13	995	0.0	6.7	988
77-4	11/16/91	185	308	290	1.12	1000	0.0	7.0	979
78-1	11/17/91	181	290	290	1.11	993	0.0	8.0	988
78-2	11/17/91	183	300	302	1.10	992	0.0	0.1	978
78-3	11/17/91	180	305	320	1.10	999	0.0	0.1	968
79-1	11/18/91	305	281	304	1.92	997	0.0	0.0	987
79-2	11/18/91	305	281	300	1.90	996	0.0	0.0	981
79-3	11/18/91	305	280	299	1.90	992	0.0	15.0	974
80-1	11/18/91	310	280	303	1.94	1010	0.0	0.0	979
80-2	11/18/91	308	278	299	1.92	999	0.0	0.0	983
80-3	11/18/91	310	280	292	1.92	999	0.0	0.0	980
81-1	1/14/92	302	280	270	1.76	994	0.0	13.7	980
81-2	1/14/92	299	270	275	1.78	994	0.0	13.5	989
81-3	1/14/92	301	270	270	1.75	997	0.0	12.7	1006
82-1	1/15/92	395	300	300	2.45	1001	0.0	10.3	980
82-2	1/15/92	395	300	300	2.42	999	0.0	10.4	995
82-3	1/15/92	395	300	300	2.42	1001	0.0	12.0	995

Table C-3 LNB / Performance Tests Summary

Test No.	Date	Test Conditions	Load	MOOS	ECON O_2 Dry %	ECON NOx ppm	ECON NOx lb/MBtu	CO ppm	Comp LOI %	Comp Carbon %
65-1	7/16/91	HI LOAD, AMIS	470	NONE	4.0	458	0.62	13	7.6	7.0
66-1	7/17/91	HI LOAD, AMIS	475	NONE	3.8	452	0.62	13		
66-2	7/17/91	HI LOAD, AMIS	474	NONE	3.8	460	0.63	15		
70-1	7/22/91	HI LOAD, AMIS, REDUCED PRIM. AIR	479	NONE	3.3	498	0.68	19	7.8	7.3
70-2	7/22/91	HI LOAD, AMIS, REDUCED PRIM. AIR	470	NONE	3.6	485	0.66	32		
71-1	7/23/91	HI LOAD, AMIS, 50% OUTER REG	473	NONE	3.5	483	0.66	15		
71-2	7/23/91	HI LOAD, AMIS, REDUCED PRIM. AIR	465	NONE	3.5	496	0.68	15		
72-1	7/24/91	HI LOAD, AMIS, REDUCED PRIM. AIR	477	NONE	3.4	475	0.65	17	8.6	8.4
73-1	7/26/91	MID LOAD, AMIS, HI O2	388	NONE	4.1	400	0.55	11	5.4	5.1
73-2	7/26/91	MID LOAD, AMIS, HI O2	389	NONE	4.1	407	0.55	7		
74-1	7/27/91	MID LOAD, AMIS, HI O2	403	NONE	3.8	404	0.55	8		
74-2	7/27/91	MID LOAD, AMIS, HI O2	405	NONE	3.6	415	0.57	9		
75-1	7/28/91	MID/LOW LOAD, E MOOS	299	E	4.3	347	0.47	8	5.8	5.3
76-1	7/28/91	MID/LOW LOAD, E MOOS	298	E	4.5	349	0.48	8		

Note: 1. Dry O2 at economizer outlet.

Table C-4 LNB / Performance Tests / Operating Data

Test Number	Date	Gross Load MW	Plant O2 Econ. East %	Plant O2 Econ. West %	CEM O2 %	CEM NOx PPM	CEM NOx lb/MBtu	Opacity %	Mill A Flow klb/hr	Mill B Flow klb/hr	Mill C Flow klb/hr	Mill D Flow klb/hr	Mill E Flow klb/hr	Mill F Flow klb/hr
65-1	7/16/91	470	3.8	3.1	4.0	458	0.62	22.1	54	55	55	55	55	55
66-1	7/17/91	475	3.6	2.7	3.8	452	0.62	28.9	54	55	56	55	55	55
66-2	7/17/91	474	3.2	2.3	3.8	460	0.63	25.4	53	55	55	55	55	55
70-1	7/22/91	479	2.6	2.8	3.3	498	0.68	24.1	56	56	55	56	56	56
70-2	7/22/91	470	2.3	2.8	3.6	485	0.66	16.7	65	58	67	62	60	69
71-1	7/23/91	473	3.1	2.5	3.5	483	0.66	33.1	55	55	55	55	55	55
71-2	7/23/91	465	3.0	2.6	3.5	496	0.68	22.3	54	54	53	54	54	53
72-1	7/24/91	477	2.7	2.0	3.4	475	0.65	28.8	54	55	55	55	55	55
73-1	7/26/91	388	3.8	1.8	4.1	400	0.55	20.0	55	55	55	55	55	55
73-2	7/26/91	389	4.0	1.7	4.1	407	0.55	17.3	55	55	55	55	55	55
74-1	7/27/91	403	3.7	2.2	3.8	404	0.55	27.1	47	47	47	47	47	47
74-2	7/27/91	405	3.7	1.8	3.6	415	0.57	19.2	47	47	47	47	47	47
75-1	7/28/91	299	5.0	2.4	4.3	347	0.47	16.7	44	41	43	43	0	43
76-1	7/28/91	298	5.1	3.8	4.5	349	0.48	15.5	43	41	43	43	0	44

Table C-4 LNB / Performance Tests / Operating Data (continued)

Test Number	Date	Gross Load MW	SAPH A Outlet Temp. Deg. F	SAPH B Outlet Temp. Deg. F	Steam Flow Mlb/hr	SH Temp. Deg. F	SH Lower Spray klb/hr	SH Upper Spray klb/hr	Hot RH Temp Deg. F.
65-1	7/16/91	470	330	335	3.13	994	0.0	0.1	996
66-1	7/17/91	475	330	325	3.15	991	0.0	0.1	997
66-2	7/17/91	474	338	335	3.15	1001	0.0	0.1	1002
70-1	7/22/91	479	320	330	3.20	1019	0.0	0.1	1001
70-2	7/22/91	470	328	338	3.14	986	0.0	0.1	989
71-1	7/23/91	473	312	320	3.15	997	0.0	0.1	994
71-2	7/23/91	465	325	340	3.11	991	0.0	0.1	998
72-1	7/24/91	477	320	335	3.22	987	0.0	0.2	990
73-1	7/26/91	388	310	320	2.53	1021	0.0	0.1	992
73-2	7/26/91	389	310	325	2.51	1012	0.0	0.1	993
74-1	7/27/91	403	310	322	2.60	991	0.0	0.1	990
74-2	7/27/91	405	319	330	2.60	1008	0.0	0.1	990
75-1	7/28/91	299	289	303	1.87	1005	0.0	0.1	986
76-1	7/28/91	298	291	312	1.85	988	0.0	0.1	990

Table C-5 LNB / Performance Tests / Summary of Mill Performance

Test	Unit Load		Mill					
No.	MW	Parameter	A	B	C	D	E	F
65-1	480	Measured Coal Flow, Klb/hr	NA	NA	68639	49382	56150	NA
		Measured PA Flow, Klb/hr	142560	131991	NA	144275	135406	NA
		A/F Ratio	NA	NA	NA	2.92	2.41	NA
		Avg. Burner Pipe Velocity, FPM	7925	7502	7934	8137	7895	9072
		High Pipe Coal Flow, Klb/hr	NA	NA	20447	20170	14876	13511
		Low Pipe Coal Flow, Klb/hr	NA	NA	13558	8219	12276	11207
		Avg. Passing 200 Mesh, PCT	NA	NA	64.83	71.04	67.44	65.05
		Avg. Passing 50 Mesh, PCT	NA	NA	99.92	97.44	97.84	99.92
66-1	480	Measured Coal Flow, Klb/hr	61389	62273	73664	40523	56648	58082
		Measured PA Flow, Klb/hr	142885	133733	141961	141025	134999	166921
		A/F Ratio	2.33	2.15	1.93	3.48	2.38	2.87
		Avg. Burner Pipe Velocity, FPM	7912	7638	8279	8307	7617	9450
		High Pipe Coal Flow, Klb/hr	18873	16242	22322	11256	14844	24061
		Low Pipe Coal Flow, Klb/hr	13056	14830	12874	8667	13806	9024
		Avg. Passing 200 Mesh, PCT	60.06	63.68	61.95	74.03	68.34	68.81
		Avg. Passing 50 Mesh, PCT	96.96	97.82	99.92	97.71	97.66	99.91
70-1	480	Measured Coal Flow, Klb/hr	55155	61315	64754	42182	60132	63585
		Measured PA Flow, Klb/hr	121859	115962	124642	133426	113199	141513
		A/F Ratio	2.21	1.89	1.92	3.16	1.88	2.23
		Avg. Burner Pipe Velocity, FPM	7119	6663	7351	7692	6892	8183
		High Pipe Coal Flow, Klb/hr	15784	18089	21426	12388	15874	23144
		Low Pipe Coal Flow, Klb/hr	11249	13030	13324	8332	13374	12536
		Avg. Passing 200 Mesh, PCT	64.69	65.79	66.32	73.63	70.97	66.35
		Avg. Passing 50 Mesh, PCT	98.11	98.4	99.95	98.02	98.33	99.96
71-1	480	Measured Coal Flow, Klb/hr	56236	61700	65901	48140	58666	67843
		Measured PA Flow, Klb/hr	130001	125450	132442	134923	120490	144364
		A/F Ratio	2.31	2.03	2.01	2.8	2.05	2.13
		Avg. Burner Pipe Velocity, FPM	7248	7172	7616	7718	6998	8184
		High Pipe Coal Flow, Klb/hr	16873	16055	19224	19559	16220	22340
		Low Pipe Coal Flow, Klb/hr	8358	14847	13474	8105	13511	13688
		Avg. Passing 200 Mesh, PCT	65.55	65.06	66.01	71.63	69.48	65.55
		Avg. Passing 50 Mesh, PCT	97.88	98.31	99.96	97.92	98.43	99.94
72-1	480	Measured Coal Flow, Klb/hr	60460	63416	69987	50542	62803	72072
		Measured PA Flow, Klb/hr	140120	130193	132365	142962	116950	152660
		A/F Ratio	2.32	2.05	1.89	2.83	1.86	2.12
		Avg. Burner Pipe Velocity, FPM	7487	7579	7949	8040	7126	8377
		High Pipe Coal Flow, Klb/hr	17795	17473	19791	18907	18198	26410
		Low Pipe Coal Flow, Klb/hr	12054	13372	14901	8689	13358	13207
		Avg. Passing 200 Mesh, PCT	60.82	63.57	63.87	70.45	70.02	64.11
		Avg. Passing 50 Mesh, PCT	97.23	98.03	99.94	97.68	98.06	99.95
73-1	400	Measured Coal Flow, Klb/hr	43903	47351	51869	38225	45376	58443
		Measured PA Flow, Klb/hr	139700	125822	127975	142814	122927	141809
		A/F Ratio	3.18	2.66	2.47	3.74	2.71	2.43
		Avg. Burner Pipe Velocity, FPM	7498	7074	7585	7999	7011	7791
		High Pipe Coal Flow, Klb/hr	12570	12850	14487	14526	12277	20911
		Low Pipe Coal Flow, Klb/hr	9498	10813	10874	8152	10258	11630
		Avg. Passing 200 Mesh, PCT	66.81	68.08	67.59	74.29	70.48	66.98
		Avg. Passing 50 Mesh, PCT	98.68	98.97	99.98	98.88	98.18	99.98
74-1	400	Measured Coal Flow, Klb/hr	49137	50405	64058	37902	49641	56793
		Measured PA Flow, Klb/hr	142212	138009	131537	143376	123634	144847
		A/F Ratio	2.89	2.74	2.05	3.78	2.49	2.55
		Avg. Burner Pipe Velocity, FPM	7612	7425	7696	7792	6853	8023
		High Pipe Coal Flow, Klb/hr	13404	13326	19905	14949	13333	18670
		Low Pipe Coal Flow, Klb/hr	10866	11556	12357	6558	11715	10792
		Avg. Passing 200 Mesh, PCT	65.05	65.49	65.44	73.45	68.75	67.67
		Avg. Passing 50 Mesh, PCT	98.22	98.64	99.96	98.65	97.77	99.98

Table C-6 LNB / Performance Tests / Combustion Air Flow Distribution

Test	Load	Secondary Air				Primary Air												Total
		Left		Right		Mill A		Mill B		Mill C		Mill D		Mill E		Mill F		
No.	MW	Mlb/hr	%	Mlb/hr	%	Mlb/hr	%	Mlb/hr	%	Mlb/hr	%	Mlb/hr	%	Mlb/hr	%	Mlb/hr	%	Mlb/hr
66-1	480	1.667	42	1.405	35.7	0.143	3.6	0.134	3.4	0.142	3.6	0.141	3.6	0.135	3.4	0.167	4.2	3.933
70-1	480	1.706	41	1.677	40.6	0.122	2.9	0.116	2.8	0.125	3.0	0.133	3.2	0.113	2.7	0.142	3.4	4.134
71-1	480	1.707	44	1.394	35.8	0.130	3.3	0.125	3.2	0.132	3.4	0.135	3.5	0.120	3.1	0.144	3.7	3.889
72-1	480	1.573	42	1.359	36.3	0.140	3.7	0.130	3.5	0.132	3.5	0.143	3.8	0.117	3.1	0.153	4.1	3.747
73-1	400	1.341	41	1.122	34.4	0.140	4.3	0.126	3.9	0.128	3.9	0.143	4.4	0.123	3.8	0.142	4.3	3.264
74-1	400	1.342	39	1.267	36.9	0.142	4.1	0.138	4.0	0.132	3.8	0.143	4.2	0.124	3.6	0.145	4.2	3.432
75-1	300	1.066	39	0.966	35.3	0.135	4.9	0.112	4.1	0.120	4.4	0.138	5.1	0.046	1.7	0.150	5.5	2.733
76-1	300	1.089	40	0.939	34.5	0.133	4.9	0.110	4.0	0.121	4.4	0.133	4.9	0.047	1.7	0.149	5.5	2.720

Table C-7 LNB / Performance Tests / Coal Analysis

Test Number	Date	H2O %	C %	H %	N %	Cl %	S %	ASH %	O	Total %	HHV Btu/lb	VOL %	FC %
65-1	7/17/91	6.85	71.18	4.62	1.34	0.01	1.42	9.67	4.93	100.02	12613	33.1	50.4
65-1	7/17/91	14.90	63.98	4.13	1.24	0.02	1.30	10.25	4.20	100.02	11364	29.5	45.4
65-1	7/17/91	4.55	73.11	4.72	1.45	0.02	1.66	9.95	4.55	100.01	12991	34.3	51.2
66-1	7/17/91	4.91	73.13	4.74	1.42	0.02	1.53	9.39	4.88	100.02	13015	32.8	52.9
66-1	7/17/91	4.62	73.54	4.74	1.38	0.02	1.66	9.31	4.75	100.02	13094	32.8	53.2
66-1	7/17/91	4.68	72.93	4.57	1.44	0.03	1.71	9.37	5.30	100.03	13058	32.6	53.4
66-1	7/17/91	3.59	74.71	4.79	1.47	0.02	1.69	9.28	4.47	100.02	13259	33.2	53.9
70-1	7/22/91	4.15	74.47	4.80	1.42	0.02	1.54	9.30	4.32	100.02	13220	32.8	53.7
70-1	7/22/91	4.94	73.88	4.71	1.40	0.02	1.56	9.11	4.40	100.02	13092	32.7	53.3
70-1	7/22/91	5.54	73.29	4.73	1.44	0.02	1.62	8.97	4.40	100.01	13041	32.8	52.7
71-1	7/23/91	4.76	73.71	4.70	1.36	0.02	1.67	9.28	4.52	100.02	13084	33.1	52.8
71-1	7/23/91	4.51	73.96	4.72	1.37	0.01	1.58	9.46	4.41	100.02	13105	33.5	52.5
71-2	7/23/91	4.53	73.94	4.77	1.42	0.01	1.77	9.07	4.50	100.01	13138	33.7	52.7
72-1	7/24/91	5.23	73.10	4.75	1.35	0.01	1.41	9.12	5.05	100.02	12928	33.7	52.0
72-2	7/24/91	6.25	71.41	4.59	1.28	0.01	1.43	9.76	5.28	100.01	12577	31.7	52.3
72-2	7/24/91	6.00	72.66	4.65	1.37	0.01	1.42	8.87	5.02	100.00	12833	32.6	52.5
72-2	7/24/91	6.36	71.64	4.39	1.35	0.01	1.42	9.48	5.36	100.01	12714	32.0	52.1
73-1	7/26/91	5.41	73.50	4.74	1.44	0.01	1.58	8.89	4.45	100.02	13042	32.7	53.0
73-1	7/26/91	5.79	71.72	4.67	1.37	0.01	1.59	9.72	4.96	99.83	12719	32.4	51.9
73-2	7/26/91	5.94	70.56	4.57	1.38	0.01	1.38	10.59	5.21	99.64	12517	31.9	51.3
74-1	7/27/91	4.93	72.76	4.74	1.45	0.01	1.64	10.03	4.45	100.01	12893	32.9	52.2
74-1	7/27/91	5.19	72.31	4.73	1.40	0.01	1.57	9.93	4.86	100.00	12892	32.6	52.3
74-2	7/27/91	5.96	72.29	4.68	1.36	0.01	1.48	9.74	4.49	100.01	12854	32.1	52.3
75-1	7/28/91	6.38	72.48	4.65	1.36	0.01	1.40	9.02	4.70	100.00	12775	31.7	52.9
75-1	7/28/91	6.34	72.36	4.65	1.44	0.01	1.47	9.15	4.59	100.01	12771	31.9	52.6
76-1	7/28/91	6.29	72.81	4.65	1.41	0.01	1.44	8.89	4.51	100.01	12819	32.0	52.8
76-1	7/28/91	5.74	72.99	4.73	1.43	0.01	1.50	9.16	4.44	100.00	12938	32.6	52.5
76-1	7/28/91	4.87	72.29	4.50	1.39	0.01	1.47	9.83	5.65	100.01	13035	33.1	52.2
76-1	7/28/91	5.70	72.58	4.96	1.46	0.01	1.49	9.21	4.87	100.28	12824	31.6	53.5
Average		5.69	72.53	4.67	1.39	0.01	1.53	9.44	4.74	100.00	12869	32.56	52.29
Std. Dev.		1.91	1.87	0.14	0.05	0.01	0.11	0.43	0.36	0.09	339	0.87	1.50
Variance		3.63	3.50	0.02	0.00	0.00	0.01	0.18	0.13	0.01	114794	0.76	2.26

Table C-8 LNB / Performance Tests / Boiler Emissions Summary

	MASS LOADING		GAS VOLUME FLOW		GAS TEMP., °F	WATER VAPOR, %	ISOKINETIC AGREEMENT, %
	gr/acf	gr/scf	acfm	dscfm			
480 MW, 7/16/91, Test 65							
RUN 1	2.05	3.46	2,207,000	1,307,000	303	8.3	97.9
RUN 2	1.95	3.28	2,266,000	1,345,000	306	7.8	96.0
RUN 3	2.03	3.43	2,300,000	1,362,000	308	7.7	95.4
AVERAGE	2.01	3.39	2,258,000	1,338,000	306	7.9	96.4
±1s	0.05	0.08	38,000	23,000	2	0.3	1.1
COV	0.02	0.02	0.02	0.02	0.01	0.03	0.01
480 MW, 7/22/91, Test 70							
RUN 1	2.04	3.36	2,189,000	1,328,000	296	7.6	95.4
RUN 2	1.80	2.99	2,196,000	1,320,000	301	7.9	97.8
RUN 3	1.91	3.16	2,181,000	1,322,000	301	7.2	97.5
AVERAGE	1.92	3.17	2,189,000	1,323,000	299	7.6	96.9
±1s	0.10	0.15	5874	3689	2	0.3	1.1
COV	0.05	0.05	0.00	0.01	0.01	0.04	0.01
480 MW, 7/24/91, Test 72							
RUN 1	2.08	3.45	2,158,000	1,304,000	297	7.6	97.2
RUN 2	1.91	3.20	2,153,000	1,283,000	302	8.3	98.4
RUN 3	1.89	3.14	2,250,000	1,352,000	303	7.4	97.5
AVERAGE	1.96	3.26	2,187,000	1,313,000	301	7.8	97.7
±1s	0.09	0.13	45,000	29,000	3	0.4	0.5
COV	0.04	0.04	0.02	0.02	0.01	0.05	0.01
400 MW, 7/25&26/91, Test 73							
RUN 1	1.76	2.84	1,868,000	1,160,000	286	7.6	99.3
RUN 2	1.71	2.77	1,872,000	1,160,000	286	8.0	98.5
RUN 3	1.77	2.87	1,854,000	1,144,000	288	8.1	99.2
AVERAGE	1.75	2.83	1,865,000	1,155,000	287	7.9	99.0
±1s	0.03	0.04	8000	7000	1	0.2	0.4
COV	0.01	0.02	0.00	0.01	0.00	0.03	0.00
300 MW, 7/28/91, Test 75							
RUN 1	1.81	2.81	1,530,000	983,000	271	7.1	99.8
RUN 2	1.87	2.93	1,502,000	960,000	272	7.7	99.6
RUN 3	1.88	2.96	1,497,000	951,000	275	7.8	100.3
AVERAGE	1.85	2.90	1,510,000	965,000	273	7.5	99.9
±1s	0.03	0.06	14,000	14,000	2	0.3	0.3
COV	0.02	0.02	0.01	0.01	0.01	0.04	0.00

Table C-9 LNB / Performance Tests / Fly Ash Chemical Composition

	Test 65, 480 MW		Test 72, 480 MW		Test 73, 400 MW		Test 75, 300 MW	
Oxide	East	West	East	West	East	West	East	West
Li_2O	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05
Na_2O	0.44	0.44	0.49	0.44	0.54	0.54	0.44	0.49
K_2O	2.8	2.8	2.8	2.7	2.8	2.8	2.8	2.6
MgO	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CaO	1.2	1.2	1.2	1.2	0.9	0.9	0.9	1.1
Fe_2O_3	14.6	14.6	14.2	14.6	15.3	14.3	11.4	12.5
Al_2O_3	26.4	27.1	26.9	27.6	26.4	27	27.2	27.3
SiO2	51.2	50.6	50.8	49.8	51.6	52.1	54.5	53.1
TiO2	1.5	1.5	1.5	1.5	1.4	1.5	1.4	1.5
P_2O_5	0.37	0.4	0.34	0.42	0.28	0.28	0.26	0.34
SO_3	0.16	0.2	0.18	0.19	0.14	0.13	0.2	0.24
LOI	3.9	10.5	6.9	4.1	7.7	4.9	14.9	6.5

Table C-10 LNB / Performance Tests / Carbon and LOI Results

			MASS TRAIN SAMPLES						ESP Hopper LOI, %	
			CARBON, %			LOI, %				
DATE	TEST	Boiler Load MW	<200 mesh	>200 mesh	Total	<200 mesh	>200 mesh	Total	East Duct	West Duct
7/16/91	65	480	4.8	20.4	7.0	5.1	22.3	7.6	3.9	10.5
7/22/91	70	480	4.8	21.1	7.3	5.1	22.5	7.8	NA	NA
7/24/91	72	480	5.4	23.2	8.4	5.5	24.3	8.6	6.9	4.1
7/26/91	73	400	3.2	16.5	5.1	3.5	17.1	5.4	7.7	4.9
7/28/91	75	300	3.2	19.0	5.3	3.6	20.1	5.8	14.9	6.5

Table C-11 Performance Tests / LNB / SOx Results

	Gas Temp. DegF	Concentration, ppm SO3	SO2	SO3-to-SO2 Ratio %
		480 MW		
7/16/91	303	6.1	1049	0.582
Test 65	304	7.8	1056	0.739
West	305	8	1057	0.757
	306	8.2	1054	0.778
7/17/91	310	7.4	1095	0.676
Test 66	312	7.9	1099	0.719
East	311	7.9	1099	0.719
7/22/91	307	4.5	1137	0.396
Test 70	310	5.5	1143	0.481
East	315	6	1150	0.522
	318	6.2	1147	0.541
7/23/91	294	5.8	1099	0.528
Test 71	295	6.8	1094	0.622
West	295	7.3	1110	0.658
	297	7.5	1111	0.675
7/24/91	299	5.6	1106	0.506
Test 72	306	6.5	1114	0.583
East	308	6.8	1128	0.603
	312	6.8	1116	0.609
Average	306	6.8	1103	0.615
		400 MW		
7/26/91	288	5.3	1029	0.515
Test 73	289	6.3	1036	0.608
East	288	6.8	1042	0.653
7/27/91	288	5.2	1023	0.508
Test 74	289	6.5	1025	0.634
West	290	7	1030	0.68
	291	7	1041	0.672
Average	289	6.3	1032	0.610
		300 MW		
7/28/91	277	3.9	930	0.419
Test 75	277	4.8	940	0.511
West	277	5.1	936	0.545
	278	5.2	938	0.554
Average	277	4.8	936	0.507

Table C-12 LNB / Performance Tests / In-Situ Ash Resistivity Results

	Gas Temp.	Dust Layer	Spark Method Field	Spark Method Resisitivity	V-I Method Field	V-I Method Resisitivity
	DegF	mm	kV/cm	ohm-cm	kV/cm	ohm-cm
480 MW Data						
7/16/91	281	0.73	12.3	8.40E+09	11.3	5.70E+10
Test 65	283	0.24	6.3	1.00E+11	35.5	1.80E+11
West	284	0.19	1.6	1.60E+09	6.6	3.30E+10
	328	0.49	6.1	5.80E+10	31	1.60E+11
7/17/91	297	0.32	9.4	1.00E+11	8.6	4.30E+10
Test 66	306	0.77	11.7	4.80E+10	8.4	4.20E+10
East	304	0.86	19.2	6.60E+09	10.6	5.30E+10
7/22/91	289	1.32	15.9	9.50E+09	0.6	2.80E+09
Test 70	296	0.92	21.2	2.80E+10	6.1	3.00E+10
East	296	1.24	15.7	2.20E+10	9.3	4.60E+10
	297	1.14	17.1	1.50E+10	14.8	7.40E+10
7/23/91	285	1.62	13.9	1.00E+10	8.9	4.50E+10
Test 71	289	1.21	14.9	1.30E+10	13.2	6.60E+10
West	291	1.1	16.4	1.50E+10	14.9	7.50E+10
7/24/91	289	2.54	8.3	8.60E+09	4.6	2.30E+10
Test 72	295	2	8.3	1.50E+10	5.3	2.70E+10
East	294	1.39	13	4.10E+09	5.4	2.70E+10
Average	294			2.72E+10		5.79E+10
Std. Dev.	11			3.12E+10		4.63E+10
400 MW Data						
7/26/91	279	1.76	11.9	4.00E+09	5.8	2.90E+10
Test 73	279	2.02	8.2	8.70E+09	1.9	9.50E+09
East	280	2	12	1.60E+09	5	2.50E+10
7/27/91	280	1.57	12.4	2.80E+09	7.1	3.50E+10
Test 74	282	1.31	13.7	3.60E+09	7.3	3.70E+10
West	283	1.38	13	7.00E+09	5.1	2.60E+10
	285	1.24	14.5	3.40E+09	10.5	5.20E+10
Average	281			4.44E+09		3.05E+10
Std. Dev.	2			2.50E+09		1.30E+10
400 MW Data						
7/28/91	271	1.73	9.5	6.30E+09	5.90E+00	2.90E+10
Test 75	272	1.63	10.1	6.10E+09	7.1	3.50E+10
West	273	1.69	9.8	6.90E+09	1.80E+00	9.10E+09
	275	1.91	8.6	7.80E+09	4.20E+00	2.10E+10
Average	273			6.78E+09		2.35E+10
Std. Dev.	2			7.63E+08		1.12E+10

Table C-13 LNB / NOx vs. LOI / Test Summary

				Burner Settings				Emissions					
Test	Date	Load	AOFA	IR	OR	CPP	Mill Bias	O_2 %	NOx	CO	LOI	C	Description
92-1	10/20/92	452	MIN	NOM	NOM	NOM	NONE	5.6	0.53	15	NA	NA	BASELINE
92-2	10/20/92	450	MIN	NOM	NOM	NOM	BOTTOM	5.6	0.52	20	NA	NA	COAL BIAS TO LOWER 2 MILLS
92-3	10/20/92	450	MIN	NOM	NOM	NOM	TOP	5.5	0.50	18	NA	NA	COAL BIAS TO UPPER 2 MILLS
93-1	10/21/92	448	MIN	NOM	NOM	NOM	NONE	4.2	0.49	15	7.9	7.0	MEDIUM O2
93-2	10/21/92	447	MIN	NOM	NOM	NOM	NONE	4.6	0.59	9	4.5	3.4	HIGH O2
93-3	10/21/92	442	MIN	NOM	NOM	NOM	NONE	2.8	0.44	130	10.4	9.5	MIN O2, CO POINT
93-4	10/21/92	442	MIN	NOM	NOM	NOM	NONE	3.5	0.49	24	6.6	6.1	MEDIUM O2
94-1	10/22/92	443	MIN	NOM	NOM	NOM	NONE	3.2	0.44	24	9.3	8.5	BASELINE
94-2	10/22/92	442	MIN	+ 20%	NOM	NOM	NONE	3.5	0.45	69	9.6	8.4	INNER REGS + 20%
94-3	10/22/92	441	MIN	+ 40%	NOM	NOM	NONE	3.3	0.45	67	8.5	7.5	INNER REGS + 40%
94-4	10/22/92	441	MIN	+ 40%	NOM	NOM	NONE	3.4	0.45	61	7.5	6.7	INNER REGS + 40%
94-5	10/22/92	442	MIN	NOM	NOM	NOM	NONE	3.5	0.46	86	7.6	6.9	BASELINE
95-1	10/23/92	443	MIN	NOM	- 30%	NOM	NONE	4.1	0.53	23	5.4		OUTER REGS - 30%
95-2	10/23/92	445	MIN	NOM	NOM	NOM	NONE	4.0	0.52	80	5.7	4.7	BASELINE
95-3	10/23/92	443	MIN	NOM	+ 30%	NOM	NONE	3.3	0.46	93	6.9	5.0	OUTER REGS + 30%
95-4	10/23/92	442	MIN	NOM	NOM	NOM	NONE	3.9	0.55	32	4.6	6.2	BASELINE
96-1	10/24/92	445	MIN	NOM	NOM	NOM	UPPER	4.4	0.50	31	7.7		COAL FLOW BIASED TO TOP BURNERS
96-2	10/24/92	441	MIN	NOM	NOM	NOM	NONE	4.1	0.51	79	6.6		BASELINE, NO COAL BIAS
96-3	10/24/92	440	MIN	NOM	NOM	NOM	LOWER	3.9	0.53	100	6.2	6.8	COAL FLOW BIASED TO BOT BURNERS
96-4	10/24/92	441	MIN	NOM	NOM	NOM	NONE	4.2	0.53	71	6.2	6.0	BASELINE, NO COAL BIAS
96-5	10/24/92	440	NOR	NOM	NOM	NOM	NONE	5.5	0.53	44	4.8	5.5	BASELINE WITH STD AOFA
97-1	10/25/92	447	MIN	NOM	NOM	NOM	NONE	4.0	0.51	158	7.8	4.2	BASELINE WITH MINIMUM AOFA
97-2	10/25/92	442	MIN	NOM	NOM	3	NONE	4.0	0.52	113	7.4		COAL PIPES AT 3" INSERTION
97-3	10/25/92	441	MIN	NOM	NOM	2	NONE	4.1	0.55	35	6.3		COAL PIPES AT 2" INSERTION
97-4	10/25/92	445	MIN	NOM	NOM	NOM	NONE	4.2	0.51	205	7.0	7.2	BASELINE WITH MINIMUM AOFA
98-1	10/26/92	447	MIN	NOM	NOM	NOM	NONE	4.2	0.52	14	6.5	5.7	BASELINE WITH MINIMUM AOFA
98-2	10/26/92	441	MIN	NOM	NOM	NOM	UPPER	4.4	0.51	25	7.8	6.2	COAL FLOW BIAS TO TOP BURNERS
98-3	10/26/92	441	MIN	NOM	NOM	2	NONE	4.3	0.56	15	5.6		COAL PIPES AT 2" INSERTION
98-4	10/26/92	440	MIN	NOM	- 20%	NOM	NONE	4.8	0.57	15	5.1		OUTER REGISTERS - 20%
98-5	10/26/92	441	MIN	NOM	NOM	NOM	NONE	4.4	0.53	66	6.8	5.7	BASELINE WITH MIN AOFA
99-1	10/27/92	442	MIN	NOM	NOM	NOM	NONE	4.2	0.51	36	5.4	4.9	BASELINE WITH MIN AOFA
99-2	10/27/92	445	MIN	NOM	-20%	2	NONE	4.3	0.56	18	5.0	4.3	COAL PIPES AND OUT. REGS ADJ.
99-3	10/27/92	440	MIN	NOM	-20%	2	NONE	3.6	0.52	153	6.3	6.1	SAME, MINIMUM O2
99-4	10/27/92	445	MIN	NOM	-20%	2	NONE	5.9	0.74	19	2.1		SAME, HIGH O2
99-5	10/27/92	445	MIN	NOM	-20%	2	NONE	4.2	0.57	26	4.0		SAME AS 99-2
100-1	10/28/92	446	MIN	NOM	NOM	NOM	NONE	4.2	0.51	36	4.2	4.4	BASELINE WITH MIN AOFA & MED O2
100-2	10/28/92	442	MIN	NOM	NOM	NOM	NONE	3.7	0.48	99	4.8	5.6	BASELINE WITH MIN AOFA & LOW O2
100-3	10/28/92	443	MIN	NOM	NOM	NOM	NONE	5.0	0.59	17	2.8	1.6	BASELINE WITH MIN AOFA & HIGH O2
100-4	10/28/92	442	MIN	NOM	NOM	NOM	NONE	3.9	0.51	34	4.2	3.6	BASELINE WITH MIN AOFA & MED O2
100-5	10/28/92	443	NOR	NOM	NOM	NOM	NONE	5.0	0.52	22	3.5		BASELINE WITH NOR AOFA, MED O2

Note: 1. Emission parameters are measured dry at the economizer outlet.

Table C-14 LNB / NOx vs. LOI / Summary of Mill Performance Tests

				October 15, 1992			
Parameter ↓	Mill →	A	B	C	D	E	F
MEASURED COAL FLOW, KLB/HR		65.1	65.8	71.6	43	72.1	65.3
MEASURED PA FLOW, KLB/HR		132.9	145.6	147.5	155.3	151	136.9
A/F RATIO		2.04	2.21	2.06	3.61	2.09	2.1
AVG BURNER PIPE VELOCITY, FPM		5288	7276	5836	7814	5993	5327
HIGH PIPE COAL FLOW, KLB/HR		20.5	18.9	22.5	14.8	20.3	18.7
LOW PIPE COAL FLOW, KLB/HR		13.1	15.1	14.4	7.3	15.5	12.8
AVG PASSING 200 MESH,PCT		77.85	65.14	78.89	69.22	78.25	78.82
AVG PASSING 50 MESH,PCT		99.98	98.01	99.95	97.93	99.93	99.87
				October 16, 1992			
Parameter↓	Mill →	A	B	C	D	E	F
MEASURED COAL FLOW, KLB/HR		57.6	62.8	72.5	38.5	71.5	66.1
MEASURED PA FLOW, KLB/HR		127.9	146.1	145.1	152.8	149.1	136.8
A/F RATIO		2.22	2.33	2	3.97	2.09	2.07
AVG BURNER PIPE VELOCITY, FPM		5093	7326	5735	7680	5913	5323
HIGH PIPE COAL FLOW, KLB/HR		15.6	18.1	21.1	14	19.5	19.1
LOW PIPE COAL FLOW, KLB/HR		13.3	14.4	15.3	6.5	17	13.7
AVG PASSING 200 MESH,PCT		81.36	66.85	77.56	68.25	70.44	74.77
AVG PASSING 50 MESH,PCT		99.97	98.28	99.98	97.77	99.88	99.92

Table C-15 LNB / Long-Term / Emissions by Load

LOAD CATEGORY	N	PCT LOAD	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX	L5% KCO3	AVG KCO3	U95% KCO3	L5% KTHC3	AVG KTHC3	U95% KTHC3
170-190	2174	8.5%	180	185	189	8.5	9.5	10.4	0.44	0.65	0.83	1.98	2.21	2.40	0	7	18	0	1	6
190-210	1582	6.2%	191	199	209	8.5	9.6	10.9	0.40	0.58	0.77	2.00	2.23	2.42	0	7	18	0	1	3
210-230	1157	4.5%	211	220	229	8.2	9.2	10.1	0.42	0.55	0.72	1.98	2.24	2.48	0	8	19	0	1	3
230-250	1382	5.4%	231	241	249	8.0	9.0	9.9	0.38	0.50	0.67	2.02	2.30	2.56	0	8	16	0	1	4
250-270	2068	8.1%	251	259	269	7.9	8.8	9.8	0.34	0.48	0.70	2.03	2.30	2.54	0	8	17	0	1	4
270-290	1954	7.7%	271	281	290	7.7	8.7	10.0	0.38	0.50	0.67	2.02	2.27	2.51	0	8	23	-1	1	3
290-310	8198	32.2%	292	300	307	7.4	8.4	9.4	0.38	0.47	0.57	2.11	2.31	2.49	0	8	23	0	1	3
310-330	820	3.2%	310	318	329	7.5	8.2	9.0	0.43	0.53	0.59	2.07	2.28	2.45	0	8	19	0	1	3
330-350	511	2.0%	331	340	349	7.3	8.0	8.8	0.45	0.55	0.61	2.02	2.25	2.46	0	8	16	0	1	3
350-370	407	1.6%	351	361	369	6.9	7.7	8.4	0.42	0.54	0.59	2.01	2.24	2.50	0	10	24	0	1	5
370-390	604	2.4%	371	380	389	6.8	7.6	8.5	0.41	0.55	0.63	2.04	2.28	2.46	0	9	22	-1	1	4
390-410	1502	5.9%	391	396	402	6.8	7.3	8.0	0.45	0.57	0.66	2.14	2.29	2.43	5	15	35	-1	1	3
410-430	283	1.1%	412	422	429	6.3	7.1	8.1	0.46	0.56	0.63	2.00	2.16	2.48	3	17	59	0	1	4
430-450	408	1.6%	431	441	449	6.3	6.9	7.7	0.55	0.60	0.65	1.99	2.17	2.42	3	11	21	0	2	5
450-470	231	0.9%	451	459	469	6.3	6.9	7.7	0.57	0.64	0.71	1.98	2.13	2.45	4	11	17	0	2	5
470-490	670	2.6%	472	483	489	6.1	6.6	7.3	0.59	0.65	0.72	2.00	2.29	2.48	3	10	21	0	1	2
490-510	1486	5.8%	492	501	508	5.7	6.4	7.1	0.62	0.70	0.78	1.95	2.23	2.49	4	9	19	0	1	2

EDITED HAMMOND PHASE 3 TEST DATA
FIVE MINUTE DATA
AUGUST 7, 1991 THROUGH DECEMBER, 19,1991
PROCESSING FOR LOAD CATEGORIES
COMMON LOAD O2 NOX SOX CO3% THC3%

Table C-16 LNB / Long-Term / Within-Day Averages

HOUR	N	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX
0	101	184.92	237.37	332.42	7.83	9.04	10.15	0.414	0.561	0.751	2.014	2.265	2.459
1	100	184.20	228.51	317.25	7.87	9.07	10.07	0.413	0.578	0.806	1.996	2.254	2.453
2	99	184.46	225.88	345.88	7.77	9.08	10.12	0.413	0.587	0.795	2.027	2.252	2.446
3	99	184.44	236.44	396.57	7.21	8.99	10.06	0.413	0.588	0.794	2.016	2.251	2.457
4	99	185.91	255.45	473.07	6.66	8.84	10.07	0.399	0.571	0.722	2.003	2.255	2.470
5	99	185.42	280.77	494.94	6.59	8.62	9.99	0.398	0.544	0.708	2.003	2.270	2.462
6	99	187.43	298.99	499.81	6.39	8.45	9.91	0.392	0.525	0.701	2.017	2.281	2.485
7	95	193.92	303.88	500.91	6.47	8.38	9.72	0.377	0.509	0.684	2.017	2.288	2.479
8	82	238.21	323.88	495.16	6.45	8.18	9.27	0.383	0.511	0.686	2.042	2.283	2.479
9	92	250.67	332.75	500.47	6.35	8.11	9.57	0.378	0.513	0.703	2.038	2.288	2.484
10	97	215.33	333.31	504.75	6.30	8.09	9.94	0.380	0.518	0.708	2.015	2.296	2.511
11	100	248.99	342.96	504.81	6.39	7.94	9.56	0.384	0.529	0.721	2.004	2.284	2.520
12	99	252.04	348.72	504.90	6.34	7.82	9.42	0.381	0.535	0.725	1.998	2.282	2.483
13	99	244.43	348.98	505.20	6.35	7.82	9.28	0.385	0.534	0.736	2.016	2.274	2.458
14	100	248.15	345.88	503.43	6.28	7.89	9.45	0.385	0.532	0.718	2.041	2.272	2.465
15	101	247.26	344.06	497.45	6.33	7.92	9.44	0.386	0.530	0.704	2.038	2.270	2.467
16	102	249.99	340.71	494.83	6.43	7.97	9.43	0.385	0.525	0.707	2.018	2.267	2.449
17	102	262.51	337.94	488.07	6.48	8.02	9.13	0.396	0.521	0.679	2.014	2.268	2.450
18	101	272.17	332.26	480.76	6.65	8.10	9.13	0.389	0.514	0.665	2.013	2.268	2.470
19	102	272.79	329.86	483.56	6.67	8.18	9.18	0.399	0.516	0.660	2.013	2.271	2.474
20	103	266.90	328.89	479.59	6.55	8.20	9.37	0.392	0.518	0.656	2.027	2.278	2.463
21	104	248.80	310.41	422.76	7.00	8.34	9.65	0.389	0.504	0.622	2.051	2.288	2.500
22	103	200.82	285.45	364.72	7.25	8.62	9.95	0.397	0.509	0.631	2.041	2.290	2.486
23	102	191.99	256.32	321.09	7.72	8.84	9.97	0.392	0.527	0.696	2.029	2.289	2.500

HAMMOND PHASE 3A TESTING
WITHIN DAY PROFILES
VALID HOURS ONLY AND COM SET TO MISSING

Table C-17 LNB / Long-Term / Daily Averages

DID	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
910807	24	405.21	7.78	0.589	2.004
910808	23	400.12	7.57	0.548	2.071
910809	23	402.64	7.07	0.577	2.068
910810	12				
910819	3				
910820	24	328.34	7.73	0.531	2.061
910821	24	356.08	8.01	0.608	2.041
910822	23	345.06	8.06	0.579	2.000
910823	23	336.14	8.18	0.572	2.001
910826	15				
910827	24	456.07	6.54	0.603	2.081
910828	24	427.04	7.26	0.589	
910829	23	318.03	8.00	0.501	
910830	21	268.73	8.71	0.460	2.208
910831	24	308.29	8.57	0.515	2.184
910901	24	335.61	8.54	0.559	2.219
910902	24	242.51	9.27	0.533	2.239
910903	23	338.03	8.15	0.629	2.216
910904	24	404.11	7.39	0.630	2.187
910905	24	376.25	8.00	0.597	2.206
910906	19	281.16	9.06	0.510	2.262
910907	24	272.21	8.95	0.519	2.246
910908	24	253.71	9.14	0.548	2.089
910909	20	238.83	8.93	0.426	2.193
910910	23	232.47	8.98	0.382	2.252
910911	24	233.00	8.80	0.408	2.335
910912	24	267.04	8.07	0.415	2.353
910913	24	272.13	8.04	0.437	2.353
910914	24	265.28	8.53	0.472	2.338
910915	24	270.55	8.50	0.473	2.279
910916	24	277.67	7.98	0.446	2.319
910917	24	280.34	8.02	0.461	2.367
910918	24	282.18	8.42	0.411	2.359
910919	24	278.08	8.54	0.480	2.270
910920	24	265.97	9.11	0.533	2.259
910921	24	269.08	8.83	0.520	2.263
910922	24	267.75	8.68	0.537	2.292
910923	23	300.67	7.97	0.428	2.364
910924	21	287.48	8.28	0.423	2.399
910929	14				
910930	23	387.57	7.44	0.591	2.427
911001	22	337.39	8.32	0.540	2.392
911002	23	353.49	8.05	0.509	2.315
911003	23	343.85	8.07	0.519	2.217
911004	23	275.34	8.48	0.475	2.306
911005	24	264.12	8.10	0.480	2.370
911006	24	234.64	8.41	0.576	2.477
911007	8				
911008	13				
911009	21	400.08	7.38	0.625	2.523
911010	24	403.97	7.40	0.613	2.485
911011	23	394.75	7.64	0.625	2.437
911012	1				
911013	24	393.71	6.99	0.731	2.243
911014	22	270.34	8.17	0.535	2.340
911015	24	268.53	8.54	0.481	2.365
911016	24	266.19	8.27	0.493	2.354
911017	24	270.01	8.44	0.510	2.411
911018	24	271.17	9.33	0.551	2.432
911019	23	277.07	9.35	0.559	2.380

Table C-17 LNB / Long-Term / Daily Averages (Continued)

DID	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
911022	14				
911023	23	285.56	8.46	0.386	2.493
911024	22	281.91	8.52	0.477	2.328
911025	24	270.81	8.16	0.565	2.315
911026	24	268.42	8.16	0.588	2.407
911027	24	259.33	8.29	0.598	2.398
911028	23	265.90	8.85	0.579	2.320
911029	22	268.52	9.53	0.573	2.229
911030	19	287.40	8.69	0.496	2.257
911031	24	270.22	7.88	0.506	2.241
911101	21	276.48	7.63	0.493	2.343
911102	24	284.52	8.34	0.480	2.454
911103	24	276.52	8.61	0.496	2.422
911104	21	280.08	8.77	0.484	2.377
911105	24	297.61	8.55	0.482	2.327
911106	24	284.91	8.74	0.492	2.156
911107	24	277.17	8.64	0.518	2.126
911108	24	279.46	9.12	0.555	2.202
911109	24	296.76	8.74	0.424	2.245
911110	24	281.44	8.84	0.438	2.192
911111	24	290.67	8.90	0.425	2.085
911112	24	262.77	9.17	0.445	1.940
911113	22	277.60	8.96	0.476	2.147
911114	24	278.61	8.77	0.452	2.187
911115	24	271.27	8.90	0.432	2.152
911116	11				
911117	16				
911118	9				
911119	24	362.81	7.69	0.608	2.378
911120	24	395.84	7.20	0.613	2.294
911121	24	385.04	7.36	0.601	2.212
911122	24	306.52	8.42	0.603	2.161
911123	24	215.20	9.48	0.643	2.114
911124	24	251.48	9.69	0.677	2.079
911125	24	280.02	9.41	0.643	2.105
911126	9				
911202	16				
911203	24	321.94	7.95	0.522	2.302
911204	20	344.38	7.79	0.520	2.371
911205	11				
911209	15				
911210	24	387.03	7.71	0.628	2.446
911211	24	441.53	6.97	0.617	2.400
911212	24	306.47	8.24	0.618	2.311
911213	21	296.63	8.53	0.561	2.304
911214	24	236.36	9.22	0.602	2.329
911215	21	251.67	9.17	0.632	2.412
911216	11				
911217	24	325.48	7.88	0.584	2.274
911218	24	322.91	8.52	0.638	2.324
911219	11				

PLANT HAMMOND PHASE 3A TESTING
FIVE MINUTE DATA
DAILY AVGS (DAYS WITH AT LEAST 18 HRS DATA)
VALID HOURS ONLY - USES COMMON VARIABLE

Table C-18 LNB / Long-Term / Rolling 30 Day Averages

30DAY#	LOAD	KO2	KNOX	KSOX
1	309.87	8.255	0.513	2.219
2	305.64	8.298	0.512	2.226
3	301.05	8.351	0.511	2.234
4	300.13	8.359	0.508	2.246
5	301.06	8.341	0.507	2.260
6	301.25	8.350	0.506	2.274
7	297.95	8.402	0.502	2.280
8	295.25	8.431	0.500	2.278
9	293.85	8.446	0.499	2.278
10	293.28	8.427	0.500	2.283
11	290.83	8.422	0.502	2.293
12	288.46	8.419	0.502	2.296
13	293.96	8.374	0.503	2.302
14	296.59	8.350	0.503	2.312
15	296.59	8.351	0.502	2.323
16	297.37	8.339	0.503	2.331
17	297.78	8.318	0.503	2.333
18	301.98	8.246	0.511	2.333
19	302.65	8.210	0.510	2.342
20	303.37	8.201	0.512	2.347
21	304.51	8.176	0.516	2.351
22	305.78	8.163	0.519	2.354
23	305.92	8.209	0.524	2.356
24	306.40	8.223	0.523	2.361
25	307.04	8.222	0.523	2.361
26	307.05	8.210	0.526	2.362
27	306.73	8.216	0.532	2.366
28	305.99	8.226	0.537	2.367
29	305.48	8.241	0.543	2.365
30	305.23	8.274	0.546	2.364
31	306.10	8.276	0.546	2.364
32	306.14	8.241	0.545	2.363
33	306.54	8.205	0.544	2.365
34	305.97	8.218	0.546	2.368
35	302.23	8.260	0.542	2.368
36	300.44	8.269	0.540	2.366
37	297.92	8.294	0.539	2.360
38	295.52	8.315	0.539	2.356
39	295.63	8.339	0.542	2.353
40	296.76	8.362	0.540	2.348
41	298.38	8.378	0.535	2.338
42	299.30	8.395	0.530	2.328
43	294.84	8.422	0.525	2.319
44	289.90	8.471	0.518	2.307
45	282.92	8.518	0.515	2.298
46	276.98	8.565	0.514	2.289
47	277.31	8.572	0.515	2.291
48	276.27	8.597	0.510	2.296
49	280.41	8.561	0.513	2.294

PLANT HAMMOND PHASE 3A TEST DATA
DAILY AVERAGES FROM EDITED 5 MINUTE DATA
PROCESS FOR ROLLING AVERAGES
VALID HOURLY AVERAGES: EACH WITH AT LEAST 1/2 DATA
EACH PARAMETER SET SEPARATELY (NO COMMON)

Table C-18 LNB / Long-Term / Rolling 30 Day Averages (Continued)

30DAY#	LOAD	KO2	KNOX	KSOX
50	284.33	8.519	0.517	2.289
51	285.68	8.524	0.521	2.282
52	283.85	8.563	0.526	2.271
53	283.20	8.575	0.530	2.259
54	282.99	8.609	0.539	2.245
55	284.31	8.588	0.541	2.244
56	286.47	8.580	0.539	2.246
57	290.46	8.564	0.541	2.247
58	296.63	8.517	0.541	2.247
59	297.94	8.496	0.543	2.247
60	298.81	8.470	0.544	2.249
61	297.00	8.471	0.547	2.252
62	296.52	8.514	0.551	2.258
63	297.44	8.530	0.553	2.255
64	298.82	8.514	0.557	2.248
65	300.38	8.511	0.562	2.245

APPENDIX D
LNB+AOFA TEST DATA

Table D-1 Abbreviated LNB+AOFA Testing / Summary

Test No.	Date	Test Description	LOAD	MOOS	OFA Dmpr.	Excess O_2 # Dry	NOx	CO Dry
			MW		%	%	lb/MBtu	PPM
83-1	02/17/92	FWEC Setup -- Bottom coal tips 2", others 3"	470	None	52	4.1	0.50	18
83-2	02/17/92	FWEC Setup -- Top coal tips 3", others 2"	470	None	52	3.9	0.49	25
83-3	02/17/92	FWEC Setup -- Top coal tips 2", others 3"	470	None	52	4.3	0.51	27
84-1	02/18/92	Full-Load -- All tips 3", I/O hoods 40/70%	495	None	49	4.1	0.54	14
84-2	02/18/92	Full-Load -- Continuation of 84-1	495	None	49	4.0	0.52	47
85-1	02/19/92	Full-Load- Low O2	495	None	49	3.3	0.45	123
85-2	02/19/92	Full-Load- Normal O2, LOI + Flow measurements	495	None	49	4.1	0.53	16
85-3	02/19/92	Full-Load -- High O2	492	None	49	4.9	0.59	10
86-1	02/20/92	Mid-Load -- Low O2	400	None	27	2.9	0.37	36
86-2	02/20/92	Mid-Load -- Normal O2	400	None	27	3.8	0.45	2
86-3	02/20/92	Mid-Load -- High O2	400	None	27	5.1	0.53	1
86-4	02/20/92	Mid-Load -- Normal O2, OFA closed	405	None	0	3.9	0.55	2
87-1	02/21/92	Low-Load -- High O2	300	BE	28	5.5	0.42	9
87-2	02/21/92	Low-Load -- Normal O2	300	BE	28	4.4	0.37	31
87-3	02/21/92	Low-Load -- Low O2	300	BE	10	4.0	0.37	31
88-1	02/22/92	Low-Load Alt., Mill Patt. -- Low O2	290	EF	14	4.5	0.33	102
88-2	02/22/92	Low-Load Alt., Mill Patt. -- Mid O2	300	EF	14	5.0	0.33	25
88-3	02/22/92	Low-Load Alt., Mill Patt. -- High O2	295	EF	14	5.9	0.37	15
88-4	02/22/92	Low-Load Alt., Mill Patt. -- High O2, OFA closed	295	EF	0	5.9	0.40	17
88-5	02/22/92	Low-Load Alt., Mill Patt. -- Mid O2, OFA closed	300	EF	0	5.1	0.36	41
89-1	02/23/92	Minimum AGC Load -- Low O2, OFA closed	190	BE	0	5.9	0.38	6
89-2	02/23/92	Minimum AGC Load -- Mid O2, OFA closed	195	BE	0	6.6	0.40	5
89-3	02/23/92	Minimum AGC Load -- High O2, OFA closed	190	BE	0	8.1	0.50	4
90-1	02/24/92	Low-Load Alt. Mill Patt. -- Low O2	400	E	28	4.3	0.43	70
90-2	02/24/92	Low-Load Alt. Mill Patt. -- Repeat of 90-1	405	E	28	4.4	0.44	70
90-3	02/24/92	Low-Load Alt. Mill Patt. -- Normal O2	405	E	25	4.8	0.48	35
90-4	02/24/92	Low-Load Alt. Mill Patt. -- High O2	405	E	25	6.1	0.55	13
90-5	02/24/92	Low-Load Alt. Mill Patt. -- Normal O2, OFA closed	405	E	0	5.0	0.55	11
91-1	02/25/92	High Load -- Normal O2	480	None	53	4.1	0.50	12
91-2	02/25/92	High Load -- Normal O2, decreased OFA	480	None	30	4.0	0.55	11
91-3	02/25/92	High Load -- Normal O2, decreased OFA	485	None	10	4.0	0.61	11
91-4	02/25/92	High Load -- Normal O2, OFA closed	490	None	0	4.1	0.66	10

Composite as measured at economizer outlet using ECEM.

Table D-2 Abbreviated LNB+AOFA Testing / Mill Performance

Pulverizer	Passing 200 Mesh	Remaining 50 Mesh
A	71.49	1.50
B	66.76	1.89
C	81.57	0.02
D	72.64	2.35
E	67.67	2.46
F	77.23	0.04

[#]Results from test 84.

Table D-3 Abbreviated LNB+AOFA Testing / LOI Test Results

Test	Date	East LOI %	West LOI %	Average LOI %
83-1	2/17/92	7.5	13.6	10.6
83-2	2/17/92	7.7	11.7	9.7
83-3	2/17/92	6.9	12.4	9.6
84-1	2/18/92	9.3	14.3	11.8
84-2	2/18/92	7.7	11.5	9.6

Hi-volume sampling.

Table D-4 Abbreviated LNB+AOFA Testing / Combustion Air Distribution

Location			Flow lb/hr	Percent of Total
Secondary Air Flow			3273451	66%
	Boiler Left Side	1635753		
	Boiler Right Side	1637698		
Overfire Air Flow			845807	17%
	Left Rear Wall	222374		
	Left Front Wall	195894		
	Right Rear Wall	199840		
	Right Front Wall	227699		
Primary Air Flow			807240	16%
	Mill A	131046		
	Mill B	131038		
	MIll C	128618		
	Mill D	142967		
	Mill E	129992		
	Mill F	143579		

[1]Results from test 84 and 85.

Table D-5 LNB+AOFA / Diagnostic Test Summary

Test No.	Date	Test Conditions	Load MW	MOOS Pattern	OFA FLOW KPPH	Excess O_2 # (Dry) (%)	NOx# lb/MBtu
101-1	05/06/93	HI-LOAD OFA VARIATION	449	AMIS	600	3.5	0.465
101-2	05/06/93	HI-LOAD OFA VARIATION	452	AMIS	455	3.6	0.488
101-3	05/06/93	HI-LOAD OFA VARIATION	446	AMIS	300	3.6	0.525
102-1	05/07/93	MID-LOAD O2 VARIATION	394	AMIS	400	4.4	0.479
102-2	05/07/93	MID-LOAD O2 VARIATION	397	AMIS	400	3.3	0.404
102-3	05/07/93	MID-LOAD O2 VARIATION	397	AMIS	400	2.7	0.349
102-4	05/07/93	HI-LOAD BASELINE	479	AMIS	763	3.1	0.405
103-1	05/08/93	MID-LOAD MILL VARIATION	407	E	310	4.1	0.492
103-2	05/08/93	MID-LOAD O2 VARIATION	402	B	320	4.6	0.476
103-3	05/08/93	MID-LOAD O2 VARIATION	398	B	300	4.0	0.440
103-4	05/08/93	MID-LOAD O2 VARIATION	399	B	303	3.1	0.365
104-1	05/09/93	LO-LOAD O2 VARIATION	305	D&F	305	5.2	0.344
104-2	05/09/93	LO-LOAD O2 VARIATION	295	D&F	295	3.9	0.286
105-1	05/10/93	MID-LOAD MILL/O2 VARIATION	395	F	300	3.9	0.362
105-2	05/10/93	MID-LOAD MILL/O2 VARIATION	396	F	344	5.1	0.442
106-1	06/08/93	HI-L0AD OFA VARIATION	450	AMIS	595	3.6	0.367
106-2	06/08/93	HI-L0AD OFA VARIATION	477	AMIS	794	3.9	0.391
106-3	06/08/93	HI-L0AD OFA VARIATION	468	AMIS	829	4.5	0.441
107-1	06/09/93	HI-LOAD NOMINAL	465	AMIS	813	4.0	0.501
108-1	06/10/93	HI-LOAD O2 VARIATION	463	AMIS	824	4.1	0.395
108-2	06/10/93	HI-LOAD O2 VARIATION	449	AMIS	792	3.8	0.371
108-3	06/10/93	HI-LOAD O2 VARIATION	472	AMIS	802	3.1	0.351
109-1	06/11/93	HI-LOAD OFA VARIATION	470	AMIS	797	3.7	0.380
109-2	06/11/93	HI-LOAD OFA VARIATION	470	AMIS	952	3.5	0.369
109-3	06/11/93	HI-LOAD OFA VARIATION	474	AMIS	611	3.6	0.405
110-1	06/12/93	LO-LOAD MILL/O2 VARIATION	302	E	314	5.3	0.404
110-2	06/12/93	LO-LOAD MILL/O2 VARIATION	305	B&E	250	4.6	0.318
110-3	06/12/93	LO-LOAD MILL/O2 VARIATION	305	B&E	326	5.5	0.369
110-4	06/12/93	LO-LOAD MILL/O2 VARIATION	302	B&E	315	6.4	0.421
110-5	06/12/93	MID-LOAD O2 VARIATION	394	B	327	5.6	0.489
110-6	06/12/93	MID-LOAD O2 VARIATION	391	B	313	4.3	0.402
110-7	06/12/93	MID-LOAD O2 VARIATION	391	B	403	4.3	0.377
111-1	06/13/93	LO-LOAD MILL/O2 VARIATION	293	B&D	310	6.3	0.410
111-2	06/13/93	LO-LOAD MILL/O2 VARIATION	295	B&D	317	5.0	0.345
111-3	06/13/93	LO-LOAD MILL/O2 VARIATION	292	B&D	306	4.3	0.309
112-1	06/14/93	MID-LOAD NOMINAL O2	400	AMIS	396	4.3	0.423
112-2	06/14/93	MID-LOAD O2 VARIATION	400	Aborted	--	--	--
112-3	06/14/93	MID-LOAD NOMINAL O2	404	AMIS	416	4.7	0.447
113-1	06/15/93	HI-LOAD OFA VARIATION	476	AMIS	799	3.8	0.395
113-2	06/15/93	HI-LOAD OFA VARIATION	474	AMIS	585	3.6	0.422
113-3	06/15/93	HI-LOAD OFA VARIATION	474	AMIS	276	3.4	0.451
114-1	06/16/93	MIN-LOAD O2 VARIATION	179	B,D,E	94	6.8	0.412
114-2	06/16/93	MIN-LOAD O2 VARIATION	186	B,D,E	93	5.4	0.377
114-3	06/16/93	MIN-LOAD O2 VARIATION	183	B,D,E	90	4.5	0.346
121-1	06/24/93	HI-LOAD OFA VARIATION	483	AMIS	954	3.7	0.411
121-2	06/24/93	HI-LOAD OFA VARIATION	482	AMIS	791	3.9	0.413
121-3	06/24/93	HI-LOAD OFA VARIATION	481	AMIS	603	3.8	0.414
121-4	06/24/93	HI-LOAD OFA VARIATION	495	AMIS	777	3.8	0.421
122-1	06/25/93	MID-LOAD MILL/O2 VARIATIONS	401	AMIS	409	4.0	0.365
122-2	06/25/93	MID-LOAD MILL/O2 VARIATIONS	402	AMIS	275	4.1	0.399
122-3	06/25/93	MID-LOAD MILL/O2 VARIATIONS	397	AMIS	516	4.2	0.348
122-4	06/25/93	MID-LOAD MILL/O2 VARIATIONS	396	AMIS	510	4.7	0.385
122-5	06/25/93	MID-LOAD MILL/O2 VARIATIONS	395	AMIS	401	4.7	0.404
122-6	06/25/93	MID-LOAD MILL/O2 VARIATIONS	392	AMIS	395	3.3	0.321

Composite as measured at economizer outlet using ECEM.

Table D-6 LNB+AOFA / Diagnostic Tests / Operating Summary

Test No,	Date	Load MW	E ECON# O_2 (Dry) %	W ECON# O_2 (Dry) %	Ex O_2 AVG Dry %	NOx ppm	Opacity %	SAPHA Out Temp. DegF	SAPHB Out Temp. DegF	Steam Flow MLBM/HR	SH Temp. DegF
101-1	05/06/93	444	3.6	3.4	3.5	334	27.6	317	310	2.86	1005
101-2	05/06/93	447	3.7	3.7	3.6	360	28.1	325	315	2.85	1002
101-3	05/06/93	444	3.5	3.8	3.6	380	28.7	326	315	2.87	1006
102-1	05/07/93	393	4.4	4.7	4.4	350	23.0	311	291	2.50	1004
102-2	05/07/93	394	3.6	3.4	3.6	360	20.2	319	308	1.72	1001
102-3	05/07/93	393	3.3	2.5	2.8	255	20.8	324	310	2.45	1000
102-4	05/07/93	471	3.1	2.6	2.8	290	39.0	340	325	3.30	1001
103-1	05/08/93	402	4.1	4.3	4.1	356	23.3	303	293	2.54	1010
103-2	05/08/93	399	5.0	4.6	4.7	350	26.4	308	300	2.52	1003
103-3	05/08/93	394	4.3	4.1	3.9	320	23.7	307	301	2.50	1002
103-4	05/08/93	395	3.5	3.3	3.1	267	20.3	305	299	2.50	1017
104-1	05/09/93	302	5.0	5.9	5.3	251	14.0	294	266	1.76	990
104-2	05/09/93	295	3.5	4.5	4.0	210	13.0	300	273	1.80	993
105-1	05/10/93	392	3.8	4.1	3.9	262	25.5	300	289	2.48	989
105-2	05/10/93	391	4.9	5.9	5.1	319	29.0	311	298	2.48	987
106-1	06/08/93	450	3.0	2.4	3.6	270	30.0	329	316	3.08	997
106-2	06/08/93	482	3.5	3.1	3.9	284	29.7	340	328	3.25	995
106-3	06/08/93	475	3.8	3.6	4.5	320	31.4	341	330	3.20	982
107-1	06/09/93	463	3.9	3.7	4.1	365	21.8	334	323	3.07	989
108-1	06/10/93	465	4.0	3.7	4.1	290	22.2	321	310	3.10	989
108-2	06/10/93	453	3.8	3.2	3.7	268	20.9	333	347	3.03	991
108-3	06/10/93	472	3.3	2.5	3.0	256	24.7	335	321	3.12	992
109-1	06/11/93	472	3.4	3.1	3.7	280	27.1	322	310	3.15	1006
109-2	06/11/93	471	3.4	3.1	3.6	270	19.0	327	317	3.11	1001
109-3	06/11/93	481	3.2	3.6	3.6	290	22.4	335	329	3.14	997
110-1	06/12/93	300	4.8	4.0	5.3	290	10.6	298	284	1.86	989
110-2	06/12/93	305	3.6	3.7	4.5	230	9.9	294	278	1.89	1004
110-3	06/12/93	305	4.3	5.0	5.5	265	9.7	293	283	1.88	992
110-4	06/12/93	302	5.6	5.9	6.4	307	10.4	291	288	1.85	985
110-5	06/12/93	396	4.9	5.4	5.5	350	20.2	323	316	2.53	989
110-6	06/12/93	395	4.0	4.2	4.2	290	15.9	320	314	2.53	1000
110-7	06/12/93	391	4.0	4.1	4.2	271	16.2	319	314	2.51	989
111-1	06/13/93	295	5.0	6.4	6.2	292	9.4	268	289	1.82	994
111-2	06/13/93	294	4.1	5.4	5.0	250	9.6	281	279	1.82	998
111-3	06/13/93	293	3.6	4.4	4.3	224	9.6	285	278	1.80	997
112-1	06/14/93	400	3.6	4.7	4.4	314	33.3	308	299	2.56	986
112-3	06/14/93	404	3.8	5.0	4.7	326	17.7	312	306	2.58	980
113-1	06/15/93	476	3.8	3.4	3.8	290	42.0	323	317	3.11	992
113-2	06/15/93	474	3.5	3.0	3.6	305	35.7	325	321	3.12	986
113-3	06/15/93	474	3.2	3.2	3.3	330	26.0	328	322	3.10	990
114-1	06/16/93	178	6.2	6.7	6.8	300	7.0	271	266	1.08	1001
114-2	06/16/93	177	5.1	5.5	5.5	277	6.2	277	275	1.14	1001
114-3	06/16/93	181	4.5	4.8	4.5	255	6.0	282	282	1.11	1005
121-1	06/24/93	477	3.6	3.3	3.7	300	20.7	328	318	3.22	998
121-2	06/24/93	478	3.5	3.6	3.9	300	19.4	332	321	3.23	1003
121-3	06/24/93	476	3.4	3.5	3.8	302	21.2	336	325	3.10	1012
121-4	06/24/93	492	3.6	3.5	3.8	310	24.0	325	415	3.35	990
122-1	06/25/93	398	3.3	4.2	4.0	267	15.0	308	417	2.58	997
122-2	06/25/93	398	3.3	4.0	4.1	290	16.5	309	419	2.57	1002
122-3	06/25/93	393	3.3	3.6	4.2	255	16.4	308	420	2.54	1000
122-4	06/25/93	394	4.1	4.0	4.7	281	17.1	308	421	2.52	993
122-5	06/25/93	391	4.4	3.9	4.7	296	14.7	310	426	2.51	1006
122-6	06/25/93	391	3.3	2.5	3.3	235	13.8	317	431	2.50	1020

#Composite as measured at economizer outlet using ECEM.

Table D-6 LNB+AOFA / Diagnostic Tests / Operating Summary (cont)

	Pulverizer Coal Flow					
Test	A	B	C	D	E	F
101-1	48.1	51.8	52.9	50.7	47.4	51.8
101-2	49.0	53.5	52.9	52.2	45.3	51.6
101-3	49.0	53.0	52.6	51.8	44.9	51.3
102-1	43.1	44.3	47.4	44.6	41.0	46.2
102-2	45.9	44.7	45.5	44.3	41.6	44.2
102-3	45.8	44.5	45.4	43.9	42.2	43.9
102-4	56.3	52.8	53.8	52.4	50.9	52.6
103-1	54.0	55.1	58.1	56.2	0.0	56.3
103-2	52.6	0.0	57.6	56.1	54.8	56.0
103-3	52.4	0.0	57.6	55.6	54.8	55.7
103-4	52.7	0.0	57.6	55.8	54.8	56.0
104-1	55.3	55.6	57.7	0.0	52.9	0.0
104-2	53.4	54.6	56.4	0.0	52.6	0.0
105-1	56.8	58.8	60.7	57.9	54.4	0.0
105-2	56.1	58.4	60.3	57.6	54.0	0.0
106-1	63.0	62.0	61.0	62.0	59.0	51.0
106-2	67.0	67.0	65.0	68.0	59.0	52.0
106-3	66.0	67.0	65.0	67.0	58.0	51.0
107-1	55.0	60.7	59.5	59.0	56.7	59.3
108-1	56.0	60.1	60.5	61.3	57.1	59.5
108-2	54.5	58.6	58.9	59.6	56.0	58.5
108-3	57.1	60.9	61.1	62.0	58.4	60.8
109-1	62.0	63.0	62.0	63.0	63.0	60.0
109-2	62.0	62.0	62.0	63.0	63.0	60.0
109-3	62.0	63.0	62.0	63.0	64.0	61.0
110-1	43.6	45.9	47.8	47.2	0.0	44.4
110-2	60.5	0.0	58.3	56.1	0.0	55.2
110-3	60.6	0.0	58.4	56.4	0.0	55.2
110-4	60.1	0.0	57.9	56.3	0.0	55.0
110-5	55.6	0.0	62.5	61.6	57.3	59.4
110-6	55.5	0.0	62.5	61.6	57.3	59.2
110-7	58.5	0.0	63.8	62.8	58.5	60.6
111-1	58.7	0.0	61.5	0.0	56.5	58.1
111-2	58.8	0.0	61.5	0.0	56.5	58.2
111-3	58.7	0.0	61.5	0.0	56.5	58.2
112-1	56.0	55.0	55.0	55.0	54.0	52.0
112-3	54.0	54.0	55.0	54.0	53.0	53.0
113-1	61.0	62.0	63.0	61.0	63.0	61.0
113-2	61.0	62.0	63.0	61.0	63.0	61.0
113-3	61.0	61.0	62.0	61.0	63.0	61.0
114-1	46.5	0.0	47.5	0.0	0.0	46.9
114-2	46.5	0.0	47.5	0.0	0.0	47.1
114-3	46.5	0.0	47.6	0.0	0.0	47.1
121-1	55.7	56.3	58.3	56.6	55.6	57.0
121-2	55.5	56.0	58.1	56.6	55.5	56.7
121-3	55.3	56.0	58.1	56.3	55.5	56.7
121-4	57.4	58.7	60.4	58.5	57.2	58.5
122-1	48.0	48.9	48.9	46.8	48.2	48.1
122-2	48.0	48.8	48.7	46.8	48.2	48.1
122-3	48.0	49.0	48.6	46.8	48.2	48.1
122-4	48.0	48.8	49.8	46.8	48.2	48.1
122-5	48.2	48.6	50.0	46.8	48.5	48.6
122-6	47.7	48.5	49.6	46.8	48.5	48.7

Table D-7 LNB+AOFA / Performance Tests Summary

Test No.	Date	Test Conditions	LOAD MW	MOOS Pattern	OFA Flow (KPPH)	DAS O2 Dry (%)	NOx Emissions (lb/MBtu)	CO ppm	COMP LOI %	COMP Carbon %
115-1A	06/17/93	PERF. TEST 480 MW	480	AMIS	790	3.8	0.433	31		
115-1B	06/17/93	PERF. TEST 480 MW	467	AMIS	784	4.0	0.441	29	8.000	7.200
115-1C	06/17/93	PERF. TEST 480 MW	462	AMIS	774	3.9	0.427	38		
116-1A	06/18/93	PERF. TEST 480 MW	476	AMIS	787	3.9	0.421	54		
116-1B	06/18/93	PERF. TEST 480 MW	472	AMIS	805	3.8	0.412	300		
117-1A	06/19/93	PERF. TEST 300 MW	303	B	311	4.0	0.320	62	5.700	5.200
117-1B	06/19/93	PERF. TEST 300 MW	299	B	297	4.1	0.320	40		
118-1A	06/20/93	PERF. TEST 300 MW	302	B	321	4.3	0.317	37		
118-1B	06/20/93	PERF. TEST 300 MW	298	B	308	4.3	0.315	41		
119-1A	06/21/93	PERF. TEST 400 MW	400	B	427	4.5	0.413	105	6.400	5.600
119-1B	06/22/93	PERF. TEST 400 MW	400	B	409	4.5	0.424	123		
120-1A	06/22/93	PERF. TEST 400 MW	401	B	421	4.5	0.415	87		
120-1B	06/23/93	PERF. TEST 400 MW	401	B	424	4.6	0.419	91		

Table D-8 LNB+AOFA / Performance Tests / Operating Data

		Econ. O_2 %		CEM O2	CEM NOx	SAPH A Out. Temp.	SAPH B Out. Temp.	Steam Flow	SH Temp	SH Spray Flows Klb/Hr		Hot Reheat Temp.
Test	Load	E	W	%	ppm		Deg. F.	Mlb/Hr		Lower	Upper	DegF
115-1	470	3.5	3.9	3.8	310	331	320	3.30	998	17	115	1003
116-1	472	3.5	3.8	3.9	305	325	318	3.20	994	19	132	1003
117-1	296	4.2	4.1	3.9	239	303	304	1.90	980	32	154	951
118-1	302	4.0	4.5	4.2	230	299	300	1.86	997	27	167	952
119-1	396	4.7	3.7	4.4	305	310	309	2.57	987	36	208	1001
120-1	398	4.6	3.8	4.5	305	315	309	2.60	995	30	147	1002

Table D-8 LNB+AOFA / Performance Tests / Operating Data (continued)

		Pulverizer Coal Flow					
Test	Load	A	B	C	D	E	F
115-1	470	58.4	56.2	58.0	57.4	56.2	57.3
116-1	472	58.9	60.1	61.9	59.9	58.5	59.9
117-1	296	45.1	0.0	46.7	43.9	45.1	45.3
118-1	302	48.0	0.0	46.0	46.0	45.0	46.0
119-1	396	56.1	0.0	58.1	56.9	57.1	56.8
120-1	398	56.1	0.0	58.6	57.0	56.1	57.1

Table D-9 LNB+AOFA / Performance Tests / Summary of Mill Performance

Test	Load	Parameter	Pulverizer						
			Totals	A	B	C	D	E	F
115	480	Control Room Mill Flow, Klb/hr	343.50	58.40	56.20	58.00	57.40	56.20	57.30
		Measured Coal Flow, Klb/hr	392.06	80.77	52.67	65.13	46.29	61.35	85.85
		Measured PA Flow, Klb/hr	836,841	146.9	151.2	139.2	134.2	137.5	127.8
		A/F Ratio	2.13	1.83	3.08	2.31	3.29	2.35	1.63
		Avg. Burner Pipe Velocity, FPM	6,473	5,805	8,183	5,860	7,696	5,737	5,555
		High Pipe Coal Flow, Klb/hr	27.9	23.1	14.3	19.4	17.9	16.2	27.9
		Low Pipe Coal Flow, Klb/hr	7.7	15.7	12.1	15.0	7.7	14.7	18.0
		Avg. Passing 200 Mesh, Pct.	72.59	76.94	66.86	74.08	63.43	80.02	74.20
		Avg. Passing 50 Mesh, Pct.	99.00	99.75	98.33	99.26	96.86	99.90	99.87
117	300	Control Room Mill Flow, Klb/hr	226.10	45.10	0	46.70	43.90	45.10	45.30
		Measured Coal Flow, Klb/hr	279.17	60.14	0	57.20	43.34	57.08	61.41
		Measured PA Flow, Klb/hr	734,279	137.9	54.3	135.3	141.9	145.8	119.1
		A/F Ratio	2.63	2.32	0	2.50	3.65	2.94	2.18
		Avg. Burner Pipe Velocity, FPM	6,154	5,521	0	5,572	7,951	6,588	5,139
		High Pipe Coal Flow, Klb/hr	18.3	16.9	0	18.3	15.4	15.3	17.8
		Low Pipe Coal Flow, Klb/hr	7.1	13.1	0	11.7	7.1	13.0	12.9
		Avg. Passing 200 Mesh, Pct.	75.48	78.74	NA	75.14	67.12	76.86	79.54
		Avg. Passing 50 Mesh, Pct.	99.50	99.87	NA	99.83	98.21	99.74	99.85
119	400	Control Room Mill Flow, Klb/hr	285.00	56.10	0	58.10	56.90	57.10	56.80
		Measured Coal Flow, Klb/hr	325.55	70.48	0	66.87	46.59	71.08	69.81
		Measured PA Flow, Klb/hr	801,480	145.6	67.4	143.8	153.4	143.6	147.7
		A/F Ratio	2.46	2.29	0	2.36	3.50	2.11	2.31
		Avg. Burner Pipe Velocity, FPM	6,668	6,487	0	6,192	8,270	5,958	6,435
		High Pipe Coal Flow, Klb/hr	21.9	20.3	0	21.9	17.2	18.6	18.8
		Low Pipe Coal Flow, Klb/hr	7.7	13.5	0	13.1	7.7	16.7	16.7
		Avg. Passing 200 Mesh, Pct.	73.50	77.98	NA	74.25	66.26	77.64	71.37
		Avg. Passing 50 Mesh, Pct.	99.23	99.81	NA	99.77	97.03	99.72	99.84

Table D-10 LNB+AOFA / Performance Tests / Combustion Air Flow Distribution

Test Number		115	116	117	118	119	120
Unit Load (MW)		480	480	300	300	400	400
Pulverizer Air	Total Flow	897,350	892,685	742,520	702,952	793,453	786,239
	% of TUA	21.45%	20.94%	27.65%	26.06%	21.69%	21.34%
Secondary Air	Total Flow	2,437,598	2,490,624	1,628,886	1,589,363	2,350,423	2,349,506
	% of TUA	58.28%	58.42%	60.65%	58.93%	64.25%	63.76%
Overfire Air	Total Flow	847,935	880,120	259,776	349,802	446,909	487,798
	% of TUA	20.27%	20.64%	9.67%	12.97%	12.22%	13.24%
Air to Off-line Mills	Total Flow	0	0	54,343	55,054	67,359	61,591
	% of TUA	0.00%	0.00%	2.02%	2.04%	1.84%	1.67%
Total Unit Air (TUA)	Total Flow	4,182,883	4,263,429	2,685,525	2,697,171	3,658,144	3,685,134

Table D-11 LNB+AOFA / Performance Tests / Coal Analysis

Test	Date	H2O	C	H	N	Cl	S	Ash	O	Total	Grind SU	HHV BTU/lb	VM %	FC %
115	06/17/93	6.16	72.22	4.67	1.32	0.02	1.58	8.69	5.36	100.02	53.0	12,780	32.21	52.94
	06/17/93	5.62	71.46	4.72	1.35	0.03	1.64	8.97	6.25	100.04	49.0	12,765	33.54	51.87
	06/17/93	6.36	71.48	4.64	1.40	0.06	1.67	9.05	5.40	100.06	48.5	12,610	33.30	51.29
116	06/18/93	6.81	69.92	4.63	1.34	0.03	1.69	9.74	5.87	100.03	49.5	12,368	33.61	49.84
	06/18/93	7.49	69.08	4.60	1.34	0.08	1.79	9.88	5.83	100.09	49.5	12,199	33.39	49.24
	06/18/93	6.71	70.73	4.60	1.40	0.06	1.82	9.86	4.88	100.06	47.5	12,358	33.66	49.77
117	06/19/93	7.10	69.95	4.66	1.38	0.05	1.72	9.93	5.25	100.04	48.5	12,327	33.17	49.80
	06/19/93	6.82	69.33	4.64	1.41	0.05	1.71	10.20	5.89	100.05	46.0	12,272	33.53	49.45
	06/19/93	7.04	69.38	4.61	1.40	0.03	1.72	10.06	5.79	100.03	46.5	12,187	34.51	48.39
118	06/20/93	6.59	69.05	4.66	1.42	0.02	1.96	10.20	6.12	100.02	50.5	12,287	34.50	49.16
	06/20/93	6.76	69.69	4.62	1.49	0.02	1.64	9.52	6.28	100.02	47.5	12,334	34.01	49.71
	06/20/93	7.08	69.46	4.65	1.43	0.03	1.75	9.92	5.71	100.03	48.0	12,212	33.73	49.27
119	06/21/93	6.27	71.13	4.68	1.37	0.05	1.56	9.49	5.51	100.06	49.5	12,497	33.35	50.90
	06/21/93	5.14	72.93	4.71	1.41	0.07	1.51	8.99	5.31	100.07	48.5	12,843	34.46	51.40
	06/21/93	5.68	72.35	4.76	1.44	0.07	1.57	8.99	5.21	100.07	48.5	12,712	34.20	51.13
120	06/22/93	5.95	71.57	4.64	1.36	0.04	1.54	9.18	5.76	100.04	48.0	12,730	33.56	51.31
	06/23/93	5.64	73.52	4.76	1.44	0.03	1.51	8.93	4.21	100.04	50.5	12,915	33.43	52.00
AVERAGE		6.42	70.78	4.66	1.39	0.04	1.67	9.51	5.57	100.05	48.8	12494	33.66	50.44
STD		0.63	1.39	0.05	0.04	0.02	0.12	0.49	0.50	0.02	1.59	244	0.55	1.22
VAR		0.40	1.92	0.00	0.00	0.00	0.01	0.24	0.25	0.00	2.53	59515	0.31	1.48

Table D-12 LNB+AOFA / Performance Tests / Boiler Emissions Summary

	Mass Loading		Gas Volume Flow		Gas Temp, °F	Water Vapor, %	Oxygen, %
	gr/acf	gr/scf	acfm	dscfm			
480 MW, 6/17/93, Test 115							
Run 1	1.81	3.00	2,148,000	1,298,000	305	7.2	5.2
Run 2	1.76	2.97	2,109,000	1,251,000	312	7.8	5.8
Run 3	1.75	2.95	2,114,000	1,249,000	317	7.6	5.4
Average	1.77	2.98	2,123,000	1,266,000	312	7.5	5.5
Std Dev	0.03	0.02	21,000	27,000	6	0.3	0.3
COV	0.02	0.01	0.01	0.02	0.02	0.05	0.05
400MW, 6/21/93, Test 119							
Run 1	1.87	3.05	1,827,000	1,117,000	297	7.5	5.9
Run 2	1.85	3.01	1,801,000	1,104,000	296	7.4	5.9
Run 3	1.72	2.80	1,820,000	1,115,000	293	7.8	6.0
Average	1.81	2.96	1,816,000	1,112,000	295	7.6	6.0
Std Dev	0.08	0.14	13,000	7,000	2	0.2	0.0
COV	0.05	0.05	0.01	0.01	0.01	0.03	0.00
300 MW, 6/19/93, Test 117							
Run 1	1.92	3.01	1,321,000	843,000	284	7.2	5.5
Run 2	1.91	3.01	1,322,000	838,000	286	7.5	6.1
Run 3	1.75	2.74	1,329,000	850,000	277	7.8	6.1
Average	1.86	2.92	1,324,000	843,000	282	7.5	5.9
Std Dev	0.09	0.16	4,000	6,000	5	0.3	0.3
COV	0.05	0.05	0.00	0.01	0.02	0.04	0.05
LOI test with various over-fire air settings , 6/24/93, Test 121							
Run 1[a]	1.82	3.05	2,105,000	1,256,000	310	7.3	5.4
Run 2[b]	1.83	3.14	2,119,000	1,238,000	313	8.8	5.0
Run 3[c]	1.73	2.98	2,136,000	1,241,000	317	8.6	5.2
Run 4[d]	1.90	2.93	2,130,000	1,385,000	312	8.1	5.3

a. Maximum over-fire air at 483 MW
b. Nominal over-fire air at 482 MW
c. Low over-fire air at 481 MW
d. Nominal over-fire air at 493 MW

Table D-13 LNB+AOFA / Performance Tests / Fly Ash Chemical Composition

Elemental Oxide	480 MW 6/17/93 Test 115	400 MW 6/22/93 Test 119	300 MW 6/19/93 Test 117
Li_2O	0.01	0.01	0.01
Na_2O	0.24	0.18	0.22
K_2O	2.47	2.66	2.55
MgO	0.67	0.66	0.56
CaO	1.66	1.29	1.71
Fe_2O_3	14.29	13.51	13.29
Al_2O_3	26.48	27.28	27.04
SiO_2	49.47	49.91	49.92
TiO_2	1.27	1.26	1.30
P_2O_5	0.48	0.37	0.45
SO_3	0.03	0.03	0.03
LOI	8.9	6.7	6.4

Table D-14 LNB+AOFA / Performance Tests / Carbon and LOI Results

			Mass Train Samples					
			Carbon, %			LOI, %		
Date	Test	Load	<200 Mesh	>200 Mesh	Total	<200 Mesh	>200 Mesh	Total
6/17/93	115	480	5.4	22.1	7.2	6	24.8	8
6/21-22/93	119	400	4.1	18.3	5.6	4.6	21	6.4
6/19/93	117	300	3.7	20.6	5.2	4.1	21.8	5.7
6/24/93	121a	483	7	30.7	9.5	7.3	33.5	10
	121b	482	7	23.6	9.1	7.4	29.1	10.1
	121c	481	7.1	27.7	9.6	7.6	29.9	10.3
	121d	495	6.9	14.7	8	7.1	27	9.8

Notes:
a. Maximum overfire air at 483 MW
b. Nominal overfire air at 482 MW
c. Low overfire air at 481 MW
d. Nominal overfire air ait 493 MW

Table D-15 LNB+AOFA / Performance Tests / SOx Results

Test	Date	Load MW	Port	Gas Temp. DegF	Concentration, ppm SO3	Concentration, ppm SO2	SO2 to SO3 Ratio %
115	6/17/93	480	5	319	7.5	1172	0.640
				319	9.3	1295	0.718
116	6/18/93	480	5	321	9.2	1341	0.686
				321	10	1324	0.755
				317	9.6	1326	0.724
				317	9.9	1314	0.753
	Average			319	9.3	1295	0.713
119	6/21/93	400	12	287	5.3	1028	0.516
				286	5.7	1046	0.545
				282	6	1056	0.568
				279	6	1040	0.577
119	6/22/93	400	5	296	6.1	1036	0.589
				295	6.7	1069	0.627
				296	7.2	1064	0.677
	Average			289	6.1	1048	0.585
117	6/19/93	300	5	291	3.1	1286	0.241
				290	4	1280	0.313
				293	4.1	1290	0.318
				297	4.4	1264	0.348
118	6/20/96	300	12	279	2.9	1257	0.231
				278	3.2	1246	0.257
				281	3.3	1242	0.266
				277	3.6	1207	0.298
	Average			286	3.6	1259	0.284

Table D-16 LNB+AOFA / Performance Tests / In Situ Ash Resitivity Results

Test	Date	Port	Gas Temp. DegF	Spark Method Field kV/cm	Spark Method Resistivity ohm-cm	V-I Method Field kV/cm	V-I Method Resistivity ohm-cm
			480 MW				
115	6/17/93	5	329	2.2	3.00E+11	5.8	2.90E+10
			330	11.7	3.10E+11	2.2	6.10E+10
			335	8.2	1.60E+11	15.1	7.50E+10
116	6/18/93	10	307	6.4	1.20E+10	18.1	9.00E+10
			308	*	*	7.1	3.60E+10
			311	*	*	8.7	4.70E+10
			308	15.4	4.40E+10	8.3	4.10E+10
	Average		*318*	*8.78*	*1.65E+11*	*9.3*	*5.41E+10*
			400 MW				
119	6/21/93	7	316	9.7	1.80E+10	5	2.50E+10
			316	10.9	1.10E+10	5.8	2.90E+10
			316	11.6	1.30E+10	4.8	2.40E+10
119	6/22/93	10	294	12.9	1.40E+10	2.5	1.20E+10
			293	13.2	1.50E+10	1.4	7.00E+09
			293	13.4	1.20E+10	4.1	2.00E+10
	Average		*305*	*11.95*	*1.38E+10*	*3.9*	*1.95E+10*
			300 MW				
117	6/19/93	10	284	13.8	5.20E+10	3.6	1.80E+10
			286	21.8		8.5	4.20E+10
			287	13.6	4.80E+10	5.5	2.70E+10
			287	12.3	3.80E+10	6.1	3.10E+10
117	6/20/93	7	292	11.2	2.20E+10	5.7	2.90E+10
			295	13.8	2.90E+10	5	2.50E+10
			297	10.2	5.30E+10	8.5	4.30E+10
	Average		*290*	*14*	*4.03E+10*	*6*	*3.07E+10*

Table D-17 LNB+AOFA / Verification Tests Summary

Test	Date	Description	Load MW	MOOS	OFA Flow klbm/hr	Ex O2 %	NOx lb/MBtu
123-1	08/09/93	VERIFICATION - NOM O2 300 MW	301	B	304	4.3	0.353
123-2	08/10/93	- HIGH O2	298	B	318	5.3	0.398
123-3	08/10/93	- LOW O2	304	B	311	3.8	0.329
123-4	08/10/93	- NOM O2	304	B	312	4.2	0.348
123-5	08/10/93	- NOM O2; MILL VARIATION	304	B,D	316	4.4	0.358
124-1	08/10/93	VERIFICATION - NOM O2 400 MW	384	B	307	4.7	0.382
125-1	08/24/93	VERIFICATION - HIGH O2 -NOM OFA	397	B	319	5.1	0.437
125-2	08/25/93	VERIFICATION - LOW O2 - NOM OFA	393	B	283	3.8	0.357
125-3	08/25/93	VERIFICATION - NOM O2 - NOM OFA	393	B	300	4.5	0.401
125-4	08/25/93	VERIFICATION - NOM O2 - HIGH OFA	394	B	417	4.7	0.384
125-5	08/25/93	VERIFICATION - NOM O2 - LOW OFA	393	B	230	4.6	0.414
126-1	8/26/93	FULL LOAD VERIFICATION, NOMINAL O2/OFA	480	AMIS	870	4.1	0.417

Table D-18 LNB+AOFA / Long-Term / Emissions by Load

LOAD CAT	N	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX	L5% KCO	AVG KCO	U95% KCO	L5% THC3	AVG THC3	U95% THC3
125-150	1040	131	140	149	10.97	11.95	12.87	0.385	0.476	0.635	2.08	2.50	3.10	1	8	16	0	0	0
150-170	1174	151	159	168	10.02	10.94	12.10	0.390	0.462	0.541	2.24	2.64	3.10	0	6	16	0	0	0
170-190	4881	175	182	188	8.87	10.48	11.72	0.323	0.428	0.582	2.11	2.47	2.93	0	11	45	0	0	2
190-210	1080	190	198	208	8.03	10.13	11.68	0.313	0.416	0.586	2.03	2.47	3.01	0	10	24	0	0	2
210-230	642	211	219	227	7.22	9.45	11.38	0.290	0.387	0.526	2.06	2.44	3.15	0	11	29	0	0	2
230-250	550	232	241	249	6.80	8.98	10.71	0.298	0.381	0.478	2.13	2.48	3.05	0	18	51	0	0	2
250-270	448	251	258	269	6.08	8.76	10.81	0.281	0.379	0.473	2.17	2.52	3.12	2	27	131	0	0	3
270-290	341	272	281	289	6.04	8.43	10.67	0.277	0.385	0.531	2.16	2.50	3.12	0	18	63	0	0	0
290-310	476	291	299	308	5.97	8.07	10.07	0.273	0.377	0.525	2.15	2.59	3.26	1	23	97	0	0	1
310-330	239	311	320	329	6.04	7.97	10.16	0.280	0.379	0.507	2.19	2.63	3.23	0	45	345	0	0	1
330-350	494	332	341	348	6.48	7.94	9.20	0.314	0.375	0.472	2.20	2.61	3.22	1	27	81	0	0	0
350-370	279	351	360	369	5.91	7.41	9.03	0.296	0.387	0.520	2.18	2.62	3.23	1	59	300	0	0	0
370-390	414	371	380	389	5.74	7.06	8.49	0.306	0.381	0.485	2.06	2.55	3.09	1	49	232	0	0	0
390-410	733	391	402	409	5.42	6.52	7.90	0.307	0.372	0.460	2.16	2.54	3.24	4	73	314	0	0	1
410-430	1184	411	421	429	5.64	6.71	7.79	0.318	0.385	0.480	2.22	2.62	3.14	2	122	364	0	0	1
430-450	1389	431	440	449	5.90	6.60	7.43	0.337	0.400	0.511	2.19	2.60	3.23	7	100	350	0	0	1
450-470	1251	452	462	469	5.19	6.15	6.84	0.341	0.400	0.489	2.05	2.56	3.21	0	156	355	0	0	1
470-490	1527	471	477	485	5.23	6.09	6.73	0.352	0.398	0.456	2.08	2.62	3.27	0	115	352	0	0	1
490-510	8	491	494	500	5.91	6.28	6.57	0.374	0.398	0.441	2.61	2.87	3.08	0	57	158	0	0	0

EDITED HAMMOND PHASE 3b(c) TEST DATA
FIVE MINUTE DATA
PROCESSING FOR LOAD CATEGORIES (common includes co and thc)

Table D-19 LNB+AOFA / Long-Term / Emissions by Load / Ex. CO & THC Bad

LOAD CAT	N	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX	L5% KCO	AVG KCO	U95% KCO	L5% THC3	AVG THC3	U95% THC3
125150	1040	131	140	149	10.97	11.95	12.87	0.385	0.476	0.635	2.080	2.503	3.102	0.826	8	16	0	0	0
150170	1174	151	159	168	10.02	10.94	12.10	0.390	0.462	0.541	2.239	2.643	3.103	0.101	6	16	0	0	0
170190	4885	175	182	188	8.87	10.48	11.72	0.323	0.428	0.582	2.107	2.470	2.928	0.000	11	45	0	0	2
190210	1080	190	198	208	8.03	10.13	11.68	0.313	0.416	0.586	2.028	2.475	3.006	0.000	10	24	0	0	2
210230	642	211	219	227	7.22	9.45	11.38	0.290	0.387	0.526	2.063	2.445	3.146	0.000	11	29	0	0	2
230250	550	232	241	249	6.80	8.98	10.71	0.298	0.381	0.478	2.132	2.477	3.046	0.000	18	51	0	0	2
250270	448	251	258	269	6.08	8.76	10.81	0.281	0.379	0.473	2.169	2.522	3.115	2.015	27	131	0	0	3
270290	341	272	281	289	6.04	8.43	10.67	0.277	0.385	0.531	2.163	2.505	3.124	0.000	18	63	0	0	0
290310	476	291	299	308	5.97	8.07	10.07	0.273	0.377	0.525	2.152	2.586	3.262	1.243	23	97	0	0	1
310330	239	311	320	329	6.04	7.97	10.16	0.280	0.379	0.507	2.193	2.630	3.230	0.000	45	345	0	0	1
330350	494	332	341	348	6.48	7.94	9.20	0.314	0.375	0.472	2.197	2.608	3.222	1.331	27	81	0	0	0
350370	279	351	360	369	5.91	7.41	9.03	0.296	0.387	0.520	2.176	2.618	3.232	0.985	59	300	0	0	0
370390	414	371	380	389	5.74	7.06	8.49	0.306	0.381	0.485	2.062	2.550	3.087	0.858	49	232	0	0	0
390410	733	391	402	409	5.42	6.52	7.90	0.307	0.372	0.460	2.162	2.544	3.238	3.901	73	314	0	0	1
410430	1184	411	421	429	5.64	6.71	7.79	0.318	0.385	0.480	2.216	2.622	3.140	2.004	122	364	0	0	1
430450	1389	431	440	449	5.90	6.60	7.43	0.337	0.400	0.511	2.188	2.599	3.229	7.284	100	350	0	0	1
450470	1251	452	462	469	5.19	6.15	6.84	0.341	0.400	0.489	2.054	2.564	3.214	0.000	156	355	0	0	1
470490	1527	471	477	485	5.23	6.09	6.73	0.352	0.398	0.456	2.077	2.618	3.268	0.388	115	352	0	0	1
490510	8	491	494	500	5.91	6.28	6.57	0.374	0.398	0.441	2.612	2.873	3.079	0.000	57	158	0	0	0

EDITED HAMMOND PHASE 3b(c) TEST DATA
FIVE MINUTE DATA
PROCESSING FOR LOAD CATEGORIES
(common only includes load, nox, and o2 - not co and thc)

Table D-20 LNB+AOFA / Long-Term / Within-Day Averages

HOUR	N	L5% LOAD	AVG LOAD	U95% LOAD	L5% KO2	AVG KO2	U95% KO2	L5% KNOX	AVG KNOX	U95% KNOX	L5% KSOX	AVG KSOX	U95% KSOX
0	62	146.74	195.02	280.57	7.623	10.026	12.128	0.316	0.415	0.559	2.069	2.510	3.070
1	61	136.38	181.02	238.22	7.819	10.340	12.165	0.317	0.426	0.568	2.064	2.500	3.065
2	62	135.51	179.92	215.32	8.316	10.457	12.268	0.326	0.435	0.571	2.062	2.496	3.027
3	62	133.98	176.37	218.88	8.641	10.521	12.262	0.324	0.439	0.593	2.052	2.497	3.079
4	61	135.37	187.85	299.03	6.445	10.362	12.212	0.326	0.438	0.597	2.121	2.506	3.008
5	62	145.18	203.99	400.52	5.898	10.218	12.199	0.327	0.438	0.577	2.066	2.505	3.024
6	64	147.82	210.76	446.48	5.592	10.015	12.082	0.324	0.428	0.569	2.109	2.513	3.021
7	63	152.83	221.94	423.79	5.668	9.719	11.876	0.325	0.419	0.543	2.112	2.535	3.068
8	61	154.48	249.20	459.54	5.685	9.256	11.573	0.330	0.414	0.547	2.102	2.540	3.100
9	61	155.18	279.40	474.14	5.713	8.895	11.561	0.330	0.415	0.549	2.156	2.546	3.093
10	64	159.43	320.59	479.66	5.667	8.321	11.413	0.347	0.408	0.541	2.156	2.548	3.185
11	66	177.07	352.16	478.83	5.775	7.826	11.137	0.326	0.401	0.500	2.166	2.558	3.148
12	66	181.29	371.77	481.41	5.855	7.556	11.248	0.343	0.400	0.519	2.158	2.555	3.142
13	67	177.67	382.26	480.40	5.610	7.401	11.387	0.326	0.400	0.496	2.156	2.557	3.231
14	67	182.64	382.37	481.46	5.588	7.329	11.344	0.333	0.398	0.497	2.129	2.563	3.224
15	67	183.11	378.73	478.66	5.780	7.410	11.140	0.332	0.397	0.494	2.107	2.563	3.245
16	67	183.25	370.90	474.79	5.787	7.579	11.357	0.340	0.401	0.559	2.102	2.558	3.241
17	66	182.30	372.12	474.32	5.666	7.555	11.586	0.333	0.399	0.513	2.139	2.563	3.210
18	66	180.95	366.16	475.66	5.697	7.653	11.546	0.327	0.397	0.512	2.158	2.559	3.213
19	65	178.33	355.80	473.40	5.792	7.830	11.549	0.316	0.398	0.524	2.165	2.556	3.214
20	65	179.01	350.94	476.10	5.825	7.851	11.435	0.308	0.397	0.533	2.152	2.553	3.160
21	62	166.07	333.67	455.21	5.833	8.056	11.541	0.303	0.395	0.544	2.164	2.565	3.160
22	61	159.36	276.83	428.60	6.414	8.906	11.663	0.315	0.398	0.524	2.094	2.563	3.175
23	61	150.34	224.14	397.02	6.938	9.652	12.394	0.319	0.405	0.540	2.025	2.531	3.093

HAMMOND PHASE 3bTESTING
WITHIN DAY PROFILES
VALID HOURS ONLY AND COM SET TO MISSING

Table D-21 LNB+AOFA / Long-Term / Daily Averages

DID	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
930511	24	345.51	6.615	0.354	2.227
930512	24	329.94	6.525	0.324	2.178
930513	17				
930518	18	391.33	6.392	0.377	2.161
930519	24	386.64	6.334	0.407	2.065
930520	24	379.17	6.225	0.396	2.069
930521	24	341.22	6.950	0.380	2.140
930522	24	165.77	11.437	0.422	2.323
930523	24	135.66	12.335	0.437	2.336
930524	24	184.72	10.851	0.396	2.405
930525	24	239.62	9.724	0.340	2.448
930526	24	195.02	10.356	0.343	2.408
930527	24	199.29	10.789	0.360	2.414
930528	24	201.96	10.416	0.350	2.451
930529	24	237.94	9.934	0.371	2.419
930530	24	266.93	9.302	0.402	2.310
930531	24	185.78	10.743	0.566	2.229
930601	24	186.93	10.724	0.583	2.345
930602	24	188.33	11.442	0.559	2.455
930603	24	283.90	8.975	0.491	2.509
930604	21	285.31	9.074	0.544	2.500
930605	24	315.71	9.059	0.481	2.593
930606	24	327.11	8.739	0.452	2.790
930607	24	298.26	9.726	0.419	2.696
930608	0				
930609	0				
930610	0				
930611	0				
930612	0				
930613	0				
930614	0				
930615	0				
930616	0				
930617	0				
930618	0				
930619	0				
930620	0				
930621	21	239.99	9.202	0.398	2.302
930622	0				
930623	22	329.78	8.199	0.444	2.324
930624	0				
930625	0				
930626	24	197.58	9.898	0.417	2.346
930627	24	205.26	10.163	0.405	2.391
930628	23	296.75	8.973	0.400	2.319
930629	24	240.47	10.242	0.426	2.347
930630	24	308.55	9.157	0.411	2.348

PLANT HAMMOND PHASE 3b TESTING
FIVE MINUTE DATA
DAILY AVGS (DAYS WITH AT LEAST 18 HRS DATA)
VALID HOURS ONLY - USES COMMON VARIABLE

Table D-21 LNB+AOFA / Long-Term / Daily Averages (Continued)

DID	N	AVG LOAD	AVG KO2	AVG KNOX	AVG KSOX
930701	24	328.13	8.233	0.344	2.637
930702	22	330.08	7.533	0.367	2.917
930703	8				
930704	11				
930705	24	253.61	9.682	0.456	3.163
930706	24	305.30	9.166	0.453	3.019
930707	24	293.17	8.679	0.421	3.075
930708	24	343.43	7.472	0.397	3.241
930709	24	348.68	7.816	0.386	2.673
930710	24	335.97	7.455	0.358	2.608
930711	24	365.66	7.161	0.355	2.825
930712	24	342.22	7.312	0.360	2.581
930713	23	328.06	8.143	0.376	2.595
930714	19	369.35	7.837	0.431	2.500
930715	24	342.56	8.010	0.399	2.577
930716	24	361.28	7.889	0.373	2.975
930717	18	372.61	6.862	0.363	2.803
930718	24	336.99	8.105	0.426	2.777
930719	24	370.64	7.783	0.403	2.775
930720	22	360.06	7.868	0.410	2.200
930721	22	377.38	7.658	0.391	2.553
930722	24	368.90	7.732	0.398	2.704
930723	24	344.32	8.043	0.429	3.158
930724	24	319.80	8.743	0.441	2.975
930725	24	312.84	8.335	0.422	2.555
930726	22	330.70	8.185	0.436	2.220
930727	24	338.58	7.857	0.409	2.160
930728	20	361.97	7.389	0.375	2.411
930729	24	344.47	8.091	0.416	2.439
930730	4				
930731	0				
930801	0				
930802	3				
930803	12				
930804	11				
930805	18	306.05	8.342	0.408	2.640
930806	24	180.34	10.528	0.434	2.632
930807	24	158.86	10.801	0.430	2.625
930808	24	247.75	8.559	0.383	2.679
930809	0				
930810	0				
930811	0				
930812	24	255.26	8.227	0.363	2.644
930813	20	218.13	10.179	0.392	2.445

PLANT HAMMOND PHASE 3b TESTING
FIVE MINUTE DATA
DAILY AVGS (DAYS WITH AT LEAST 18 HRS DATA)
VALID HOURS ONLY - USES COMMON VARIABLE

Table D-22 LNB+AOFA / Long-Term / 30 Day Rolling Averages

30DAY#	LOAD	KO2	KNOX	KSOX
1	287.47	9.378	0.426	2.377
2	288.87	9.510	0.429	2.384
3	290.87	9.660	0.434	2.394
4	290.28	9.837	0.436	2.412
5	286.99	10.039	0.438	2.431
6	284.58	10.222	0.441	2.448
7	287.69	10.096	0.440	2.448
8	296.26	9.954	0.441	2.455
9	301.42	9.794	0.444	2.451
10	305.19	9.799	0.451	2.451
11	307.60	9.758	0.459	2.454
12	307.54	9.693	0.463	2.449
13	307.65	9.674	0.467	2.445
14	309.67	9.606	0.469	2.438
15	308.77	9.675	0.471	2.441
16	312.94	9.558	0.459	2.449
17	317.74	9.376	0.442	2.471
18	322.22	9.098	0.428	2.502
19	322.00	9.178	0.424	2.515
20	321.39	9.133	0.415	2.541
21	319.28	9.183	0.413	2.587
22	318.54	9.218	0.413	2.605
23	318.37	9.133	0.413	2.636
24	317.19	9.010	0.412	2.681
25	315.34	8.927	0.410	2.680
26	313.63	8.832	0.407	2.675
27	312.64	8.731	0.403	2.685
28	313.76	8.649	0.401	2.679
29	313.99	8.623	0.400	2.674
30	314.46	8.591	0.401	2.667
31	312.91	8.562	0.401	2.663
32	312.02	8.530	0.399	2.677
33	310.22	8.511	0.401	2.682
34	310.27	8.480	0.401	2.686
35	312.85	8.456	0.401	2.667
36	315.72	8.427	0.401	2.663
37	319.49	8.373	0.401	2.677
38	318.01	8.360	0.402	2.696
39	317.44	8.380	0.402	2.719
40	316.17	8.379	0.403	2.713
41	318.56	8.372	0.404	2.697
42	323.32	8.300	0.403	2.691
43	328.43	8.206	0.403	2.693
44	330.01	8.176	0.403	2.697
45	332.94	8.113	0.403	2.708
46	333.08	8.073	0.403	2.721
47	329.43	8.067	0.405	2.725
48	327.76	8.084	0.406	2.717
49	328.11	8.044	0.406	2.711
50	328.97	8.035	0.406	2.701
51	331.05	7.977	0.404	2.681
52	326.57	8.033	0.403	2.665
53	321.75	8.120	0.403	2.646
54	318.33	8.165	0.403	2.623
55	315.99	8.180	0.403	2.621
56	315.14	8.212	0.405	2.621
57	311.18	8.260	0.406	2.613

PLANT HAMMOND PHASE 3B TEST DATA
DAILY AVERAGES FROM EDITED 5 MINUTE DATA
PROCESS FOR ROLLING AVERAGES
VALID HOURLY AVERAGES: EACH WITH AT LEAST 1/2 DATA
EACH PARAMETER SET SEPARATELY (NO COMMON)

APPENDIX E
AOFA ERECTION

AOFA ERECTION

Generally, combustion NOx reduction techniques attempt to stage the introduction of oxygen into the furnace. This staging reduces NOx production by creating a delay in fuel and air mixing which lowers combustion temperatures. This staging also reduces the quantity of oxygen available to the fuel-bound nitrogen. Typical overfire air (OFA) systems accomplish this staging by diverting 10 to 20 percent of the total combustion air to ports located above the primary combustion zone. AOFA improves this concept by introducing the OFA through separate ductwork in greater quantities, with more control, and at higher pressures. The resulting system is capable of providing deep staging of the combustion process with accurate measurement of the AOFA airflow.

The FWEC AOFA system that is offered commercially utilizes a number of high velocity ports located at a higher elevation than the conventional OFA and uses a maximum of 20 percent of the total combustion air. As shown in Figure E-1, the AOFA system diverts air from the secondary air ducts and introduces it through a number of overfire air ports in the front and rear wall. The Hammond Unit 4 boiler design characteristics and project requirements had an impact on the design of the AOFA system. The Hammond AOFA system differs from the standard FWEC AOFA design in the following two features:

- It utilizes four AOFA ports instead of the six proposed originally by FWEC.
- It is located closer to the burners than FWEC would have liked (Hammond distance between the top burner and the bottom of the AOFA = 9' 2").

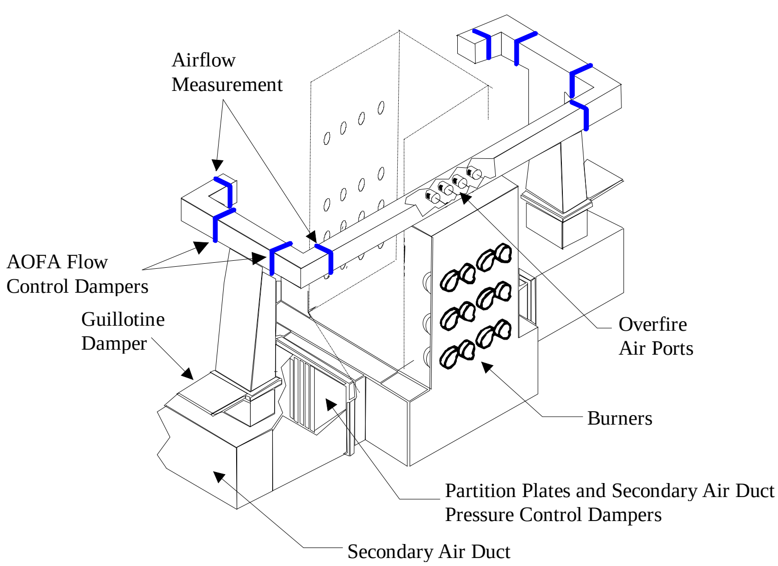

Figure E-1 Advanced Overfire Air System

These two design features of the AOFA system are believed to have impacted the NOx reduction potential, but they should not compromise the applicability of the test results for other wall-fired units because many units are subject to similar limitations. The AOFA system operation at

Hammond was not automated; a separate control panel was provided in the control room through which the operators manually controlled the AOFA dampers. However, the AOFA system has been automated for the Advance Optimization/Controls portion of the test program.

During the month of April 1990, the AOFA system was installed at the demonstration site (Figure E-2). The majority of the work was performed during the scheduled four week outage starting April 5, 1990, with only insulation and lagging, access structures, and electrical and controls work left for on-line completion. During the outage, the construction subcontractor worked two, ten hour shifts per day, six days per week. Radiography was performed on all pressure welds between the night and morning shifts. At peak work levels, the construction subcontractor employed approximately 130 craft personnel. However, very early in the outage it became evident that a shortage of certified craft personnel existed for the project owing to several boiler outages at other sites in the area. This shortage created scheduling difficulties throughout the outage.

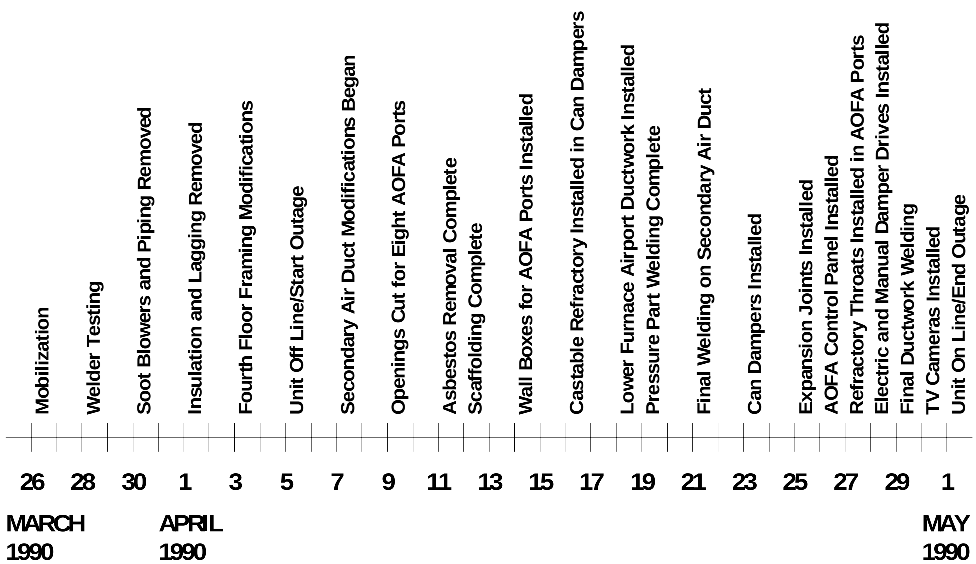

Figure E-2 Advanced Overfire Air System Erection Timeline

The turnkey contractor for design, supply and installation of the AOFA system was Foster Wheeler Energy Corporation (FWEC). FWEC designed and supplied the equipment and material but opted to subcontract the erection activities to others. Flame Refractories received the contract for all erection activities except electrical work, insulation and lagging. White Electric received the contract for all electrical work and North Brothers received the contract for removal and reinstallation of insulation and lagging, including removal of asbestos.

Prior to the outage, the erection contractors mobilized and did as much work as possible before the unit came off-line. Pre-outage work consisted of the following activities:

- Receiving and unloading new equipment and materials
- Moving tools and welding machines to work areas and testing welders

- Removing soot blowers and piping from the fourth floor area where the AOFA ports would be installed
- Stripping insulation and lagging from the boiler front and rear walls in the fourth floor area and on top of the secondary air duct where the AOFA duct would tie in
- Removing existing access walkways and handrails in affected areas
- Installing rigging
- Moving as much of the new equipment and materials as possible up to the boiler areas were it would eventually be installed (Figures E-3 and E-4)
- Modifications to the fourth floor framing for the AOFA duct penetration

The pre-outage work was critical to the project because of the length of the outage (only 4 weeks), the large scope of work to be performed (in addition to the DOE work, a great deal of other boiler repair, component replacement and maintenance work were scheduled), and the limited access to critical areas.

The new equipment and material were received by truck and were unloaded near the Unit 4 boilerhouse. During removal of lagging on the secondary air duct, abestos insulation was discovered. Work in this area was stopped until the abestos was properly removed and disposed of.

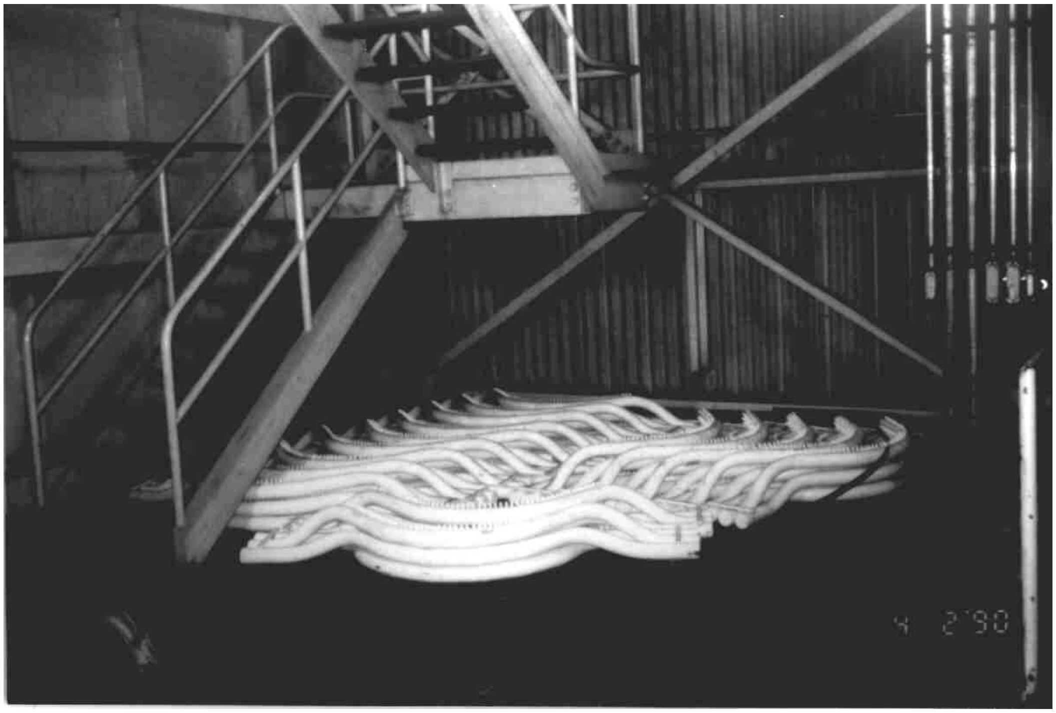

Figure E-3 AOFA Port Bent Tubes Staged for Erection Prior to Outage

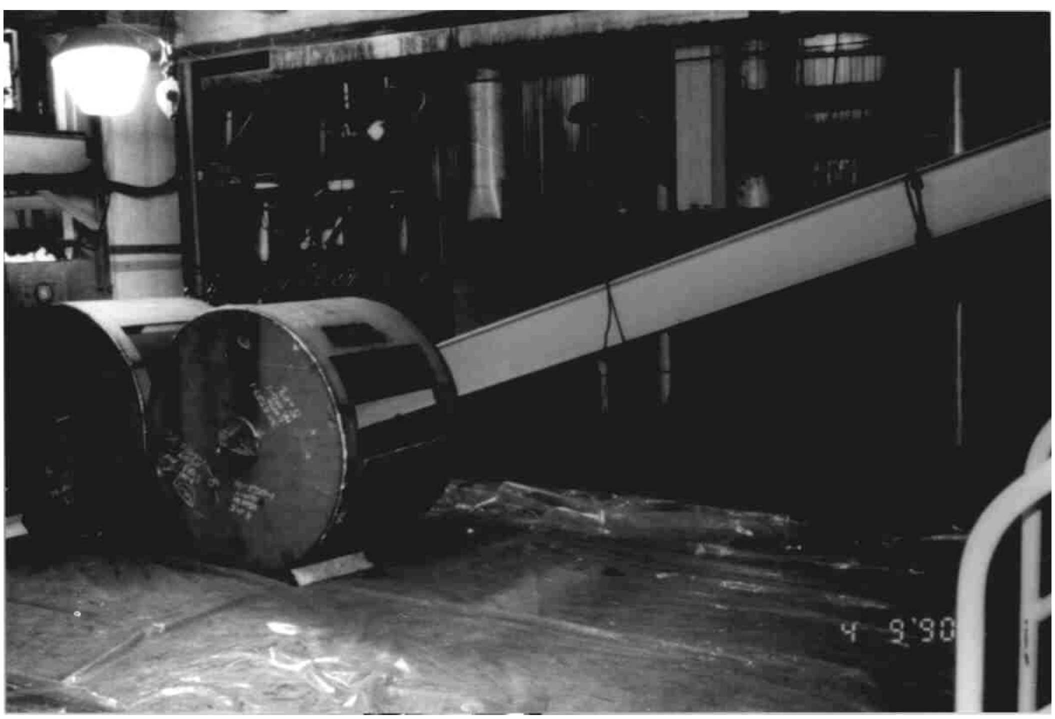

Figure E-4 AOFA Port Wall Boxes and Can Dampers Staged for Erection

At midnight, on Thursday, April 5, 1990, Hammond Unit 4 was brought off-line. As soon as the boiler cooled down, deslagging was performed and erection of scaffolding inside the furnace began. Scaffolding ran behind schedule and was not completed until Thursday, April 12, 1992.

Plant outage meetings were held each Tuesday and Thursday during the outage. The meetings were attended by the Plant Manager, Assistant Plant Manager, key supervisory personnel, the DOE Project Site Coordinator and the DOE Project Design Coordinator. All aspects of the outage were discussed in detail, both DOE activities and non-DOE activities. These meetings proved to be very beneficial and were a crucial factor in the overall success of the erection activities.

During the first week of the outage, results were received from the first arsenic testing. The testing showed unacceptable levels of arsenic in the furnace and lower dead air space. It was determined that the workers would have to continue to wear respirators and protective clothing until the measured values dropped to acceptable levels.

The following activities also occured during the first week of the outage:

- Three inch wide bands were sand blasted completely around the circumference of the furnace at eight elevations for NDT of the boiler tubes before and after each test phase (Figures E-5 and E-6)
- All asbestos removal was completed
- Soot blower seal boxes and bent tubes were removed on the fourth floor elevation
- Seal boxes and bent tubes for existing TV cameras and observation ports were removed on the fourth floor elevation
- Prepped, scarfed, fit and welded new straight tubes to close previous openings for soot blowers, TV cameras and observation ports
- Openings were cut in the furnace walls for eight AOFA ports (12 tubes wide by 6 feet high), four lower furnace air ports (8 tubes wide by 5 feet high) and two new TV cameras (1 tube wide by 3 feet high) (Figure E-7)
- Work began on the modifications to the secondary air duct inlet plenum (new duct transition to existing windbox, new pressure control dampers, new splitter plates and new access doors and platforms)
- Work began in the lower dead air space for the boundary air system (slots were cut between tubes in the hopper throat area and the side walls in the hopper area, scallop bars were welded to the side walls to attach the inlet plenums, ductwork and dampers were added) (Figures E-8 and E-9)

New power transformer was added and distribution and breaker panels were installed for the new damper drives, flow monitoring system and TV cameras (Figure E-10)

It became apparent very early in the outage that an insufficient number of boiler makers were available for work at Plant Hammond. This continued to be a problem throughout the outage and made an already tight schedule even more difficult.

During the second week of the outage the following activities occured:

- NDT of the boiler waterwalls at all eight elevations was completed
- Bent tubes were prepped, scarfed, fit and welded for the AOFA ports, the lower furnace air ports and the TV cameras (Figure E-11)
- Radiography of all pressure welds was performed in the four hour periods between the night and morning shifts
- All pressure part welding was completed by Thursday, April 19, 1990
- Work continued in the lower dead air space on the boundary air system (Figure E-12)
- Wall boxes were installed for the AOFA ports, lower furnace air ports and TV cameras
- New wall boxes were filled with refractory
- Work continued on the secondary air duct inlet plenum and in the lower dead air space
- Castable refractory was installed inside the can dampers (Figures E-13 and E-14)
- Portions of the AOFA ductwork were moved to the fourth floor for later installation
- Modifications were made to the boiler house steel to support the AOFA ductwork on each side of the boiler; duct hangers were installed
- Ductwork and dampers (4 louver type) were installed for the lower furnace air ports
- Cable trays and conduit were installed

Testing for arsenic continued to yield unacceptable results during the second week of the outage and workers inside the furnace and lower dead air space continued to wear respirators and protective clothing.

During the third week of the outage, enough craft personnel finally became available to fully man the job. The average workforce was approximately 70 workers during the day and approximately 60 workers during the night shift. During this time, testing for arsenic was discontinued and a decision was made to provide respirators and protective clothing to the workers in the affected areas for the remainder of the outage.

During the third week of the outage, the following activities occured:

- Final welding began on the new secondary air plenums, partition plates and dampers

- Vertical take-off ducts and guillotine dampers for AOFA system were set in place (Figure E-15)
- Can dampers were set in place and welded to the wall boxes (Figure E-16)
- Scallop bars were welded to the boiler tubes on the front and rear walls (for attaching the new AOFA windbox roof to the waterwalls)
- The front and rear walls for the AOFA windbox were set in place
- The AOFA windbox roof was set in place for both the front and rear windboxes
- The AOFA ductwork on each side of the boiler connecting the vertical take-off duct with the front and rear windboxes was set in place
- Expansion joints (4 fabric joints) and dampers (4 louver type) were installed in the AOFA ductwork
- Flow monitoring devices (4 multi-grid pitot type) were installed in the AOFA ductwork (Figures E-17 and E-18)
- Downcomer seals were set in place and welded to the downcomers and the front AOFA windbox roof
- Installation of access platforms, walkways and handrailing began
- Power and control wiring was installed
- The control panel for the AOFA system was installed in boiler control room (Figure E-19)
- Air filter and regulator stations for the TV cameras were installed
- Plant air and instrument air piping was installed for the TV cameras

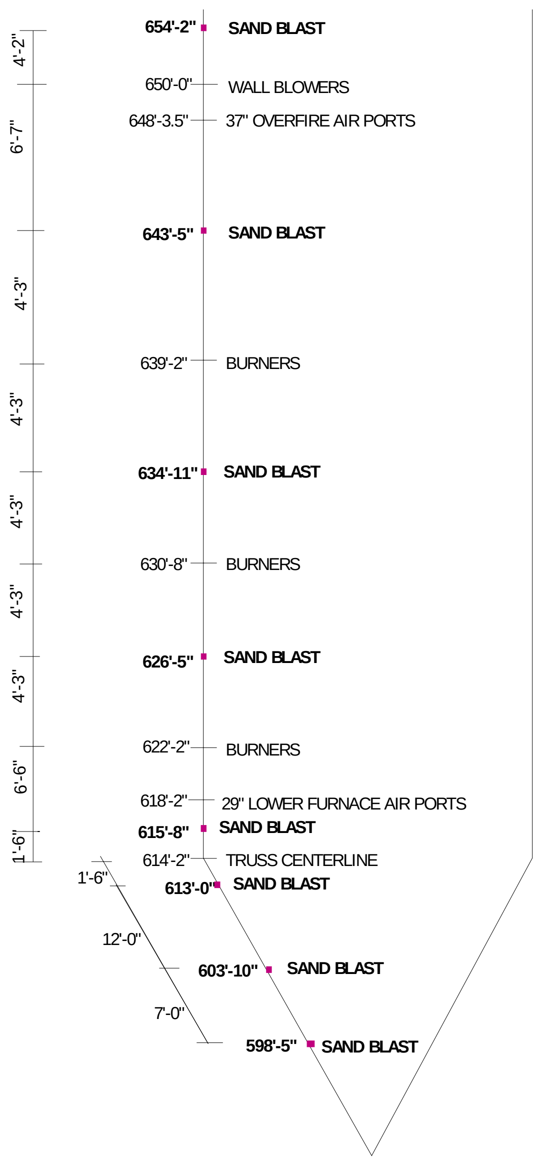

Figure E-5 Sand Blasted Band Locations

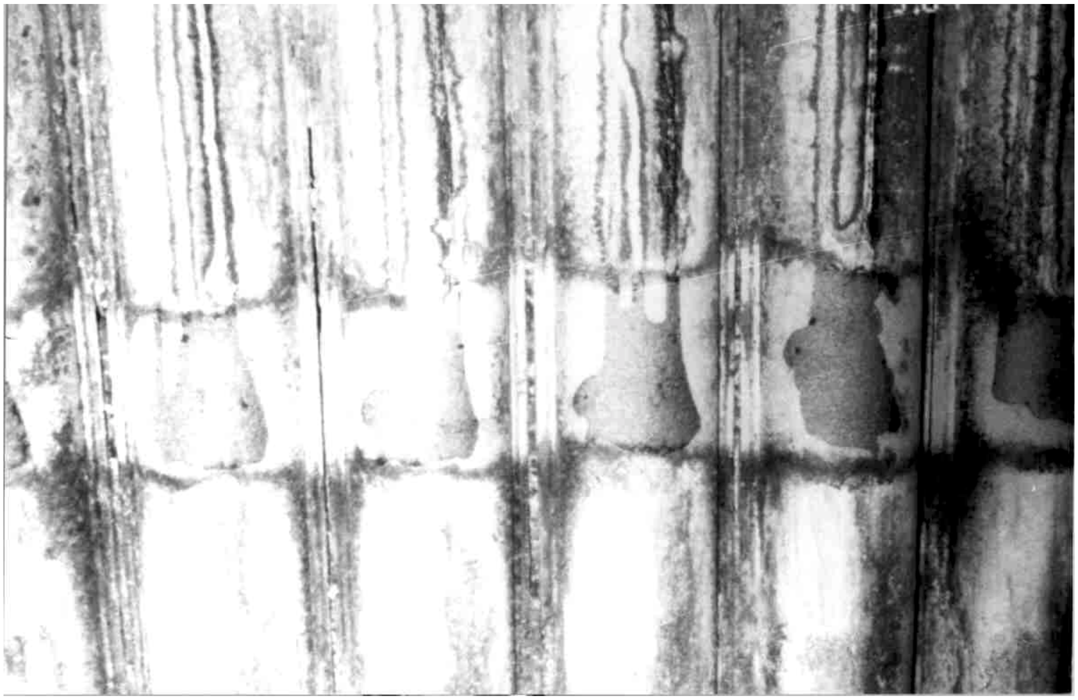

Figure E-6 Sand Blasted Bands for NDT of Boiler Tubes

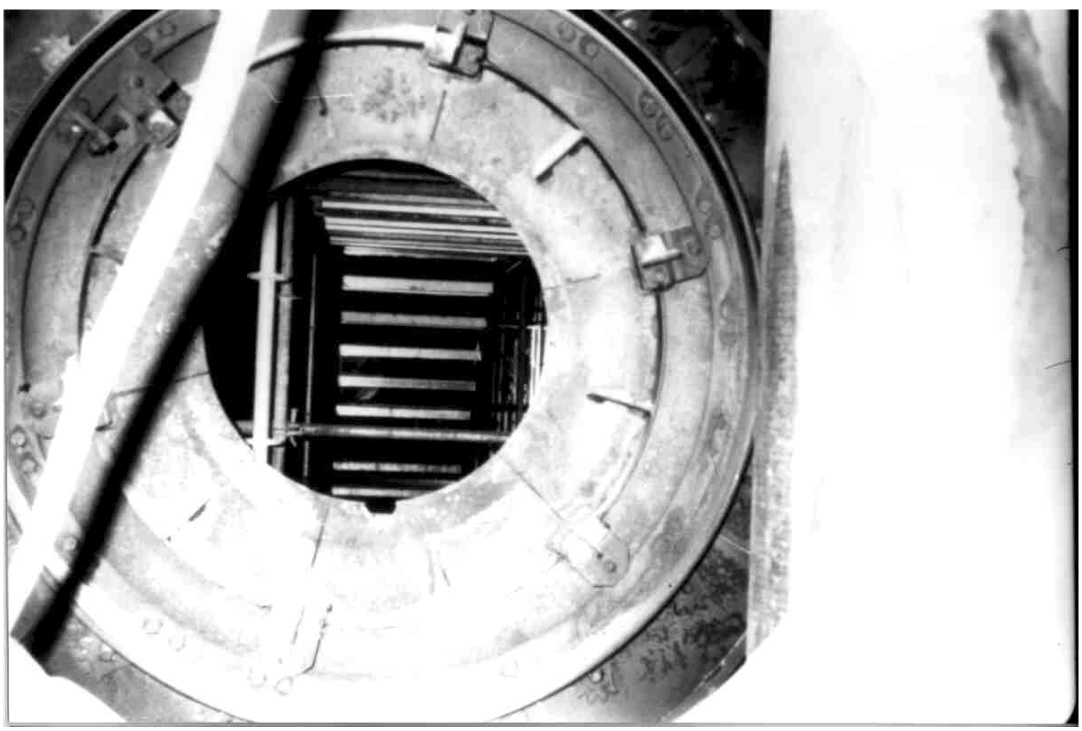

Figure E-7 AOFA Port Opening Cut in Waterwall

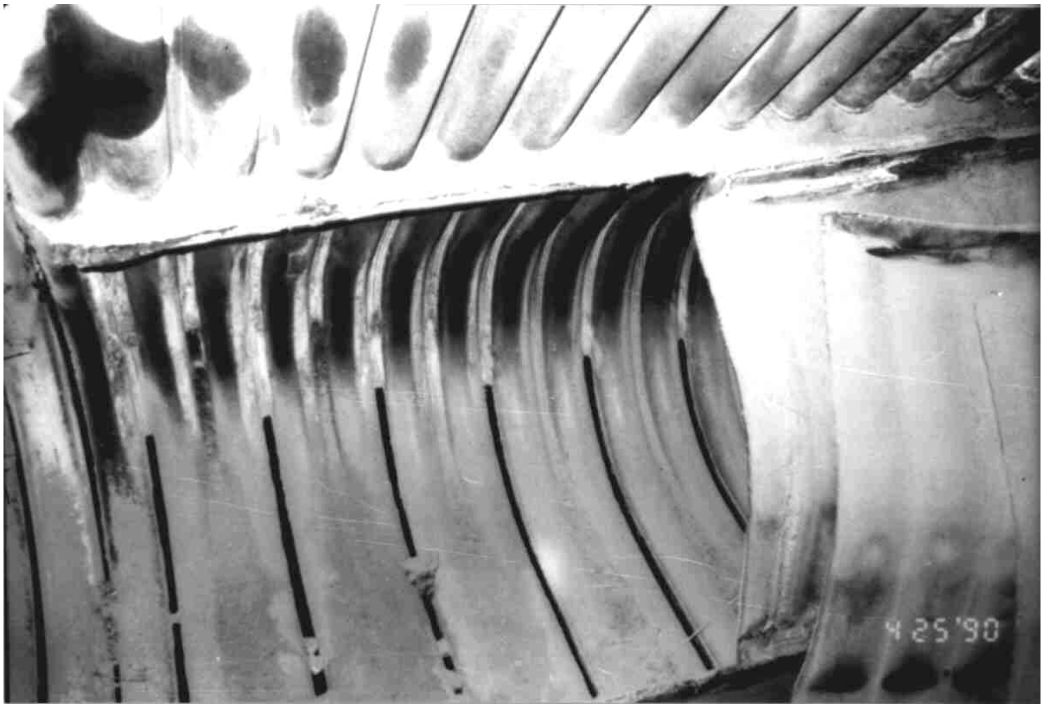

Figure E-8 Slots in Hopper Throat for Boundary Air System

Figure E-9 Slots in Side Walls for Boundary Air System

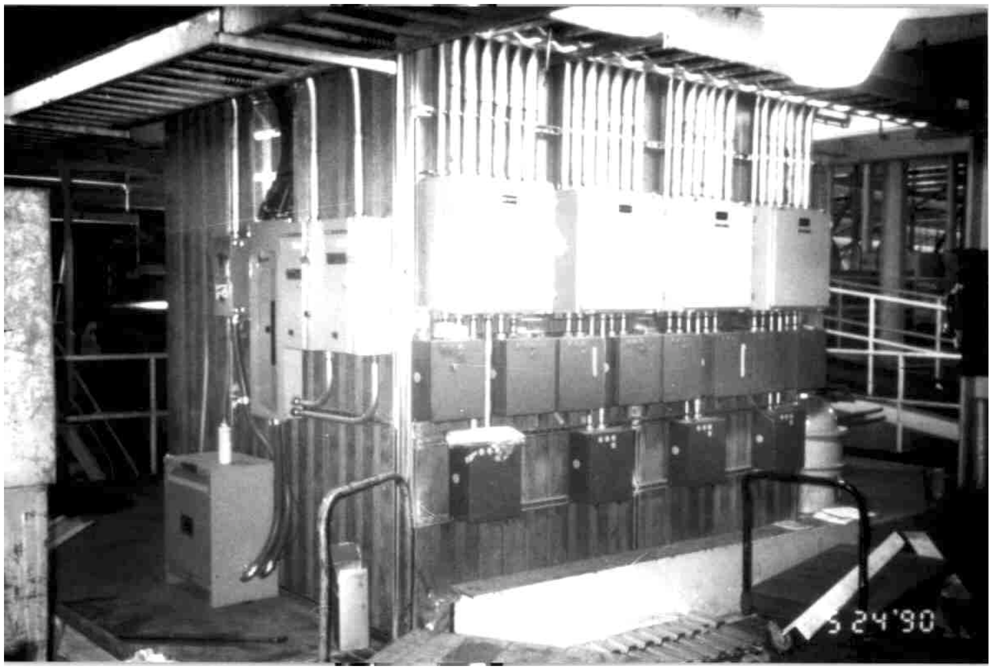

Figure E-10 Transformer, Distribution and Breaker Panels for AOFA System

Figure E-11 Bent Tubes for AOFA Port Welded in Place

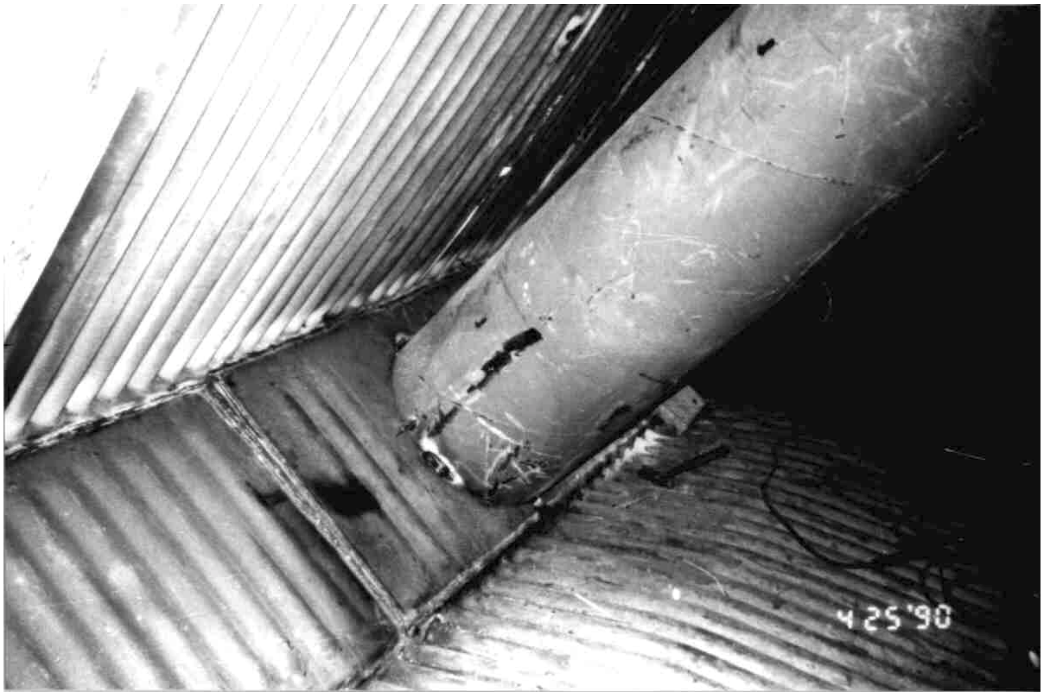

Figure E-12 Boundary Air System Plenum and Ductwork

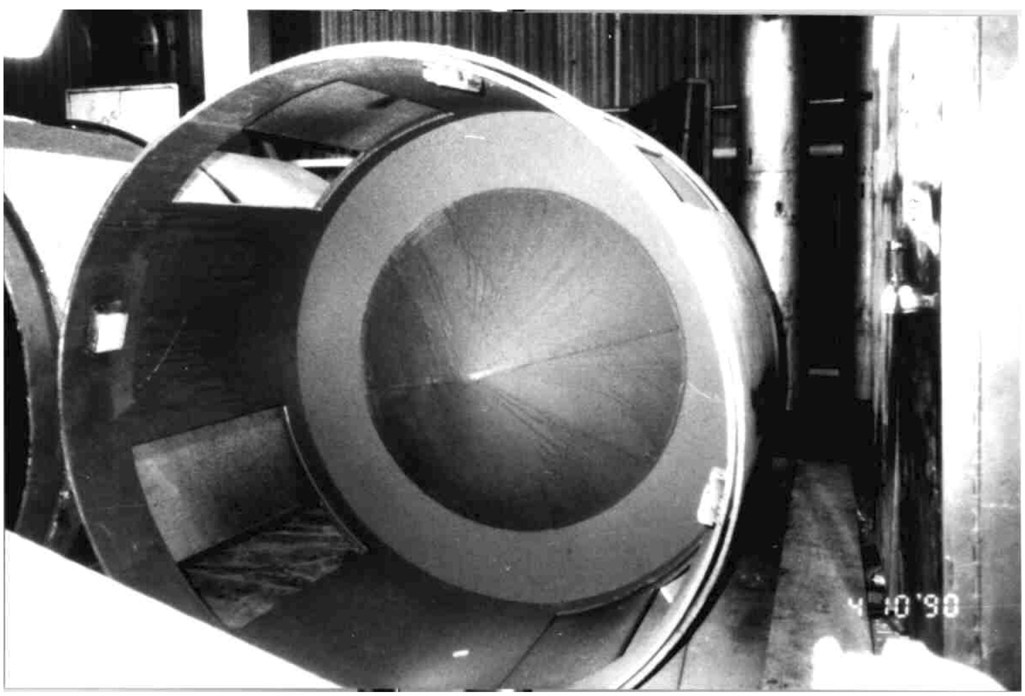

Figure E-13 Interior of Can Damper Before Refractory Installation

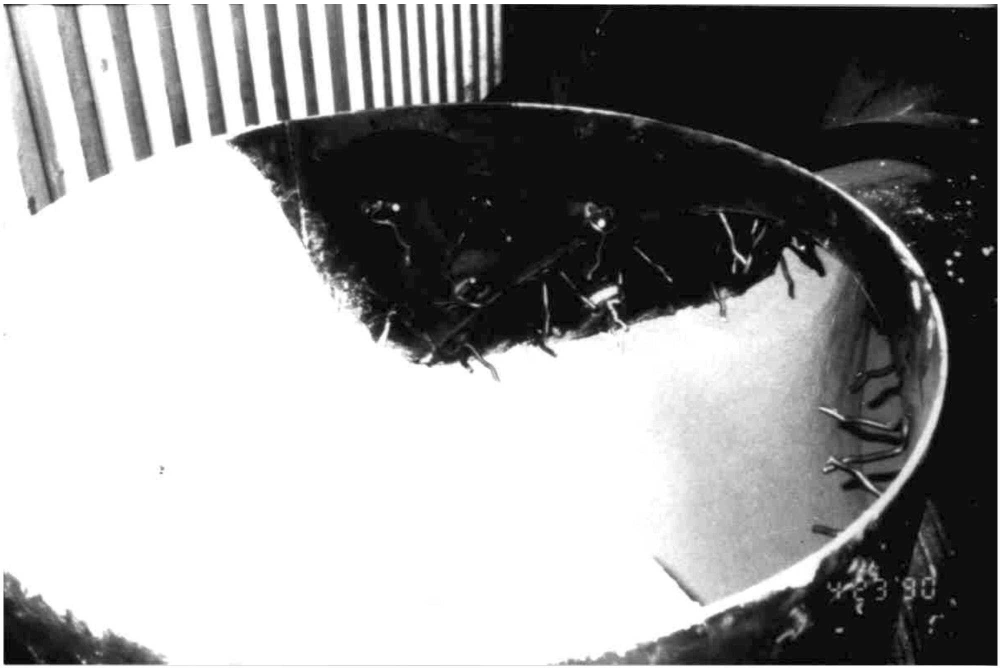

Figure E-14 Refractory Being Installed in Can Damper

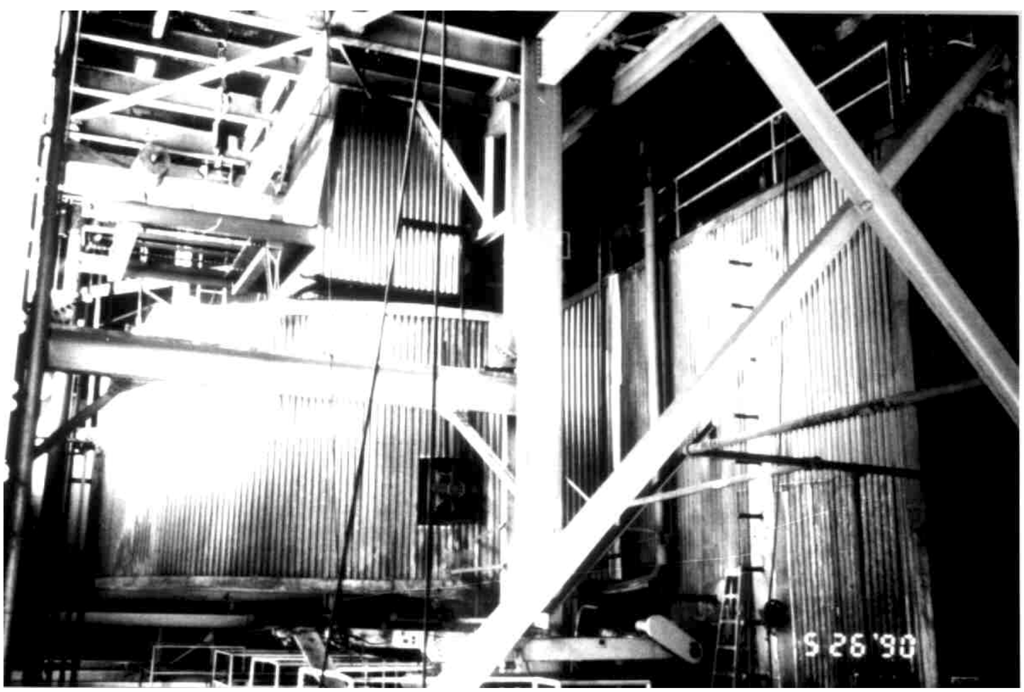

Figure E-15 New Secondary Air Inlet Plenum and Vertical Duct to AOFA System

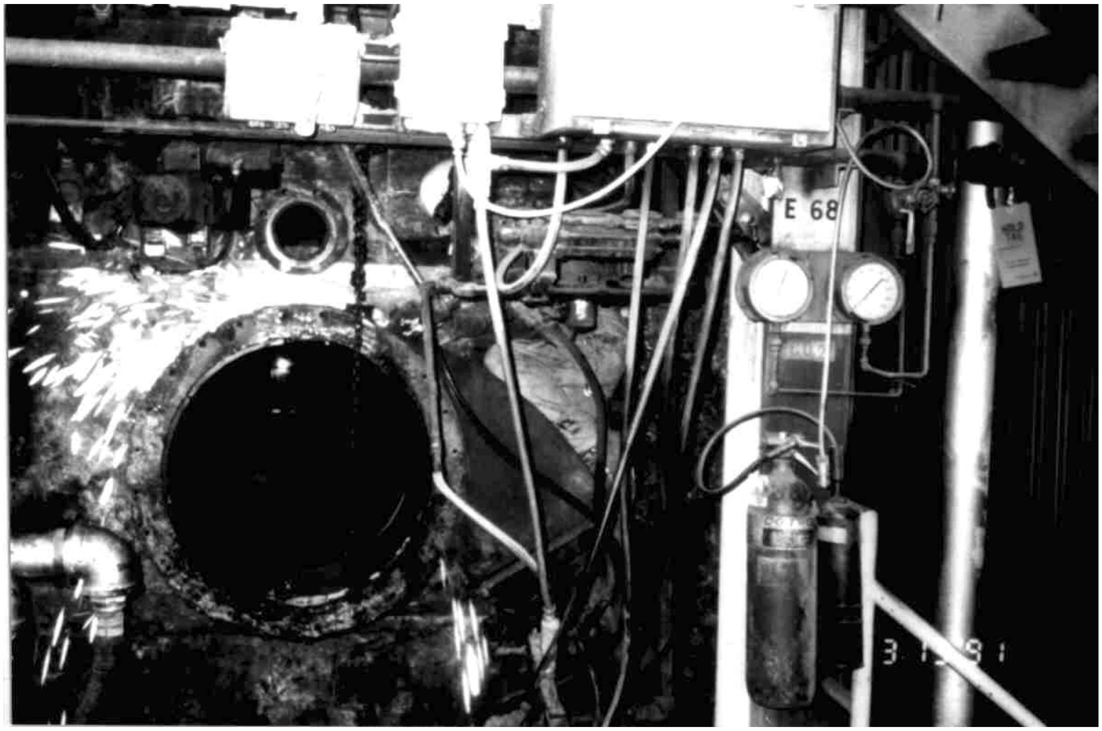

Figure E-16 New Secondary Air Inlet Plenum and Vertical Duct to AOFA System Can Damper Inside AOFA Windbox

During the final week of the outage, the following activities occured:

- Final welding of all ductwork
- Refractory throats were installed for the AOFA ports and the lower furnace air ports (Figure E-20)
- Access doors were installed in the AOFA ductwork
- Installation of insulation and lagging began
- Installation of manual operators for 4 lower furnace airport dampers, 2 hopper throat boundary air dampers and 2 hopper side wall boundary air dampers
- Installation of electric drives for 4 AOFA flow control dampers and 8 can dampers
- Relocated miscellaneous piping
- TV cameras were installed in the furnace with the monitors in the boiler control room (Figure E-21)
- Miscellaneous electrical work

- Removal of scaffolding

On Tuesday, May 1, 1990, a hydro test was performed on the boiler. With the guillotine dampers in the AOFA system closed, the unit began start-up at 3:30 pm on Saturday, May 5, 1990.

Following start-up of the unit the following activities occurred:

- Installation of remaining insulation and lagging
- Installation of remaining access structures
- Field painting
- Completion of electrical work
- Limit setting on dampers
- Check-out and start-up of new equipment
- Demobilization

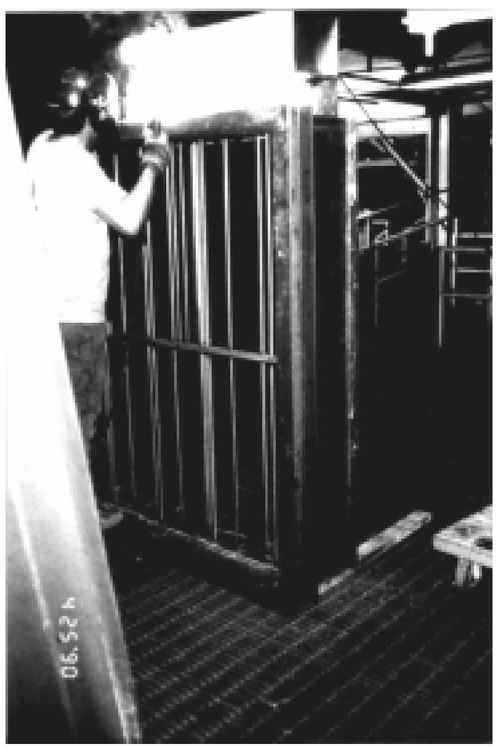

Figure E-17 Installation of AOFA System Air Flow Measuring Device

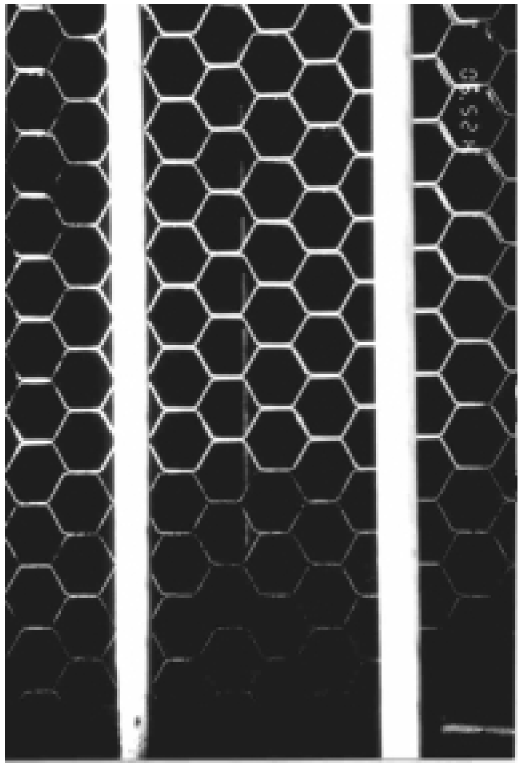

Figure E-18 AOFA System Air Flow Measuring Device Close-up

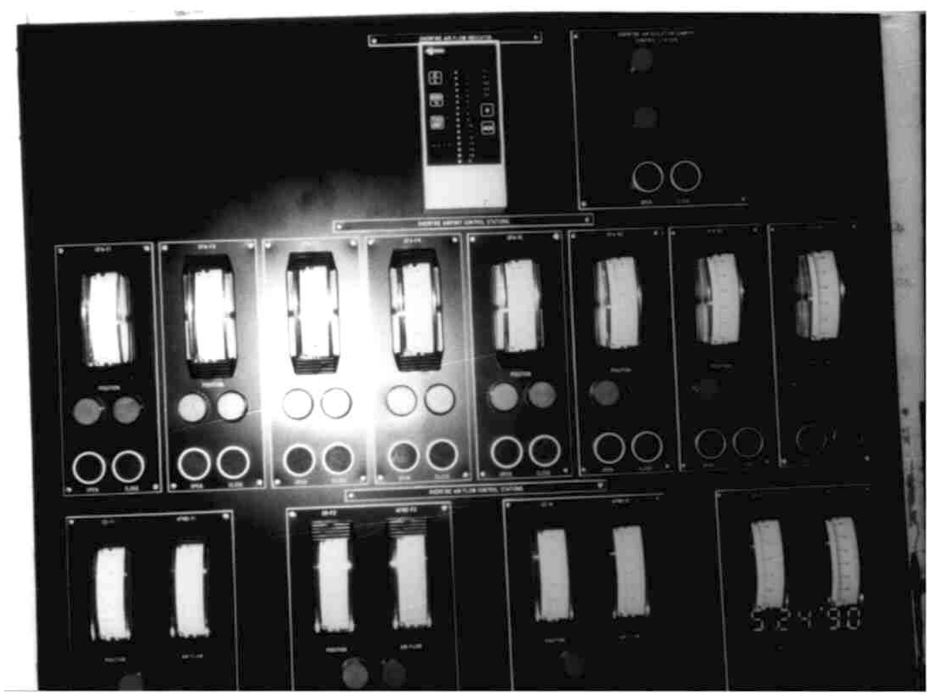

Figure E-19 Control Panel for AOFA System

Figure E-20 Installation of Refractory in AOFA System Air Port Throat

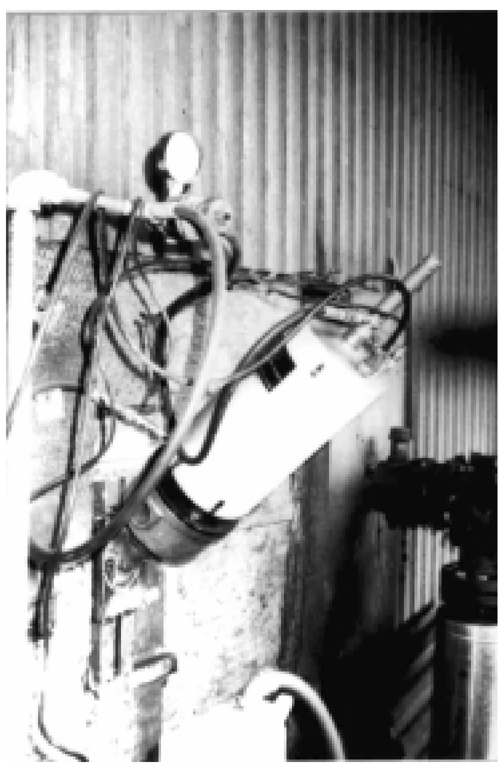

Figure E-21 Color TV Camera to Monitor Inside of Furnace

APPENDIX F
LNB ERECTION

LNB ERECTION

Low NOx burner systems attempt to stage combustion without the need for the additional ductwork and furnace ports required by OFA and AOFA systems. These commercially available burner systems introduce the air and coal into the furnace in a well controlled, reduced turbulence manner. To achieve this, the burner must regulate the initial fuel/air mixture, velocities and turbulence to create a fuel-rich core, with sufficient air to sustain combustion at a severely sub-stoichiometric air/fuel ratio. The burner must then control the rate at which additional air, necessary to complete combustion, is mixed with the flame solids and gases to maintain a deficiency of oxygen until the remaining combustibles fall below the peak NOx producing temperature (around 2800°F). The final excess air can then be allowed to mix with the unburned products so that the combustion is completed at lower temperatures. Burners have been developed for single-wall and opposed-wall boilers.

Foster Wheeler Energy Corporation (FWEC) was competitively selected to design, fabricate, and erect the opposed-wall, low NOx burner shown in Figure F-1. In the FWEC Controlled Flow/Split Flame (CFSF) burner, secondary combustion air is divided between inner and outer flow cylinders. A sliding sleeve damper regulates the total secondary air flow entering the burner and is used to balance the burner air flow distribution. An adjustable outer register assembly divides the burners secondary air into two concentric paths and also imparts some swirl to the air streams. The secondary air which traverses the inner path, flows across an adjustable inner register assembly that, by providing a variable pressure drop, apportions the flow between the inner and outer flow paths. The inner register also controls the degree of additional swirl imparted to the coal/air mixture in the near throat region. The outer air flow enters the furnace axially, providing the remaining air necessary to complete combustion. An axially movable inner sleeve tip provides a means for varying the primary air velocity while maintaining a constant primary flow. The split flame nozzle segregates the coal/air mixture into four concentrated streams, each of which forms an individual flame when entering the furnace. This segregation minimizes mixing between the coal and the primary air, assisting in the staged combustion process. The adjustments to the sleeve dampers, inner registers, outer registers, and tip position are made during the burner optimization process and thereafter remain fixed unless changes in plant operation or equipment condition dictate further adjustments.

The new LNBs were installed during a seven week outage which began March 8, 1991, and continued to April 28, 1991 (Figure F-2). Prior to the outage, rigging was installed, access pathways were formed, and when possible, insulation and lagging were removed. Although no pressure part modifications were required, installation of the new Foster Wheeler burners was far from simple. Complicating factors included craft labor shortages, the presence of asbestos and unacceptable levels of arsenic in the boiler, and the requirement to coordinate with the many other work activities occurring at the plant during a major outage. Approximately thirty craft personnel were involved in the retrofit, working a single ten-hour shift six days per week, for four weeks, and two ten-hour shifts, six days per week, for the remaining three weeks.

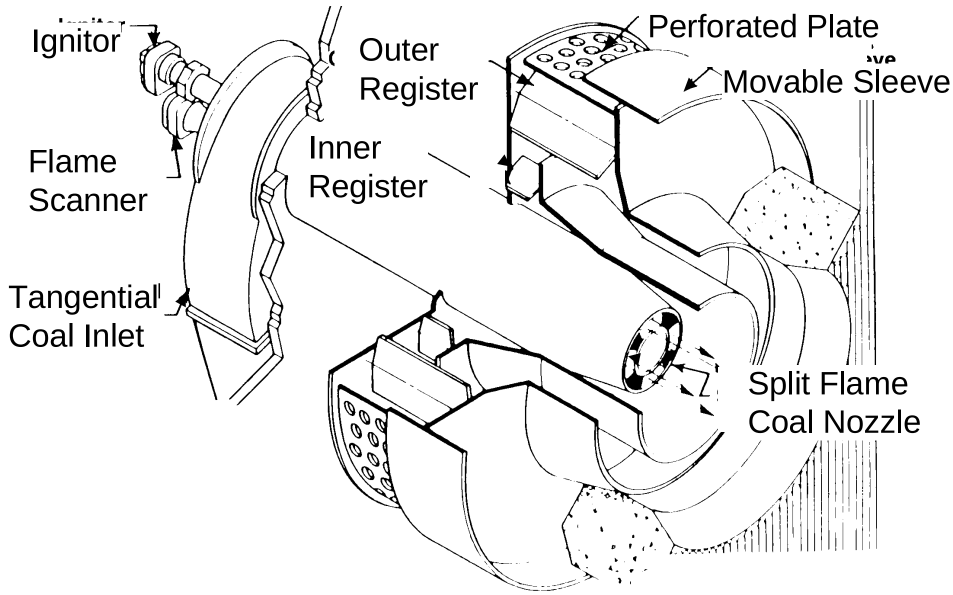

Figure F-1 FWEC Controlled Flow / Split Flame Low NOx Burner

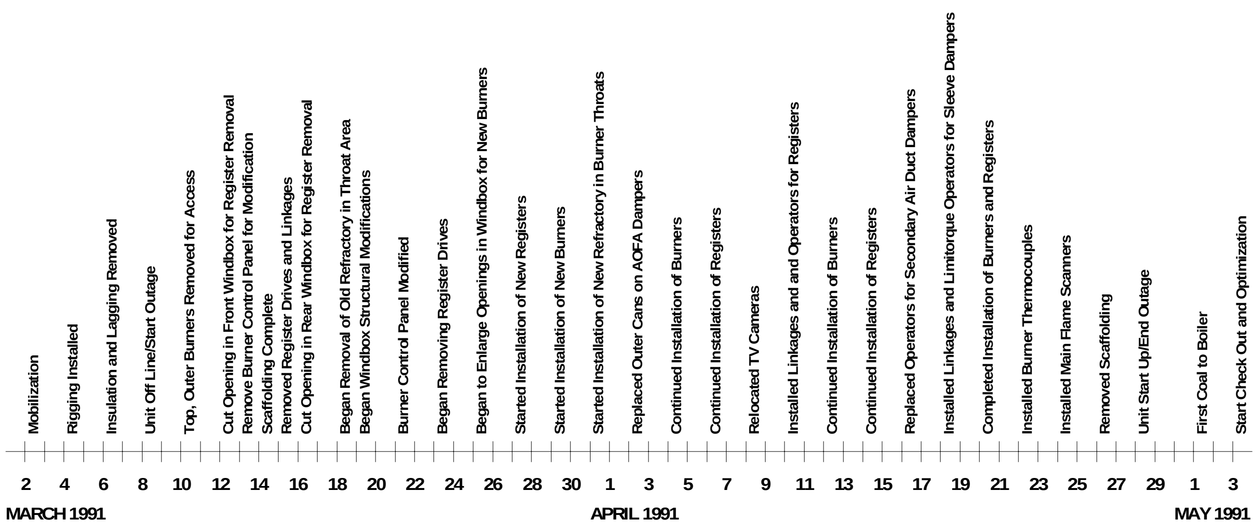

Figure F-2 LNB Erection Timeline

Foster Wheeler Corporation was responsible for the design, supply, installation and start up of the Low NOx Burner (LNB) system for Plant Hammond Unit 4. The erection of the LNB system was subcontracted to Brock and Blevins. Electrical work was subcontracted to White Electric and insulation removal and installation was subcontracted to North Brothers. All of the above were on site and had begun work by March 4, 1991, one week before the outage was scheduled to begin.

Prior to the outage, Brock and Blevins performed as much work as possible with the unit on line. The pre-outage work was very important because of the length of the outage (only 7 weeks), the large scope of work to be performed (in addition to the DOE work, a great deal of other boiler repair, component replacement and maintenance work were scheduled), and the limited access to critical areas. Prior to the outage, equipment was received and unloaded, rigging was installed, access pathways were formed and a great deal of insulation and lagging were removed.

The new equipment and material were received by truck and were unloaded near the Unit 4 boilerhouse. (Figures F-3, F-4, and F-5).

Unit 4 came off line at 5:00 p.m. EST on March 8, 1990.

The boiler and backpass were washed and deslagged on March 9, 1991. Full boiler scaffolding began on March 10, 1991 and was completed on March 13, 1991.

Plant outage meetings were held each Tuesday and Thursday during the outage. The meetings were attended by the Plant Manager, Assistant Plant Manager, key supervisory personnel, the DOE Project Site Coordinator and the DOE Project Design Coordinator. All aspects of the outage were discussed in detail, both DOE activities and non-DOE activities.

Unacceptable levels of arsenic were detected within the boiler and workers were required to wear respirators and disposable clothing. This continued to be a problem until March 13, 1991 when arsenic levels came within acceptable levels.

An unexpected area of asbestos was discovered on the rear windbox near the burners. The contaminated area was removed and properly disposed of.

During the first week of the outage, the following activities occurred:

- Removed piping (oil and air) and wiring from all the burner assemblies (Figure F-6)
- Removed ignitor assemblies from burners
- Removed insulation and lagging from the burner area (Figure F-7)
- Began removal of burner assemblies; remove inner barrel, disconnect coal piping, remove scroll piece, remove outer barrel (Figures F-8 through F-18)
- The top, outer burner assemblies on both the front and rear of the boiler (burners CD-1, CA-4, FA-13 and FD-16) were removed first to gain access to the furnace for erection of the scaffolding
- Eight 3-inch vertical bands on the waterwalls were located and sandblasted within the furnace

Figure F-3 New Low NOx Burners Arriving by Truck

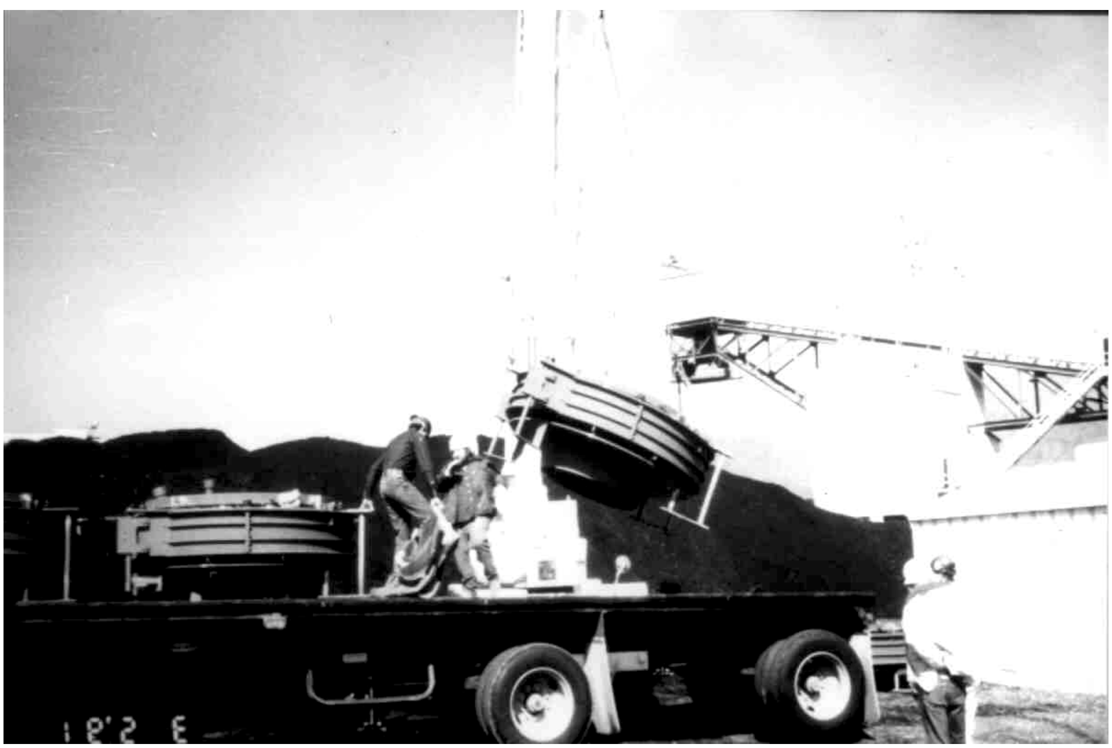

Figure F-4 New Registers Arriving by Truck

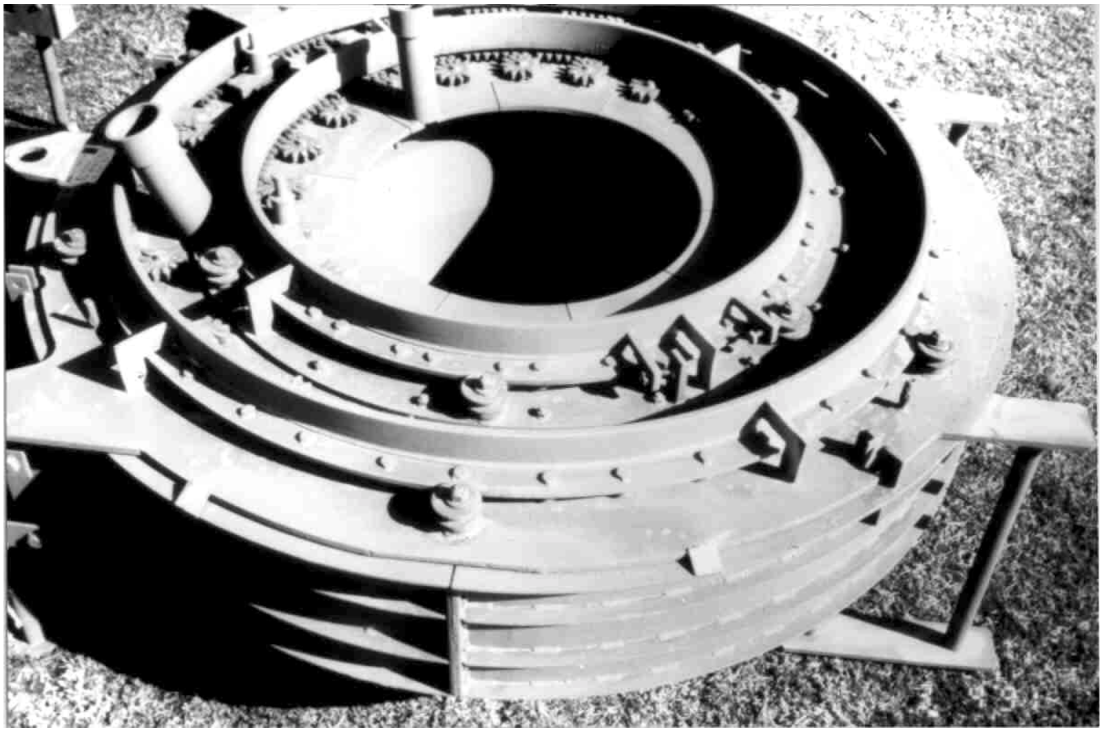

Figure F-5 New Register Assembly

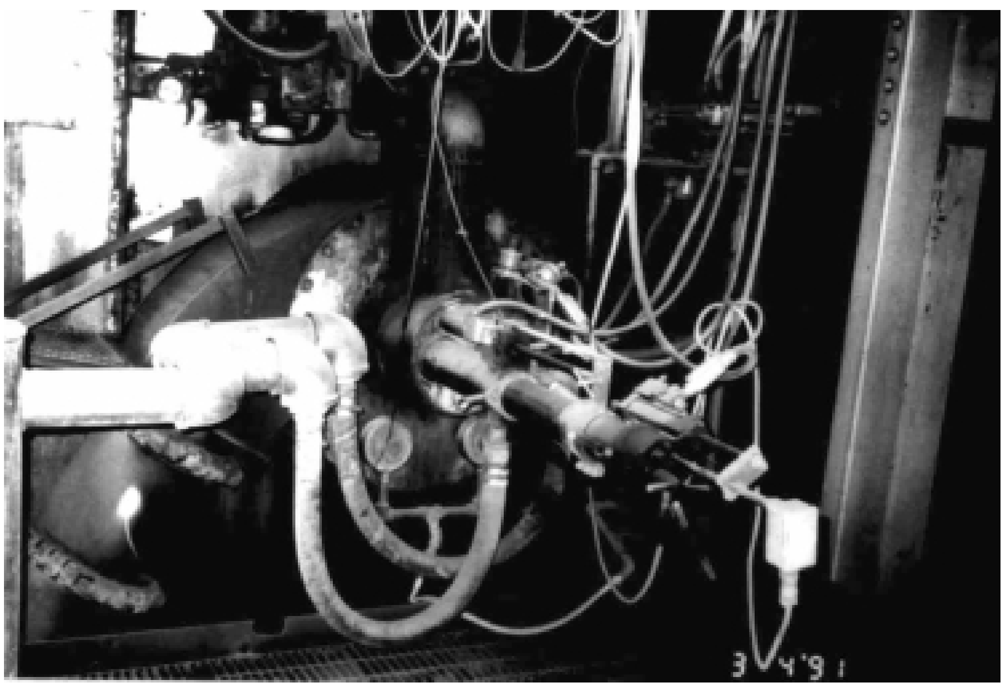

Figure F-6 Existing Burner Front

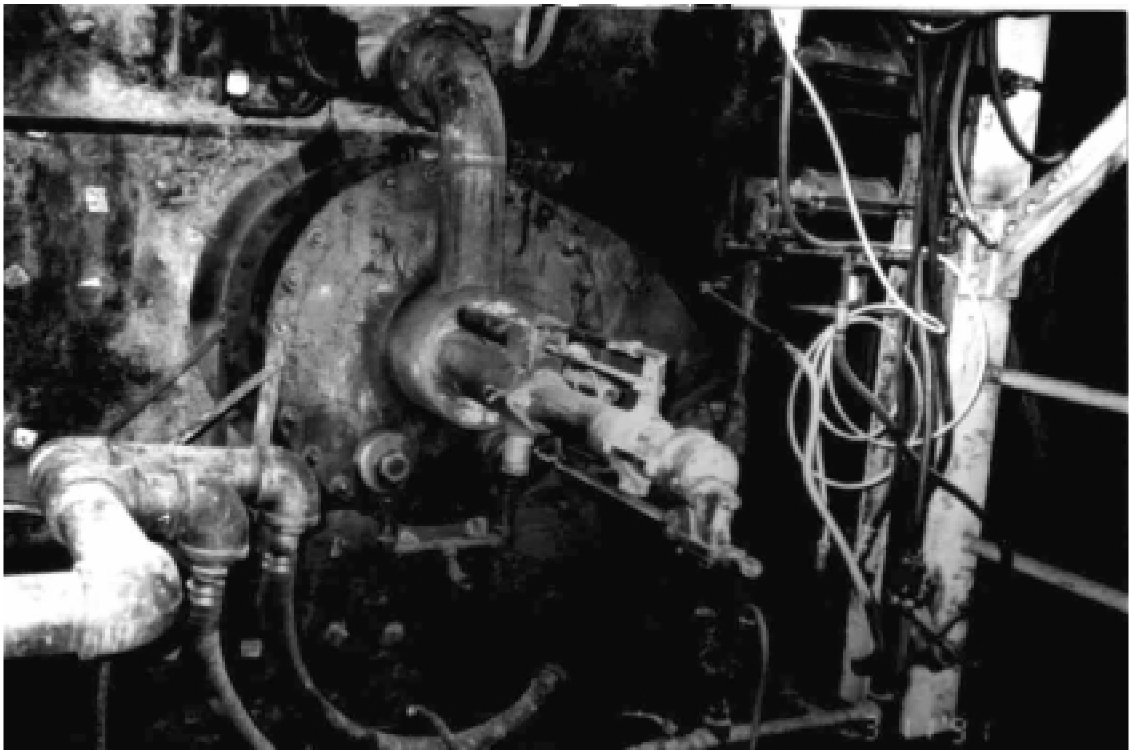

Figure F-7 Existing Burner Front with Insulation Removed

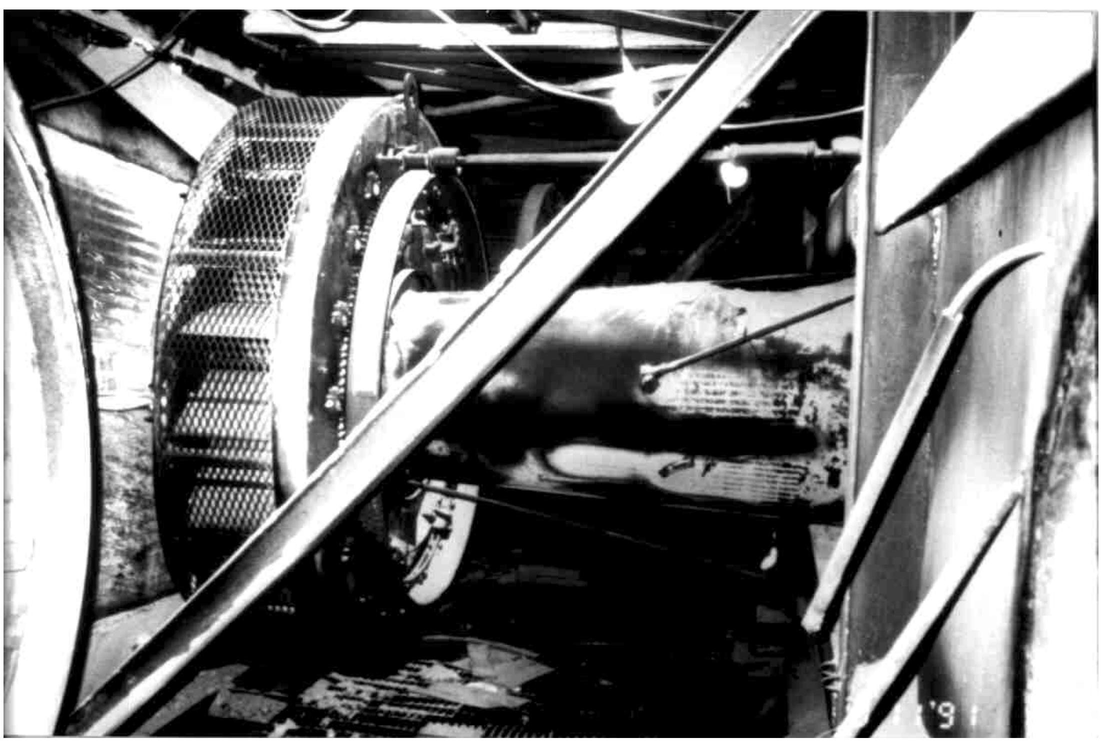

Figure F-8 Existing Burner and Register Inside Windbox

Figure F-9 Existing Burner Inside Furnace

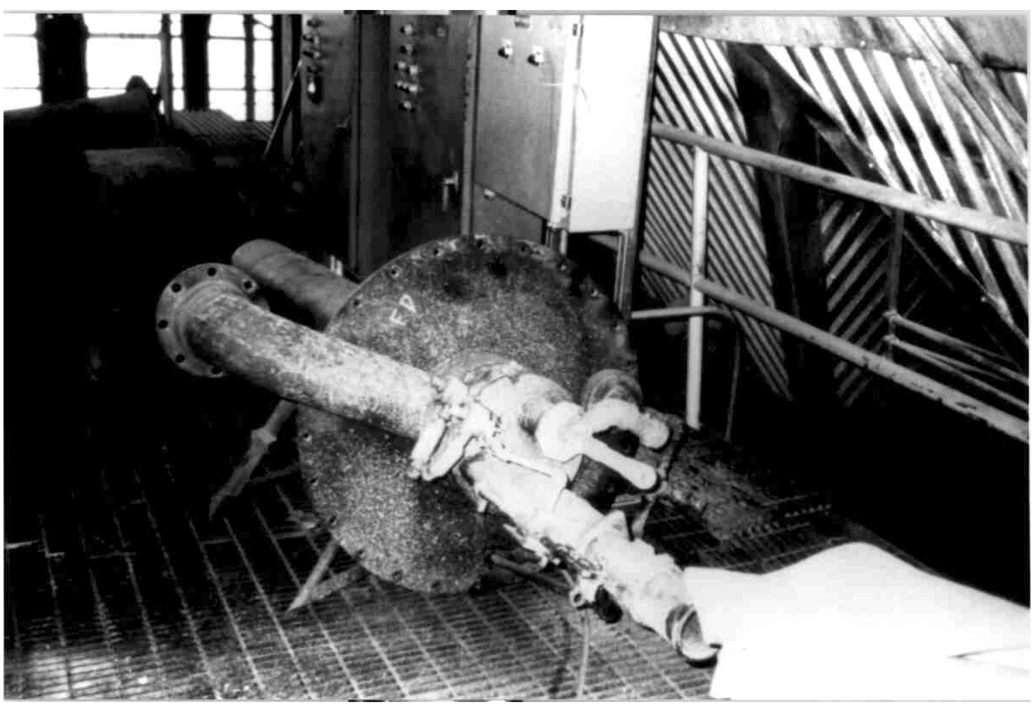

Figure F-10 Inner Barrel Removed, Front View

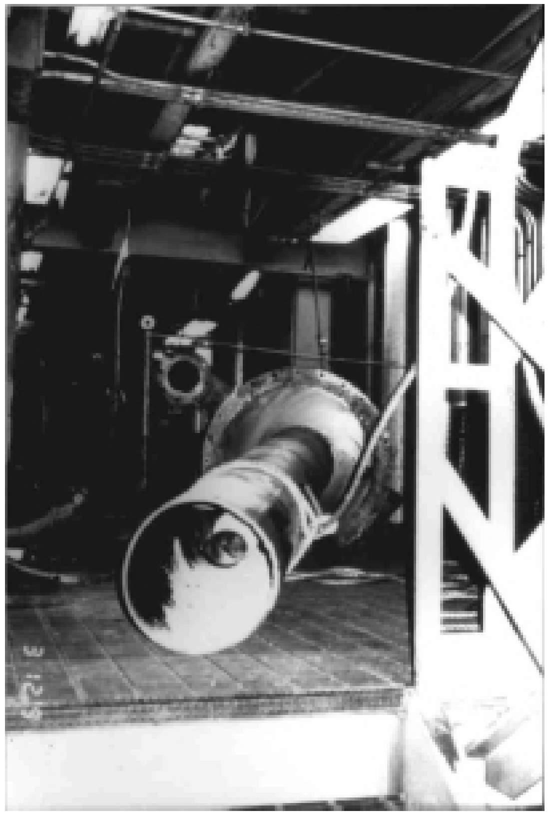

Figure F-11 Inner Barrel Removed, Rear View

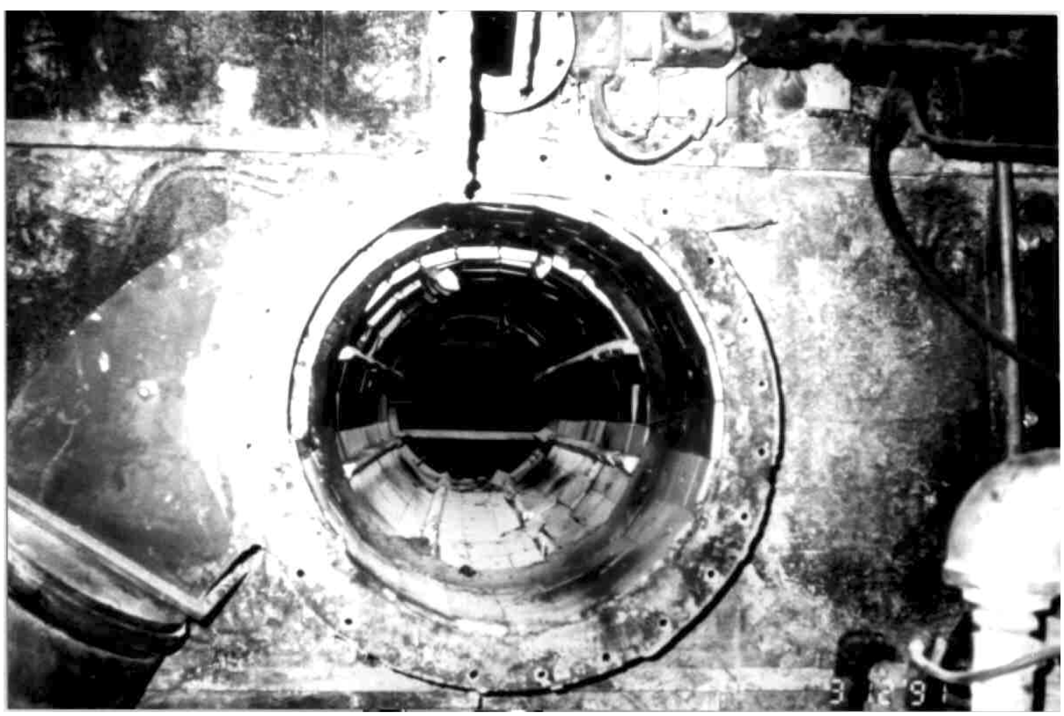

Figure F-12 Windbox View with Inner Barrel Removed

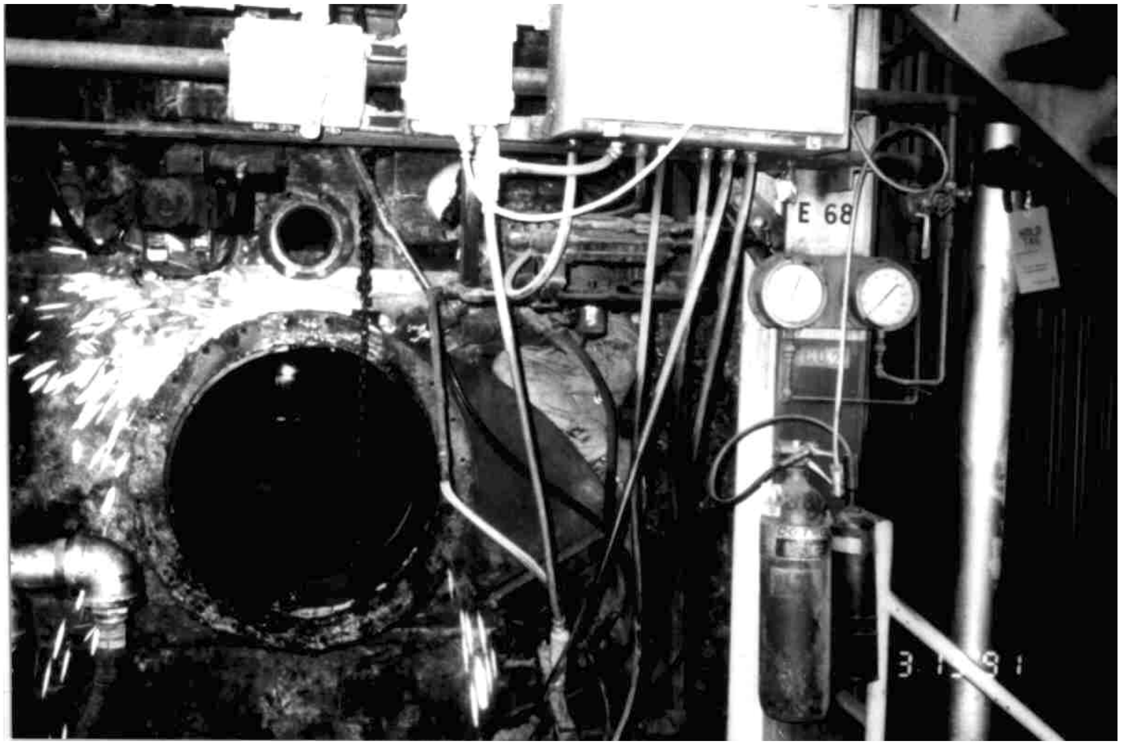

Figure F-13 Removal of Scroll Section

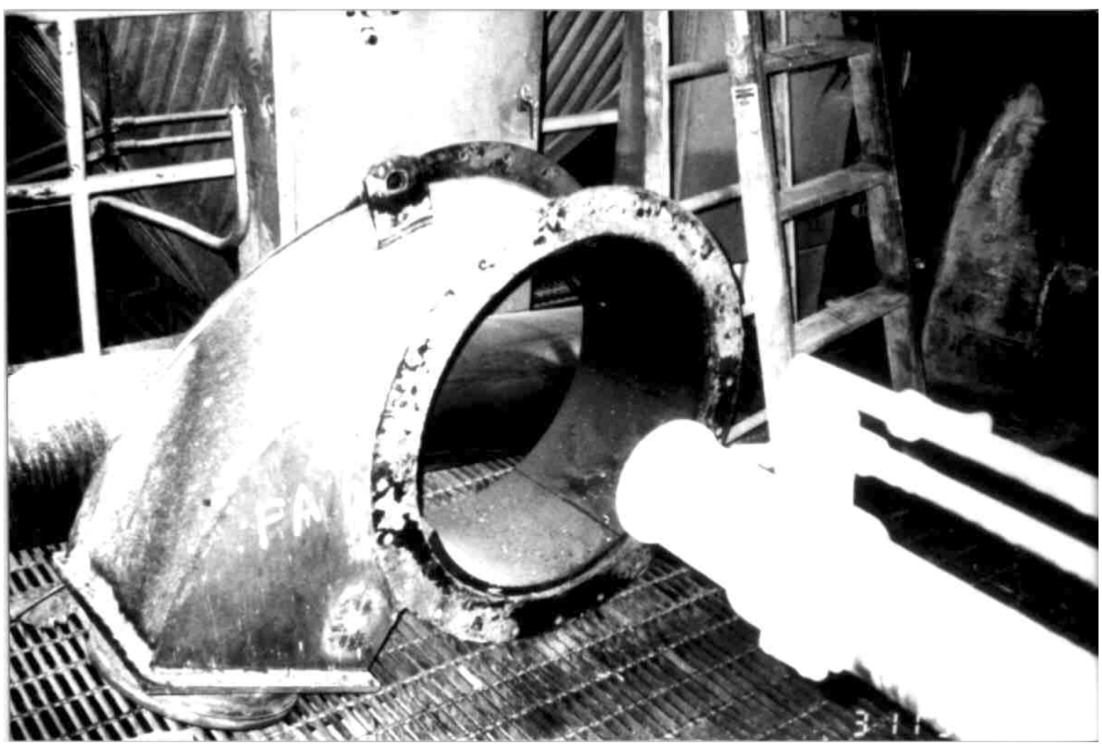

Figure F-14 Scroll Section Removed

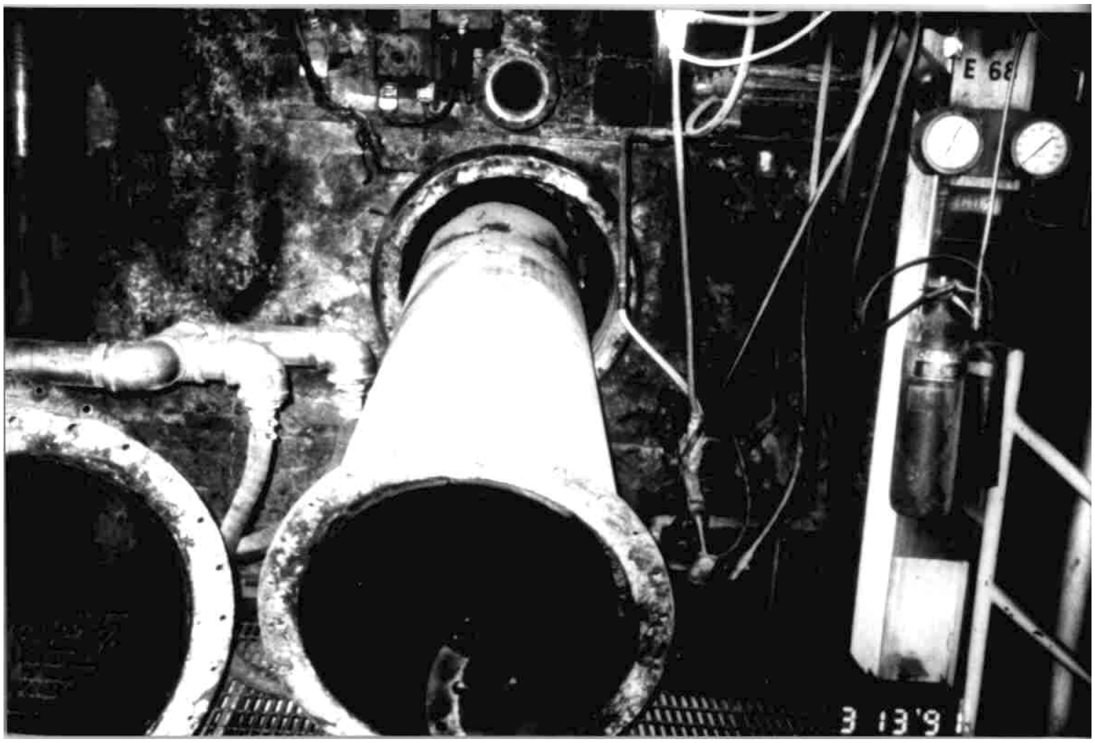

Figure F-15 Removal of Outer Barrel

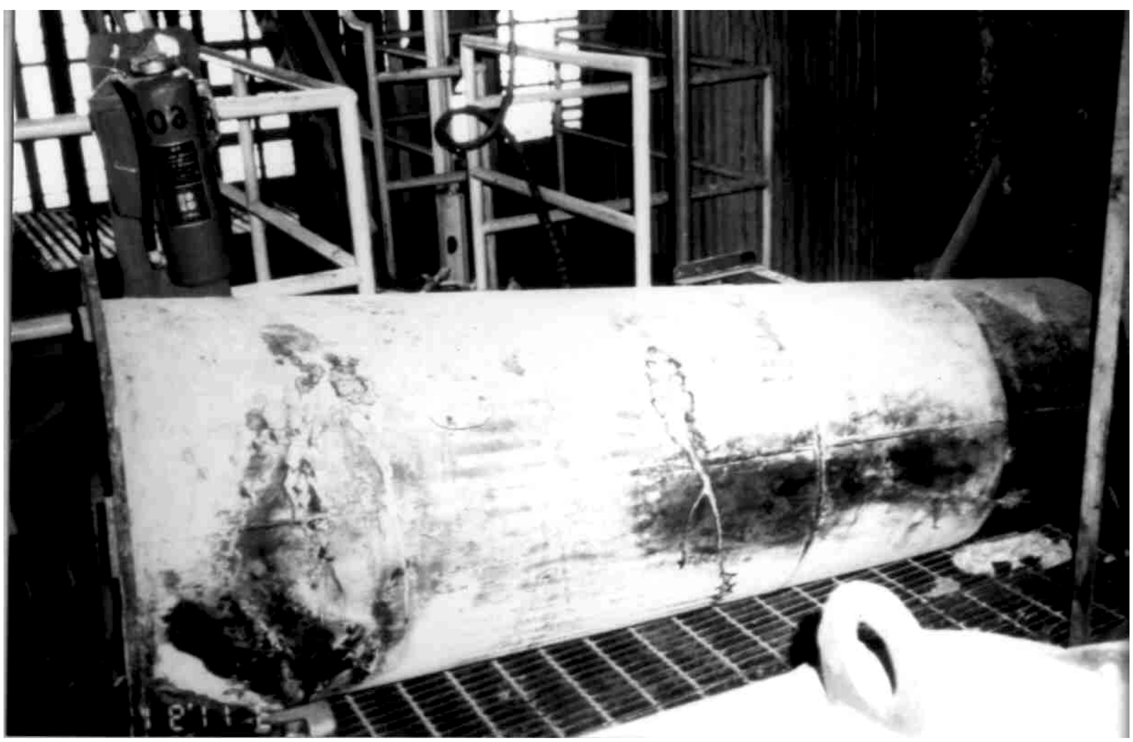

Figure F-16 Outer Barrel

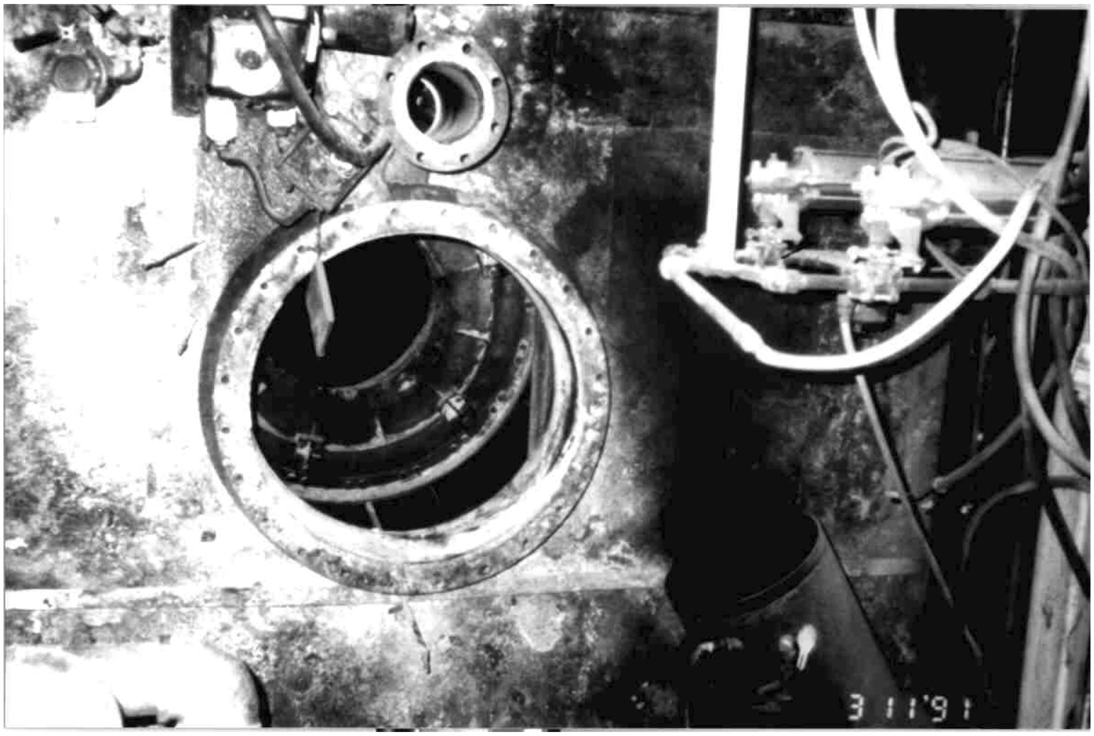

Figure F-17 Windbox View with Outer Barrel Removed

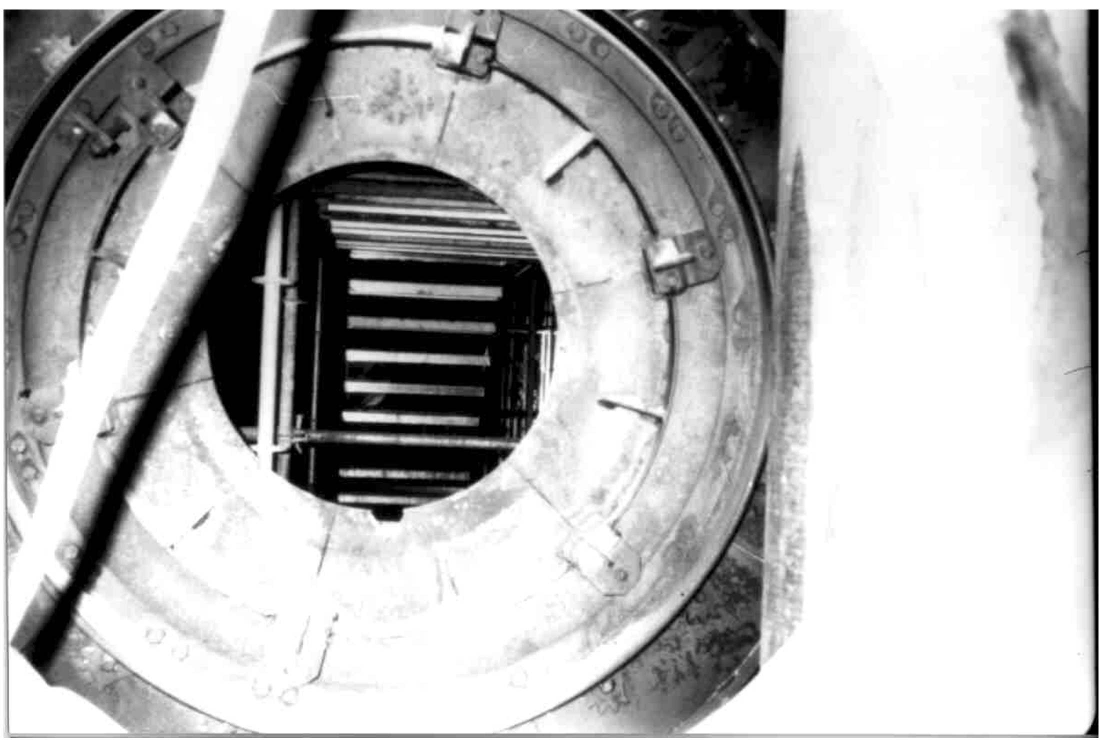

Figure F-18 Existing Register Inside Windbox with Burner Removed

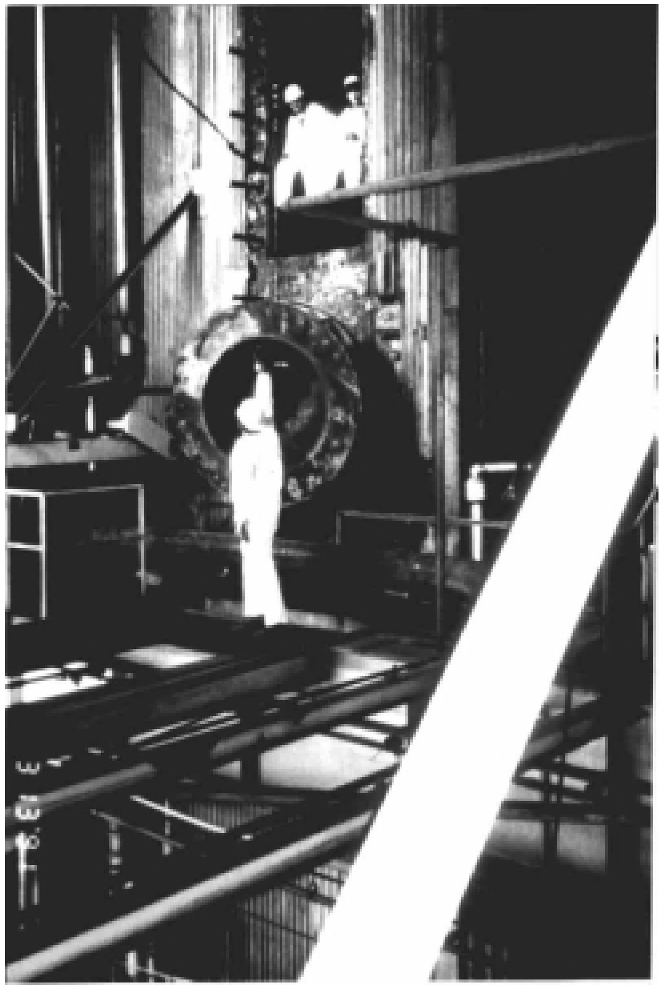

Figure F-19 Register Removal Through Opening in West Side of Front Windbox

- Removed burner assemblies DD-5 and DC-6
- Burner control panel was removed from boiler control room for modification (addition of indicator lights for new main flame scanners)
- Removed register drives and linkages
- Cut opening in west side of front windbox, at middle burner row elevation, for register removal (Figure F-19)
- Removed burner assemblies DB-7, DA-8, ED-9 and EA-12
- Removed registers DD-5 and DC-6 (Figure F-20)
- Completed scaffolding

During the second week of the outage, the following activities occured:

- NDT of the eight sand blasted bands was completed
- Removed burner assemblies AD-20, EC-10 and EB-11
- Removed registers DB-7, DA-8, ED-9 and EC-10

- Removed burner assemblies AB-18, AC-19, CC-2, CB-3 and AA-17
- Removed registers CD-1, EB-11 and EA-12
- Removed burner assemblies BA-21, BB-22, BC-23 and BD-24
- Removed registers CC-2, CB-3 and CA-4
- Cut opening in bottom, center of rear windbox for register removal
- Began removal of old refractory from burner throat area (Figure F-21)
- Began windbox structural modifications (stiffening) to carry additional loading
- Removed burners FB-14 and FC-15
- Removed registers BB-22, BC-23, AB-18 and AC-19
- Removed registers FB-14, FC-15, FA-13, FD-16, AD-20 and AA-17
- Began removing old register drives from windbox
- Added new indicator lights to burner control panel for new flame scanners
- Marked locations for sandblasting bands around boiler perimenter for NDT of waterwalls

During the third week of the outage, the following activities occured:

- Removed registers BA-21 and BD-24
- Began to enlarge openings in windbox for new burners
- Began to remove old 3" refractory pin studs in burner throat area
- Began to install new 1" pin studs in burner throat area
- Began to install the new air registers(Figures F-22 through F-26)
- Began to install the new burners (inner barrel, outer barrel and scroll section installed as a single assembly)
- Began to install new refractory in burner throat area

During the fourth week of the outage, the following activities occured:

- Replace outer cans on AOFA dampers (Figure F-27)
- Continued with the installation of the new burners
- Continued with the installation of the new registers
- Continued with refractory installation

Figure F-20 Close-up View of Existing Single Register Assembly

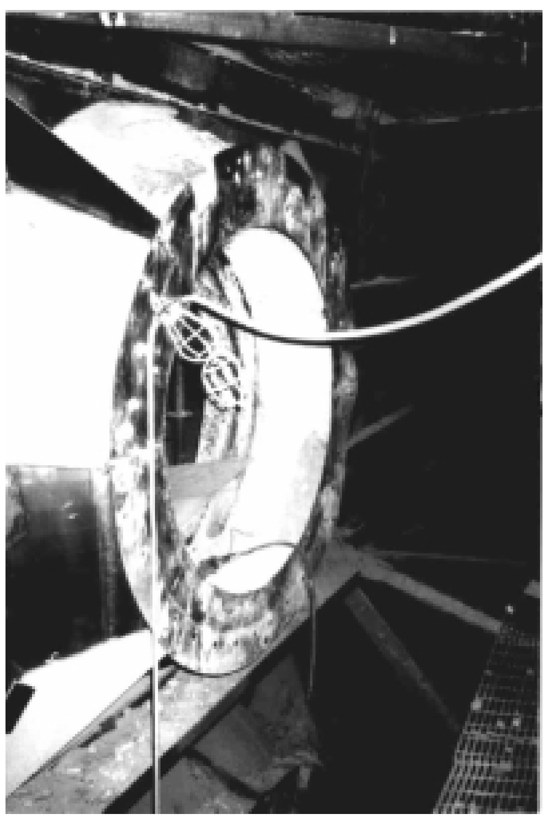

Figure F-21 Side View of Seal Can Ready for New Register

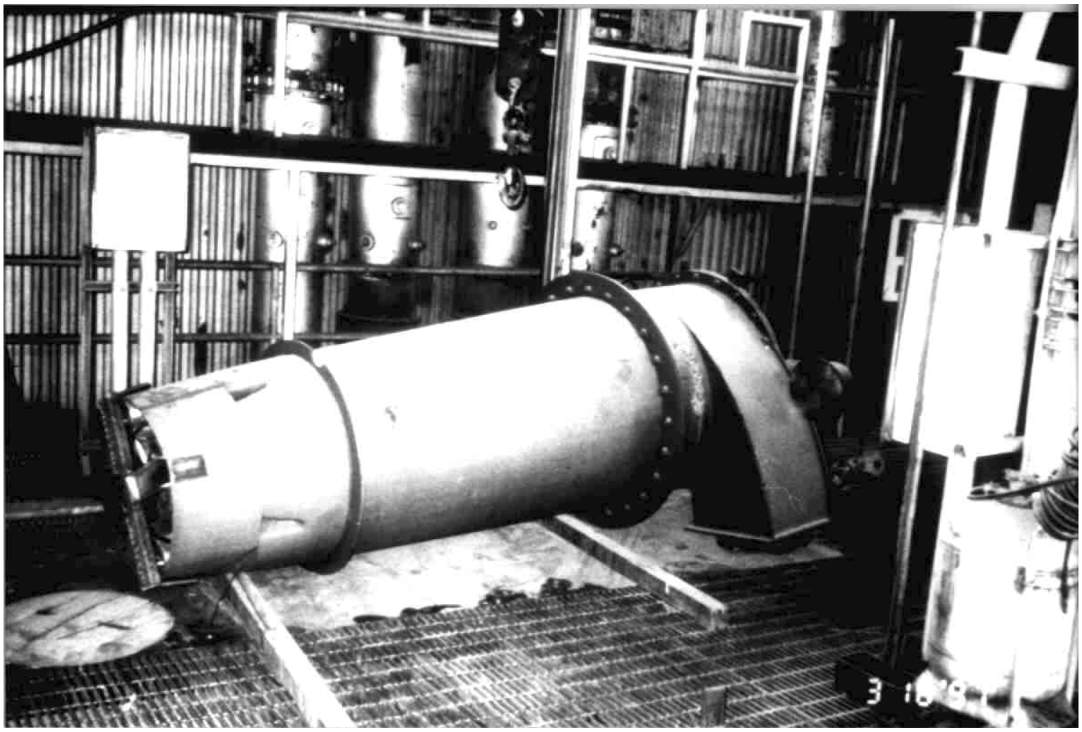

Figure F-22 New Burner Staged for Installation

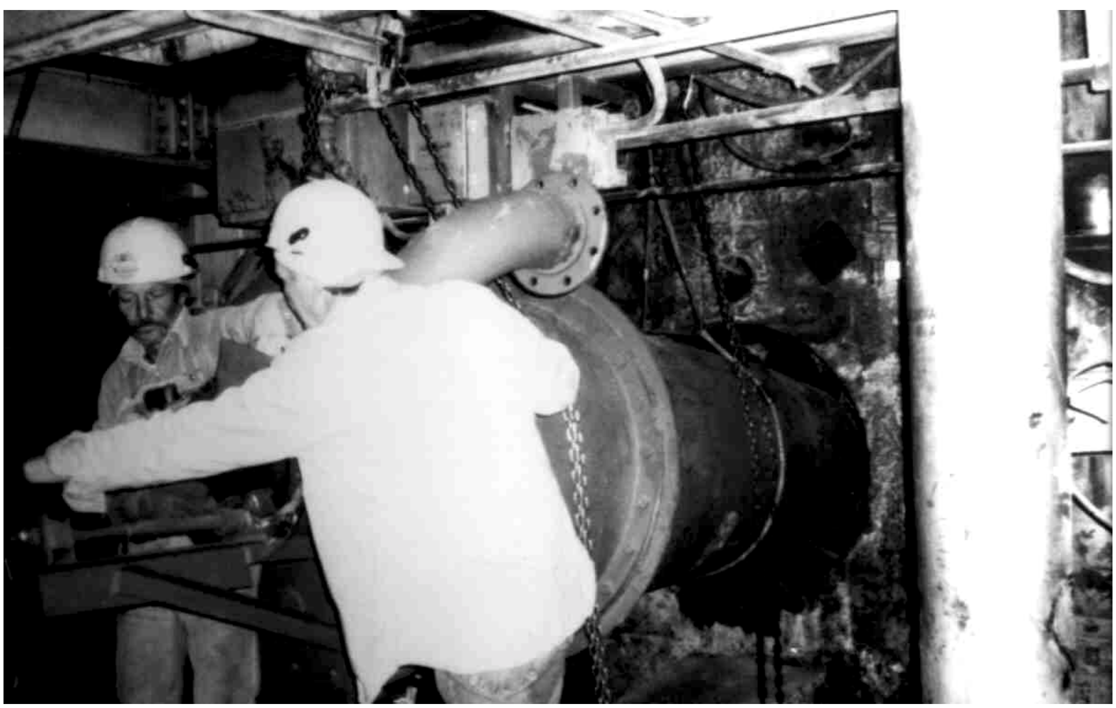

Figure F-23 Installation of New Burner

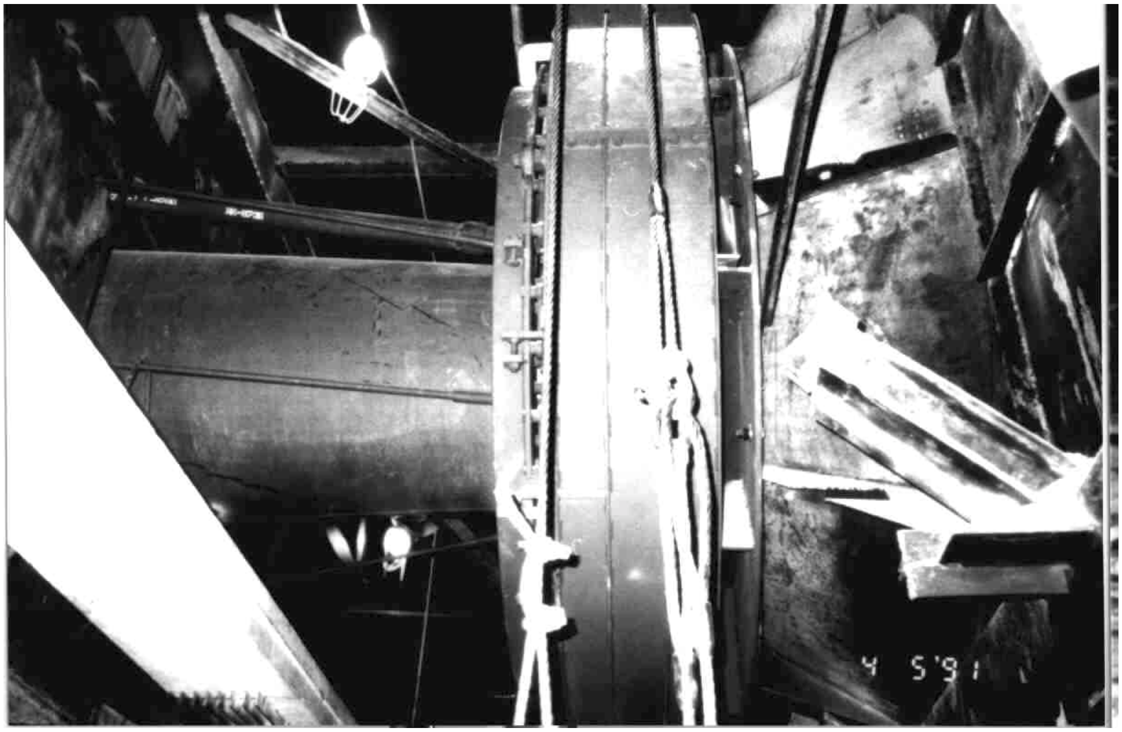

Figure F-24 New Burner and Register Inside Windbox

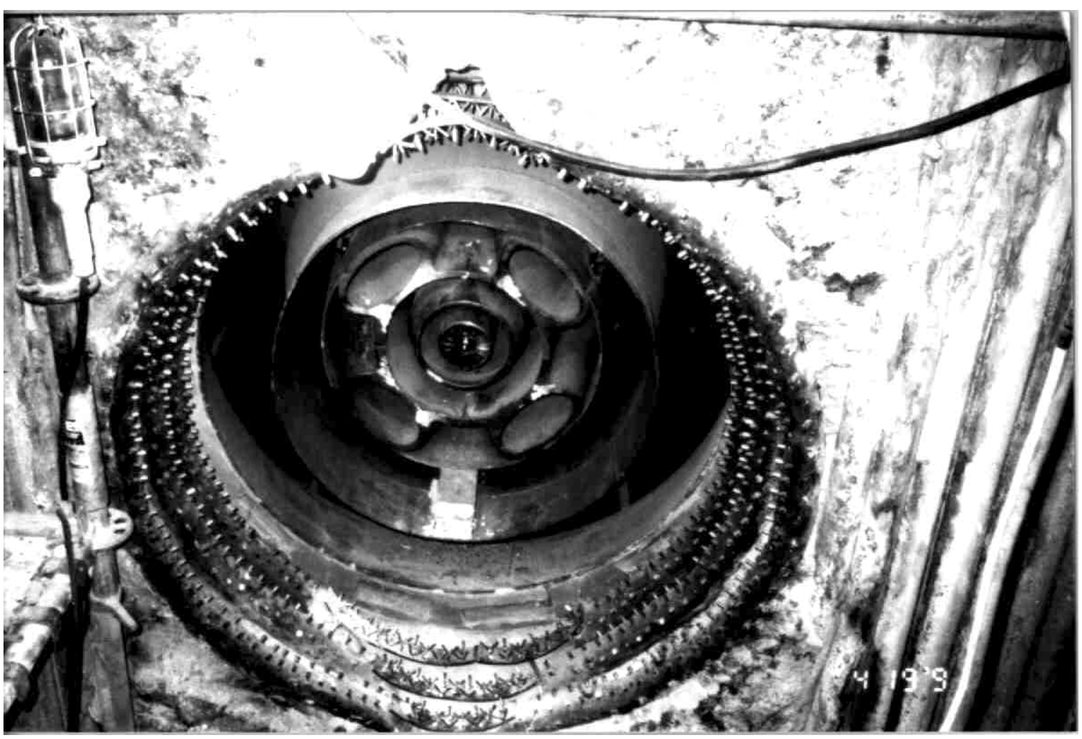

Figure F-25 Burner from Inside Furnace with Pin Studs in Throat Area

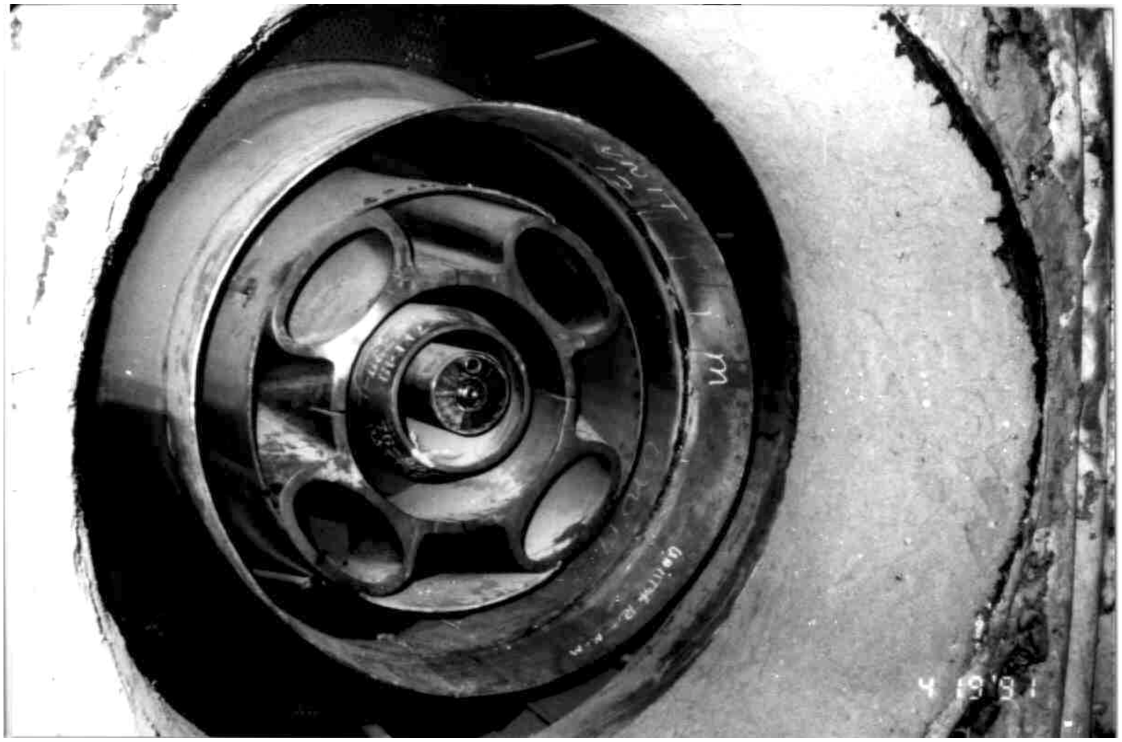

Figure F-26 Burner from Inside Furnace with Refractory Throat Installed

Figure F-27 New Outer Can on AOFA Damper

During the fifth week of the outage, the following activities occured:

- Relocated the two TV cameras and added additional cooling air
- Installed the linkage and manual operators for the inner and outer registers
- Continued with the installation of the new burners
- Continued with the installation of the new registers
- Continued with refractory installation

During the sixth week of the outage, the following activities occured:

- Replaced the manual operators on the pressure control dampers located in the new secondary air duct transition
- Continued with the installation of the new burners
- Continued with the installation of the new registers
- Continued with refractory installation
- Installed the linkage and Limotorque operators for the sleeve dampers on the registers

During the final week of the outage, the following activities occured:

- Completed the installation of the new burners (Figures F-28 and F-29)
- Completed the installation of the new registers
- Completed the refractory installation

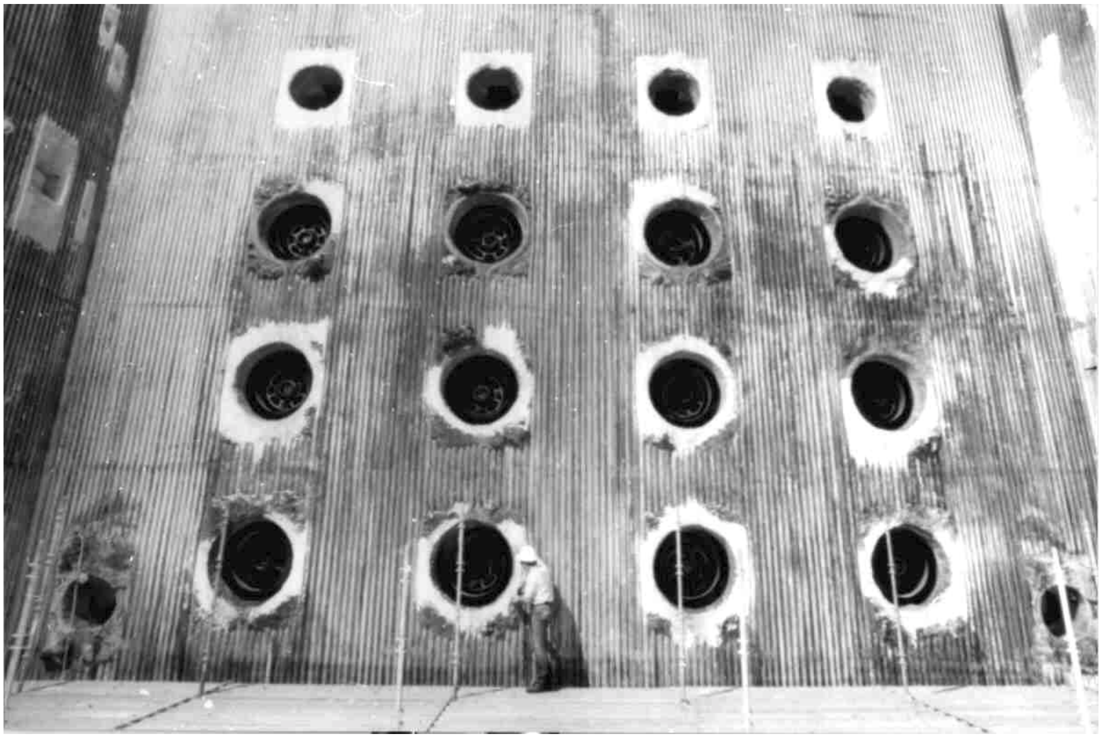

Figure F-28 AOFA Ports, Burners and Lower Furnace Air Ports From Inside Furnace

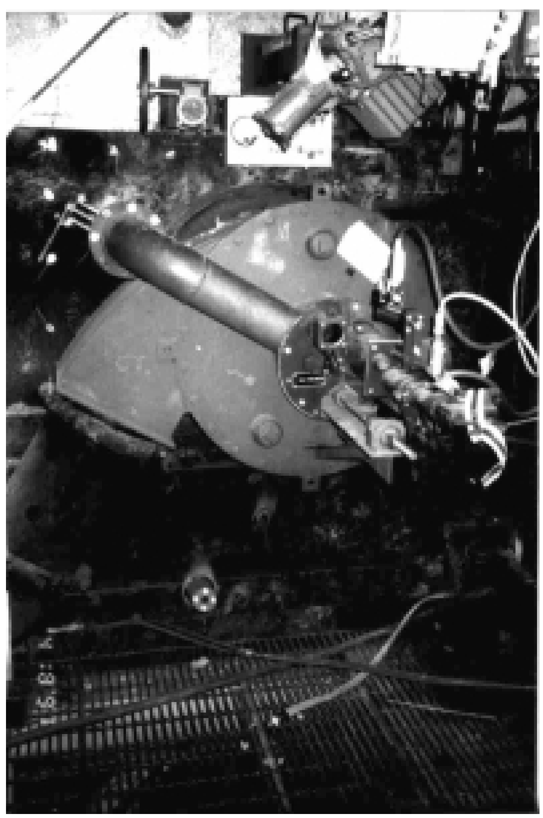

Figure F-29 New Burner Front

- Miscellaneous electrical work
- Removal of scaffolding
- Installed piping and pressure gauges for the burner flow measuring devices
- Installed burner thermocouples
- Installed main flame scanners
- Installed insulation and lagging

The first oil fire was introduced to the boiler at approximately 6:20 p.m. EST on April 28, 1991. The first coal was introduced to the boiler and the turbine was rolled on May 1, 1991.

Following start-up of the unit the following activities occurred:

- Installation of remaining insulation and lagging
- Installation of remaining access structures
- Field painting
- Completion of electrical work
- Limit setting on dampers
- Checkout and start-up of new equipment
- Demobilization

In addition to the DOE work, Georgia Power Company also installed a Forney smokeless ignitor system in conjunction with the low NOx burners. This consisted of 24 new oil guns and HESI spark rods, two combustion air fans and related ductwork, valves and piping. Also, new valve stations for oil and compressed air were installed for 16 of the burners. Georgia Power Company also installed a new thermocouple monitoring and recording device for the burner thermocouples.