INNOVATIVE CLEAN COAL TECHNOLOGY (ICCT)

180 MW DEMONSTRATION OF ADVANCED
TANGENTIALLY-FIRED COMBUSTION TECHNIQUES
FOR THE REDUCTION OF NITROGEN OXIDE (NO_x)
EMISSIONS FROM COAL-FIRED BOILERS

Technical Progress Report
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Prepared by:

Southern Company Services, Inc.
800 Shades Creek Parkway
Birmingham, Alabama 35209

Cleared by DOE Patent Counsel on February 22, 1993

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EXECUTIVE SUMMARY

This quarterly report discusses the technical progress of a U. S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) Project demonstrating advanced tangentially-fired combustion techniques for the reduction of nitrogen oxide (NO_x) emissions from a coal-fired boiler. The project is being conducted at Gulf Power Company's Plant Lansing Smith Unit 2 located near Panama City, Florida. The primary objective of this demonstration is to determine the long-term effects of commercially available tangentially-fired low NO_x combustion technologies on NO_x emissions and boiler performance. A target of achieving fifty percent NO_x reduction using combustion modifications has been established for the project.

The stepwise approach that is being used to evaluate the NO_x control technologies requires three plant outages to successively install the test instrumentation and the different levels of the low NO_x concentric firing system (LNCFS). Following each outage, a series of four groups of tests are performed. These are (1) diagnostic, (2) performance, (3) long-term, and (4) verification. These tests are used to quantify the NO_x reductions of each technology and evaluate the effects of those reductions on other combustion parameters such as particulate characteristics and boiler efficiency.

During this quarter, tests of the LNCFS Level III system were conducted to determine the effect that fuel fineness has on NO_x emissions and unburned carbon levels. Results showed that changing the fineness of the fuel has almost no effect on NO_x emissions; however, unburned carbon levels can be reduced significantly by increasing fuel fineness.

Also, disposition of project test equipment was begun. It was determined that all of the low NO_x combustion equipment will remain in service at the site. However, the continuous emissions monitor, data acquisition system, and supporting data collection equipment are being removed.

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1. INTRODUCTION

This document discusses the technical progress of a U. S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) Project demonstrating advanced tangentially-fired combustion techniques for the reduction of nitrogen oxide (NO_x) emissions from coal-fired boilers. The project is being conducted at Gulf Power Company's Plant Lansing Smith near Panama City, Florida.

The project is being managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: The Southern Company, the U. S. Department of Energy (DOE), and the Electric Power Research Institute. In addition to SCS, The Southern Company includes five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering and research services to The Southern Company. Through cost sharing in the installed low NO_x retrofit technology, Asea Brown Boveri Combustion Engineering Services (ABB CE) is also participating as a project co-funder.

The Innovative 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 which are different from traditional research and development programs sponsored by the DOE. The traditional projects focused on long-range, high-risk, high-payoff technologies with the DOE providing the majority of the funding. In contrast, the goal of clean coal projects is to demonstrate commercially feasible advanced coal-based technologies which 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 which are conducted as cooperative agreements in which the industrial participant contributes at least fifty percent of the total project cost.

ABB CE's Low NO_x Concentric Firing System (LNCFS) and Low NO_x Bulk Furnace Staging (LNBFS) System are demonstrated in stepwise fashion. These systems incorporate the concepts of advanced overfire air (AOFA), clustered coal nozzles, and offset air. A complete description of the installed technologies is provided in the following section.

The primary objective of the Plant Lansing Smith demonstration is to determine the long-term effects of commercially available tangentially-fired low NO_x combustion technologies on NO_x emissions and boiler performance. Short-term tests of each technology are also being performed to provide engineering information about emissions and performance trends. A target of achieving

fifty percent NOx reduction using combustion modifications has been established for the project. Through the modifications shown in Figure 1, the project seeks to address the following objectives:

1. Demonstrate in a logical stepwise fashion the short-term NOx reduction capabilities of the following advanced low NOx combustion technologies:
 - a. Low NOx Bulk Furnace Staging (LNBFS)
 - b. Low NOx Concentric Firing System (LNCFS) Levels I, II, and III
2. Determine the dynamic long-term emissions characteristics of each of these combustion NOx reduction methods using sophisticated statistical techniques.
3. Evaluate the progressive cost effectiveness (i.e., dollars per ton NOx removed) of the low NOx combustion techniques tested.
4. Determine the effects on other combustion parameters (e.g., CO production, carbon carryover, particulate characteristics) of applying the NOx reduction methods listed above.

Figure 1. Plant Lansing Smith Unit 2 Boiler

2. DEMONSTRATED TECHNOLOGIES

As shown in the Statement of Work (SOW) revised in December 1991, four different low NO_x combustion technologies offered by ABB Combustion Engineering (ABB CE) for tangentially-fired boilers were planned for this demonstration. The demonstration of these technologies progressed in the most logical manner from an engineering and construction viewpoint. During Phase I of the project, the baseline conditions of the unit was studied. During Phase II, Low NO_x Concentric Firing System (LNCFS) Level II and the Low NO_x Bulk Furnace Staging (LNBFS) system were demonstrated. Finally, LNCFS Levels I and III was demonstrated during Phase III.

The concept of overfire air is included in all of these systems. In LNCFS Level I, a Close-Coupled Overfire Air (CCOFA) system is integrated directly into the windbox. Compared to the baseline configuration, LNCFS Level I is arranged by exchanging the highest coal nozzle with the air nozzle immediately below it. This configuration provides the NO_x reducing advantages of an overfire air system without major pressure part modifications to the boiler.

In LNCFS Level II and LNBFS, a separated overfire air (SOFA) system is used. This is an advanced overfire air system having backpressuring and flow measurement capabilities. The air supply ductwork for the SOFA is taken off from the secondary air duct and routed to the corners of the furnace above the existing windbox. The inlet pressure to the SOFA system can be increased above windbox pressure using dampers downstream of the takeoff in the secondary air duct. The intent of operating at a higher pressure is to increase the quantity and injection velocity of the overfire air into the furnace. A multicell venturi is used to measure the amount of air flow through the SOFA system. LNCFS Level III utilizes both CCOFA and SOFA.

In addition to overfire air, the LNCFS incorporates other NO_x reducing techniques into the combustion process. Using offset air nozzles, two concentric circular combustion regions are formed. The inner region contains the majority of the coal thereby being fuel rich. This region is surrounded by a fuel lean zone containing combustion air. For this demonstration, the size of this outer circle of combustion air will be varied using adjustable offset air nozzles. The separation of air and coal at the burner level further reduces the production of NO_x.

The LNBFS consists of a standard tangentially-fired windbox configuration with a SOFA system. This technology will be demonstrated by repositioning the offset air nozzles in the main windbox to be in line with the fuel nozzles. No other modifications to the windbox will be required. Due to the limits of the project schedule, LNBFS will be demonstrated using short-term diagnostic tests only.

When the SOW for this project was prepared in June 1990, ABB CE offered the following low NOx combustion systems:

- 1) Low NOx Concentric Firing System (LNCFS)
- 2) Concentric Clustered Tangential Firing System (CCTFS)

Since that time, the technologies which ABB CE offers to the public have evolved to reflect the results of their most recent knowledge. The equipment that is presently offered comprises a family of technologies called the Low NOx Concentric Firing System Levels I, II, and III as discussed above. These technologies provide a stepwise reduction in NOx emissions with LNCFS Level III providing the greatest reduction.

Although the names of these technologies have changed, the basic concepts for the reduction of NOx emissions have remained constant. The Low NOx Concentric Firing System (LNCFS) included the NOx reduction techniques of overfire air and adjustable offset air nozzles as part of its design. These features are now incorporated into the design of LNCFS Level II.

The Concentric Clustered Tangential Firing System (CCTFS) included two sets of overfire air and clustered coal nozzles. Both LNCFS Levels I and III utilize clustered coal nozzles and overfire air in their design. Research by ABB CE has shown that the use of clustered coal nozzles does not positively or negatively affect the production of nitrogen oxides in a coal-fired boiler. As a result, one set of coal nozzles at the top of the main windbox are clustered to facilitate the addition of the CCOFA system discussed in the section above. This modification allowed the low pressure overfire air system (now designated the CCOFA) to be integrated directly into the windbox. This design change reduced the number of pressure part modifications required to install this low NOx combustion technology. No significant design changes to the high pressure overfire air system (now designated the SOFA) were made.

Figure 2: Demonstrated Technologies

Figure 3: Concentric Firing System

3. UNIT DESCRIPTION

Plant Lansing Smith Unit 2, owned and operated by Gulf Power Company, utilizes a tangentially-fired boiler (aspect ratio = 1.5 width/depth) rated at 180 MW with the capability to provide loads of up to 200 MW. The boiler is a Combustion Engineering radiant reheat, natural circulation steam generator which came on line in 1967. It is designed for continuous indoor service to deliver 1,306,000 pounds of steam per hour at normal rated load, a pressure of 1800 psig, and a temperature of 1000°F at the superheater and the reheater outlets. Five Combustion Engineering Raymond bowl mills equipped with exhausters at the outlet of each mill deliver pulverized coal (66.5% C, 9.9% H₂O, 4.6% H, 1.4% N, 2.8% S, 6.3% O, 8.5% ash, 0.1% Cl; HHV = 11,886 Btu/lb, FC = 46.0%, VM = 35.6%) through twenty tangential coal nozzles with five nozzles at each corner of the furnace. The unit is equipped with Ljungstrom air preheaters and two forced-draft fans which deliver all the combustion air to the boiler. Exhaust gases are treated with both hot- and cold-side electrostatic precipitators. Although originally designed for pressurized furnace operation, the unit was converted to balanced-draft operation in 1976.

4. PROJECT DESCRIPTION

In order to accomplish the project objectives, a Statement of Work (SOW) was developed which included the Work Breakdown Structure (WBS) found in Table 1. The WBS is designed around a chronological flow of the project. The chronology requires design, construction, and operation activities in each of the first three phases following project award. Although this project structure is inconsistent with the typical ICCT project phase structure of (1) permitting and design, (2) construction, and (3) operation, it prevents phases from starting and stopping several times during the project.

The stepwise approach to evaluating the NO_x control technologies requires that three plant outages be used to successively install (1) the test instrumentation and new air heater baskets, (2) the LNCFS Level II, and (3) the LNCFS Levels I and III. These outages are scheduled to coincide with existing plant outages in the fall of 1990, spring of 1991, and the fall of 1991.

The Data Acquisition System (DAS) for the Lansing Smith Unit 2 ICCT project is a custom designed microcomputer based system used to collect, format, calculate, store, and transmit data derived from power plant mechanical, thermal, and fluid processes. The extensive process data selected for input to the DAS has in common a relationship with either boiler performance or boiler exhaust gas properties. This system includes two continuous emissions monitoring systems (NO_x, SO₂, O₂, THC, CO) with a multi-point flue gas sampling and conditioning system, an acoustic

Table 1: Work Breakdown Structure			
Phase	Task	Description	Scheduled Date
0		Pre-Award Activities	
I		Setup and Pre-Retrofit	
	1.1.1	Project Management and Reports	9/90 - 3/91
	1.1.2	Site Preparation	10/90 - 11/90
	1.1.3	Flow Modeling	9/90 - 7/91
	1.1.4	Instrumentation	8/90 - 12/90
	1.1.5	Baseline Characterization	11/90 - 3/91
II		LNCFS Level II Retrofit	
	1.2.1	Project Management and Reports	4/91 - 9/91
	1.2.2	LNCFS Level II Installation	4/91 - 5/91
	1.2.3	LNBFS and LNCFS Level II Characterization	5/91 - 9/91
	1.2.4	Chemical Emissions Testing	9/91 - 12/91
III		LNCFS Level III Retrofit	
	1.3.1	Project Management and Reports	9/91 - 1/93
	1.3.2	LNCFS Level III Installation	9/91 - 10/91
	1.3.3	LNCFS Levels I and III Characterization	10/91 - 8/92
	1.3.4	Chemical Emissions Testing	12/91 - 9/92
IV		Final Reporting and Disposition	
	1.4.1	Project Management and Reports	8/92 - 9/93
	1.4.2	Disposition	11/92

pyrometry and thermal mapping system, furnace tube heat flux transducers, and boiler efficiency instrumentation. The instrumentation system is designed to provide data collection flexibility to meet the schedule and needs of the various testing efforts throughout the demonstration program. A summary of the type of data collected is shown in Table 2.

Following each outage, a series of four groups of tests are performed. These are (1) diagnostic, (2) performance, (3) long-term, and (4) verification. The diagnostic, performance, and verification tests consist of short-term data collection during carefully established operating conditions. The diagnostic tests are designed to map the effects of changes in boiler operation on NO_x emissions. The performance tests evaluate a more comprehensive set of boiler and combustion performance indicators. The results from these tests will include particulate characteristics, boiler efficiency, and boiler outlet emissions. Mill performance and air flow distribution are also tested. The verification tests will be used to characterize any changes that might have occurred during long-term testing.

As stated previously, the primary objective of the demonstration is to collect long-term, statistically significant quantities of data under normal operating conditions with and without the various NO_x reduction technologies. Earlier demonstrations of emissions control technologies have relied solely

Table 2: Plant Data Points

Boiler Drum Pressure	Superheat Outlet Pressure
Cold Reheat Pressure	Hot Reheat Pressure
Barometric Pressure	Superheat Spray Flow
Reheat Spray Flow	Main Steam Flow
Feedwater Flow	Coal Flows
Secondary Air Flows	Tempering Air Flows
Main Steam Temperatures	Cold Reheat Temperature
Hot Reheat Temperature	Feedwater Temperature
Desuperheater Outlet Temp.	Desuperheater Inlet Temp.
Economizer Outlet Temp.	Air Heater Air Inlet Temp.
Air Heater Air Outlet Temp.	Ambient Temperature
BFP Discharge Temperature	Relative Humidity
Stack NOx	Stack SO2
Stack O2	Stack Opacity

on data from a matrix of carefully established short-term (one- to four-hour) tests. However, boilers are not typically operated in this manner considering plant equipment inconsistencies and economic dispatch strategies. Therefore, statistical analysis methods for long-term data have been developed that can be used to determine the achievable emissions limit or emission tonnage of a control technology. These analysis methods have been developed over the past fifteen years by the Control Technology Committee of the Utility Air Regulatory Group (UARG). Because the uncertainty in the analysis methods is reduced with increasing data set size, UARG recommends that acceptable results can be achieved with data sets of at least 51 days with each day containing at least 18 valid hourly averages.

5. PROJECT STATUS

5.1. Phase I Setup and Pre Retrofit

5.1.1. Baseline Characterization

Baseline tests were completed in March 1990. A summary of the baseline long-term test results is shown in Table 3. Seventy-five days of long-term data were collected generating an average NOx emission level of 0.62 lb/MBtu. Figure 4 shows that baseline NOx emissions decreased slightly with decreases in unit load and ranged from 0.64 lb/MBtu at full load to 0.55 lb/MBtu at minimum load. The bands about the mean represent the 95 percentiles of the data set. Ninety-five percent of the long-term data fall below the upper limit and 5 percent of the data fall below the lower limit. These limits show that NOx emissions varied by as much as 0.2 lb/MBtu for a given load point during normal load-dispatched operations. The final version of the Phase I Baseline Topical Report was issued in the first quarter 1992.

Table 3. Baseline, LNCFS Level I, LNCFS Level II, and LNCFS Level III Long-Term Test Results.								
Unit Configuration	Baseline		LNCFS I (‡)		LNCFS II		LNCFS III	
	Mean	RSD, %	Mean	RSD, %	Mean	RSD, %	Mean	RSD, %
Number of Daily Averaged Values	75	-	70	-	55	-	71	-
Average Load (MW)	155	14.8	185	4.3	172	7.1	141	15.1
Average NOx Emissions	0.62	5.8	0.41	3.0	0.41	6.9	0.39	9.7
Average O2 Level at stack, percent	6.55	11.6	6.41	4.4	6.50	8.8	7.56	7.8
NOx 30 Day Achievable Emission Limit	0.68	-	0.42	-	0.45	-	0.44	-
NOx Annual Achievable Emission Limit	0.63	-	0.41	-	0.41	-	0.40	-

* RSD = Relative Standard Deviation = 100 * Standard Deviation / Mean

‡ LNCFS I data are corrected for leakage effects.

NOx emissions are in lb/MBtu

Figure 4: Baseline Long-Term NOx Emissions Results

5.2. Phase II LNCFS Level II Retrofit and Testing

5.2.1. LNCFS Level II Retrofit

LNCFS Level II was installed during a three week outage that began on March 29, 1991. During that outage, craft laborers worked seven days a week with two ten-hour shifts per day. The remaining four hours of the day were reserved for x-raying welds in the furnace walls. During peak work loads, as many as seventy craft laborers per shift were involved in the retrofit. A full furnace scaffold was installed to expedite the job.

Due to the scope of the work required to be performed during the outage, the SOFA ductwork was hung in place prior to the unit coming off line. The installation of the SOFA windboxes required pressure part modifications to each corner of the boiler above the main windbox. Preassembled bent tube panels were welded into the four 10 feet high by 4 feet wide holes cut in the boiler. The SOFA windboxes with three sets of air nozzles were inserted into the 5 feet high by 2 feet wide openings in the tube panels. Each nozzle has its own automatically controlled damper to provide regulation of the flow to the SOFA ports. The yaw adjustment on each SOFA nozzle is manually adjustable. The three nozzles tilt in unison via automatic controls linked to the tilting of the nozzles in the main windbox.

The critical path for this outage was the modification to the main windboxes. The windboxes were completely stripped of coal nozzles, auxiliary air nozzles, tilt linkages, and all bearings and bushings. After removing this equipment, the partition plates and windbox turning vanes were inspected for warpage and wear. When necessary, these parts were replaced or refurbished. Additional partition plates were installed in the top and bottom auxiliary air compartments. All of the partition plates were cut back approximately three inches to allow greater tilting mobility of the new coal and air nozzles. All coal nozzles and tips were replaced, Rockwell couplings were installed in the fuel lines to relieve fuel pipe loadings on the windbox, and four elevations of flame scanners were installed including a cooling air system with a dedicated fan. The windbox tilting mechanism was completely replaced. The offset air nozzles in the main windbox have the capability to move in the horizontal direction by a manual adjustment. The air and coal nozzles tilt in unison via automatic controls.

5.2.2. LNCFS Level II Characterization

Prior to testing, the LNCFS Level II system was optimized for performance and NO_x emissions by engineers from ABB CE. A portion of this process required the proper positioning of the three

adjustable SOFA nozzles, and the adjustable offset air nozzles in the main windbox. The optimized configuration for these nozzles with respect to the injection angle of the coal nozzles is shown in Table 4. The optimum tilt position for the SOFA nozzles was determined to be 0°. Tilt position for the main windbox varies to maintain unit reheat and superheat temperatures.

LNCFS Level II tests were completed in October 1991. A summary of the long-term test results is shown with the baseline results in Table 3. Fifty-five days of long-term data were collected generating an average emission level of 0.41 lb/MBtu. Long-term NO_x emissions over the entire load range are shown in Figure 5 and range from 0.39 lb/MBtu (full load) to 0.57 lb/MBtu (minimum load). When operating with LNCFS Level II, NO_x emissions varied by as much as 0.3 lb/MBtu at individual load values. The trend of increasing NO_x emissions with decreases in load is consistent with previously reported data for low NO_x combustion equipment on T-fired boilers.

Table 4: Optimized Orientation of SOFA and Offset Air Nozzles With Respect to the Coal Nozzles for LNCFS Level II (Positive Indicates Rotation with the Fireball).				
Corner/ elevation	Right Front	Right Rear	Left Front	Left Rear
SOFA Top	+15°	-15°	+15°	+15°
SOFA Middle	0°	-15°	0°	0°
SOFA Lower	-15°	-15°	-15°	-15°
Offset Air	+22°	+22°	+22°	+22°

Figure 5: LNCFS Level II Long-Term NOx Emissions Results

5.3. Phase III LNCFS Level III Retrofit and LNCFS Levels I and III Testing

5.3.1. LNCFS Level III Installation

LNCFS Level III was installed during a two week outage that began in October 1991. During that outage, craft laborers worked five days a week with two ten-hour shifts per day. An average of thirty-six craft laborers per day were involved in the retrofit. A full furnace scaffold was installed to expedite the job.

During the two week outage, the CCOFA air ports were installed in the top of the main windbox. This modification required the reconfiguration of the top three windbox compartments in each corner of the boiler. The existing coal compartment and the two auxiliary air compartments in the top of the windbox were replaced with one stationary auxiliary air compartment, one coal compartment and two CCOFA compartments. To facilitate the relocation of the coal nozzle to a lower elevation, coal piping, ignitors, flame scanners, and platform steel in each corner were also relocated.

5.3.2. LNCFS Level III Characterization

Prior to testing, the LNCFS Level III system was optimized for performance and NO_x emissions by engineers from ABB CE. This process required the proper positioning of the three adjustable SOFA nozzles and the adjustable offset air nozzles in the main windbox. The final configuration for these nozzles with respect to the injection angle of the coal nozzles is shown in Table 5. The CCOFA nozzles are in line with the coal nozzles. ABB CE's report for the optimization of the LNCFS Level III equipment is included in Appendix A.

LNCFS Level III testing began in November 1991, and was completed in March 1992. The short-term test data are included in the **Technical Progress Report, Fourth Quarter 1991**. A summary of the long-term test results is shown with the baseline and LNCFS Level II results in Table 3. Seventy-one days of long-term data were collected generating an average emission level of 0.39 lb/MBtu. Long-term NO_x emissions over the entire load range are shown in Figure 6 and range from 0.32 lb/MBtu (140 MW) to 0.60 lb/MBtu (minimum load). When operating with LNCFS Level III, NO_x emissions varied by 0.3 lb/MBtu at minimum load values. However, the variations in emissions at full load were much less than the variations in the baseline or LNCFS Level II data.

During this quarter, tests were conducted to investigate the effects of changes in fuel fineness of NO_x emissions and unburned carbon levels. These tests were conducted in two phases with the

boiler operating at 180 MW. In the first phase, the mills were characterized to determine their grinding capabilities. Using this initial set of data, the second phase of testing was conducted. Over a three day test period, isokinetic unburned carbon samples were collected with the mills set at the maximum, median, and minimum grinding capabilities.

Results from the tests showed that changes in fuel fineness have a minimal impact on NO_x emissions. However, flyash unburned carbon levels can be significantly reduced by improving the fineness of the fuel. The letter report prepared by Energy Technology Consultants that discusses these findings is attached as Appendix B.

Table 5: Optimized Orientation of SOFA, CCOFA, and Offset Air Nozzles With Respect to the Coal Nozzles for LNCFS Level III (Positive Indicates Rotation with the Fireball).

Corner/ elevation	Right Front	Right Rear	Left Front	Left Rear
SOFA Top	+12°	-12°	+12°	+12°
SOFA Middle	0°	-12°	0°	0°
SOFA Lower	-12°	-12°	-12°	-12°
Offset Air	+16°	+16°	+16°	+16°

Figure 6: LNCFS Level III Long-Term NOx Emissions Results

5.3.3. LNCFS Level I Characterization

The LNCFS Level I technology is being tested by closing the dampers of the SOFA system used for LNCFS Level III. In order to maintain the material integrity of the SOFA nozzles, a minimum amount of leakage flow is maintained through the SOFA ductwork. According to ABB CE, the effect of this leakage flow is to reduce NO_x emissions below those of a true LNCFS Level I system.

In addition, the secondary air nozzles of a true LNCFS Level I system would provide a larger exit area than those installed at Plant Smith. This difference in secondary air nozzle design is required to pass all of the secondary air through the main windbox with the appropriate design velocities for the furnace dimensions and the fuel being fired. The design of the Level I system at Plant Smith results in a higher velocity through the secondary air nozzles than a true Level I system. The effect of this Level I simulation, with its associated higher mixing velocities, may cause NO_x emissions to be higher than normal and carbon loss to be lower than normal. The potential exists for the SOFA leakage effect of decreasing NO_x emissions and the nozzle design effects of increasing NO_x emissions to negate each other. Although a correction factor is being used to correct for SOFA leakage, no attempt is being made to correct for the nozzle design effects on NO_x emissions.

Prior to testing, the LNCFS Level I system was optimized for performance and NO_x emissions by engineers from ABB CE. Optimization of the system resulted in the CCOFA ports being positioned in line with the fuel nozzles. The position of the offset air nozzles was determined to be the same as the LNCFS Level III configuration (Table 5).

A portion of the LNCFS Level I diagnostic tests included the characterization of the SOFA leakage effects on NO_x emissions. These tests showed that the leakage effects are only significant at full load. At minimum loads, the effect on NO_x emissions is less than 0.1 percent. At full load, the leakage effects reduce unit NO_x emissions by 4.6 percent. A summary of all the short-term test data is included in the **Technical Progress Report, Second Quarter 1992**.

LNCFS Level I long-term testing began in June 1992 and was completed in September 1992. A summary of the long-term test results is shown with the baseline, LNCFS Level II, and LNCFS Level III results in Table 3. Seventy days of long-term data were collected generating an average emission level of 0.41 lb/MBtu. This emission level is corrected for leakage. Long-term NO_x emissions over the entire load range are shown in Figure 7. Since these data were collected during the summer, the unit was operated at or near full load during the entire test period due to system

load requirements. The NO_x emissions and unit load profiles for long-term testing are provided in Appendix A. A vast majority of the operations and emissions data below 100 MW was collected during start ups and shut downs of the unit and does not represent typical operation of the unit at those loads. As a result, these data are not included in any graphs. Compared to the baseline emissions, NO_x reduction at full load (180 MW) with LNCFS Level I was 37 percent. A maximum NO_x reduction of 38 percent was achieved at 170 MW.

Figure 7: LNCFS Level I Long-Term NOx Emissions Results

5.4. Data Comparison

The following section compares the long-term NOx emissions results from baseline, LNCFS Level I, LNCFS Level II, and LNCFS Level III.

5.4.1. NOx Emissions

Figure 8 compares the averages of the baseline, LNCFS Level I, LNCFS Level II, and LNCFS Level III long-term NOx emissions data. At full load, all three technologies provide substantial NOx reductions over the baseline values. LNCFS Level I provides a maximum reduction of 38 percent at 170 MW, LNCFS Level II provides a maximum NOx reduction of 40 percent at 190 MW and LNCFS Level III provides a maximum NOx reduction of 48 percent at 160 MW. At minimum load, NOx reduction is near zero percent for both LNCFS Level II and Level III. While not yet verified due to a lack of significant amounts of low load data, it is anticipated that LNCFS Level I would provide a similar trend of little or no NOx reduction at minimum loads.

5.4.2. Excess Oxygen Requirements

Figure 9 compares the baseline, LNCFS Level I, LNCFS Level II, and LNCFS Level III excess oxygen requirements. These measurements were taken at the boiler economizer outlet using a multi-point grid of in-situ oxygen analyzers. During baseline operation, full load excess oxygen levels were near 3.5 percent. As load decreased, excess oxygen requirements increased to 7.0 percent at minimum load. Excess oxygen levels for LNCFS Levels II and III were greater than the baseline levels. LNCFS Level II excess oxygen levels ranged from 4.0 percent at full load to 7.5 percent at low load. LNCFS Level III excess oxygen levels ranged from 3.8 percent to 7.1 percent. Excess oxygen requirements for LNCFS Level I were less than the baseline configuration and varied from 3.0 at full load to 6.7 percent at minimum load.

The short-term characterization data collected during the project confirmed that for all the technologies tested, NOx emissions are highly dependent upon excess oxygen levels. As the excess oxygen level is lowered, NOx emissions are reduced. The limiting factors when lowering excess oxygen levels are increases in CO production and/or increases in flyash carbon content. As shown in Figure 9, LNCFS Level I allows boiler operation at lower excess oxygen levels than the other technologies. This characteristic contributes to the LNCFS Level I capability to achieve NOx reduction comparable to LNCFS Level II.

To further illustrate the difference between the operating excess oxygen levels for the different technologies, Appendixes C and D provide the measured excess oxygen levels during testing of LNCFS Level I and LNCFS Level III. By observation of this data, the excess oxygen levels during LNCFS Level III operation were more erratic and higher than those during LNCFS Level I operation.

During low load LNCFS Level II operations at Plant Smith, excess air levels were higher than full load levels to maintain unit reheat and superheat temperatures (Fig. 9). Also the coal and air nozzles in the main windbox were tilted upward to assist in maintaining steam temperatures. This mode of normal operation could have contributed to the increase in NO_x emission at lower loads (Fig. 8). Following the long-term LNCFS Level II tests, ABB CE conducted a series of tests to determine if NO_x emissions at lower loads could be reduced. The results indicated that increasing SOFA flows above ABB CE's previously optimized levels and reducing excess oxygen levels decreases low load NO_x emissions to the full load values. These results have not been substantiated with long-term operation.

Figure 8: Comparison of Baseline, LNCFS Level I, LNCFS Level II, and LNCFS Level III Long-Term NOx Emissions Results

Figure 9: Comparison of Baseline, LNCFS Level II, and Level III Long-Term Excess Oxygen Levels

5.4.3. CO Emissions

Figure 10 compares the CO emissions measured during each phase of long-term testing. In a manner similar to the NOx emissions measurements, these values were taken at the stack with the CEM and have been corrected to a 3 percent O₂ level. The CO emissions during operation of LNCFS Level III were greater than baseline, LNCFS Level I, or LNCFS Level II values. Maximum CO emissions with LNCFS Level III occurred at the same load value where the NOx reduction was greatest. It is anticipated that these CO emissions could be reduced with extended operational experience.

5.4.4. Flyash Loss On Ignition and Mill Performance

Figure 11 compares the flyash loss-on-ignition (LOI) percentages measured during each set of performance tests. These measurements were made using EPA's Method 17 isokinetic sampling technique traversing multiple points at the economizer outlet of the boiler. LOI values during operation of LNCFS Level I were consistent with the baseline values. LOI values for operation with LNCFS Level II are below those of baseline values for all load levels tested. Baseline tests were not conducted at 200 MW. LOI levels with LNCFS Level III were greater than baseline levels. These higher values were confirmed during a short test series of LNCFS Level III.

Mill performance levels during each set of tests are shown in Table 6. Fuel fineness was measured using an isokinetic sampler at the exhaust outlet of each mill. The isokinetic sampling method has consistently resulted in lower fineness results than ABB CE's recommended method for collecting fuel samples. While the ABB CE procedure is not an isokinetic sampling method, it is widely recognized as the standard for the collection of fuel samples on CE mills. Data from both testing methods are shown.

During LNCFS Level II tests, mill performance levels were greater than the baseline values and during LNCFS Level III tests mill performance levels were lower. As a result, the effect of decreases and increases in LOI levels cannot be attributed solely to the performance of LNCFS Levels II and III, respectively. Due to concern over the increased LOI values with LNCFS Level III, additional LOI tests were conducted in May 1992. These results are also shown in Figure 11 and are labeled "LNCFS III (retested)." Based on the isokinetic fuel sampling method (Table 6), fineness levels were 2.5 percent on 50 mesh and 56 percent through 200 mesh. Measurements taken by plant personnel using ABB CE's recommended method showed that the fineness was 1.1 percent on 50 mesh and 71 percent through 200 mesh during the LNCFS Level III retest.

Figure 10: Comparison of Baseline, LNCFS Level II, and Level III Long-Term CO Levels

Figure 11: Comparison of Baseline, LNCFS Level I, LNCFS Level II, and Level III LOI Results

Table 6: Coal Flow Weighted Mill Performance at Full Load (180 MW) Using Isokinetic Fuel and Flyash Sampling Techniques at the Exhauster Outlet.				
	Percent Left on 50 Mesh		Percent Passing 200 Mesh	
	Isokinetic Method *	ABB CE Rec'd Method ‡	Isokinetic Method *	ABB CE Rec'd Method ‡
Baseline	2.6	2.4	58.9	68.6
LNCFS Level II	2.0	0.8	n/a	n/a
LNCFS Level III	3.2	1.3	55.7	75.3
LNCFS Level I	2.9	1.1	55.4	71.6
LNCFS Level III (retest)	2.5	1.1	55.5	71.6

* Mill Coal Flow Weighted Average

‡ Simple Average

5.4.5. Superheat and Reheat Temperatures

Since the combustion modifications to reduce NO_x emissions frequently result in changes in the heat distribution in the furnace, the potential exists for changes in the steam temperatures. The Smith boiler was designed to achieve 1000°F superheat and reheat outlet temperatures. Over the useful load range, the unit is capable of achieving the design superheat temperature. The unit historically has not been able to maintain the design reheat temperature at lower loads. Figures 12 and 13 illustrate the long-term reheat and superheat characteristics for the baseline configuration and all three LNCFS technology configurations. These data show that there was a depression in these temperatures for LNCFS Levels I and III. Both of these configurations use the clustered coal nozzle concept. The LNCFS Level II configuration did not have any effects on unit steaming capabilities.

If the steam temperature depressions for Levels I and III cannot be economically corrected, they may result in long term heat rate penalties. Further analyses are required to determine if these depressions can be corrected without diminishing the NO_x reduction potential for the technologies.

Fig. 12. Comparison of Average Superheat Temperatures.

Fig. 13. Comparison of Average Reheat Temperatures.

5.5. Unit Operations

In the baseline configuration of the boiler, the coal and air nozzles were fixed in the horizontal position since the tilting mechanisms were inoperable. During the outage to install LNCFS Level II, the burner tilting system was completely replaced. As a result, unit operators reported that the tilt mechanisms allowed better control of reheat and superheat temperatures with all three levels of the LNCFS.

Other than the tilt improvements, unit operation with LNCFS Level I was reported to be similar to baseline conditions. Fireball rotation, furnace clarity (visibility), flame brightness, and flexibility in unit operations did not change appreciably from the baseline condition. Unit operations with LNCFS Level II were also reported to provide the flexibility in operations of the baseline configuration. With LNCFS Levels II and III operation, fireball rotation rate slowed, furnace clarity decreased, and flame brightness dimmed. The redirection of secondary air to the SOFA nozzles is the primary reason for the change in fireball rotation rate and in furnace brightness. The extended combustion zone created by the overfire air process resulted in lower furnace gas clarity. With operation of all three levels of LNCFS, there was no increased loading on the precipitator; however, the predominant slagging location moved from the combustion zone of the furnace to the convection pass.

Although there were no effects on unit availability, boiler operation with LNCFS Level III was characterized as more difficult than the baseline, Level I, or Level II configurations. Load transitions that require bringing mills into and out of service generally resulted in spikes of CO and NO_x emissions. Flexibility in unit operations with respect to the range of excess oxygen levels available for operation was more restricted. This characteristic is reflected in the tight band of NO_x emissions generated at each load during LNCFS Level III operation (Fig. 6). Slagging patterns and precipitator loadings with LNCFS Level III were similar to those experienced with Level II.

5.6. Phase IV Final Reporting and Disposition

5.6.1. Disposition

The low NO_x combustion equipment that provided the greatest NO_x reduction, LNCFS Level III, will remain in service at Plant Smith. This equipment includes the separated overfire air system with its controls board, ductwork, and dampers, the concentric firing system with the flame

attachment coal nozzle tips, flame scanners and cooling air fans, combustion monitoring camera, and the SOFA and main windbox and tilting mechanisms.

All of the data collection equipment and analyzers will be removed from the site. This equipment includes the continuous emissions monitor, data acquisition system, flux domes, acoustic pyrometers, instrumentation trailer, sampling probes, thermocouples, and oxygen analyzers.

6. FUTURE PLANS

The following is a quarterly outline of the activities scheduled during the remainder of the project:

QUARTER	ACTIVITY
First Quarter 1993	Complete Project Disposition Continue Final Reporting
Second Quarter 1993	Continue Final Reporting
Third Quarter 1993	Complete Final Reporting Project Completion

7. ACKNOWLEDGMENTS

The management of this project wish to gratefully acknowledge the support and dedication of the following personnel for their work at the tangentially-fired test site: Mr. J. D. McDonald, Gulf Power Company, and Mr. Lamar Sumerlin, Southern Company Services, for their coordination of the design and retrofit efforts and Mr. James Gibson, full-time Instrumentation Specialist from Spectrum Systems, Inc. We also thank Messrs. Jim Witt, John Sorge, and Jimmy Horton of Southern Company Services for their work coordinating the procurement and installation of the instrumentation at this site. We would also like to recognize the following companies for their outstanding testing and data analysis efforts: Energy Technology Consultants, Inc., Flame Refractories, Inc., Southern Research Institute, W. S. Pitts Consulting, and Radian Corporation.

8. APPENDIX A

ABB Combustion Engineering Services Report
PHASE III - LNCFS Level III Optimization

SCS CONTRACT NO. C-90-000286
GULF POWER CO. - LANSING SMITH NO. 2
"180 MW DEMONSTRATION OF ADVANCED TANGENTIALLY-FIRED
COMBUSTION TECHNIQUES FOR THE REDUCTION OF NITROGEN
OXIDE (NO_x) EMISSIONS FROM COAL-FIRED BOILERS"
ABB CE SERVICES CONTRACT NO. 52589

PHASE III - LNCFS LEVEL III RETROFIT

Report Written By:

Susan A. Morrison
Glen Treger
Mike Barry

ABB CE SERVICES, INC.
Technical Services

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APPENDICES

Appendix A

- Operating Range of NO_x (corr) vs. Load (MW)
- Separated and Close-Coupled Overfire Air Damper Positions vs. Load
- %O₂ vs. Load
- Windbox Pressure vs. Load
- Percent NO_x Reduction vs. NO_x (corr) (#/MBTU)
- NO_x (corr) (#/MBTU) vs. Test Data Sets
 - a. At 200 MW, 180 MW, 135 MW, 115 MW, 80 MW with "C" and "D" pulverizers in service, and 80 MW with "D" and "E" pulverizers in service

Appendix B

- Diamond Electronics TV System

SECTION I

SUMMARY

INTRODUCTION

In order to adjust unit parameters to demonstrate the Level III system, the following items were completed:

- A. Coordinate tests to demonstrate the capabilities of LNCFS Level III System, considering all directly related system components

The test program began on November 14, 1991 and was completed on December 3, 1991.

- B. Determine percentage of Overfire Air Damper Openings versus a main steam flow input signal to the MOD 30 Control System and program the controllers

The curves for both the SOFA and CCOFA dampers are included in Appendix A. Similar curves were left for plant operations personnel.

- C. Determine appropriate settings for excess air and secondary air dampers to achieve the NOx reduction related to the LNCFS Level III System

The curves for these parameters versus unit load are included in Appendix A. Similar curves were left for plant operations personnel and adequate instruction for secondary air damper operation was provided.

RESULTS AND CONCLUSIONS

The unit was set up to demonstrate the capabilities of the LNCFS Level III System. Load points of 200 MW, 180 MW, 115 MW, and 80 MW were chosen to test the unit and determine adequate staging of the overfire air. Carbon Monoxide and NOx emissions were monitored by the CEM under the control of Spectrum, Inc. Flyash samples were collected during various tests from the economizer outlet ducts using the high volume technique. These samples are to be analyzed by Southern Company Services, Inc.

Various emissions results were collected with changes made to auxiliary and fuel air damper settings, overfire air damper settings, yaw adjustment mechanisms, %O₂, and tilts. The following is a summary of the results obtained at the above mentioned load points, representing the reduction in NOx obtainable while the unit was operating in a normal (new) control arrangement. As a reference, the baseline NOx (corr) level was approximately 0.620 #/MBTU.

<u>Load</u>	<u>Best Obtained NOx (#/MBTU)</u>	<u>Rec. Operating NOx (#/MBTU)</u>	<u>% Reduction</u>	<u>CO (ppm)</u>
200 MW	0.291	0.322	48%	14
180 MW	0.290	0.306	51%	26
115 MW	0.294	0.313	50%	7
80 MW	0.284	0.284	46%	7

Included in Appendix A are Charts I-VI which represent the NOx levels achieved throughout various tests performed. Although the final Nox level on the charts indicate the maximum reduction, limitations were found that prevented the unit from operating with these low levels. A short summary of data is included which indicates unit parameters and various limitations.

Based on this data, operating guidelines were provided to plant personnel which produced specification NOx reduction (41%-50%). In addition, it is our opinion that these guidelines offered a "comfort" zone for the operating personnel.

It should be recognized that these are only preliminary settings and actual settings may change over a long period, taking into consideration fuel changes, equipment changes, etc.

Full sets of unit data are included in Section III of this report.

RESULTS AND CONCLUSIONS

The percentage of reduction in the NOx levels found during testing exceeds the published range of reduction for LNCFS Level III system. However, several limitations were determined during the test program. At full load (200 MW), the limitation in the NOx reduction was found to be CO generation. At 80 MW, NOx reduction was limited by excess air and the amount of overfire air. This was a result of operating personnel being uncomfortable with the windbox pressure below 1.5" H2O and the auxiliary air dampers closed. Further slight reduction in the NOx could be achieved through further testing and adjustments, but time did not permit.

The pulverizers were not worked on during the outage, and have not been since the spring outage. Fineness results were not available at the time the unit adjustments were made for the Level III system. The primary airflow results obtained during Performance Testing of the Level II system indicate approximately 2.7 lb air/lb fuel, higher than the recommended ratio of 1.5 lb air/lb fuel. Recently, fineness results have been received that were taken during Performance Testing of the Level III system. The results indicate a degradation of mill fineness, with some mills in serious fineness trouble in every test. Due to the condition of the mills, no accurate conclusions can be made concerning carbon loss. Ignition points were not as close as desired at all loads, which could be contributed to mill fineness and primary airflow.

Steam temperatures, steam pressures, and slagging conditions have not changed drastically from the baseline values to Level II to Level III values.

Furnace appearance was as expected with the Low NOx firing system, lazier, not as defined flames.

Comments have been received from many sources concerning the sensitivity of the Level III system, but it should be recognized that the Level II system was more "sensitive" to operate than the original burner arrangement. The closer a stoichiometry of 1 is approached, the less upsets and imbalances the unit can tolerate. As a result, operating personnel had difficulty becoming accustomed to the operation of the unit with the LNCFS Level III system. This was expected as we are now operating closer to the edge than with the Level II system.

SECTION II

LNCFS LEVEL III SYSTEM COMPONENTS

LNCFS LEVEL III SYSTEM COMPONENTS

The following new equipment was installed in each burner corner for the LNCFS Level III retrofit:

- Two (2) Close-Coupled Overfire Air tips (CCOFA)
- Three (3) partition plates
- One (1) air "bullet" nozzle
- Two (2) Foxboro Jordan Electric Damper Drives
- One (1) eddy plate ignitor assembly

The conversion from LNCFS Level II to LNCFS Level III consisted of installing two (2) close-coupled overfire air compartments at the top of the main windboxes. The original "EE" top end air and "E" fuel compartments are now considered the upper and lower CCOFA (Close-Coupled Overfire Air). The bottom partition plates were cut out in the previous "EE" and "E" compartments, and new plates were installed in accordance with the size of the CCOFA tips. The top "E" fuel tip and nozzle were relocated to the previous "DE" auxiliary air compartment. The coal piping for "E" elevation was modified by cutting a section out of the straight run below the Rockwell coupling.

A new partition plate was installed below "E" elevation to create a compartment for a small air nozzle tip. The associated secondary air damper was not replaced but modified by trimming the bottom blade to fit the compartment. The tip does not tilt, but is pinned to the upper and lower partition plates for this compartment. This allows some airflow between the "E" and "D" fuel tips.

Foxboro Jordan electric damper drives were installed for CCOFA damper control, two (2) per burner corner, on the existing "EE" and "E" secondary air damper shafts. These drive units are identical to those installed at each SOFA elevation. They are specified clockwise or counter-clockwise rotation, which was factory wired and checked, and were mounted according to the rotation of the damper shafts. The units drive the dampers open on increasing input signal (2V to 10V). A functional checkout was performed on each drive unit to ensure proper wiring and rotation. The limit switch settings on the units assure a stroke of 90 degrees. The angle of rotation of the damper shaft was measured to be approximately 87 degrees.

The Taylor MOD 30 control system was installed during the Spring 1991 outage. This system consists of one controller for SOFA tilt drive, three controllers for SOFA damper drives (one per elevation), and two controllers for the CCOFA damper drives (one per elevation). The input/output parameters were programmed into the Linearization block of the software program. For the damper drive controls, the input parameter is the Main Steam Flow signal from the plant Westinghouse logic, and the output from the controllers is the damper position. The bias for the SOFA tilts remains the same for Level III as for Level II. This bias is +/- 70 bias in relation to +/- 300 main tilt operation.

LNCFS LEVEL III SYSTEM COMPONENTS

All five (5) OFA controllers were programmed according to the test results for NO_x reduction. The controllers for the SOFA damper drives were reprogrammed due to the change in OFA staging required to meet the capabilities of the Level III system. The curves for damper position (%) versus load (MW) and the input/output parameters programmed for each damper elevation have been included in Appendix A of this report.

A new 6" eddy plate ignitor assembly was installed adjacent to the now top elevation of coal. The associated ignitor control cabinet was moved down for access to both components from one elevation. This was approved by plant personnel. The ignitor control cabinets for "AB", "C", and "D" fuel elevations also had to be relocated in the right and left front corners to accommodate the change. Plant personnel performed functional checkouts on each control station.

Several modifications were made to the Diamond Electronics TV system. Because the TV camera had been removed from the guide tube assembly over a long period of time, the guide tube had been exposed to the furnace without cooling air. The portion extending through the refractory into the furnace had to be replaced due to overheating. The original and new guide tube assemblies were installed per the installation drawing, which has been verified through Diamond Electronics as proper installation. A more detailed description of modifications are included in Appendix B.

Unit Inspection

The burner corners were thoroughly inspected during the outage. Several fuel tips were slightly warped with some slag build-up in the secondary air partitions, which was cleaned out. The removable portion of one fuel tip was replaced.

The windbox channels in the right front and left rear corners were slightly warped in the top compartments of the windboxes. These channels were repaired prior to installation of the close-coupled overfire air (CCOFA) tips. Thermocouple wires were installed on the channels in all four corners at "E" fuel elevation and "A" coal elevation in the right front corner. The temperatures were checked during unit testing and were approximately 5730F.

The tilts were stroked and all clearances verified to ensure that binding problems do not occur. The yaw mechanisms in both the main windboxes and the SOFA windboxes were in good condition. The offset angles were changed to +160 from +220 in the main windbox and +120/-120 (top/bottom) from +150/-150 (top/bottom) in the SOFA windbox to prevent contact with the waterwalls.

During initial testing, an attempt was made to determine the effects of the secondary air dampers, installed downstream of the SOFA duct take-off from the secondary air duct. The dampers would not rotate, thus, the impact of these dampers on the system is unknown. To evaluate the impact, the dampers should be inspected.

SECTION III

POST OUTAGE UNIT TESTING

POST OUTAGE UNIT TESTING

The unit was tested by Technical Services and Firing Systems, Windsor, at several load points - 200 MW, 180 MW, 135 MW, 115 MW, and 80 MW. At each load point, a series of adjustments were made to % excess air, secondary air dampers, overfire air dampers, tilts, and yaw mechanisms to determine the required staging of overfire air to reduce NOx emissions in accordance with the maximum capability of the LNCFS Level III system. Following this section are data sheets representative of results obtained from these adjustments.

The following are the recommended SOFA and main windbox settings:

SOFA Yaw Mechanisms (All Loads)

Right Front, Left Front, and Left Rear Corners

Upper	+12°
Middle	0°
Lower	-12°

Right Rear Corner

Upper	-12°
Middle	-12°
Lower	-12°

Main Windbox Yaw Mechanisms (All Loads)

All Corners	+16°
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Fuel/Air Dampers

80 MW	10% open
115-200 MW	20% open

Auxiliary Air Dampers

Per Windbox Pressure vs. Load curve in Appendix A

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		9	10	11
DATE		11/15/91	11/18/91	11/18/91
TIME		15:45	10:46	15:35
LOAD	MW	200	200	200
THROTTLE PRESSURE	LB/IN2	1800	1800	1800
ECON (FW) IN TEMP	F	476	475	475
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F (L/R)	999/1003	1004/1007	998/1002
SH DESH IN TEMP	F	877/907	849/885	843/875
SH DESH OUT TEMP	F	820/821	814/816	827/821
RH OUT TEMP	F (L/R)	997	992	989
RH DESH IN TEMP	F	-	704/703	704/703
RH DESH OUT TEMP	F	707/705	701/690	703/701
O2 (BOARD)	%	5.5	4.4	4.8
TOTAL AIR FLOW	KLB/HR	1440	1400	1400
TILT POS	DEG	0	0	0
ELEV. IN SERVICE	---	5	5	5
WINDBOX/FURN dP	"H2O	5.5	4.5	7
WINDBOX PRESSURE	"H2O	5	4	6.5
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	152	152	153
FLOWS				
FEEDWATER	KLB/HR	1375	1396	1440
MAIN STEAM	KLB/HR	1477	1467	1473
FW MAKEUP	LB/MIN	NA	-	-
SH DESH SPRAY	KLB/HR	64	44	33
RH DESH SPRAY	KLB/HR	NA	8	3.2
PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	2089	2087	2091
SH OUT	LB/IN2	1799	1802	1800
RH IN	LB/IN2	538	539	539
(COLD RH @ TURB)				
RH OUT	LB/IN2	511	512	512
(HOT RH @ TURB)				

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		9	10	11
DATE		11/15/91	11/18/91	11/18/91
TIME		15:45	10:46	15:35
SH SPRAY VALVE POS. %		45/46	36/32	26/26
RH SPRAY VALVE POS. %		0/0	1.6/2	0/0
APH TEMPERATURES	(L/R)			
GAS IN	F	656/652	646/641	646/639
GAS OUT	F	301/314	296/311	299/314
AIR IN	F	116/151	111/148	118/153
AIR OUT	F	559/551	554/546	553/544
AMBIANT AIR TEMP	F	72	73	75
PULVERIZER DATA				
MILL OUT TEMPS				
A	F	151	150	149
B	F	151	151	150
C	F	150	150	151
D	F	150	149	151
E	F	151	150	149
MILL LOADING				
A	KLB/HR	39	36	37
B	KLB/HR	35	35	35
C	KLB/HR	36	33	34
D	KLB/HR	36	34	34
E	KLB/HR	34	37	37
MILL POWER				
A	AMPS	34	34	34
B	AMPS	37	36	36
C	AMPS	38	38	38
D	AMPS	38	38	38
E	AMPS	33	36	35
BOWL dP				
A	"H2O	6.6	7	6.8
B	"H2O	9	8.4	9.2
C	"H2O	8.3	7.6	8
D	"H2O	8.5	7.8	8.6
E	"H2O	7.7	6.8	7.8

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		9	10	11
DATE		11/15/91	11/18/91	11/18/91
TIME		15:45	10:46	15:35
MILL IN TEMPS				
A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA
HOT AIR DAMPER POS (PRIMARY AIR)				
A	%	98	100	97
B	%	100	98	98
C	%	99	96	96
D	%	100	80	80
E	%	100	75	74
COLD AIR DAMPER POS (TEMPERING AIR)				
A	%	44	40	38
B	%	52	47	49
C	%	50	45	42
D	%	53	44	48
E	%	46	38	47
MILL AIR FLOW				
A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA
MILL CLASSIFIER POSITION				
A		3	3	3
B		4	4	4
C		3.5	3.5	3.5
D		3.5	3.5	3.5
E		3	3	3
MILL EXH/FURN dP				
A	"H2O	18	17.2	18.2
B	"H2O	17.2	16.3	17.5
C	"H2O	17.3	15.8	17.8
D	"H2O	17.8	17.4	18.5
E	"H2O	15.5	15.1	16.2

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	9	10	11
DATE	11/15/91	11/18/91	11/18/91
TIME	15:45	10:46	15:35

COAL FINENESS

A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%	Not available	Not available	Not available
C % ON 50	%			
C % THRU 100	%			
C % THRU 200	%			
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			

FD FAN DATA (L/R)

DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	952/949	881/874	951/944
OUTLET PRESS	"H2O	+13/+13	+11/+11	+14/+14
AMPS		125/120	100/100	120/115
ID FAN DATA				
INLET VANE POS	%	72/72	62/62	66/66
OUT VANE POS	%	98/90	98/96	98/96
IN PRESS	"H2O	-16/-17	-17/-17	-17/-17
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		270/270	260/250	265/260
BFP MOTOR SPEED	RPM	3364/3356	3346/3354	3364/3366
BFP AMPS		308/310	300/305	300/310

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	9	10	11
DATE	11/15/91	11/18/91	11/18/91
TIME	15:45	10:46	15:35

SECONDARY AIR/
FUEL AIR DAMPER
POSITION

E	%	50	50	30
D	%	50	50	30
CD	%	0	0	10
C	%	50	50	30
BC	%	0	0	10
B	%	50	50	30
AB	%	0	0	10
A	%	50	50	30
AA	%	0	70	65

SOFA DAMPER POS

UPPER	%	100	100	100
CENTER	%	100	100	100
LOWER	%	100	100	100

CCOFA DAMPER POS

UPPER	%	100	100	0
LOWER	%	100	60	0

OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	15R,0,15L	15R,0,15L	15R,0,15L
RR	DEG	15L	15L	15L
LF	DEG	15R,0,15L	15R,0,15L	15R,0,15L
LR	DEG	15R,0,15L	15R,0,15L	15R,0,15L
AUX AIR YAW POS				
RF	DEG	16R	16R	16R
RR	DEG	16R	16R	16R
LF	DEG	16R	16R	16R
LR	DEG	16R	16R	16R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	9	10	11
DATE	11/15/91	11/18/91	11/18/91
TIME	15:45	10:46	15:35

GAS DATA (local)

O2	%	5.7	4.3	4.3
CO	PPM	44	44	23
NOx (UC)	PPM	205	212	193
NOx (CORR)	PPM	247	243	242
NOx (CORR)	LB/MBTU	0.343	0.338	0.337
SO2 (UC)	PPM	2438	2260	2118
THC	%	1.2	1.1	1.1

FURNACE CONDITIONS	---	*	**
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IGNITIONS POINTS

RF CORNER	FT	*	**	1
RR CORNER	FT	*	**	1
LR CORNER	FT	*	**	1
LF CORNER	FT	*	**	1

NOTE:

- * - Slight build-up of slag on waterwalls at SOFA elevation (approx. 1/2")
 - Coal particles were noticed in OB ports.
 - 0" to 6" slag build-up on nose arch
 - Fireball bright yellow to white in color at the SOFA elevation.
 - "Burnt" orange at "A" and "B" coal elevations
 - Feedwater flow and steam flow transmitters do not appear accurate, but are calibrated to the best of the plant's ability.
- It was hard to determine the ignition points due to visibility across the furnace.
- ** - By opening bottom end air dampers, the bottom of the furnace "brightened" up.
 - Ignition points were approximately 1' off the tips at the upper elevations.

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		12	13	14
DATE		11/18/91	11/19/91	11/19/91
TIME		17:45	10:15	14:45
LOAD	MW	200	180	180
THROTTLE PRESSURE	LB/IN2	1800	1800	1800
ECON (FW) IN TEMP	F	475	464	463
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F (L/R)	1002/1005	997/999	1007/980
SH DESH IN TEMP	F	860/898	822/876	827/862
SH DESH OUT TEMP	F	819/808	812/826	816/823
RH OUT TEMP	F (L/R)	993	964	953
RH DESH IN TEMP	F	709/708	683/682	679/677
RH DESH OUT TEMP	F	690/689	682/680	678/676
O2 (BOARD)	%	4.1	4.7	4.4
TOTAL AIR FLOW	KLB/HR	1380	1240	1260
TILT POS	DEG	0	0	0
ELEV. IN SERVICE	---	5	5	5
WINDBOX/FURN dP	"H2O	6.5	6	6
WINDBOX PRESSURE	"H2O	6	5.5	5.5
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	154	140	141
FLOWS				
FEEDWATER	KLB/HR	1400	1330	1334
MAIN STEAM	KLB/HR	1460	1320	1330
FW MAKEUP	LB/MIN	-	0	38
SH DESH SPRAY	KLB/HR	58	23	34
RH DESH SPRAY	KLB/HR	12	3	3.2
PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	2082	2043	2049
SH OUT	LB/IN2	1801	1802	1803
RH IN	LB/IN2	534	477	477
(COLD RH @ TURB)				
RH OUT	LB/IN2	507	452	453
(HOT RH @ TURB)				

LANSING SMITH UNIT 2 - LOW NOX DEMONSTRATION OPTIMIZATION TEST

TEST NO.		12	13	14
DATE		11/18/91	11/19/91	11/19/91
TIME		17:45	10:15	14:45
SH SPRAY VALVE POS. %		43/40	1.6/2.6	1.6/22
RH SPRAY VALVE POS. %		1.6/0	0/0	0/0
APH TEMPERATURES	(L/R)			
GAS IN	F	651/645	617/613	617/614
GAS OUT	F	308/293	285/300	287/301
AIR IN	F	111/151	112/148	114/150
AIR OUT	F	544/550	531/525	532/526
AMBIANT AIR TEMP	F	71	75	77
PULVERIZER DATA				
MILL OUT TEMPS				
A	F	147	150	151
B	F	149	150	151
C	F	147	150	150
D	F	146	149	151
E	F	145	148	150
MILL LOADING				
A	KLB/HR	37	34	33
B	KLB/HR	35	29	28
C	KLB/HR	34	32	33
D	KLB/HR	36	33	32
E	KLB/HR	38	35	36
MILL POWER				
A	AMPS	34	32	32
B	AMPS	36	34	33
C	AMPS	38	37	36
D	AMPS	38	35	37
E	AMPS	35	34	35
BOWL dP				
A	"H2O	6.8	7	7
B	"H2O	9.3	9	9
C	"H2O	8	8	8
D	"H2O	8.6	8.6	8.6
E	"H2O	7.8	7.6	8.6

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	12	13	14
DATE	11/18/91	11/19/91	11/19/91
TIME	17:45	10:15	14:45

MILL IN TEMPS

A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA

HOT AIR DAMPER POS (PRIMARY AIR)

A	%	100	98	98
B	%	98	91	86
C	%	90	96	96
D	%	82	79	75
E	%	78	75	74

COLD AIR DAMPER POS (TEMPERING AIR)

A	%	48	36	32
B	%	57	47	43
C	%	56	48	44
D	%	56	50	44
E	%	55	45	42

MILL AIR FLOW

A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA

MILL CLASSIFIER POSITION

A	3	3	3
B	4	4	4
C	3.5	3.5	3.5
D	3.5	3.5	3.5
E	3	3	3

MILL EXH/FURN dP

A	"H2O	17.8	17.3	17.2
B	"H2O	17.6	16.6	16.4
C	"H2O	16.7	16.8	16.3
D	"H2O	17.8	17.9	17.6
E	"H2O	15.2	15.4	15.4

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	12	13	14
DATE	11/18/91	11/19/91	11/19/91
TIME	17:45	10:15	14:45

COAL FINENESS

A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%			
C % ON 50	%	Not	Not	Not
C % THRU 100	%	available	available	available
C % THRU 200	%			
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			

FD FAN DATA (L/R)

DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	910/899	859/866	859/866
OUTLET PRESS	"H2O	+13/+13	+12/+12	+12/+12
AMPS		115/110	100/100	100/100

ID FAN DATA

INLET VANE POS	%	62/62	54/54	54/53
OUT VANE POS	%	96/98	100/100	100/100
IN PRESS	"H2O	-17/-17	-16/-16	-16/-16
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		255/250	250/240	250/240

BFP MOTOR SPEED	RPM	3337/3334	3258/3240	3262/3258
BFP AMPS		300/300	280/280	280/280

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	12	13	14
DATE	11/18/91	11/19/91	11/19/91
TIME	17:45	10:15	14:45

SECONDARY AIR/
FUEL AIR DAMPER
POSITION

E	%	30	50	25
D	%	30	50	25
CD	%	0	15	10
C	%	30	50	25
BC	%	0	15	10
B	%	30	50	25
AB	%	0	15	10
A	%	30	50	25
AA	%	65	70	70

SOFA DAMPER POS

UPPER	%	100	0	0
CENTER	%	100	0	0
LOWER	%	100	0	0

CCOFA DAMPER POS

UPPER	%	100	0	100
LOWER	%	0	15	30

OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	15R,0,15L	15R,0,15L	15R,0,15L
RR	DEG	15L	15L	15L
LF	DEG	15R,0,15L	15R,0,15L	15R,0,15L
LR	DEG	15R,0,15L	15R,0,15L	15R,0,15L
AUX AIR YAW POS				
RF	DEG	16R	13R	13R
RR	DEG	16R	6L	6L
LF	DEG	16R	6L	6L
LR	DEG	16R	13R	13R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	12	13	14
DATE	11/18/91	11/19/91	11/19/91
TIME	17:45	10:15	14:45

GAS DATA (local)

O2	%	4.3	4.5	4.8
CO	PPM	23	22	12
NOx (UC)	PPM	196	269	238
NOx (CORR)	PPM	228	287	265
NOx (CORR)	LB/MBTU	0.317	0.399	0.368
SO2 (UC)	PPM	2060	2155	2327
THC	%	1.1	1	0.8

FURNACE CONDITIONS	---	good	good	good
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IGNITIONS POINTS

RF CORNER	FT	1	4	4
RR CORNER	FT	1	3	3
LR CORNER	FT	1	4	4
LF CORNER	FT	1	2	2

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		16	17	18
DATE		11/19/91	11/19/91	11/19/91
TIME		16:45	18:00	19:20
LOAD	MW	180	180	180
THROTTLE PRESSURE	LB/IN2	1800	1800	1800
ECON (FW) IN TEMP	F	464	465	466
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F (L/R)	1005/1007	1000/1000	1000/1000
SH DESH IN TEMP	F	844/865	849/872	855/887
SH DESH OUT TEMP	F	*830/814	810/824	815/817
RH OUT TEMP	F (L/R)	975	981	985
RH DESH IN TEMP	F	690/689	691/690	693/692
RH DESH OUT TEMP	F	688/689	689/690	691/693
O2 (BOARD)	%	4	3.9	4.5
TOTAL AIR FLOW	KLB/HR	1240	1240	1300
TILT POS	DEG	0	0	0
ELEV. IN SERVICE	---	5	5	5
WINDBOX/FURN dP	"H2O	4.5	4	4
WINDBOX PRESSURE	"H2O	4	3.5	3.5
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	136	138	138
FLOWS				
FEEDWATER	KLB/HR	1330	1340	1300
MAIN STEAM	KLB/HR	1320	1330	1320
FW MAKEUP	LB/MIN	38	37	39
SH DESH SPRAY	KLB/HR	34	34	48
RH DESH SPRAY	KLB/HR	3.2	3.2	3.1
PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	2043	2044	2042
SH OUT	LB/IN2	1799	1801	1800
RH IN	LB/IN2	480	479	479
(COLD RH @ TURB)				
RH OUT	LB/IN2	456	455	455
(HOT RH @ TURB)				

* - These numbers are questionable. They were taken off the control room strip chart recorder and compared with the CRT. It seems that incorrect designation for left and right side temps. on the strip chart has the plant questioning how these values are designated.

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	16	17	18
DATE	11/19/91	11/19/91	11/19/91
TIME	16:45	18:00	19:20
SH SPRAY VALVE POS. %	7/30	23/31	36/41
RH SPRAY VALVE POS. %	0/0	0/0	0/0

APH TEMPERATURES

GAS IN	F	623/616	623/617	627/622
GAS OUT	F	287/302	287/302	287/302
AIR IN	F	111/149	109/148	107/144
AIR OUT	F	537/531	539/531	540/532
AMBIANT AIR TEMP	F	73	71	68

PULVERIZER DATA

MILL OUT TEMPS

A	F	147	149	148
B	F	150	151	150
C	F	149	150	150
D	F	149	150	150
E	F	147	149	147

MILL LOADING

A	KLB/HR	33	34	33
B	KLB/HR	29	28	28
C	KLB/HR	32	32	33
D	KLB/HR	32	32	32
E	KLB/HR	36	35	37

MILL POWER

A	AMPS	32	33	33
B	AMPS	34	34	34
C	AMPS	37	36	36
D	AMPS	37	36	36
E	AMPS	34	35	35

BOWL dP

A	"H2O	7.3	7.4	7.4
B	"H2O	8.8	8.6	8.6
C	"H2O	7.6	7.4	7.6
D	"H2O	8	8	8
E	"H2O	7	7	7

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	16	17	18
DATE	11/19/91	11/19/91	11/19/91
TIME	16:45	18:00	19:20

MILL IN TEMPS

A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA

HOT AIR DAMPER POS (PRIMARY AIR)

A	%	100	99	99
B	%	90	87	88
C	%	96	94	96
D	%	76	77	77
E	%	48	75	76

COLD AIR DAMPER POS (TEMPERING AIR)

A	%	40	38	36
B	%	46	46	45
C	%	47	46	44
D	%	45	46	45
E	%	44	41	40

MILL AIR FLOW

A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA

MILL CLASSIFIER POSITION

A	3	3	3
B	4	4	4
C	3.5	3.5	3.5
D	3.5	3.5	3.5
E	3	3	3

MILL EXH/FURN dP

A	"H2O	16.3	16	16.2
B	"H2O	15.4	15.3	15
C	"H2O	15.8	15.6	15.6
D	"H2O	16.6	16.3	16.5
E	"H2O	14.8	14.2	14.2

LANSING SMITH UNIT 2 - LOW NOX DEMONSTRATION OPTIMIZATION TEST

TEST NO.	16	17	18
DATE	11/19/91	11/19/91	11/19/91
TIME	16:45	18:00	19:20

COAL FINENESS

A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%			
C % ON 50	%	Not	Not	Not
C % THRU 100	%	available	available	available
C % THRU 200	%			
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			

FD FAN DATA (L/R)

DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	811/814	782/789	819/814
OUTLET PRESS	"H2O	+10/+10	+9/+9	+10/+10
AMPS		90/95	75/70	90/80

ID FAN DATA

INLET VANE POS	%	52/52	49/51	54/54
OUT VANE POS	%	100/98	98/100	98/100
IN PRESS	"H2O	-15/-15	-15/-15	-16/-16
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		240/230	240/230	250/240

BFP MOTOR SPEED	RPM	3267/3238	3270/3233	3260/3230
BFP AMPS		280/280	280/280	280/280

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	16	17	18
DATE	11/19/91	11/19/91	11/19/91
TIME	16:45	18:00	19:20

SECONDARY AIR/ FUEL AIR DAMPER POSITION

E	%	25	25	25
D	%	25	25	25
CD	%	10	10	10
C	%	25	25	25
BC	%	10	10	10
B	%	25	25	25
AB	%	10	10	10
A	%	25	25	25
AA	%	70	70	70

SOFA DAMPER POS

UPPER	%	0	0	100
CENTER	%	0	100	100
LOWER	%	100	100	100

CCOFA DAMPER POS

UPPER	%	100	100	100
LOWER	%	30	30	20

OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	15R,0,15L	15R,0,15L	15R,0,15L
RR	DEG	15L	15L	15L
LF	DEG	15R,0,15L	15R,0,15L	15R,0,15L
LR	DEG	15R,0,15L	15R,0,15L	15R,0,15L
AUX AIR YAW POS				
RF	DEG	13R	13R	13R
RR	DEG	0	0	0
LF	DEG	0	0	0
LR	DEG	13R	13R	13R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	16	17	18
DATE	11/19/91	11/19/91	11/19/91
TIME	16:45	18:00	19:20

GAS DATA (local)

O2	%	4.2	4	4.8
CO	PPM	9	10	23
NOx (UC)	PPM	225	204	201
NOx (CORR)	PPM	241	216	223
NOx (CORR)	LB/MBTU	0.335	0.3	0.305
SO2 (UC)	PPM	2326	2220	2209
THC	%	0.7	0.7	0.6

FURNACE CONDITIONS	---	good	*	*
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IGNITIONS POINTS

RF CORNER	FT	4	1-2	1-2
RR CORNER	FT	3	1	1
LR CORNER	FT	4	2-3	2-3
LF CORNER	FT	2	1	1

- * - Slag build-up in the LR corner
- Ignition points are very hard to determine due to low visibility across the furnace. We approximate 1'-2' off the tip at "D" and "E" fuel elevations.
- Slag on nose arch is approx. 1"-3".

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO. 19
 DATE 11/20/91
 TIME 15:00

NOTE: A leak was found
 in the analyzer
 and was repaired
 prior to this
 test.

LOAD	MW	180
THROTTLE PRESSURE	LB/IN2	1800
ECON (FW) IN TEMP	F	466
ECON OUT TEMP	F	NA

SH OUT TEMP	F(L/R)	999/1000
SH DESH IN TEMP	F	844/873
SH DESH OUT TEMP	F	811/816

RH OUT TEMP	F(L/R)	986
RH DESH IN TEMP	F	686/685
RH DESH OUT TEMP	F	683/685

O2 (BOARD)	%	4.3
TOTAL AIR FLOW	KLB/HR	1290
TILT POS	DEG	0
ELEV. IN SERVICE	---	5

WINDBOX/FURN dP	"H2O	5.5
WINDBOX PRESSURE	"H2O	5
FURNACE PRESSURE	"H2O	-0.5
TOTAL FUEL FIRED	KLB/HR	136

FLows

FEEDWATER	KLB/HR	1340
MAIN STEAM	KLB/HR	1320
FW MAKEUP	LB/MIN	36
SH DESH SPRAY	KLB/HR	38
RH DESH SPRAY	KLB/HR	3

Pressures

ECON IN PRESS	LB/IN2	NA
STEAM DRUM	LB/IN2	2046
SH OUT	LB/IN2	1803
RH IN	LB/IN2	480
(COLD RH @ TURB)		
RH OUT	LB/IN2	456
(HOT RH @ TURB)		

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	19
DATE	11/20/91
TIME	15:00

SH SPRAY VALVE POS. %	33/31
RH SPRAY VALVE POS. %	0/0

APH TEMPERATURES (L/R)

GAS IN	F	629/622
GAS OUT	F	296/310
AIR IN	F	118/154
AIR OUT	F	545/538
AMBIANT AIR TEMP	F	78

PULVERIZER DATA

MILL OUT TEMPS

A	F	150
B	F	151
C	F	150
D	F	151
E	F	150

MILL LOADING

A	KLB/HR	30
B	KLB/HR	26
C	KLB/HR	24
D	KLB/HR	26
E	KLB/HR	32

MILL POWER

A	AMPS	34
B	AMPS	34
C	AMPS	36
D	AMPS	36
E	AMPS	35

BOWL dP

A	"H2O	7.2
B	"H2O	8.6
C	"H2O	7.6
D	"H2O	8
E	"H2O	7

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO. 19
 DATE 11/20/91
 TIME 15:00

MILL IN TEMPS

A	F	NA
B	F	NA
C	F	NA
D	F	NA
E	F	NA

HOT AIR DAMPER POS (PRIMARY AIR)

A	%	99
B	%	93
C	%	84
D	%	75
E	%	74

COLD AIR DAMPER POS (TEMPERING AIR)

A	%	26
B	%	35
C	%	32
D	%	36
E	%	33

MILL AIR FLOW

A	LB/HR	NA
B	LB/HR	NA
C	LB/HR	NA
D	LB/HR	NA
E	LB/HR	NA

MILL CLASSIFIER POSITION

A	3
B	4
C	3.5
D	3.5
E	3

MILL EXH/FURN dP

A	"H2O	17
B	"H2O	16
C	"H2O	15.6
D	"H2O	17.2
E	"H2O	15

LANSING SMITH UNIT 2 - LOW NOX DEMONSTRATION OPTIMIZATION TEST

TEST NO.	19
DATE	11/20/91
TIME	15:00

COAL FINENESS

A % ON 50	%	
A % THRU 100	%	
A % THRU 200	%	
B % ON 50	%	
B % THRU 100	%	
B % THRU 200	%	
C % ON 50	%	
C % THRU 100	%	Not
C % THRU 200	%	available
D % ON 50	%	
D % THRU 100	%	
D % THRU 200	%	
E % ON 50	%	
E % THRU 100	%	
E % THRU 200	%	

FD FAN DATA (B/A) (L/R)

DAMPER POS	%	100/100
FAN SPEED	RPM	846/852
OUTLET PRESS	"H2O	+11/+11
AMPS		100/100

ID FAN DATA		
INLET VANE POS	%	54/56
OUT VANE POS	%	98/100
IN PRESS	"H2O	-16/-16
OUTLET PRESS	LB/IN2	NA
AMPS		240/240

BFP MOTOR SPEED	RPM	3262/3245
BFP AMPS		280/280

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	19
DATE	11/20/91
TIME	15:00

SECONDARY AIR/
FUEL AIR DAMPER
POSITION

E	%	25
D	%	25
CD	%	10
C	%	25
BC	%	10
B	%	25
AB	%	10
A	%	25
AA	%	70

SOFA DAMPER POS

UPPER	%	100
CENTER	%	0
LOWER	%	0

CCOFA DAMPER POS

UPPER	%	100
LOWER	%	15

OFA TILT POS	DEG	0
OFA YAW POS (T,M,B)		
RF	DEG	15R,0,15L
RR	DEG	15L
LF	DEG	15R,0,15L
LR	DEG	15R,0,15L
AUX AIR YAW POS		
RF	DEG	13R
RR	DEG	0
LF	DEG	0
LR	DEG	13R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	19
DATE	11/20/91
TIME	15:00

GAS DATA
(local)

O2	%	3.4
CO	PPM	9
NOx (UC)	PPM	246
NOx (CORR)	PPM	252
NOx (CORR)	LB/MBTU	0.35
SO2 (UC)	PPM	2352
THC	%	0.9

FURNACE CONDITIONS	---	*good
--------------------	-----	-------

IGNITIONS POINTS

RF CORNER	FT	2
RR CORNER	FT	2
LR CORNER	FT	2
LF CORNER	FT	2

* - Slag build-up in LR corner

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		20	21	22
DATE		11/21/91	11/21/91	11/21/91
TIME		21:20	01:00	03:00
LOAD	MW	115	115	115
THROTTLE PRESSURE	LB/IN2	1800	1850	1801
ECON (FW) IN TEMP	F	420	422	420
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F (L/R)	1001/988	1012/1014	1012/1015
SH DESH IN TEMP	F	793/823	823/828	856/860
SH DESH OUT TEMP	F	786/808	787/812	813/789
RH OUT TEMP	F (L/R)	930	941/946	944/950
RH DESH IN TEMP	F	614/605	616/624	617/625
RH DESH OUT TEMP	F	613/605	616/623	623/624
O2 (BOARD)	%	4.3	4.2	5.5
TOTAL AIR FLOW	KLB/HR	900	930	980
TILT POS	DEG	0	0	0
ELEV. IN SERVICE	---	3	3	3
WINDBOX/FURN dP	"H2O	4	2.5	3.5
WINDBOX PRESSURE	"H2O	3.5	2	3
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	85	84	86
FLOWS				
FEEDWATER	KLB/HR	940	*935	**745
MAIN STEAM	KLB/HR	800	810	805
FW MAKEUP	LB/MIN	28	32	35
SH DESH SPRAY	KLB/HR	8	13	28
RH DESH SPRAY	KLB/HR	2.6	2.4	2.3
PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	1906	1904	1903
SH OUT	LB/IN2	1801	1800	1801
RH IN	LB/IN2	288	288	290
(COLD RH @ TURB)				
RH OUT	LB/IN2	272	272	274
(HOT RH @ TURB)				

* - From strip chart, the value is 935 klb/hr.
From CRT, the value is 758 klb/hr.

** - This value was taken from the CRT.

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		20	21	22
DATE		11/21/91	11/21/91	11/21/91
TIME		21:20	01:00	03:00
SH SPRAY VALVE POS. %		1.6/13	25/1.6	37/36
RH SPRAY VALVE POS. %		0/0	0/0	0/0
* LAPH TEMPERATURES L/R				
GAS IN	F	538/532	535/527	549/539
GAS OUT	F	251/267	248/264	249/263
AIR IN	F	101/143	100/142	99/139
AIR OUT	F	480/477	476/471	481/476
AMBIANT AIR TEMP	F	62	62	62
PULVERIZER DATA				
MILL OUT TEMPS				
A	F	-	-	-
B	F	-	-	-
C	F	147	148	148
D	F	148	146	148
E	F	145	147	146
MILL LOADING				
A	KLB/HR	-	-	-
B	KLB/HR	-	-	-
C	KLB/HR	28	31	28
D	KLB/HR	27	29	28
E	KLB/HR	30	32	30
MILL POWER				
A	AMPS	-	-	-
B	AMPS	-	-	-
C	AMPS	37	38	38
D	AMPS	37	37	37
E	AMPS	34	34	34
BOWL dP				
A	"H2O	-	-	-
B	"H2O	-	-	-
C	"H2O	7.4	7.2	7.4
D	"H2O	7.8	7.6	7.8
E	"H2O	7	6.8	7

* The left side steam coil air heater had coils cut out.

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	20	21	22
DATE	11/21/91	11/21/91	11/21/91
TIME	21:20	01:00	03:00

MILL IN TEMPS

A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA

HOT AIR DAMPER POS
(PRIMARY AIR)

A	%	-	-	-
B	%	-	-	-
C	%	96	90	92
D	%	94	92	96
E	%	90	92	92

COLD AIR DAMPER POS
(TEMPERING AIR)

A	%	-	-	-
B	%	-	-	-
C	%	47	52	54
D	%	51	52	54
E	%	48	52	52

MILL AIR FLOW

A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA

MILL CLASSIFIER
POSITION

A	3	3	3
B	4	4	4
C	3.5	3.5	3.5
D	3.5	3.5	3.5
E	3	3	3

MILL EXH/FURN dP

A	"H2O	-	-	-
B	"H2O	-	-	-
C	"H2O	15.5	14.6	15.6
D	"H2O	16.2	16	16.4
E	"H2O	14	13.5	13.8

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	20	21	22
DATE	11/21/91	11/21/91	11/21/91
TIME	21:20	01:00	03:00

COAL FINENESS

A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%			
C % ON 50	%	Not	Not	Not
C % THRU 100	%	available	available	available
C % THRU 200	%			
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			

FD FAN DATA (L/R)

DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	594/596	554/553	610/618
OUTLET PRESS	"H2O	+7/+7	+5/+5	+7/+7
AMPS		60/60	52/52	54/54

ID FAN DATA				
INLET VANE POS	%	34/34	34/34	38/38
OUT VANE POS	%	98/100	99/100	99/100
IN PRESS	"H2O	-10/-11	-10/-11	-10/-11
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		160/150	155/145	165/145

BFP MOTOR SPEED	RPM	2947/2912	2953/2914	2946/2910
BFP AMPS		200/200	200/210	205/200

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		20	21	22
DATE		11/21/91	11/21/91	11/21/91
TIME		21:20	01:00	03:00

SECONDARY AIR/
FUEL AIR DAMPER
POSITION

E	%	25	25	25
D	%	25	25	25
CD	%	15	10	10
C	%	25	25	25
BC	%	15	10	10
B	%	-	-	-
AB	%	-	-	-
A	%	-	-	-
AA	%	-	-	-

SOFA DAMPER POS

UPPER	%	0	100	0
CENTER	%	0	0	0
LOWER	%	0	0	100

CCOFA DAMPER POS

UPPER	%	0	30	30
LOWER	%	15	20	20

OFA TILT POS

	DEG	0	0	0
--	-----	---	---	---

OFA YAW POS (T,M,B)

RF	DEG	15R, 0, 15L	15R, 0, 15L	15R, 0, 15L
RR	DEG	15L	15L	15L
LF	DEG	15R, 0, 15L	15R, 0, 15L	15R, 0, 15L
LR	DEG	15R, 0, 15L	15R, 0, 15L	15R, 0, 15L

AUX AIR YAW POS

RF	DEG	13R	13R	13R
RR	DEG	0	0	0
LF	DEG	0	0	0
LR	DEG	13R	13R	13R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	20	21	22
DATE	11/21/91	11/21/91	11/21/91
TIME	21:20	01:00	03:00

GAS DATA (local)

O2	%	3.7	3.4	5.1
CO	PPM	5	13	3
NOx (UC)	PPM	264	211	228
NOx (CORR)	PPM	275	216	258
NOx (CORR)	LB/MBTU	0.382	0.3	0.359
SO2 (UC)	PPM	2315	2292	2276
THC	%	0.6	0.4	0.4

FURNACE CONDITIONS	---	good	good	good
--------------------	-----	------	------	------

IGNITIONS POINTS

RF CORNER	FT	*	*	*
RR CORNER	FT	*	*	*
LR CORNER	FT	*	*	*
LF CORNER	FT	*	*	*

* - Ignition points for all three tests

	RF	RR	LF	LR
"E"	Flame att.	1'-2'	1'	Flame att.
"D"	4'	3'	1'	2'
"C"	2'	1'-2'	1'	Flame att.

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO. 23
 DATE 11/22/91
 TIME 23:00

NOTE: Closed PA damp-
 ers, "D" mill,
 in order to
 bring ignition
 points back in
 to tip and
 bring exh/furn
 delta P in
 line with "C"
 and "E" mills.

LOAD	MW	115
THROTTLE PRESSURE	LB/IN2	1803
ECON (FW) IN TEMP	F	419
ECON OUT TEMP	F	NA

SH OUT TEMP	F (L/R)	1000/987
SH DESH IN TEMP	F	819/834
SH DESH OUT TEMP	F	805/809

RH OUT TEMP	F (L/R)	927
RH DESH IN TEMP	F	610/617
RH DESH OUT TEMP	F	609/616

O2 (BOARD)	%	5.5
TOTAL AIR FLOW	KLB/HR	970
TILT POS	DEG	0
ELEV. IN SERVICE	---	3

WINDBOX/FURN dP	"H2O	3
WINDBOX PRESSURE	"H2O	2.5
FURNACE PRESSURE	"H2O	-0.5
TOTAL FUEL FIRED	KLB/HR	86

FLOWS

FEEDWATER	KLB/HR	763
MAIN STEAM	KLB/HR	807
FW MAKEUP	LB/MIN	0
SH DESH SPRAY	KLB/HR	12
RH DESH SPRAY	KLB/HR	2.3

PRESSURES

ECON IN PRESS	LB/IN2	NA
STEAM DRUM	LB/IN2	1901
SH OUT	LB/IN2	1803
RH IN	LB/IN2	285
(COLD RH @ TURB)		
RH OUT	LB/IN2	269
(HOT RH @ TURB)		

LANSING SMITH UNIT 2 - LOW NOX DEMONSTRATION OPTIMIZATION TEST

TEST NO.	23
DATE	11/22/91
TIME	23:00

SH SPRAY VALVE POS. %	16/0
RH SPRAY VALVE POS. %	0/0

APH TEMPERATURES

GAS IN	F	546/538
GAS OUT	F	243/259

AIR IN	F	95/136
AIR OUT	F	478/473
AMBIANT AIR TEMP	F	57

PULVERIZER DATA

MILL OUT TEMPS

A	F	-
B	F	-
C	F	148
D	F	147
E	F	146

MILL LOADING

A	KLB/HR	-
B	KLB/HR	-
C	KLB/HR	33
D	KLB/HR	31
E	KLB/HR	37

MILL POWER

A	AMPS	-
B	AMPS	-
C	AMPS	37
D	AMPS	30
E	AMPS	35

BOWL dP

A	"H2O	-
B	"H2O	-
C	"H2O	7.6
D	"H2O	6.2
E	"H2O	7

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	23
DATE	11/22/91
TIME	23:00

MILL IN TEMPS

A	F	NA
B	F	NA
C	F	NA
D	F	NA
E	F	NA

HOT AIR DAMPER POS
(PRIMARY AIR)

A	%	-
B	%	-
C	%	96
D	%	*34
E	%	90

COLD AIR DAMPER POS
(TEMPERING AIR)

A	%	-
B	%	-
C	%	68
D	%	74
E	%	61

MILL AIR FLOW

A	LB/HR	NA
B	LB/HR	NA
C	LB/HR	NA
D	LB/HR	NA
E	LB/HR	NA

MILL CLASSIFIER
POSITION

A	3
B	4
C	3.5
D	3.5
E	3

MILL EXH/FURN dP

A	"H2O	-
B	"H2O	-
C	"H2O	14.6
D	"H2O	12.3
E	"H2O	13.6

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	23
DATE	11/22/91
TIME	23:00

COAL FINENESS

A % ON 50	%	Not available
A % THRU 100	%	
A % THRU 200	%	
B % ON 50	%	
B % THRU 100	%	
B % THRU 200	%	
C % ON 50	%	
C % THRU 100	%	
C % THRU 200	%	
D % ON 50	%	
D % THRU 100	%	
D % THRU 200	%	
E % ON 50	%	
E % THRU 100	%	
E % THRU 200	%	

FD FAN DATA (B/A) (L/R)

DAMPER POS	%	100/100
FAN SPEED	RPM	574/583
OUTLET PRESS	"H2O	+6/+6
AMPS		60/60

ID FAN DATA		
INLET VANE POS	%	36/36
OUT VANE POS	%	98/100
IN PRESS	"H2O	-10/-11
OUTLET PRESS	LB/IN2	NA
AMPS		170/150

BFP MOTOR SPEED	RPM	2940/2909
BFP AMPS		200/200

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	23
DATE	11/22/91
TIME	23:00

SECONDARY AIR/ FUEL AIR DAMPER POSITION

E	%	25
D	%	25
CD	%	10
C	%	25
BC	%	10
B	%	-
AB	%	-
A	%	-
AA	%	-

SOFA DAMPER POS

UPPER	%	0
CENTER	%	100
LOWER	%	100

CCOFA DAMPER POS

UPPER	%	30
LOWER	%	20

OFA TILT POS	DEG	0
--------------	-----	---

OFA YAW POS (T,M,B)		
RF	DEG	15R,0,15L
RR	DEG	15L
LF	DEG	15R,0,15L
LR	DEG	15R,0,15L

AUX AIR YAW POS		
RF	DEG	16R
RR	DEG	16R
LF	DEG	16R
LR	DEG	16R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO. 23
 DATE 11/22/91
 TIME 23:00

GAS DATA (local)

O2	%	5
CO	PPM	7
NOx (UC)	PPM	199
NOx (CORR)	PPM	225
NOx (CORR)	LB/MBTU	0.313
SO2 (UC)	PPM	2194
THC	%	0.4

FURNACE CONDITIONS --- good

IGNITIONS POINTS

RF CORNER	FT	*
RR CORNER	FT	*
LR CORNER	FT	*
LF CORNER	FT	*

* - Ignition points

	RF	RR	LF	LR
"E"	2'	2'	1'-2'	2'
"D"	3'-4'	2'	1'-2'	2'
"C"	4'	2'	1'-2'	Flame att.

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	24	25
DATE	11/30/91	11/30/91
TIME	03:30	04:50

LOAD	MW	83	83
THROTTLE PRESSURE	LB/IN2	1800	1807
ECON (FW) IN TEMP	F	391	390
ECON OUT TEMP	F	NA	NA

SH OUT TEMP	F (L/R)	1002/1000	999/979
SH DESH IN TEMP	F	827/836	814/818
SH DESH OUT TEMP	F	804/836	803/807

RH OUT TEMP	F (L/R)	927/930	903/908
RH DESH IN TEMP	F	592/594	583/584
RH DESH OUT TEMP	F	592/594	582/582

O2 (BOARD)	%	6.5	6.6
TOTAL AIR FLOW	KLB/HR	850	850
TILT POS	DEG	+10	0
ELEV. IN SERVICE	---	2	2

WINDBOX/FURN dP	"H2O	2	2
WINDBOX PRESSURE	"H2O	1.5	1.5
FURNACE PRESSURE	"H2O	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	62	61

FLOWS

FEEDWATER	KLB/HR	*535	*760
MAIN STEAM	KLB/HR	570	580
FW MAKEUP	LB/MIN	35	0
SH DESH SPRAY	KLB/HR	8	6
RH DESH SPRAY	KLB/HR	3	3

PRESSURES

ECON IN PRESS	LB/IN2	NA	NA
STEAM DRUM	LB/IN2	1856	1857
SH OUT	LB/IN2	1799	1803
RH IN	LB/IN2	203	202
(COLD RH @ TURB)			
RH OUT	LB/IN2	190	190
(HOT RH @ TURB)			

* - Value taken from CRT

** - Value taken from strip chart

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	24	25
DATE	11/30/91	11/30/91
TIME	03:30	04:50
SH SPRAY VALVE POS. %	20/5	1.2/1.6
RH SPRAY VALVE POS. %	0/0	0/0

APH TEMPERATURES

GAS IN	F	505/498	504/500
GAS OUT	F	237/249	236/248
AIR IN	F	104/141	103/140
AIR OUT	F	453/447	452/447
AMBIANT AIR TEMP	F	68	68

PULVERIZER DATA

MILL OUT TEMPS

A	F	-	-
B	F	-	-
C	F	150	150
D	F	152	151
E	F	-	-

MILL LOADING

A	KLB/HR	-	-
B	KLB/HR	-	-
C	KLB/HR	30	35
D	KLB/HR	31	37
E	KLB/HR	-	-

MILL POWER

A	AMPS	-	-
B	AMPS	-	-
C	AMPS	36	37
D	AMPS	38	38
E	AMPS	-	-

BOWL dP

A	"H2O	-	-
B	"H2O	-	-
C	"H2O	6.6	7.2
D	"H2O	6.7	7.6
E	"H2O	-	-

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	24	25
DATE	11/30/91	11/30/91
TIME	03:30	04:50

MILL IN TEMPS

A	F	NA	NA
B	F	NA	NA
C	F	NA	NA
D	F	NA	NA
E	F	NA	NA

HOT AIR DAMPER POS * (PRIMARY AIR)

A	%	-	-
B	%	-	-
C	%	90	97
D	%	100	99
E	%	-	-

COLD AIR DAMPER POS (TEMPERING AIR)

A	%	-	-
B	%	-	-
C	%	76	71
D	%	80	82
E	%	-	-

MILL AIR FLOW

A	LB/HR	NA	NA
B	LB/HR	NA	NA
C	LB/HR	NA	NA
D	LB/HR	NA	NA
E	LB/HR	NA	NA

MILL CLASSIFIER POSITION

A	3	3
B	3	3
C	3	3
D	3.5	3.5
E	3	3

MILL EXH/FURN dP

A	"H2O	-	-
B	"H2O	-	-
C	"H2O	15.4	15.3
D	"H2O	15.8	16.1
E	"H2O	-	-

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	24	25
DATE	11/30/91	11/30/91
TIME	03:30	04:50

COAL FINENESS

A % ON 50	%		
A % THRU 100	%		
A % THRU 200	%		
B % ON 50	%		
B % THRU 100	%		
B % THRU 200	%		
C % ON 50	%	Not	Not
C % THRU 100	%	available	available
C % THRU 200	%		
D % ON 50	%		
D % THRU 100	%		
D % THRU 200	%		
E % ON 50	%		
E % THRU 100	%		
E % THRU 200	%		

FD FAN DATA (B/A) (L/R)

DAMPER POS	%	100/100	100/100
FAN SPEED	RPM	481/491	478/495
OUTLET PRESS	"H2O	+4/+4	+8/+8
AMPS		45/45	50/50

ID FAN DATA

INLET VANE POS	%	29/29	29/29
OUT VANE POS	%	100/100	100/100
IN PRESS	"H2O	-10/-12	-10/-12
OUTLET PRESS	LB/IN2	NA	NA
AMPS		155/135	90/100

BFP MOTOR SPEED	RPM	2826/2811	2829/2815
BFP AMPS		175/175	180/180

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	24	25
DATE	11/30/91	11/30/91
TIME	03:30	04:50

SECONDARY AIR/ FUEL AIR DAMPER POSITION

E	%	5	5
D	%	20	20
CD	%	5	5
C	%	20	20
BC	%	5	5
B	%	-	-
AB	%	-	-
A	%	-	-
AA	%	-	-

SOFA DAMPER POS

UPPER	%	0	0
CENTER	%	70	70
LOWER	%	100	100

CCOFA DAMPER POS

UPPER	%	0	0
LOWER	%	0	0

OFA TILT POS	DEG	0	0
OFA YAW POS (T,M,B)			
RF	DEG	15R,0,15L	15R,0,15L
RR	DEG	15L	15L
LF	DEG	15R,0,15L	15R,0,15L
LR	DEG	15R,0,15L	15R,0,15L
AUX AIR YAW POS			
RF	DEG	16R	16R
RR	DEG	16R	16R
LF	DEG	16R	16R
LR	DEG	16R	16R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	24	25
DATE	11/30/91	11/30/91
TIME	03:30	04:50

GAS DATA (local)

O2	%	6.4	6.5
CO	PPM	7	10
NOx (UC)	PPM	190	170
NOx (CORR)	PPM	235	211
NOx (CORR)	LB/MBTU	0.327	0.293
SO2 (UC)	PPM	2213	2204
THC	%	0.4	0.4

FURNACE CONDITIONS	---	dull fire	smokier
--------------------	-----	-----------	---------

IGNITIONS POINTS

RF CORNER	FT	3-4	3-6
RR CORNER	FT	0-2	0-2
LR CORNER	FT	1-4	1-4
LF CORNER	FT	0-2	0

* - Ignition points

	RF	RR	LF	LR
"C"	3'-6'	Flame att.	Flame att.	Flame att.
"D"	3'-6'	2'	Flame att.	2'-3'

LANSGING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		26	27	28
DATE		12/2/91	12/2/91	12/2/91
TIME		03:00	06:00	11:35
LOAD	MW	135	75	200
THROTTLE PRESSURE	LB/IN2	1804	1798	1804
ECON (FW) IN TEMP	F	389	384	476
ECON OUT TEMP	F	NA	NA	NA
SH OUT TEMP	F	1000/1000	956/956	1001/1002
SH DESH IN TEMP	F	825/852	792/787	864/883
SH DESH OUT TEMP	F	811/822	782/779	820/823
RH OUT TEMP	F	932/937	869	993/998
RH DESH IN TEMP	F	643/638	545/547	703/704
RH DESH OUT TEMP	F	643/638	545/546	703/704
O2 (BOARD)	%	6	6	4.6
TOTAL AIR FLOW	KLB/HR	925	800	1430
TILT POS	DEG	0	0	0
ELEV. IN SERVICE	---	3	2	5
WINDBOX/FURN dP	"H2O	3	2	5.5
WINDBOX PRESSURE	"H2O	2.5	1.5	5
FURNACE PRESSURE	"H2O	-0.5	-0.5	-0.5
TOTAL FUEL FIRED	KLB/HR	100	60	156
FLOWS				
FEEDWATER	KLB/HR	930	*740	143
MAIN STEAM	KLB/HR	945	540	147
FW MAKEUP	LB/MIN	0	41	57
SH DESH SPRAY	KLB/HR	12	5.5	47
RH DESH SPRAY	KLB/HR	3	2.7	3
PRESSURES				
ECON IN PRESS	LB/IN2	NA	NA	NA
STEAM DRUM	LB/IN2	1933	1850	2084
SH OUT	LB/IN2	1799	1799	1797
RH IN	LB/IN2	338	183	537
(COLD RH @ TURB)				
RH OUT	LB/IN2	321	173	510
(HOT RH @ TURB)				

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	26	27	28
DATE	12/2/91	12/2/91	12/2/91
TIME	03:00	06:00	11:35

SH SPRAY VALVE POS. %	17/1.6	1.2/0	35/40
RH SPRAY VALVE POS. %	0/0	0/0	0/0

APH TEMPERATURES

GAS IN	F	568/561	521/519	655/649
GAS OUT	F	259/273	253/266	302/318
AIR IN	F	110/146	108/147	115/149
AIR OUT	F	492/485	479/474	560/550
AMBIANT AIR TEMP	F	72	71	73

PULVERIZER DATA

MILL OUT TEMPS

A	F	-	-	150
B	F	-	-	149
C	F	150	-	149
D	F	150	151	151
E	F	150	150	150

MILL LOADING

A	KLB/HR	-	-	35
B	KLB/HR	-	-	31
C	KLB/HR	34	-	29
D	KLB/HR	31	30	29
E	KLB/HR	34	30	29

MILL POWER

A	AMPS	-	-	33
B	AMPS	-	-	36
C	AMPS	38	-	37
D	AMPS	38	38	40
E	AMPS	38	38	38

BOWL dP

A	"H2O	-	-	6.4
B	"H2O	-	-	8.8
C	"H2O	7	-	7.8
D	"H2O	7.5	7.2	8
E	"H2O	7	6.8	7.5

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		26	27	28
DATE		12/2/91	12/2/91	12/2/91
TIME		03:00	06:00	11:35
MILL IN TEMPS				
A	F	NA	NA	NA
B	F	NA	NA	NA
C	F	NA	NA	NA
D	F	NA	NA	NA
E	F	NA	NA	NA
HOT AIR DAMPER POS (PRIMARY AIR)				
A	%	-	-	100
B	%	-	-	100
C	%	100	-	100
D	%	100	98	100
E	%	100	96	100
COLD AIR DAMPER POS (TEMPERING AIR)				
A	%	-	-	47
B	%	-	-	52
C	%	70	-	50
D	%	70	56	61
E	%	60	48	43
MILL AIR FLOW				
A	LB/HR	NA	NA	NA
B	LB/HR	NA	NA	NA
C	LB/HR	NA	NA	NA
D	LB/HR	NA	NA	NA
E	LB/HR	NA	NA	NA
MILL CLASSIFIER POSITION				
A		3	3	3
B		3	3	3
C		3	3	3
D		3.5	3.5	3.5
E		3	3	3
MILL EXH/FURN dP				
A	"H2O	-	-	17.5
B	"H2O	-	-	17.2
C	"H2O	15.6	-	17.3
D	"H2O	27.2	16.1	19.2
E	"H2O	13.7	12	15.1

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	26	27	28
DATE	12/2/91	12/2/91	12/2/91
TIME	03:00	06:00	11:35

COAL FINENESS

A % ON 50	%			
A % THRU 100	%			
A % THRU 200	%			
B % ON 50	%			
B % THRU 100	%			
B % THRU 200	%			
C % ON 50	%			
C % THRU 100	%	Not	Not	Not
C % THRU 200	%	available	available	available
D % ON 50	%			
D % THRU 100	%			
D % THRU 200	%			
E % ON 50	%			
E % THRU 100	%			
E % THRU 200	%			

FD FAN DATA (L/R)

DAMPER POS	%	100/100	100/100	100/100
FAN SPEED	RPM	*682/414	*454/272	951/937
OUTLET PRESS	"H2O	+7/+7	+4/+4	+13/+13
AMPS		70/70	40/40	122/117
ID FAN DATA				
INLET VANE POS	%	49/48	28/24	73/72
OUT VANE POS	%	100/100	100/100	100/100
IN PRESS	"H2O	-10/-10	-10/-14	-18/-18
OUTLET PRESS	LB/IN2	NA	NA	NA
AMPS		150/110	160/130	270/265
BFP MOTOR SPEED	RPM	3014/2990	2815/2801	3364/3342
BFP AMPS		225/225	170/170	310/305

* - "A" FD Fan tachometer requires calibration.

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.		26	27	28
DATE		12/2/91	12/2/91	12/2/91
TIME		03:00	06:00	11:35

SECONDARY AIR/ FUEL AIR DAMPER POSITION				
E	%	10	10	20
D	%	10	10	20
CD	%	25	10	10
C	%	10	-	20
BC	%	25	-	10
B	%	-	-	20
AB	%	-	-	10
A	%	-	-	20
AA	%	-	-	70

SOFA DAMPER POS				
UPPER	%	50	0	100
CENTER	%	100	0	100
LOWER	%	100	100	100

CCOFA DAMPER POS				
UPPER	%	60	0	100
LOWER	%	20	20	20

OFA TILT POS	DEG	0	0	0
OFA YAW POS (T,M,B)				
RF	DEG	15R, 0, 15L	15R, 0, 15L	15R, 0, 15L
RR	DEG	15L	15L	15L
LF	DEG	15R, 0, 15L	15R, 0, 15L	15R, 0, 15L
LR	DEG	15R, 0, 15L	15R, 0, 15L	15R, 0, 15L
AUX AIR YAW POS				
RF	DEG	16R	16R	16R
RR	DEG	16R	16R	16R
LF	DEG	16R	16R	16R
LR	DEG	16R	16R	16R

LANSING SMITH UNIT 2 - LOW NOx DEMONSTRATION OPTIMIZATION TEST

TEST NO.	26	27	28
DATE	12/2/91	12/2/91	12/2/91
TIME	03:00	06:00	11:35

GAS DATA (local)

O2	%	5.5	5.9	4.7
CO	PPM	6	7	13
NOx (UC)	PPM	193	202	218
NOx (CORR)	PPM	224	241	241
NOx (CORR)	LB/MBTU	0.311	0.335	0.335
SO2 (UC)	PPM	2418	2427	2372
THC	%	0.4	0.5	0.3

FURNACE CONDITIONS	---	*	**
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IGNITIONS POINTS

RF CORNER	FT	*	**	**
RR CORNER	FT	*	**	**
LR CORNER	FT	*	**	**
LF CORNER	FT	*	**	**

* - Ignition points

	RF	RR	LF	LR
"C"	0'-1'	0'-1'	0'-1'	0'-1'
"D"	3'-4'	3'-4'	3'-4'	2'
"E"	0'-1'	0'-1'	0'-1'	0'-1'

** - Ignition points

	RF	RR	LF	LR
"D"	6'	8'	6'	6'
"E"	Flame att.	4'	Flame att.	Flame att.

APPENDIX A

OPERATING RANGE of NOx (#/MBTU) vs. LOAD (MW)

LOWER CCOFA DAMPER OPENING vs. MAIN STEAM FLOW

The following pages show the ten (10) input/output values programmed in the MOD 30 controllers for the SOFA and CCOFA dampers. The input values were entered as percentage of Main Steam Flow. The final curves drawn, however, represent % Damper Opening vs. Load (MW).

Y = % Damper Opening
X = % Total Steam Flow

LOWER CCOFA DAMPER

<u>X Values</u>	<u>Y Values</u>
30 (60 MW)	0
40 (80 MW)	20
45	20
50	20
55	20
60	20
70	20
80	20
90 (180 MW)	20
100 (200 MW)	20

UPPER CCOFA

<u>X Values</u>	<u>Y Values</u>
40 (80 MW)	0
45.5	11
51	22
56.5	33
62	44
67.5	55
73	66
78.5	77
90 (180 MW)	100
100 (200 MW)	100

LOWER SOFA

<u>X Values</u>	<u>Y Values</u>
30 (60 MW)	0
31.1	11
32.2	22
33.3	33
34.4	44
35.5	55
36.6	66
37.7	77
40 (80 MW)	100
100 (200 MW)	100

LOWER CCOFA DAMPER OPENING vs. MAIN STEAM FLOW

Y = % Damper Opening
X = % Total Steam Flow

MIDDLE SOFA

<u>X Values</u>	<u>Y Values</u>
35 (70 MW)	0
36.1	11
37.2	22
38.3	33
39.4	44
40.5	55
41.6	66
42.7	77
45 (90 MW)	100
100 (200 MW)	100

UPPER SOFA

<u>X Values</u>	<u>Y Values</u>
58 (115 MW)	0
59.1	11
60.2	22
61.3	33
62.4	44
63.5	55
64.6	66
65.7	77
68 (135 MW)	100
100 (200 MW)	100

LANSING SMITH - UNIT #2 LOWER CCOFA DAMPERS vs. LOAD (MW)

LANSGING SMITH - UNIT #2 UPPER CCOFA vs. LOAD (MW)

LANSING SMITH - UNIT #2 LOWER SOFA vs. LOAD (MW)

LANSING SMITH - UNIT #2 CENTER SOFA vs. LOAD (MW)

LANSING SMITH - UNIT #2 UPPER SOFA vs. LOAD (MW)

LANSING SMITH - UNIT #2 O2 % versus LOAD (MW)

LANSING SMITH - UNIT #2 WINDBOX PRESSURE versus LOAD (MW)

CHART I

The following is a summary of the unit conditions for Test Data Sets No. 1, No. 15, and No. 29 at 200 MW.

Test Data Set No. 1

Windbox Pressure (in. H2O)	7.0
O2 (%)	5.0
Auxiliary Air Dampers (% open)	35
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	70
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	0
CCOFA Dampers (% open)	
- Upper	0
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.514
CO (ppm)	13

Test Data Set No. 15

Windbox Pressure (in. H2O)	5.0
O2 (%)	4.5
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	20
Bottom End Air Dampers (% open)	70
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	100
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.322
CO (ppm)	14

CHART I

Test Data Set No. 29

Windbox Pressure (in. H2O)	6.0
O2 (%)	4.7
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	30
Bottom End Air Dampers (% open)	70
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	40
- Lower	0
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.261
CO (ppm)	20

Test Data Set No. 29 demonstrates the highest NOx reduction at 58% reduction. However, the ignition points at these conditions were not stable and the CO level started to increase. Test Data Set No. 15 represents the final settings achieved during ABB CE Services' test program.

NOx REDUCTION

AT 200 MW

GULF POWER COMPANY - LANSING SMITH UNIT #2

CHART II

The following is a summary of the unit conditions for Test Data Sets No. 1, No. 10, No. 20, and No. 24 at 180 MW.

Test Data Set No. 1

Windbox Pressure (in. H2O)	6.0
O2 (%)	5.4
Auxiliary Air Dampers (% open)	20
Fuel Air Dampers (% open)	50
Bottom End Air Dampers (% open)	70
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	0
CCOFA Dampers (% open)	
- Upper	0
- Lower	0
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.470
CO (ppm)	29-50

Test Data Set No. 10

Windbox Pressure (in. H2O)	3.5
O2 (%)	4.7
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	70
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	100
- Lower	20
OFA and Main Tilts (°)	+10
NOx (#/MBTU)	0.397
CO (ppm)	7

CHART II

Test Data Set No. 20

Windbox Pressure (in. H2O)	3.5
O2 (%)	4.7
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	70
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	100
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.347
CO (ppm)	10

Test Data Set No. 24

Windbox Pressure (in. H2O)	3.5
O2 (%)	4.5
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	50
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	100
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.306
CO (ppm)	26

Test Data Set No. 24 is representative of the unit conditions recommended for NOx reduction. By opening the bottom end air dampers to 70% and closing the fuel air dampers to 20%, CO level came down and the furnace conditions improved in the main burner zone, particularly at "A" and "B" fuel elevations.

NOx REDUCTION

AT 180 MW

GULF POWER COMPANY - LANSING SMITH UNIT #2

TEST DATA SET NO.

CHART III

The following is a summary of the unit conditions for Test Data Sets No. 1, No. 2, and No. 3 at 135 MW. Only three (3) sets of data were taken at this load due to limited time.

Test Data Set No. 1

Windbox Pressure (in. H2O)	2.0
O2 (%)	4.8
Auxiliary Air Dampers (% open)	25
Fuel Air Dampers (% open)	10
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	60
- Lower	20
OFA and Main Tilts (°)	+10
NOx (#/MBTU)	0.301
CO (ppm)	7

Test Data Set No. 2

Windbox Pressure (in. H2O)	2.0
O2 (%)	4.6
Auxiliary Air Dampers (% open)	25
Fuel Air Dampers (% open)	10
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	60
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.282
CO (ppm)	22

CHART III

Test Data Set No. 3

Windbox Pressure (in. H ₂ O)	1.5
O ₂ (%)	1.0
Auxiliary Air Dampers (% open)	25
Fuel Air Dampers (% open)	10
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	100
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	60
- Lower	20
OFA and Main Tilts (°)	0
NO _x (#/MBTU)	0.266
CO (ppm)	79

By lowering %O₂ by 0.5%, the CO level increases to 79 ppm. However, the NO_x level represents a maximum reduction of 57%.

NOx REDUCTION

AT 135 MW

GULF POWER COMPANY - LANSING SMITH UNIT #2

TEST DATA SET NO.

CHART IV

The following is a summary of the unit conditions for Test Data Sets No. 1, No. 4, and No. 11 at 115 MW.

Test Data Set No. 1

Windbox Pressure (in. H2O)	3.5
O2 (%)	4.8
Auxiliary Air Dampers (% open)	15
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	0
CCOFA Dampers (% open)	
- Upper	0
- Lower	15
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.417
CO (ppm)	4

Test Data Set No. 4

Windbox Pressure (in. H2O)	2.5
O2 (%)	4.8
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	30
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.352
CO (ppm)	5

CHART IV

Test Data Set No. 11

Windbox Pressure (in. H2O)	2.0
O2 (%)	4.3
Auxiliary Air Dampers (% open)	15
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	100
CCOFA Dampers (% open)	
- Upper	0
- Lower	100
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.294
CO (ppm)	51-110

NOx REDUCTION

AT 115 MW

GULF POWER COMPANY - LANSING SMITH UNIT #2

TEST DATA SET NO.

CHART V

The following is a summary of the unit conditions for Test Data Sets No. 1, No. 14, No. 26, and No. 27 at 80 MW with "C" and "D" mills in service.

Test Data Set No. 1

Windbox Pressure (in. H2O)	2.0
O2 (%)	5.3
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	40
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	0
CCOFA Dampers (% open)	
- Upper	0
- Lower	0
OFA and Main Tilts (°)	+10
NOx (#/MBTU)	0.457
CO (ppm)	9

Test Data Set No. 14

Windbox Pressure (in. H2O)	1.5
O2 (%)	6.4
Auxiliary Air Dampers (% open)	5
Fuel Air Dampers (% open)	20
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	70
- Lower	100
CCOFA Dampers (% open)	
- Upper	0
- Lower	0
OFA and Main Tilts (°)	+15
NOx (#/MBTU)	0.358
CO (ppm)	10

CHART V

Test Data Set No. 26

Windbox Pressure (in. H2O)	1.0
O2 (%)	6.4
Auxiliary Air Dampers (% open)	5
Fuel Air Dampers (% open)	20
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	100
- Lower	100
CCOFA Dampers (% open)	
- Upper	0
- Lower	0
OFA and Main Tilts (°)	+10
NOx (#/MBTU)	0.318
CO (ppm)	9

Test Data Set No. 27

Windbox Pressure (in. H2O)	1.5
O2 (%)	6.4
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	10
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	40
- Lower	100
CCOFA Dampers (% open)	
- Upper	0
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.316
CO (ppm)	10

NOx REDUCTION

AT 80 MW LOAD WITH C & D MILLS IN SERVICE
GULF POWER COMPANY - LANSING SMITH UNIT #2

TEST DATA SET NO.

CHART VI

The following is a summary of the unit conditions for Test Data Sets No. 1, No. 7, and No. 9 at 80 MW with "D" and "E" mills in service.

Test Data Set No. 1

Windbox Pressure (in. H2O)	2.0
O2 (%)	6.7
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	25
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	20
CCOFA Dampers (% open)	
- Upper	20
- Lower	0
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.489
CO (ppm)	11

Test Data Set No. 7

Windbox Pressure (in. H2O)	1.5
O2 (%)	6.0
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	10
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	0
- Lower	100
CCOFA Dampers (% open)	
- Upper	0
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.336
CO (ppm)	7

CHART VI

Test Data Set No. 9

Windbox Pressure (in. H2O)	1.0
O2 (%)	5.8
Auxiliary Air Dampers (% open)	10
Fuel Air Dampers (% open)	10
Bottom End Air Dampers (% open)	-
SOFA Dampers (% open)	
- Upper	0
- Middle	50
- Lower	100
CCOFA Dampers (% open)	
- Upper	0
- Lower	20
OFA and Main Tilts (°)	0
NOx (#/MBTU)	0.284
CO (ppm)	7

NOx REDUCTION

AT 80 MW LOAD WITH D & E MILLS IN SERVICE
GULF POWER COMPANY - LANSING SMITH UNIT #2

APPENDIX B

Diamond Electronics TV System

The Diamond Electronics color camera (Model SC - 95) was installed during Phase II in the spring of 1991. During Phase III in the fall of 1991, the camera was modified in several ways to ensure proper operation.

The lens tube supply air was designed to run at 32 SCFM, with a recommended pressure setting of 6-12 psi. A flow meter was used to determine that a pressure setting of 23 psi is needed to maintain the required flow. The camera should never be operated with a setting below this to ensure that the tip does not overheat.

Thermocouple wire was installed in the lens tube and on the bullet tip lens assembly. The purpose is to monitor and ensure the temperature does not exceed 2000. A higher temperature could result in damage to the lens tip. The flow should be increased as necessary to maintain a temperature below 2000. A recorder could be attached to monitor this reading.

An additional air supply was installed to the guide tube assembly, which is tied to the supply air to the lens tube. This supply was installed for several reasons: 1) if the camera is removed with the unit on line, this air can be turned on to prevent overheating of the guide tube, and 2) the new air supply could also be used to help cool the lens tube if the temperature exceeds 2500. This air supply should always be valved closed under normal operating conditions to prevent reduction of flow to the lens tube.

A new housing was installed with a modified jacket, allowing hot air to escape out the sides of the jacket. The housing components will remain "cooler". A thermocouple was also added to monitor housing temperature, which should be within 700 and 900. The housing airflow can be increased to reduce temperature if a problem should ever arise.

The camera can be shifted to center the fireball on the monitoring screen. All-threads and nuts were installed above and below the camera mounting plate to allow for adjustments.

9. APPENDIX B

Energy Technology Consultants Letter Report

***Effects of Coal Fineness on NO_x Emissions and Loss on Ignition
for Lansing Smith Unit 2 Testing***

January 18, 1993

Mr. Robert Hardman
SOUTHERN COMPANY SERVICES
800 Shades Creek Parkway
Birmingham, AL 35209

**SUBJECT: Effects of Coal Fineness on NOx Emissions and Loss on Ignition for Lansing
Smith Unit 2 Testing**

Dear Rob:

During the period from October 9 to November 19, 1992 the effects of mill classifier settings (coal fineness) on both NOx emissions and loss on ignition (LOI) were determined at Gulf Power Company's Lansing Smith Unit 2. The coal fineness was measured using isokinetic measurement techniques similar to those prescribed by EPA in the draft Title IV NOx rules. The result of testing during this period on Unit 2 showed that coal fineness has no significant impact on NOx emissions. Over the coal fineness range of 51 to 64 percent (approximately 66 to 83 percent at exhaustor exit) through 200 mesh, NOx decreased by less than 0.01 lb NOx/MMBtu (i.e., from 0.30 to 0.29 lb NOx/MMBtu). LOI decreased when fineness was increased from 51 (66 at exhaustor) to approximately 60 (77 at exhaustor) percent through 200 mesh. This corresponds to a fineness range of 95.5 to 98.8 percent through 50 mesh based upon isokinetic measurements. For coal fineness levels above about 60 percent (isokinetic) through 200 mesh, increasing fineness did little to reduce LOI. For coal fineness above 98 percent through 50 mesh, increasing fineness did little to reduce LOI.

Flame Refractories, Inc. (FRI) initially characterized the five mills between October 6 and 8, 1992. These initial tests were performed 1) to characterize the coal fineness produced by various classifier settings, 2) to establish the appropriate primary air-to-fuel ratios and their associated air damper settings and 3) to measure the coal flow to each mill. LOI testing was originally scheduled to immediately follow these mill tests; however, the 2-A mill required maintenance work which precluded testing at that time. Previously scheduled test efforts at

ENERGY TECHNOLOGY CONSULTANTS, INC.

One Technology Drive, Suite 1-809, Irvine, CA 92718 (714) 753-9129 Fax (714) 753-1528
51 Virginia Avenue, West Nyack, NY 10994 (914) 353-0306 Fax (914) 353-0308
12337 Jones Road, Suite 400, Houston, TX 77070 (713) 894-1091 Fax (713) 894-1094

other locations and plant maintenance requirements resulted in postponement of the LOI testing. The tests were rescheduled for the week of November 16, 1992, and were subsequently completed on November 19.

These special LOI tests on Lansing Smith Unit 2 were designed to document the effects of coal fineness on both NO_x emission rate and unburned combustibles (LOI) in the fly ash with the unit in the LNCFS Level 3 burner configuration; i.e. with both close coupled OFA (CCOFA) and separated OFA (SOFA) ports at their recommended settings for full-load. This LNCFS Level 3 configuration was thoroughly tested in the DOE Innovative Clean Coal Technology II (ICCT II) Demonstration Program during the Phase 3A test effort on Lansing Smith Unit 2. At each of three mill classifier settings, NO_x and LOI measurements were made over a range of excess O₂ levels. During the testing effort the following activities were performed by the contract participants and plant personnel:

Energy Technology Consultants, Inc. (ETEC) established the appropriate boiler operating conditions, recorded control room and burner front data readings, and coordinated the efforts of the other test participants,

Flame Refractories, Inc. (FRI) set the mill classifiers and air/fuel ratios and measured coal fineness and flow distributions to each coal pipe along with the primary air flow rates,

Southern Research Institute (SoRI) performed Method 17 ash sampling, on-site LOI determinations and subsequent laboratory Carbon/Hydrogen/Nitrogen (CHN) analysis of the ash samples,

Gulf Power Company (GPC) measured coal fineness based on the method recommended by the mill manufacturer (exhauster exit),

and Spectrum Systems operated the CEM flue gas analysis system and recorded the CEM and DAS instrumentation data.

TEST METHODS

The methods used during the LOI testing for flue gas analysis, coal fineness, and ash sampling and analysis were identical to the methods used during all of the previous Performance Test segments of the Lansing Smith Unit 2 DOE ICCT II Demonstration Program,

with only a minor difference in the procedures used to acquire the fly ash samples. These methods are explained thoroughly in the Phase I Interim Report for the Lansing Smith DOE Project (Reference 1). These methods are briefly described below.

For this special LOI testing, SoRI sampled both the A and B flue gas ducts simultaneously with two identical Method 17 probes. This was done to expedite the testing rate in order to accomplish up to four separate O₂ excursion tests in a single day, each consisting of two replicate samples from each duct for each test condition (excess oxygen and classifier setting). The samples were analyzed separately, resulting in four separate sample analysis for each test, two for each duct. The results for each test were mathematically averaged to obtain the average LOI and carbon content. LOI analyses were performed on-site by first desiccating the samples and then driving off all volatile and combustible matter at high temperature, and noting the weight differences. CHN analyses were subsequently performed in the SoRI laboratories in Birmingham.

The coal fineness and flow distributions were measured by FRI using their modified ASME sampling apparatus, which provides an approximately isokinetic sample from traverses on two diameters in each coal pipe. Fineness determinations were made using a mechanical shaker with U.S. Standard Sieves of 50 and 200 mesh. Primary air measurements were made with a type S pitot probe.

Flue gas measurements of excess oxygen (O₂), nitric oxide (NO) and carbon monoxide (CO) were made using the KVB gas sampling and analysis system. Samples were drawn from eight probes in each economizer exhaust duct and manifolded to provide a composite gas sample. Various combinations of probes were also sampled in order to provide composite samples of each duct (A & B) separately, and localized areas of each duct so as to indicate the distribution of gas species throughout the ducts. Additionally, samples were periodically drawn from the single probe located at the inlet to the stack. Measurement of approximately one hundred boiler operating parameters (steam conditions, fuel and air flow rates, etc.) were recorded from plant instrumentation using the Data Acquisition System (DAS) provided for the DOE Clean Coal II Demonstration Program. During each test, various boiler operating parameters were recorded from the control room instrumentation and the positions

of all burner and OFA dampers were obtained from observation of the indicators on the burner front.

For each LOI test series, FRI first established the appropriate mill classifier setting to provide the desired coal fineness level for each mill. FRI then measured the primary air flow to each mill and verified the desired air/fuel ratios (between 1.7 and 2.0 lb. air per lb. fuel), adjusting the primary air dampers as necessary. When the mills were properly set, ETEC established the desired excess oxygen level and the test commenced. All tests were conducted at a nominal load of 180 MWe, with all five mills in service. For each classifier setting (coal fineness) tests were conducted at three excess O₂ levels; minimum (determined by high carbon monoxide emissions), nominal (between 3.0 and 3.5 % O₂) and high (approximately 1% above nominal). For each test series (one classifier setting for each mill) on a given test day, FRI made one measurement of the coal fineness and flow in each coal pipe. LOI and flue gas composition measurements were made at each separate excess O₂ level for each classifier setting on the three days of testing. Similarly, boiler operating parameters were recorded at the beginning and end of each test, which lasted approximately 2 hours. A single coal sample was obtained for each day of testing, consisting of equal portions from each mill feeder.

TEST CONDITIONS

Table 1 summarizes the conditions and results of each test performed. During the three day test period, 11 tests were performed. Tables 2 and 3 provide information on the mill test conditions and results which were performed by FRI and the Lansing Smith Plant personnel simultaneously during evaluation of the fineness effects. Table 4 summarizes the LOI and carbon measurements and results obtained by SoRI.

During the October testing, FRI performed tests to correlate the classifier settings with the resulting coal fineness. These tests were performed with the classifiers in three different positions (1, 3 and 6). This initial evaluation resulted in curves of fineness versus setting that allowed estimation of the settings that would result in equal fineness for each mill. FRI also determined the appropriate primary damper settings to provide the desired air/fuel ratios

between 1.7 and 2.0. Subsequently, on November 16 through November 19, FRI determined that the coal fineness was slightly worse (lower) for a given classifier setting - for most mills - than that measured on during October. This comparison can be seen in Tables 2 and 3. FRI attributed this slight degradation in coal fineness to a higher coal surface moisture during the November test period. This variation in moisture as well as other coal properties is normal for this plant and for that matter would be normal for other plants using other coal sources. Nevertheless, the coal fineness was only marginally lower and the relative relationship of fineness to classifier settings was essentially unchanged.

The FRI mill testing location is different than that used by Plant personnel for their routine fineness tests. The plant personnel follow sampling procedures recommended by ABB-CE utilizing a cyclone sampler at the exhaustor exit of each coal pipe. FRI utilizes a sampling location downstream of the exhaustor. To quantify the differences between these two sampling methods, fineness tests were performed simultaneously by FRI and the plant personnel. It should be pointed out that the fineness results at the plant measurement location (exhaustor exit) are more indicative of results reported elsewhere that have been obtained on tangential boilers which also follow the ABB-CE recommended measurement location. Unfortunately, due to delays in the testing on November 17, 1992, the plant personnel were not able to obtain fineness results. Fineness results were obtained for the remaining two test days.

On November 18 and 19, Plant personnel performed coal size analyses on each mill at the identical conditions for which the FRI tests were conducted on those dates. The plant procedures are those prescribed by ABB-CE and consist of sampling along two diagonals of the rectangular duct at the outlet of the primary air inductor fan. The plant results are included in Table 3. As expected, and experienced in previous comparisons during the ICC II Performance Tests, the plant fineness results indicate higher fineness levels (i.e. higher percentages passing both 50 and 200 mesh) than the FRI results. The ABB-CE recommended sampling procedures tend to exclude a portion of the larger, heavier coal particles which are thrown by centrifugal force against the outer wall of the inductor fan scroll, while the smaller, lighter particles are conveyed along the air streams in the middle of the duct where the majority of the coal sample is obtained. The FRI procedure includes sampling

isokinetically along two diameters in each vertical coal pipe near the burners, where the coal particles of all sizes should be more uniformly distributed. Thus, the FRI procedure would tend to include all particle sizes in proportion to their true distribution in the coal/air stream. For comparison with other CE units, the plant measurements should be utilized. In this engineering evaluation to determine the impact of fineness on LOI and NO_x, the FRI results should be utilized. Figure 1 compares the FRI and plant fineness measurements (particles passing 200 mesh) which shows some differences resulting from the test location and the procedures.

Table 3 shows the measured coal flows to each mill during the three day test period. Examination of this table shows that the flows to each mill were relatively balanced for all tests. In addition, the air/fuel ratios were relatively close to the prescribed test requirement of 1.8:1. The mills and primary air flows were as close to the desired levels as was practical during these tests.

On November 17, FRI established the classifier settings to provide an average coal fineness of approximately 50 percent passing through 200 mesh for each mill. The primary air/fuel ratios were set to approximately 1.8. Tests 103-1 through 103-3 were performed at excess O₂ levels of approximately 2.3, 3.2, and 4.1 percent, respectively. All other boiler parameters were maintained as constant as possible during the testing. Boiler soot blowing and bottom ash pulling were restricted to periods between tests. The average fineness for this test day was measured by FRI to be 51.3 percent through 200 mesh or slightly above the target fineness. Fineness through 50 mesh was measured to be 95.4 percent. Plant fineness measurements were not obtained for this test day.

On November 18, FRI established an average coal fineness for each mill of approximately 58 percent through 200 mesh, and verified the primary air/fuel ratios. Tests 104-1 through 104-4 were conducted at excess O₂ levels of 2.4, 3.1, 3.9, and 3.3 percent, respectively. The average fineness for this test day was measured by FRI to be 55.8 percent or slightly below the target fineness. Fineness through 50 mesh was measured to be 97.9 percent. The fineness measurement at the exhaustor outlet was 72.3 percent through 200 mesh and 99 percent through 50 mesh.

On November 19, FRI set all mill classifiers to their maximum position (maximum fineness setting #6), to achieve an average coal fineness of about 64 percent. Tests 105-1 through 105-4 were conducted at excess O₂ levels of 2.6, 3.1, 4.2, and 3.0 percent. The average fineness for this test day was measured by FRI to be 63.7 percent or very close to the target fineness of 63 percent. The fineness through 50 mesh was measured to be 98.8 percent. Fineness measured at the exhaust exit for this test day was 83.3 percent through 200 mesh and 99.8 percent through 50 mesh.

At the conclusion of the scheduled LOI tests on November 19, the boiler load was increased to 200 Mwe to determine whether full rated load could be maintained with no apparent adverse conditions with the maximum classifier settings (best fineness). At this condition the following conditions were recorded:

- 1) mill feeder controls ranged from 60 to 74 percent of maximum setting,
- 2) mill differential pressures ranged from 6.8 to 9.0 inches H₂O,
- 3) mill amps ranged from 34 to 40,
- 4) all PA dampers were 100% open,
- 5) economizer exit excess O₂ averaged 2.8 percent,

Most of these conditions are at the upper limit of what is normally measured during day-to-day operation. Based upon the mill amp measurements the amperage changed by approximately 13 percent from the intermediate fineness setting to the maximum fineness setting. There was no measurable change in amperage from the lowest fineness setting to the intermediate setting. For this single maximum fineness test to determine the boiler load limitations, no adverse boiler operating conditions were observed over a period of approximately one hour.

TEST RESULTS

Figure 2 presents the results of the three days of tests in terms of measured NO_x versus the economizer outlet composite excess O₂ for each classifier setting. The lines are drawn representing linear least squares fit of each set of data. Despite some scatter, the data are reasonable consistent. This variation of the NO_x at various O₂ levels and classifier

settings is within the range expected for normal operation for fixed classifier settings for each mill. Figure 3 illustrates the results of the short-term Diagnostic testing on Lansing Smith Unit 2 during the Phase 3A LNCFS Level 3 effort concluded in March 1992. Figure 3 also provides a comparison with the results from the current Special LOI tests shown in Figure 2. The scatter in NO_x data for this Phase 3A test series was in the same order, if not greater than, that for the Special LOI test series. The classifier settings fixed at a constant setting during this Phase 3A test effort. In Figure 2, NO_x is dependent on excess O₂ level, as expected, but appears to be only weakly affected by the coal fineness. The variation in NO_x with fineness is hardly distinguishable from the normal variations experienced during the Phase 3A test effort and consequently it is concluded that fineness does not have significant influence on NO_x emissions within this fineness variation range. This is especially true at the low excess oxygen levels where the unit is normally operated.

The impact of fineness on LOI is illustrated by the results shown in Figure 4. The data indicate that LOI is strongly affected by coal fineness as well as excess oxygen. The lines in Figure 4 are the best least squares linear fit of the data. The results shown in Figure 4 indicate that the LOI sensitivity decreases as the fineness is increased. The sensitivity ranges from 2.67 to 1.37 percent increase in LOI for each percent decrease in excess oxygen for finenesses of 51.3 percent (~66 % at exhaust exit) to 63.6 percent (83.3 % at exhaust exit), respectively. Table 1 provides data that shows that LOI and carbon levels are nearly identical.

Speculation is that there is a trade-off between NO_x and LOI for a specific condition. Figure 5 shows the relationship between NO_x and LOI for the conditions tested during this test effort. Figure 5 shows that NO_x is a weak function of LOI for all of the classifier settings tested. This curve shows that NO_x changes by only 0.013 lb/MMBtu for each percent change in LOI. It should be pointed out that NO_x is not actually directly dependent upon the LOI level. There is no first-order dependence, however, NO_x and LOI are both dependent upon the excess oxygen level during combustion. This presentation is only to show that there is a potential trade-off between NO_x and LOI.

The impact of fineness on NOx and LOI can be most clearly illustrated by normalizing the data to three percent excess oxygen (slightly below the ABB-CE recommended level) and plotting against the three measured fineness levels for particles passing 200 mesh. Figure 6 provides the results of this normalization for NOx and LOI utilizing the equations in Figures 2 and 4. For this near normal operating condition, it is clear that NOx is not affected by fineness but LOI is dramatically affected up to point. The NOx is decreased by less than 0.01 lb/MMBtu over the fineness range of 51 to 64 percent through 200 mesh (66 to 83 % for plant measurements). This variation is much less than the normal data scatter experienced during daily operation which is due to normal daily coal variation, setting variations (mills-out-of-service, mill bias, etc.) and atmospheric conditions. The LOI appears to significantly decrease as fineness improves but the rate of improvement diminishes as the fineness approaches 64 percent (83 % at exhaust exit) through 200 mesh. As a consequence of this trend, improving fineness to 64 percent through 200 mesh would not measurably improve NOx emission characteristics but would improve LOI levels. If LOI levels were not a primary concern, improving fineness for the purpose of decreasing NOx emissions would be ineffective on this unit.

Figure 7 presents the same data as presented in Figure 6 for particles passing 50 mesh. Since the range of particles passing 50 mesh cover only a small range (three percentage points) this figure is plotted for the particles remaining on 50 mesh. The data again illustrate that NOx is not dependent upon fineness. The LOI is, however, dependent upon fineness and the data appear to suggest that below fineness levels of 97 percent through 50 mesh for the FRI measurements, LOI is significantly affected. At fineness levels above 97 percent, LOI decreases by only 1 ½ percentage points.

It is unclear at this point which measure of fineness should be used to establish the relationship between fineness and LOI. Many feel that most of the carbon resides in the particles remaining on 50 mesh. Prior to the final report, laboratory analyses will be performed to establish exactly where the carbon resides as a function of particle fineness. Until these analyses are complete, it would only be speculative to suggest that the fineness through 50 mesh is the appropriate measure.

CONCLUSIONS

Based on the initial analysis of the results of the LOI testing on Plant Smith, Unit 2, the following preliminary conclusions are drawn:

- 1) Coal fineness has a measurable effect on the LOI and carbon content of the fly ash up to a point (60 % through 200 mesh) beyond which fineness appears to have no impact.**
- 3) LOI decreases significantly as fineness approaches 97 percent through 50 mesh. At fineness levels above 97 percent, little improvement in LOI is evident.**
- 3) Setting the mill classifiers at their maximum setting to produce the finest coal sizing (64% through 200 mesh) does not appear to restrict the achievement of full load on Lansing Smith Unit 2, while firing with the LNCFS Level 3 configuration. However, it does not significantly improve LOI beyond the classifier setting for 60 percent (77 % at exhaust exit) through 200 mesh.**
- 4) Mill power requirements are increased by as much as 13 percent over the base mill fineness setting by operation at the maximum possible fineness setting.**
- 5) Coal fineness has no significant impact on NOx emissions over the fineness range of 51 to 64 percent through 200 mesh (66 to 83 % for Plant measurement). NOx varies by only 0.0007 lb/MMBtu for each percent increase in fineness.**
- 6) Coal fineness has no significant impact on NOx over the fineness range of 95.4 to 98.8 percent passing 50 mesh.**
- 7) Boiler excess O₂ level has a moderate to strong influence on NOx emissions but only a moderate effect on LOI.**
- 8) LOI measurement provides a reasonably accurate indication of incomplete combustion as represented by unburned carbon in the fly ash.**

The most significant finding from this brief study is that fineness does not affect the NOx emissions over a relatively large range of fineness levels (15 to 20 percentage points improvement in fineness through 200 mesh). The changes in NOx as a result of improved fineness were much less than the normal variation in NOx data. The finding that fineness affects LOI was expected. The LOI versus fineness curve showed that LOI would not improve significantly beyond a specific fineness setting and that operation at the maximum classifier

setting to achieve 64 percent through 200 mesh and 98.8 percent through 50 mesh offered no benefit for NOx or LOI improvement.

The results of this study will be included in the Final Report for the DOE Clean Coal Technology Demonstration on Lansing Smith Unit 2. These results have been arrived at through thorough analysis and are not expected to change significantly for the presentation in the final report.

If you have any questions, please don't hesitate to contact Lowell Smith at (714) 753-9126.

Reference 1: "180 MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal-Fired Boilers- Topical Report: Phase I: Baseline Tests", Southern Company Services, Inc., DOE Contract Number DE-FC22-90PC89653, Jan 1992.

Sincerely,

Lowell L. Smith
Vice President

Larry L. Larsen
Principle Engineer

cc:

J. D. McDonald - Gulf Power

Stratos Tavoulareas - Decision Focus

ATTACHMENTS

Tables 1 through 4

Figures 1 through 6

TABLE 1

SUMMARY OF LOI TESTING

LANSING SMITH UNIT 2 SPECIAL LOI TESTING

ALL MILLS IN SERVICE

12/30/92
04:03 PM

TEST	DATE	LOAD	C/OFA U/L	SOFA U/M/L	BURN TILT	DAS O2 dry	NOC dry ppm	NO dry lb/mmBtu	CO dry ppm	CLASSIF SETTING A/B/C/D/E	COAL FINENESS % THRU 200 MESH A/B/C/D/E	ASH LOI PCT			CARBON IN ASH PCT			COMMENTS
												A	B		A	B		
103--1	11/17/92	181	83/20	100/100/100	0	2.3	206	0.279	214	3/1/1/2/3	54/53/50/49/51	10.6	13.1		10.6	11.8		LOI AT MIN X8 O2, MINIMUM COAL FINENESS
103--2	11/17/92	181	83/20	100/100/100	0	3.2	221	0.301	22	3/1/1/2/3	54/53/50/49/51	9.7	11.9		8.7	11.6		LOI AT MED X8 O2, MINIMUM COAL FINENESS
103--3	11/17/92	180	83/20	100/100/100	0	4.1	247	0.336	13	3/1/1/2/3	54/53/50/49/51	6.3	7.9		5.9	7.3		LOI AT HIGH X8 O2, MINIMUM COAL FINENESS
104--1	11/18/92	179	83/20	100/100/100	0	2.4	202	0.275	208	4/2/3/3/4	57/57/56/52/56	7.2	8.4		6.8	6.2		LOI AT MIN X8 O2, MEDIUM COAL FINENESS
104--2	11/18/92	180	83/20	100/100/100	0	3.1	220	0.303	20	4/2/3/3/4	57/57/56/52/56	5.0	6.2		5.1	5.6		LOI AT MED X8 O2, MEDIUM COAL FINENESS
104--3	11/18/92	179	83/20	100/100/100	0	3.9	234	0.322	15	4/2/3/3/4	57/57/56/52/56	3.7	4.5		3.5	4.3		LOI AT HIGH X8 O2, MEDIUM COAL FINENESS
104--4	11/19/92	179	83/20	100/100/100	0	3.3	216	0.287	43	4/2/3/3/4	57/57/56/52/56	5.4	6.7		4.9	6.5		LOI AT MED X8 O2, MEDIUM COAL FINENESS
105--1	11/19/92	182	83/20	100/100/100	0	2.6	204	0.279	125	6/6/6/6/6	64/63/64/63/63	5.1	4.9		5.5	5.5		LOI AT MIN X8 O2, MAXIMUM COAL FINENESS
105--2	11/19/92	182	83/20	100/100/100	0	3.1	215	0.283	39	6/6/6/6/6	64/63/64/63/63	3.3	3.4		2.6	3.9		LOI AT MED X8 O2, MAXIMUM COAL FINENESS
105--3	11/19/92	181	83/20	100/100/100	0	4.2	230	0.315	13	6/6/6/6/6	64/63/64/63/63	2.5	2.2		1.9	2.3		LOI AT HIGH X8 O2, MAXIMUM COAL FINENESS
105--4	11/19/92	182	83/20	100/100/100	0	3.0	214	0.283	21	6/6/6/6/6	64/63/64/63/63	3.1	3.2		2.4	3.1		LOI AT MED X8 O2, MAXIMUM COAL FINENESS

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TABLE 2
SUMMARY OF CALIBRATION MILL TEST RESULTS
LANSING SMITH UNIT 2 SPECIAL LOI TESTING

ALL MILLS IN SERVICE

TEST NUMBER DATE	MO1 10/6/82					MO2 10/7/82					MO3 10/8/82				
	A	B	C	D	E	A	B	C	D	E	A	B	C	D	E
CLASSIFIER SETTING	1	1	1	1	1	3	3	3	3	3	6	6	6	6	6
MEASURED PA FLOW, KLB/HR	66.50	57.20	59.00	55.50	67.10	58.90	53.96	57.52	54.64	64.77	58.88	53.96	57.52	54.64	64.77
MEASURED COAL FLOW, KLB/HR	28.30	27.10	29.60	33.70	27.70	28.43	28.98	28.28	28.58	27.36	28.13	28.48	28.10	28.58	29.06
AIR/FUEL RATIO	2.36	2.02	2.07	1.84	2.30	2.07	1.86	2.03	1.91	2.37	1.97	2.00	2.08	1.94	2.20
AVERAGE COAL FINENESS															
PCT PASSING 200 MESH	48.1	54.3	53.7	51.7	54.5	56.9	63.2	60.5	59.7	55.2	70.6	74.7	73.6	72.7	67.2
PCT REMAINING ON 50 MESH	8.4	4.1	5.4	5.6	6.8	2.6	1.6	1.2	2.0	3.6	1.3	0.9	0.35	0.65	1.15
MILL OUTLET TEMP, DEG F	145	146	150	148	150	150	153	152	149	148	153	153	153	152	150
MILL DIFF PRESS, IWC	7.2	6.9	7.4	6.8	5.0	6.0	6.0	8.0	5.4	3.8	6.5	6.6	7.0	6.2	4.5
PA DAMPER POSITION, % OPEN	61	63	68	68	57	20	28	27	26	19	20	28	27	28	20
MILL AMPS	30.7	33.7	30.0	32.7	31.3	32.7	35.0	32.3	33.0	31.0	38.8	38.3	38.3	38.5	38.3
GPC FINENESS TEST RESULTS															
PCT PASSING 200 MESH	86.2	85.2	81.6	85.8	82.4	84.2	83.4	84	83.8	80	90.4	89	88.4	87.2	83.6
PCT REMAINING ON 50 MESH	2.4	2.6	4	2.2	4.6	1	0.8	0.6	0.8	2.4	0.4	0.2	0.4	0.6	1

6/20/2018 10:08:11 AM LANSING UNIT 2

TABLE 3
SUMMARY OF MILL TEST RESULTS
LANSING SMITH UNIT 2 SPECIAL LOI TESTING

ALL MILLS IN SERVICE

TEST NUMBER DATE	103 11/17/82					104 11/18/82					105 11/19/82				
	A	B	C	D	E	A	B	C	D	E	A	B	C	D	E
CLASSIFIER SETTING	3	1	1	2	3	3.6	2.3	3	3	4	6	6	6	6	6
MEASURED PA FLOW, KLB/HR	55.28	53.61	52.80	52.88	51.75	55.02	57.43	54.59	54.78	52.70	58.48	52.72	51.92	55.98	54.34
MEASURED COAL FLOW, KLB/HR	26.54	25.95	25.78	27.80	27.17	26.75	28.52	25.51	28.10	28.81	27.20	27.88	27.88	28.59	25.74
AIR/FUEL RATIO	1.90	1.80	1.82	1.69	1.73	1.88	1.98	1.83	1.91	1.78	1.91	1.78	1.77	1.97	1.84
AVERAGE COAL FINENESS PCT PASSING 200 MESH	53.6	53.3	50.4	48.5	50.5	58.8	58.8	58.2	51.8	55.9	64.4	63.2	64.3	62.6	63.4
PCT REMAINING ON 50 MESH	3.3	4.6	5.2	5.8	4.2	1.4	3.2	1.4	2.8	1.8	1.5	1.5	0.8	1.1	1.5
MILL OUTLET TEMP, DEG F	134	143	130	118	140	146	149	135	123	146	148	148	144	140	148
MILL DIFF PRESS, IWC	6.5	6.4	5.9	6.1	4.8	6.7	6.3	6.3	6.0	4.4	7.1	6.7	6.7	6.4	4.6
PA DAMPER POSITION, % OPEN	21	33	27	32	22	21	33	29	32	21	23	33	28	32	22
MILL AMPS	32.3	32.8	30.8	34.3	30.7	32.8	33.3	32.8	31.6	32.0	35.3	38.8	37.2	37.5	33.7
GPC FINENESS TEST RESULTS INDICATED CR COAL FLOW, KLB/HR	*	*	*	*	*	28	27	29	28	28	30	30	30	28	29
PCT PASSING 200 MESH	*	*	*	*	*	79.2	69.4	72.8	73.0	67.2	87.4	85.4	83.4	82.2	78.0
PCT REMAINING ON 50 MESH	*	*	*	*	*	0.4	2.0	0.8	1.0	1.0	0.2	0.0	0.2	0.2	0.8

* NO GPC PLANT TESTS CONDUCTED

* NO GPC PLANT TESTS CONDUCTED

TABLE 4
CARBON / LOI DATA SUMMARY
LANSING SMITH UNIT 2 SPECIAL LOI TESTS

TEST #	MASS LOADING GR/ACF		GAS FLOW KACFM		TEMPERATURE DEG F		EXCESS O2 PERCENT		LOI OF ASH PERCENT		CARBON IN ASH PERCENT	
	A	B	A	B	A	B	A	B	A	B	A	B
103-1-1	1.24	1.54	410	408	650	651	2.5	2.5	10.5	13.8	10.0	13.4
103-1-2	1.25	1.29	412	413	655	655	3.1	3.5	10.7	12.3	11.7	10.2
103-2-1	1.06	1.57	728*	426	655	655	3.5	3.5	10.0	12.5	9.0	13.3
103-2-2	1.33	1.44	483	425	659	659	3.5	3.5	9.4	11.3	8.3	10.4
103-3-1	0.70	0.79	484	454	671	671	3.8	3.8	8.6	8.2	5.7	7.1
103-3-2	1.19	1.21	498	460	675	675	4.3	4.3	8.0	7.6	6.1	7.5
104-1-1	1.43	1.37	393	392	650	650	2.3	2.3	7.3	8.8	7.0	8.5
104-1-2	1.31	1.35	412	424	652	652	2.8	2.8	7.0	8.3	6.7	7.8
104-2-1	1.36	1.28	407	415	661	661	3.9	3.0	5.0	6.3	5.1	5.6
104-2-2	1.16	1.12	424	411	663	663	4.0	3.2	5.1	6.0	5.0	5.7
104-3-1	1.07	1.19	473	436	671	671	4.6	4.2	3.8	4.8	3.5	4.6
104-3-2	1.33	1.14	449	435	674	674	4.3	4.3	3.6	4.2	3.4	4.0
104-4-1	1.39	1.25	416	402	661	661	3.7	3.4	5.8	7.1	5.3	7.0
104-4-2	1.18	1.20	438	417	667	667	3.8	3.6	4.9	6.2	4.6	6.0
105-1-1	1.58	1.22	407	415	661	661	3.2	2.6	4.5	5.8	4.4	5.6
105-1-2	1.34	1.09	418	404	663	663	3.2	2.9	4.3	5.5	6.6	5.4
105-2-1	1.23	1.18	433	393	675	675	3.9	3.5	2.8	3.7	2.7	3.7
105-2-2	1.62	1.14	435	378	678	678	3.3	3.3	2.9	3.8	2.9	4.0
105-3-1	1.19	1.06	472	451	689	687	4.5	3.8	2.3	2.7	2.1	2.4
105-3-2	0.99	0.98	477	480	687	689	4.3	4.1	1.8	2.5	1.8	2.3
105-4-1	1.12	1.00	443	446	683	683	3.0	3.0	2.7	3.5	2.4	3.2
105-4-2	1.11	0.93	436	454	682	682	3.5	3.0	3.1	3.3	2.3	3.0

* RUN 103-2-1A HIGHER FLOW VALUES THAN ACTUAL - NON-ISOKINETIC SAMPLE.

FIGURE 1
COMPARISON OF PLANT AND FRI FINENESS MEASUREMENTS

FIGURE 2
NOx CHARACTERISTICS
FULL-LOAD LNCFS LEVEL 3 CONFIGURATION

FIGURE 3
PHASE IIIa 180 MWe NOx CHARACTERIZATION
FULL-LOAD LNCFS LEVEL 3 CONFIGURATION

FIGURE 4
LOI CHARACTERISTICS
FULL-LOAD LNCFS LEVEL 3 CONFIGURATION

FIGURE 5
NOx/LOI TRADE-OFF CHARACTERISTICS
FULL-LOAD LNCFS LEVEL 3 CONFIGURATION

FIGURE 6
NOx AND LOI SENSITIVITIES
FULL-LOAD LNCFS LEVEL 3 CONFIGURATION OPERATING AT 3 PERCENT O2

FIGURE 7
NO_x AND LOI SENSITIVITIES
FULL-LOAD LNCFS LEVEL 3 CONFIGURATION OPERATING AT 3 PERCENT O₂

10. APPENDIX C
Excess Oxygen Levels measured
during long-term operation of LNCFS Level I

Figure B-1: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of June 3, 1992

Figure B-2: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of June 10, 1992

Figure B-3: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of June 17, 1992.

Figure B-4: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation for the Week of June 24, 1992.

Figure B-5: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of July 1, 1992.

Figure B-6: LNCFS Level 1 Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of July 8, 1992.

Figure B-7: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of July 15, 1992.

Figure B-8: LNCFS Level 1 Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of July 22, 1992.

Figure B-9: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of July 29, 1992.

Figure B-10: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of August 5, 1992.

Figure B-11: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of August 12, 1992.

Figure B-12: LNCFS Level 1 Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of August 19, 1992.

Figure B-13: LNCFS Level I Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of August 26, 1992.

11. APPENDIX D
Excess Oxygen Levels measured
during long-term operation of LNCFS Level III

Figure F-1: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of December 23, 1991

Figure F-2: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of December 30, 1991

Figure F-3: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of January 6, 1992

Figure F-4: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of January 13, 1992

Figure F-5: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of January 20, 1992

Figure F-6: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of January 27, 1992

Figure F-7: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of February 3, 1992

Figure F-8: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of February 10, 1992

Figure F-9: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of February 17, 1992

Figure F-10: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of February 24, 1992

Figure F-11: LNCFS Level III Long-Term Excess Oxygen (%) and Unit Generation (MW) for the Week of March 2, 1992

END

**DATE
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10/5/93