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NUCLA CIRCULATING ATMOSPHERIC FLUIDIZED BED DEMONSTRATION PROJECT

Final Report

October 1991

Work Performed Under Contract No. FC21-89MC25137

For
U.S. Department of Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Colorado-Ute Electric Association, Inc.
Montrose, Colorado

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Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

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October 1991

Final Technical Report

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PARTICIPANT'S
PROJECT FINAL TECHNICAL REPORT

Policy Statement

The Project Participant does hereby designate this Project Final Technical Report as the official document submission to DOE in accordance with the Cooperative Agreement.

Raymond E. Keith
Executive Vice President, Operations
Colorado-Ute Electric Association, Inc.

17 JUNE 91

Date

FOREWORD

This Final Report on Colorado-Ute Electric Association's (CUEA) Nucla Circulating Fluidized Bed (CFB) Demonstration Program covers the period from February 1987 through January 1991. Key results from the Phase I and Phase II test programs are presented. The Phase I test program began in February 1987 and was completed in June 1990. This segment was jointly sponsored by the United States Department of Energy (DOE) and the Electric Power Research Institute (EPRI). The Phase II test program commenced at the conclusion of this period and was completed in January 1991 with sole sponsorship by the DOE. The DOE Cooperative Agreement, DE-FC21-89MC25137, was awarded to CUEA for this project in August 1988.

The primary objective of this Cooperative Agreement is to conduct a cost shared clean coal technology project to demonstrate the feasibility of circulating fluidized bed combustion technology and to evaluate the economic, environmental, and operational benefits of CFB steam generators on a utility scale. At the conclusion of testing in January 1991, this objective was completed and the analysis of results is documented in this final report, three annual progress reports, and an economic evaluation report.

CUEA's original Nucla Station was built in 1959 and consisted of three identical stoker-fired units, each rated at 12.5 MWe. Due to its reduced position on the dispatch order resulting from poor station efficiency and increased maintenance costs, the decision was made in 1984 to upgrade and repower the station with a new 925,000 lb/hr circulating fluidized bed boiler and 74 MWe turbine-generator. This followed a detailed review of existing technologies, including several bubbling and circulating fluidized bed designs.

At this time, there were several small bubbling FBC's operating in the United States, but it wasn't until 1985 that the first two industrial CFB's built by Pyropower came into commercial operation. The boiler contract for Nucla was eventually awarded to Pyropower for their proposed CFB design. Utilizing twin combustion chambers, each chamber represented a 2:1 scale-up in height and plan area from their pilot plant in Karhula, Finland.

Except for the old stoker-fired units, most of the equipment from the old plant, including the turbine-generator sets, was refurbished and reused, bringing the total plant electrical output to 110 MWe. Using finalized capital cost numbers, this upgrade and life extension using CFB technology was accomplished for approximately $1021/gross kW. The project offered several advantages to CUEA including a station heat rate improvement of 15%, reduced fuel costs due to the inherent fuel flexibility of the CFB design, lower emissions required by New Source Performance Standards, and life extension 30 years beyond that of the plant's original design.

Construction of the new CFB boiler began in the spring of 1985 and was completed over a two year period. First turbine roll was initiated in May 1987 and first coal fires were achieved in June of that year. Following a start-up period which was prolonged by a two month outage from an overheat incident, acceptance tests on the design western bituminous coal were performed in October 1988, and operational tests on a high ash (~35 wt.%) and high sulfur (~1.5 wt.%) western bituminous coals were conducted the following year.

Detailed planning for a test program was initiated by EPRI in 1985. Preparation for the test program commenced in February 1987 with the arrival on site of a permanent testing staff. Through the third quarter of 1988, the Cold-Mode Shakedown Plan was implemented. This involved calibrating instruments, commissioning the data acquisition system, developing specialized software, procuring and commissioning equipment for the solids preparation laboratory and other specialized test instrumentation, developing procedures, and training test personnel. This work was largely completed by October 1988. Also during this period and through the remainder of the test program, data were collected to satisfy the requirements of on-going test plans. These included the collection of plant commercial performance statistics and information related to the operating performance of the solids feed and disposal systems, tubular air heater, baghouses, and CFB materials-related components.

In August 1988, after expressing interest in the Nucla project as part of its Clean Coal Technology Program, the U.S. Department of Energy awarded a cooperative agreement to the Colorado-Ute Electric Association as co-sponsors of the test program. This was after careful review of the overall scope and objectives of the Nucla project to verify the DOE's criteria for demonstrating clean coal technology in new and retrofit/upgrade applications.

Detailed performance testing of the Nucla CFB at specified unit operating conditions commenced in March 1989 with the completion of the Hot-Mode Test Plan. The objective of this plan was to establish the conduct for performing future boiler performance tests, including the required times to steady-state, the required number of solids samples and data points to assure results accuracy, and the required duration of each test.

From April 1988 through the completion of the Phase I test program in June 1990, a total of 45 steady-state performance tests were completed. These tests established the effects of load, excess air, primary to secondary air ratio, unit operating temperatures, coal and limestone feed configurations, and coal type and size distributions on emissions performance, and combustion and boiler efficiencies. Data were also collected from these tests to quantify heat transfer in the combustion chambers, tubular air heater effectiveness, and baghouse collection efficiency. Dynamic response and unit start-up data were collected to determine any CFB technology limitations and to optimize unit performance. Using water-cooled traversing probes, gas samples were extracted from two elevations in the freeboard region of each combustion chamber to determine the extent of solids and gas mixing.

During the Phase II test program between July 1990 and January 1991, an additional 27 steady-state performance tests were conducted. These additional tests provided new information in areas with limited test results from Phase I. Tests were also completed on Dorchester coal as part of alternate fuels testing. This coal had a much higher sulfur content (~1.5 wt.%) compared to Salt Creek coal (~0.5 wt.%) and a local Nucla coal (~0.7 wt.%) used in earlier tests. In addition, dynamic response tests were completed at rates up to 7 MWe/min.

In summary, a total of 72 steady-state performance tests were completed during the Phase I and II test programs. Of these tests, 8 were conducted on a local Nucla coal and 2 on a local Dorchester coal as part of alternate fuels testing, and 62 were completed on Salt Creek coal. This latter coal was the baseline fuel used for the test program. A total of 22 tests were performed at 50% MCR, 6 tests at 75% MCR, 2 tests at 90% MCR, and 42 tests at full load (110 MWe). Except for limestone sizing tests, which were not possible with existing plant preparation equipment, all independent process variables proposed in the original test matrix were completed.

Test results and information collected to satisfy the objectives of the original test plans are presented in this Final Report. Detailed data and support information are contained in the Annual Reports for 1987-1988, 1989, and 1990-1991. The outline for presentation in this report includes a summary of unit operations along with individual sections for each of the study plan areas. These include cold-mode shakedown and calibration, hot-mode shakedown, plant commercial performance statistics, performance testing, unit start-up (cold, warm, and hot), load following and rates of load change (dynamic response), solids and gas mixing, heat transfer, hot cyclone performance, coal and limestone preparation and handling, ash handling system performance and operating experience, tubular air heater, baghouse operation and performance, materials monitoring, reliability monitoring, and alternate fuels testing.

The program on the Nucla CFB began in February 1987 with the mobilization of permanent staff to the site. Since then, unit operations, acceptance test results, equipment reliability, performance statistics, and steady-state performance test results have been documented in three Annual Reports and this Final Report. These reports are a valuable resource for utilities, industrial users, and independent power producers planning new capacity and considering CFB technology as an option. The database and information generated during the course of the Phase I and II test programs is the most comprehensive and available resource of its kind in the CFB technology area.

This report was prepared by Combustion Systems Incorporated for the Colorado-Ute Electric Association with assistance and input from CUEA. The following individuals from CUEA are responsible for the implementation of the DOE agreement:

Raymond E. Keith, Acting Project Manager, Business Contact
Thomas J. Heller, Technical Contact
Stuart A. Bush, Senior Engineer, Project Coordinator

CUEA, Inc. would like to acknowledge the Electric Power Research Institute (EPRI) for providing use of their test hardware and software in completing this report and for their direct involvement and sponsorship of the Phase I test program, of which some data are reported herein.

Section 1

SUMMARY

This report summarizes information and test data collected during the course of the Phase I and Phase II test programs on Colorado-Ute Electric Association's Nucla CFB. Both phases of testing were completed between the period from February 1987 through January 1991. Results in sixteen topical areas are presented as individual sections in this report. In addition, Section 2 contains highlights of the unit operating history and includes an outage summary and review of equipment problems. Detailed background and supporting data for each of the topical report areas are contained in the three Annual Reports for 1987-1988, 1989, and 1990-1991.

1.1 PROJECT OVERVIEW

Colorado-Ute Electric Association began a study to evaluate options for upgrading and extending the life of its Nucla power station in 1982. Located in southwestern Colorado near the town of Nucla (see Figure 1-1), this station was commissioned in 1959 with a local bituminous coal as its design fuel for three identical stoker-fired units, each rated at 12.6 MWe. Poor station efficiency, high fuel costs, and spiraling boiler maintenance costs forced the Nucla Station into low priority in the CUEA dispatch order as early as 1981.

Among the options CUEA considered was to serve as a host utility to demonstrate Atmospheric Fluidized Bed Combustion (AFBC) technology. The anticipated environmental benefits and apparent attractive economics of a circulating AFBC led to Colorado-Ute's decision to proceed with the design and construction of a demonstration project in 1984 at the Nucla facility.

Studies produced by the company in 1983 and 1984 indicated that the new circulating AFBC boiler technology would:

- Increase plant capacity from 36 MWe net to 100 MWe net for an investment of approximately $840/kW;
- Improve the station heat rate by approximately 15%;
- Reduce fuel costs (approximately 30%) by burning the local area, lower quality coal;

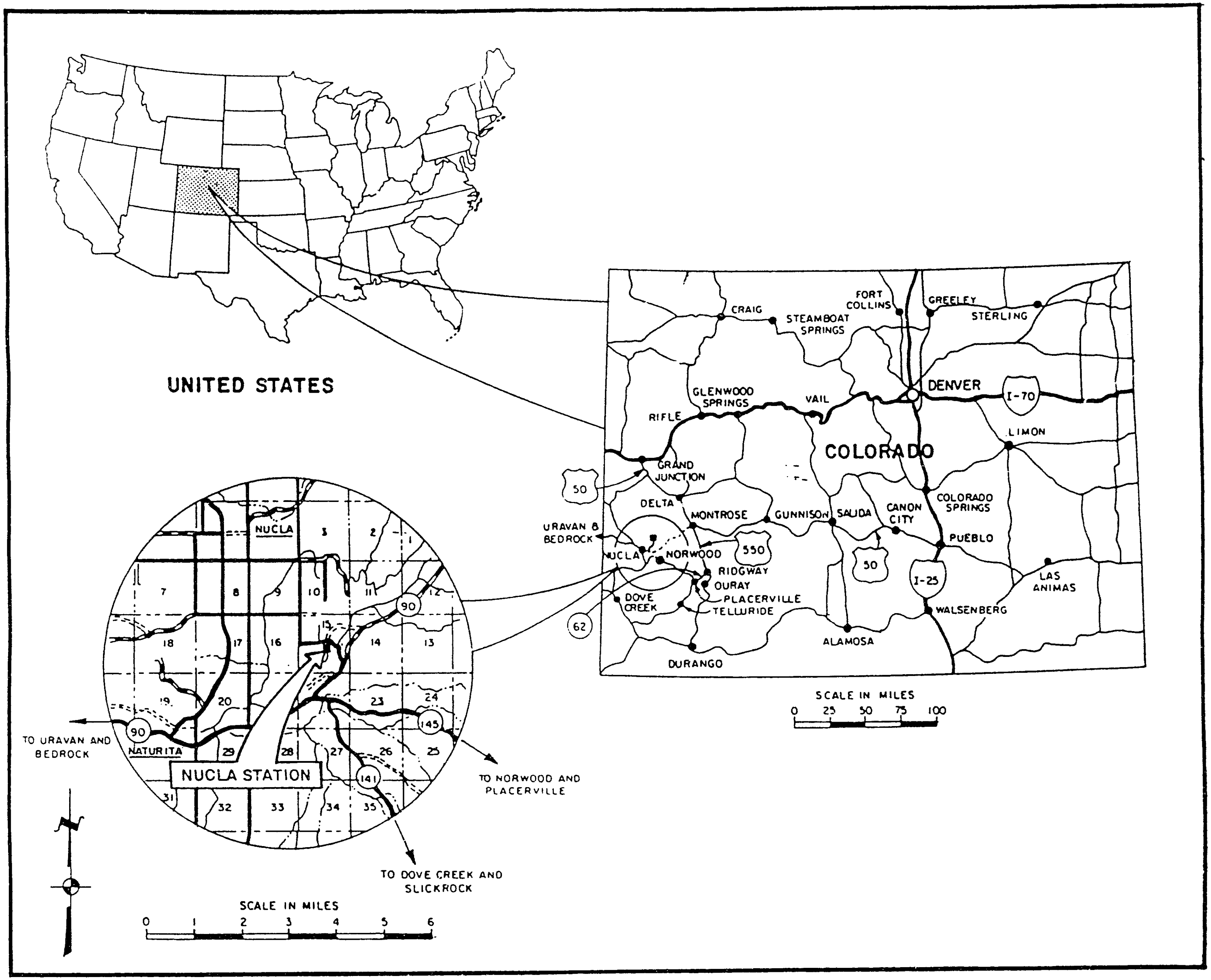


Figure 1-1. Location of CUEA's Nucla Station.

- Reduce emissions to the point where anticipated New Source Performance Standards for SO_2 and NO_x could be met; and

- Extend the plant operating life by approximately 30 years.

Many factors went into Colorado-Ute's decision to proceed with the demonstration project. Among these were two Electric Power Research Institute (EPRI)-sponsored boiler design studies conducted by Combustion Engineering/Lurgi and Pyropower Corporation (a subsidiary of Ahlstrom) in late 1983. Based on lower combined capital and life-cycle costs, a boiler contract was awarded to Pyropower for its CFB design in late 1984. Tests of the local Nucla coal and limestone at Ahlstrom's CFB pilot plant in Karhula, Finland produced results that enabled further refinement of the design of the boiler and complementary auxiliary equipment.

To reduce the potential technical risks assumed by CUEA in this first utility-sized circulating AFBC demonstration in the Unites States, CUEA negotiated the following two agreements:

- The various equipment vendors and the architect/engineer of the project agreed to postpone payments until the unit was operational.

- A two-year test program was funded by EPRI to characterize performance of the plant. EPRI assumed the risk for non-economical operation during the same period.

In 1984, the National Rural Utilities Cooperative Finance Corporation (CFC) approved a loan for the total project cost of $87 million. Regarding permits and licensing, the Rural Electrification Administration (REA) gave its approval on the basis of the borrower's environmental report in a relatively short period of time. This was possible because an environmental impact statement was not required.

The Nucla Circulating AFBC demonstration project consisted of in-place retirement of the three stoker-fired boilers and replacement with a new circulating AFBC boiler and balance-of-plant equipment to increase the station's net generating capacity from 36 MWe to 100 MWe. The original station is shown in Figure 1-2. Construction of the new boiler began in 1985. The completed boiler house superstructure is shown in Figure 1-3. The completed plant is shown in Figure 1-4. The balance-of-plant equipment included a new single automatic-extraction turbine-generator unit. The modification and refurbishment of the three existing steam turbine-generator units, addition of coal-handling equipment and a baghouse to

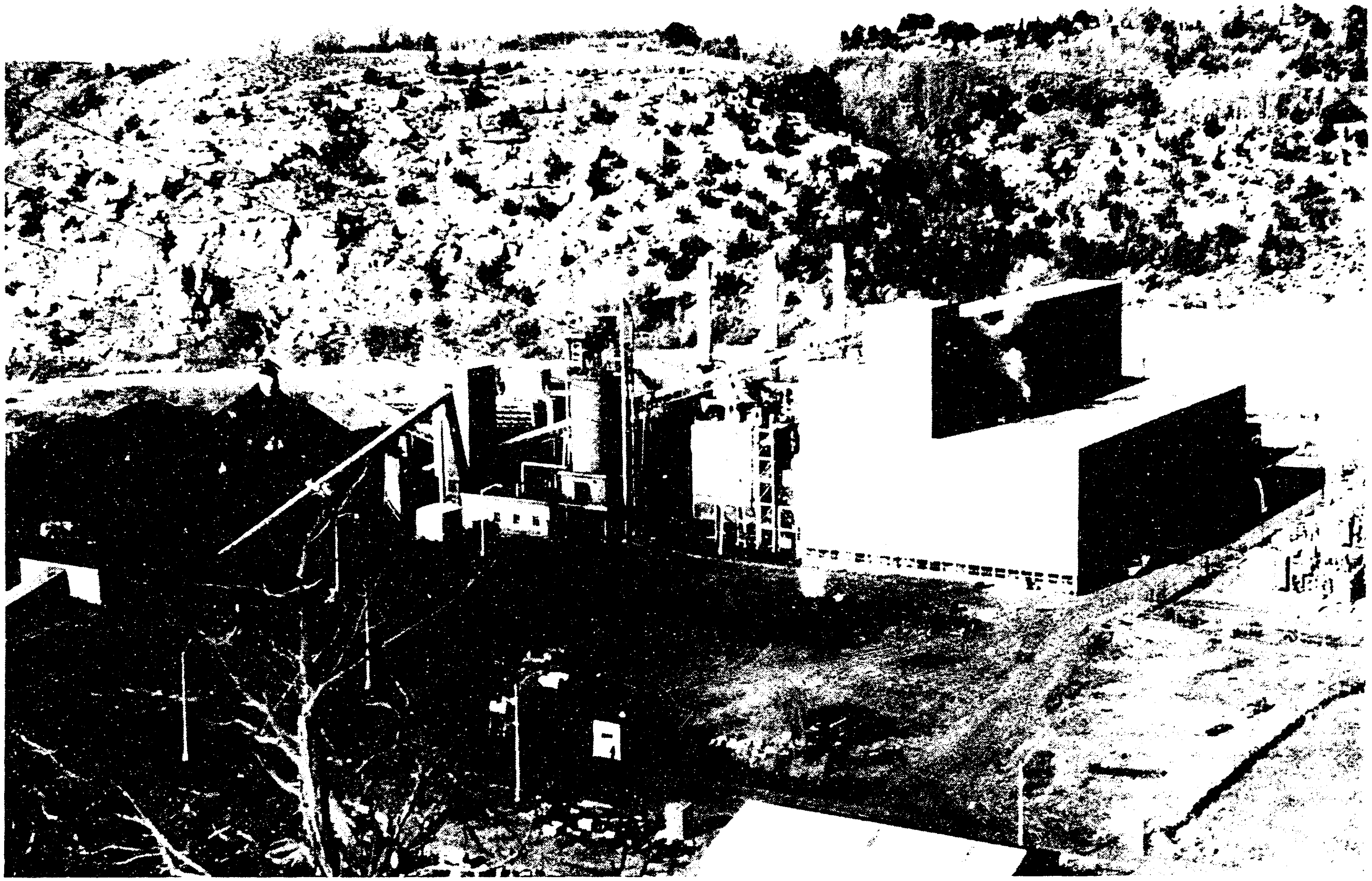


Figure 1-2. Original 36 MWe Nucla Station.

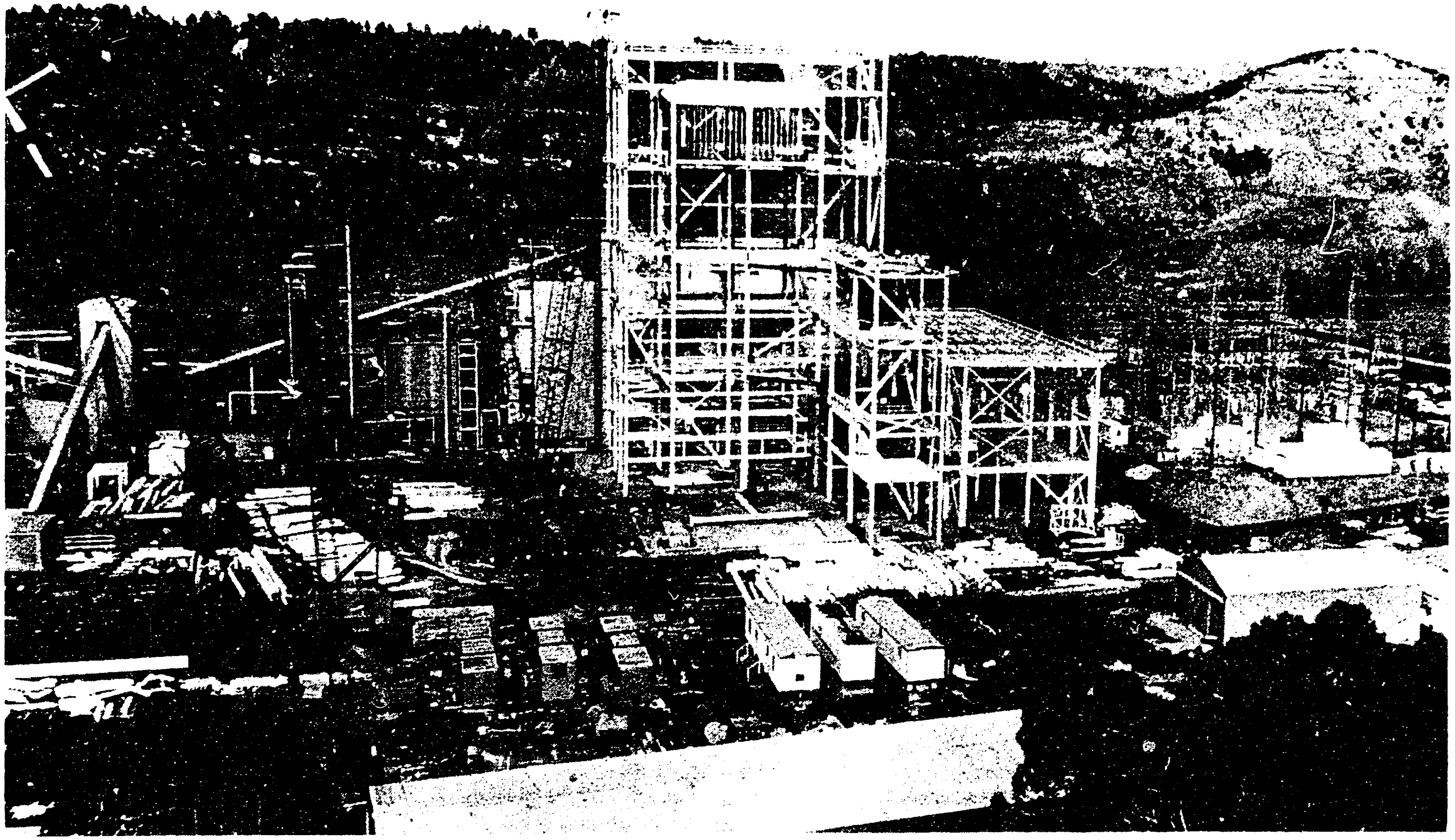


Figure 1-3. Construction of the New 110 MWe CFB Boiler.

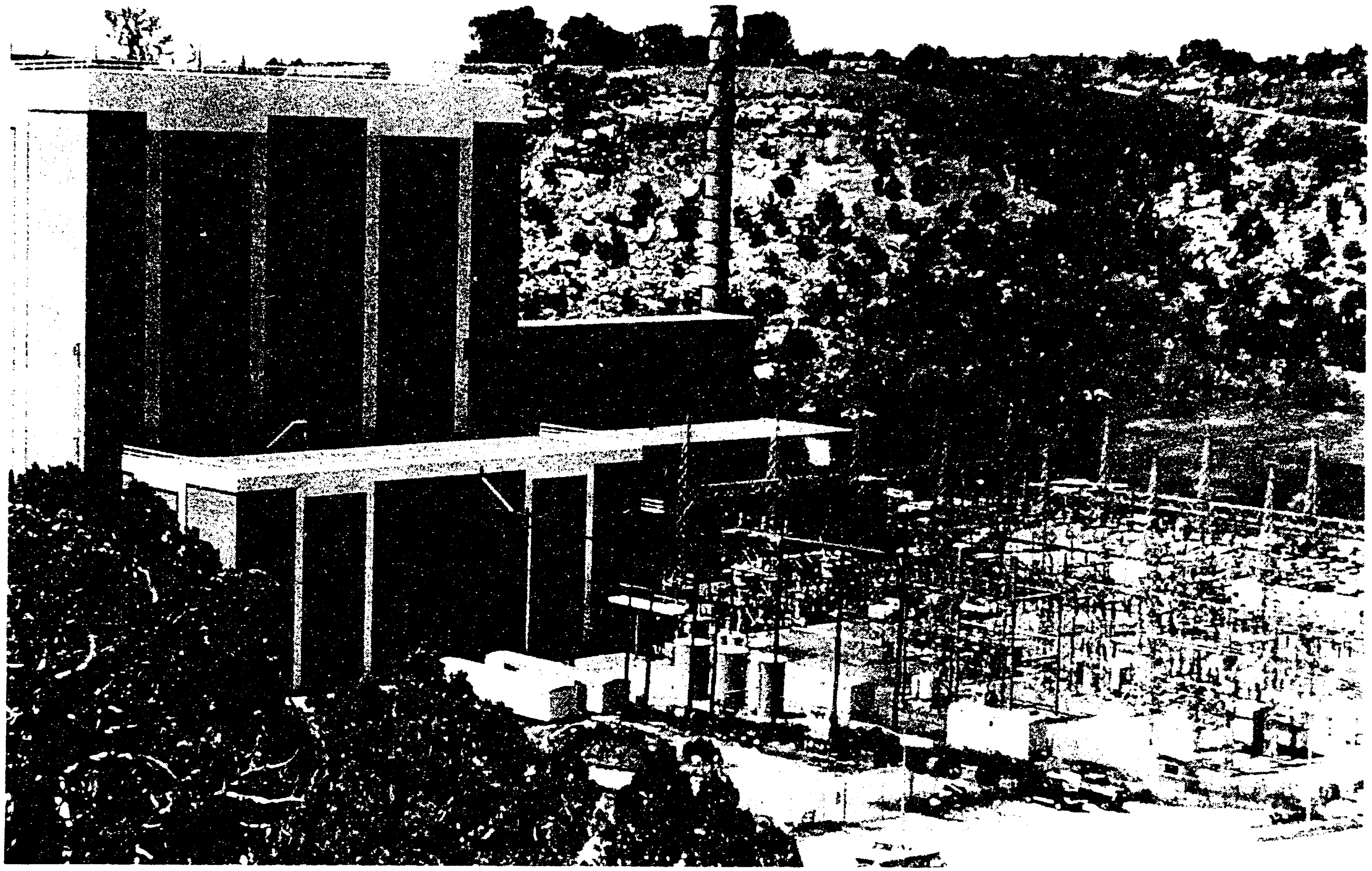


Figure 1-4. Completed 110 MWe Nucla Station With CFB Boiler.

the existing plant system, and installation of new limestone-handling equipment rounded out the project.

The circulating fluidized-bed boiler (CFB) generates 925 klb/h of steam at 1500 psig and 1005 °F, utilizing a twin combustion chamber design with a height of approximately 110 feet and a total plan area of 1055 square feet. At the time of the design, the twin chamber design allowed for a safer 2:1 scale-up from the previous plant designs.

The two combustion chambers have individual systems for fuel, air, and sorbent supply and ash removal. Because both chambers share a common steam/water circuit and steam drum, independent firing is not possible. Coal is gravity fed at two locations along the front wall and to the recycle loop seal return leg along the rear wall of each chamber. Limestone is pneumatically conveyed in the vicinity of the coal feed points along the front and rear walls and to a single location along the side wall of each chamber.

Figure 1-5 is a side view of the combustion chambers, cyclone separator, convection pass, and tubular air heater. Each combustion chamber is equipped with wrap-around, radiant superheater surface along three walls in the upper furnace section. The cyclones are approximately 23 feet in diameter and are refractory lined with a combined 1 foot layer of insulating and abrasion resistant refractory surface. The outlets of the cyclones join together and enter a common convection pass. Captured solids are recycled to the combustion chambers through loop seals located near the bottom of each chamber. Flue gas flows through a common convection pass, tubular air heater, shake/deflate type baghouses (three from the original stoker-fired units and a fourth new baghouse), and induced draft fan to the stack.

Extensive use of existing equipment was made during the plant modifications. This includes the coal receiving, preparation and storage equipment, baghouses, feed water systems, condensers, and the three 12.5 MWe turbine generators. Extraction steam from a new 74 MWe turbine is used to supply the existing 610 psig turbines. The three old stoker units, including their feed and draft systems and high pressure feed water heaters, represent the major equipment items retired for the upgrade.

The plant was designed to burn a locally mined western bituminous coal, Peabody, with a high variability ash, heating value, moisture, and sulfur content. Table 1-1 summarizes the properties of this coal and the ranges of values burned. The coal supply was changed in the summer of 1989 to take advantage of a more economical fuel supply. The new coal, Salt Creek, is also a western bituminous coal, but is more homogeneous and has less ash than the design coal. The properties of Salt Creek coal are also listed in Table 1-

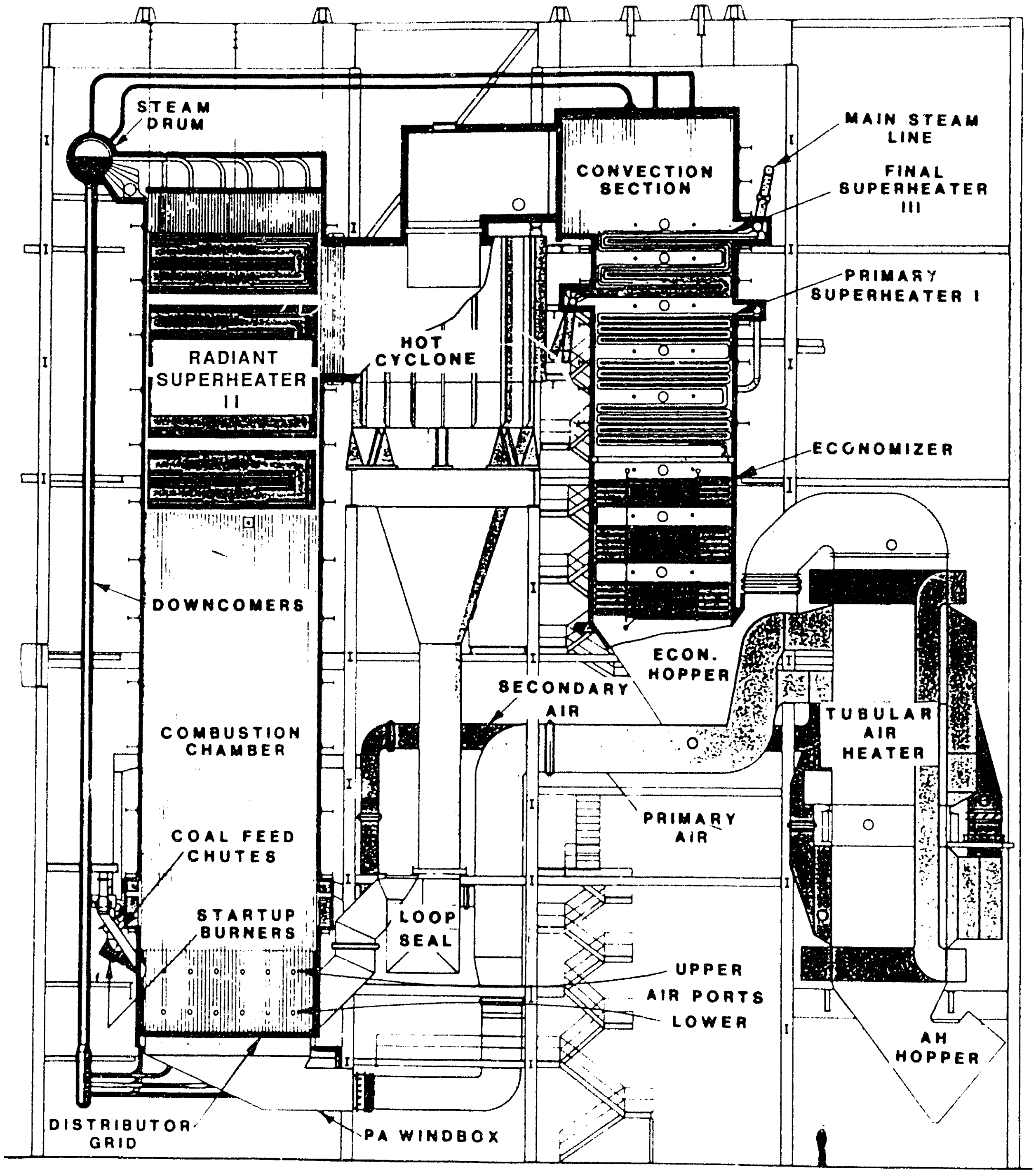


Figure 1-5. Side View of 110 MWe Nucla CFB Boiler.
(Source: Pyropower Corporation)

1. The state emission regulations are compatible with the New Source Performance Standards for this size unit and are shown in Table 1-2. Supplemental NO_x control schemes are not required to meet these standards. SO_2 emissions are controlled with limestone addition to the lower region of the combustion chambers.

Table 1-1. Properties of Peabody and Salt Creek Coals

	Peabody	Salt Creek
Heating Value, BTU/lb	7,490-11,840	10,460
Sulfur, wt %	0.51 - 2.75	0.44
Ash, wt %	9.8 - 42.8	14.6
Moisture, wt %	4.1 - 14.9	10.0
Fixed Carbon, wt % (acceptance test value)	43.5	43.4
Volatiles, wt % (acceptance test value)	28.4	32.3

Table 1-2. Nucla Plant Emission Requirements

Particulates	0.03 lb/MBtu
NO_x	0.5 lb/MBtu
SO_2	0.4 lb/MBtu
CO	No Requirements

Because of the potential offered by use and commercialization of circulating AFBC technology to the electric power industry, Colorado-Ute Electric Association, Inc. and the Electric Power Research Institute initiated a program to study the Nucla CFB and its operating characteristics. This project is being conducted in conjunction with two other EPRI-sponsored AFBC demonstration projects: Northern States Power Company's bubbling AFBC 130 MWe Black Dog demonstration and Tennessee Valley Authority's bubbling AFBC 160 MWe Shawnee demonstration. For the Nucla demonstration, EPRI installed special hardware for the program including instrumentation, data acquisition and processing equipment, and facilities necessary to conduct a two-year test program. The U. S. Department of Energy likewise participated in the project through the Clean Coal Technology Program - Phase I. The Cooperative Agreement, DE-FC21-89MC25137, was administered by DOE's Morgantown Energy Technology Center located in Morgantown, West Virginia.

1.2 UNIT OPERATING STATISTICS

In Section 3, monthly unit operating statistics are presented since July 1988, at which time the test program's data acquisition system and software became fully operational. From this point through January 1991, the plant operated with an average availability of 58.3% and a capacity factor of 39.6%. Since first coal fires in June 1987, the plant has accumulated 15,700 operational hours on coal. The average on-line net plant heat rate since September 1988 has been 12,099 Btu/kWh. A comparison of these values with averages compiled by the North American Reliability Council Generating Availability Data System (NERC GADS) for non-CFB coal-fired units in the 100-199 MWe size range between 1984 and 1988 indicates average availability and capacity factors of 83.9% and 49.7%, respectively.

Although many of the operating problems which contributed to these statistics at Nucla can be attributed to "first-generation" CFB equipment component design, the total quantity and duration of outages were often affected by factors related to the demonstration nature of this project. For example, periodic boiler inspections were made as part of the test program's materials monitoring plan (Section 16), which initiated or extended unit outages. The lack of power demand during certain periods also contributed to the latter. In addition, capacity factors were affected by extensive part-load testing.

The largest CFB-related contributor to plant outage time has been from secondary superheater tube failures. Although this problem has been addressed temporarily through an operational change, it contributed to over 70% of the outage time between October 1989 and January 1991. Other CFB-related outages over the course of the test program have been required for refractory repairs, primary air fan upgrades, bubble cap replacement, bottom ash disposal system upgrade, and limestone feed system modifications. Most of these problems have been addressed, and unit operating availabilities have shown marked improvements through the fourth quarter of 1990.

1.3 RELIABILITY ISSUES

In order to demonstrate long-term reliability, operability, and reduced maintenance costs of the Nucla CFB, several problems remain to be addressed at the conclusion of the four year test program. These are summarized below and are discussed in greater detail in this report.

- Refractory condition in the lower combustion chambers, cyclone "bull nose" and impact areas, the cyclone conical sections and downcomers, and certain regions in the loop seals.

- Structural integrity of the cyclone vortex finders.

- Air distributor bubble cap erosion and retention.

- Adequate means for the collection and removal of backsifted bed material in the windboxes.

- Water-wall tube erosion at the lower combustion chamber refractory interface and on sections of the water walls that were warped during the 1987 overheat incident.

- Secondary superheater erosion on out-of-plane tubes and on the back side of panels in regions conducive to solids flow channeling.

- Long-term overheat of secondary superheater tubes. This has been addressed temporarily through an operational change resulting in an increase in plant heat rate.

- Temperature matching between combustion chambers in order to optimize limestone consumption for SO_2 control.

1.4 COLD- AND HOT-MODE SHAKEDOWN

Results from these two topical areas are discussed in Sections 4 and 5 of this report. Both cold- and hot-mode shakedown testing are the first activities to be completed in the conduct of a test program and form the foundation for all future testing. Cold-mode calibration and preparation covers the basic scope and design of the test program and involves calibrating instruments, commissioning the data acquisition system, developing specialized software, procuring and commissioning equipment for the solids preparation laboratory and other specialized test instrumentation, developing detailed test plans and procedures, and training test personnel.

Hot-mode testing follows and is used to establish required times to steady-state, test duration, and data quantities necessary to assure the proper uncertainty in test results. Based on this testing, a 24 to 48 hour period was established as the time required for the unit to reach steady-state following changes to unit operating conditions such as load and Ca/S ratio. A total of 5 coal, 2 limestone, 2 bottom ash, and 6 fly ash samples were required to achieve the proper uncertainty levels in calculated results. This established a test duration for performance testing of 6 hours, based on the manpower availability for solids sampling. All other data points are collected on the plant's digital control system at a frequency much higher than necessary for assuring proper results uncertainties.

1.5 UNIT PERFORMANCE TESTING

Following the completion of cold- and hot-mode testing, a total of 72 steady-state performance tests were conducted between April 1989 and January 1991 as part of the Phase I and II test programs. Unit performance testing, discussed in Section 6, formed the bulk of the overall test program effort, including manpower resources and expenses, and also generated the most substantial database compared to that acquired in other topical report areas. A total of 22 tests at 50% MCR, 6 tests at 75% MCR, 2 tests at 90% MCR, and 42 tests at 100% MCR were completed. Operating variables that were tested include load, operating temperature, excess air, primary to secondary air ratio, Ca/S molar ratio, coal and limestone feed distribution, and coal type and sizing.

Performance testing was complicated by the inability to control operating temperatures within set ranges during series of tests. This made parametric testing, in which one variable is changed while all other variables are fixed, difficult to implement. Unit operating temperatures were found to increase with unit load from approximately 1450-1550 °F at half load to over 1700 °F at full load. For tests conducted at the same load under nearly identical operating conditions, differences in operating temperatures were related to the solids distribution in the freeboard region of the combustors. Adjustments to ash cooler classifying velocities, total bed inventory, and primary to secondary air ratio did not significantly affect the solids distribution or operating temperatures. Rather, the ash content in the input coal stream, which is an uncontrollable parameter, had the greatest impact on solids density profiles and combustor operating temperatures.

Another difficulty with performance testing, particularly at full load, was the existence of a temperature differential between combustors which, at times, exceeded 100 °F at full load. Operating temperatures are higher on combustion chamber B due to poorer distribution of solids in the freeboard region when compared to chamber A. This results in lower heat transfer rates to the water walls. The cause for the denser bed at the bottom of chamber B is not clearly understood. Gross physical differences between the combustion paths include the warped water walls in combustor A (which may improve internal circulation) and cyclone orientation. The vortex finder on cyclone B was straightened in March 1990, but this did not improve solids collection efficiencies or eliminate the temperature differential.

As a result, tests with a large temperature differential were conducted as "split" combustor tests in which emissions performance from each combustor is analyzed separately. Because fly ash samples are common to both combustion chambers and cannot be separated, combustion and boiler efficiency calculations are based on average operating conditions, i.e., combustor temperatures from both chambers. This method of testing provides a simultaneous comparison of the effects of process temperature on emissions performance, and yields two data sets for each test.

1.6 EMISSIONS PERFORMANCE

Emissions data are presented in this report for all steady-state performance tests. Results indicate strong correlations of absolute CO, SO_2, and NO_x emission levels with combustor operating temperatures. Although compliance is maintained within NSPS for each emission type, a penalty on limestone feed requirements for sulfur retention is realized at the higher operating temperatures. For temperatures below 1620 °F, 70% retention is achieved with a Ca/S ratio of 1.5. 95% retention is achieved with a Ca/S ratio of 4.0. At combustor operating temperatures around 1700 °F, a Ca/S ratio of greater than 5.0 is required to maintain 70% sulfur retention. In addition to the costs of higher limestone consumption, solids waste quantities also increase along with associated disposal costs. Increased limestone feed, with all other operating conditions held constant, also resulted in an increase in NO_x emissions. Despite this increase, NO_x emissions remained within compliance levels at Nucla for all performance test configurations.

During performance tests, emissions were monitored for different coal and limestone feed distributions, primary to secondary air ratios, and excess air ratios. Uniform coal distribution between the front and rear walls of each combustion chamber gave the best sulfur capture results, particularly at full load and at high operating temperatures. This suggests that additional coal feed points or enhanced mixing in the lower chambers may improve performance. Only a limited number of limestone feed configuration tests were conducted because of mechanical limitations with the feed equipment. Tests with limestone feed points out of service did not indicate any significant change in sulfur capture performance compared to baseline tests.

The effect of excess air on emissions performance is difficult to interpret since increased excess air results in lower combustor operating temperatures at a given load. This generally results in lower NO_x emissions and Ca/S ratio requirements, and higher CO emissions. Excess air below 10% resulted in increases in CO emissions due to incomplete combustion. These tests were restricted at full load due to combustion air fan capacity limitations. Primary to secondary air ratio had for the spacing between locations used at Nucla, no discernable effect on emissions. This is a significant conclusion and should be considered in the design of the next generation of CFB boilers.

The ability to significantly change the coal size distribution was restricted due to limitations with the coal preparation and handling equipment. Tests conducted did not indicate a substantial change in operating performance over the range of sizes that were affected. Limestone sizing tests were not possible with the as-installed preparation equipment.

As part of alternate fuels testing, 8 tests were performed on a local Nucla coal with a similar sulfur content compared to the baseline Salt Creek coal (0.5 wt. %), but with a higher variability in ash content. Two tests were also performed on a Dorchester coal that had higher sulfur content (1.53 wt. %) and ash content (20 wt. %) than Salt Creek coal. Changes in unit performance were subtle with the Nucla coal and differences are discussed in Section 18. With the higher sulfur Dorchester coal, results favorably indicated lower Ca/S ratio requirements for comparable sulfur retentions.

Freeboard gas sampling traverses were conducted at the 40' and 80' ports located on the outside wall of combustion chamber B as part of the solids and gas mixing test plan discussed in Section 9. Two water-cooled probes allow combustor gas samples to be collected from the outside wall to the centerline of the combustion chamber at each elevation. Data were collected at full and half load for various coal and limestone feed configurations. Although data suggest poor lateral mixing between elevations, firm conclusions regarding combustion and emissions performance cannot be made due to the limited number of traverse points. Additional testing to obtain temperature and solids density profiles, along with the use of tracer gases, may provide additional, useful information. Existing data should be reviewed by CFB combustion and particle experts and incorporated into their models.

1.7 COMBUSTION AND BOILER EFFICIENCY

For all performance tests, combustion efficiency ranged between 96.9% and 98.9%. No significant difference between Salt Creek and the local Nucla coals was apparent and no single process parameter (e.g., boiler load, bed temperature, excess air, primary to secondary air ratio, coal feed configuration, etc.) appeared to have a direct impact on the results.

Boiler efficiencies (by the ASME losses method) varied between 85.6 % and 88.6 % for the tests completed. Peabody coal resulted in the highest efficiencies due to the lowest losses from moisture in the fuel. Dorchester coal produced the lowest boiler efficiencies due to a higher moisture content in the fuel and a larger sorbent calcination loss. The latter was the result of the higher sulfur content of the Dorchester coal. Net plant heat rate decreased with increasing boiler load from 12,400 Btu/NkWh at 50% MCR to 11,600 Btu/NkWh at full load. The lowest value achieved during a full load steady-state test was 10,980 Btu/NkWh. These values are affected by the absence of reheat, the presence of the three older 12.5 MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing. Since 1988, the Nucla CFB has been restarted almost 175 times following various intervals of unit outage.

1.8 START-UP AND DYNAMIC TEST RESULTS

Data from cold, warm, and hot restarts are presented in Section 7 of this report. In general, under optimum circumstances, the unit can achieve full load from a cold condition in 10 to 12 hours. The first five hours are required to achieve 100 °F of superheat at approximately 600 psig prior to turbine roll. Drum-metal temperature limitations of 100 °F/h are a restriction during the first two hours of gas firing, but decrease to less than 75 °F/h for the remainder of start-up. Refractory temperature increases generally do not exceed 60 °F/h, which is well under the 100 °F/h limitation suggested by the manufacturer. Between 2 and 5 hours, the firing rate on propane is established to limit pressure part metal temperature increases to less than 100 °F/h and to minimize drum-level fluctuations caused by swell from the increase in the specific volume. This is followed by a 3-hour turbine soak, a 1-hour period at minimum load on propane at 5 MWe to stabilize, and finally, the initiation of coal flow and increase in power to 45 MWe for stabilization.

Except for the time required to bring each of the three 12.5 MWe turbines on line, the remainder of time to full load is dictated by the boiler/turbine ramp rate. The latter has been tested successfully at 5 MWe/min without any process or control limitations. Additional testing at 7 MWe/min during the Phase II test program identified drum-level control as a limitation. This may be correctable with adjustments to the steam flow rate calculation under certain conditions. Calculated steam flow rate is used for three-element drum level control. Dynamic test results are discussed in greater detail in Section 8.

Warm restarts (off-line for less than 12 hours) generally require 2 to 4 hours to achieve the minimum safe operating load on coal of 45 MWe. This interval is dictated by the time required to reestablish superheat temperatures and/or minimum bed temperatures of 950 °F necessary for the initiation of coal feed. The former condition is determined by how quickly the turbine is brought off-line following a controlled shutdown or unit trip. The latter is controlled by the time required to remove fans from service. Hot restarts (unit off-line for less than six hours) typically follow the same scenario although, in some cases, the turbine can remain on-line and gas and/or coal feed can be reestablished immediately.

1.9 MATERIALS MONITORING

A materials monitoring report is included in Section 16 and highlights results from boiler inspections made during the Phase I and II test programs. Current areas of concern to the plant include: 1) bubble cap retention and erosion, 2) lower combustor refractory condition, particularly around the recycle port entrances to the combustor and at the water-wall interface, 3) water-wall erosion at the refractory interface, especially along the front wall and front-side walls, 4) water-wall erosion in areas where combustor water walls are warped from the overheat incident, which is most pronounced along the front wall of combustion chamber A approximately 22' above the distributor plate, 5) erosion and long term overheat damage to the radiant, secondary superheater tubes in isolated, localized areas, 6) cyclone vortex finder warpage, 7) upper cyclone refractory condition around the "bull nose", target area, and inlet spiral shelf, 8) spalling of large refractory pieces in the conical sections of each cyclone, 9) generally poor condition of the cyclone downcomer and sections of the loop seals. These areas have been photographed and are documented in this and the Annual Reports.

1.10 OTHER TESTING

Sections are presented in this report on testing and operational performance of the baghouse, air heater, and solids feed and disposal systems. Baghouse efficiency and pressure drop (Section 15) were primary concerns during the design stage of the Nucla CFB because of differences between CFB fly ash and that from a pulverized unit. However, the system has operated reliably with a collection efficiency of 99.96% and full-load pressure drop between 5.0 and 6.5 in. wg. Bag failure rate has been 7.8% of total since initial start-up, but has been reduced considerably after the first year of operation by decreasing the deflation pressure to less than 0.5 in. wg. This pressure initially was set much higher than design. Results of Mullen-Burst tests on selected bags after approximately 10,000 hours of service do not indicate significant deterioration in bag strength compared to similar measurements made after 5000 hours of service.

The air heater (Section 14) also has operated reliably with an effectiveness ranging from 70% to 76% across the load range. Leakage of primary air across the tube sheet into the secondary air pass at low loads remains a performance consideration. Solids feed and disposal systems, discussed in Sections 12 and 13, operate with improved reliability following upgrades and modifications to the limestone feed and bottom ash disposal systems prior to the operational acceptance tests on high ash and high sulfur coals. The limestone feed system continues to be a source of relatively high fugitive dust emissions within the boiler room. Erosion in the fly ash disposal transport lines, cyclone separator, and lock hopper valves, along with high pressure drop across the pulsed-jet baghouse separation system, continue to be areas of high maintenance.

Heat transfer correlations to the combustor water walls are presented in Section 10 from data gathered using chordal thermocouples located on the rear wall of combustion chamber B at 10 ft. elevations. Correlations are made between heat transfer and solids density profiles in the combustors. A correlation is also developed which predicts combustor operating temperatures for the local Nucla and Salt Creek coals.

Cyclone performance, particularly collection efficiency and recycle rates, are difficult measurements on a CFB due to high temperatures and solids loadings and the presence of a thick outer shell and refractory layer. Using size distribution data from fly ash collected downstream of the cyclones, the collection performance has been estimated using two classical cyclone models. These results are presented in Section 11 of this report.

1.11 SUMMARY

Although unit start-up problems delayed performance testing by over a year, most of these problems have been addressed during the period covering the Phase I and II test programs. The list of equipment responsible for these delays includes the primary air fan, bottom ash removal system, limestone feeders, refractory components, windbox ash removal system, and balance of plant equipment such as boiler feed pumps, circulating water pumps, fan controls, generator exciter, etc. Other problems that may not have been readily apparent during the first two years of operation include superheater erosion and long term overheat, bubble cap erosion in the region in front of the recycle return, continued refractory degradation, and water-wall erosion in warpage areas left over from the overheat incident. These areas will require capital expenditure in the future in order to improve unit reliability and availability.

Steady-state performance testing has been completed in all areas of the original performance test matrix outlined in the Detailed Test Plan, except for coal and limestone sizing tests. Coal size tests were attempted by adjusting the final coal crushers, but the results indicate only minor changes in size distribution. Limestone sizing tests were also attempted by adjusting the classifier bar and pulverizer speeds on the air-swept pulverizer, but the results were similar.

Performance testing on the Nucla CFB has been complicated by the inability to control combustor operating temperatures and by differences in temperatures between combustion chambers. This makes parametric testing difficult since more than one variable often changes during a test sequence. The test program has accommodated this to a degree by running tests on individual combustion chambers, thereby satisfying the original objectives of the test program. Efforts should continue towards understanding and controlling combustor operating temperatures at Nucla since it has such a significant impact on emissions performance. Three areas that may benefit in this regard include: 1) measurements of combustor solids density profiles through the 40' and 80' traverse ports, 2) pulsed-tracer gas injection into the windbox with subsequent measurement through the traverse ports to identify mixing, and 3) measurement of cyclone collection efficiency and recycle rate versus unit load.

Section 2

PLANT OPERATING HISTORY

2.1 OVERVIEW

During the period from July 1988 through January 1991, the plant operated with an average availability of 58.3% and a capacity factor of 39.6%. Since initial coal fires in June 1987, the cumulative time on coal is 15,700 hours. A breakdown of the coal hours by month since this period is shown in Figure 2-1. This section also contains a monthly summary of operations at the Nucla plant from May 1985 through January 1991. Following the operations summary is Figure 2-2, which shows a breakdown of outage hours to date, and Figure 2-3, which shows a comparison of outage and in-service hours. These are followed by Table 2-1, an outage summary report which contains the date, outage duration, and summary description of the outage cause. Section 2.3 is a description of boiler acceptance test results, and Section 2.4 is a description of equipment and operating problems.

2.2 OPERATIONS AND OUTAGE SUMMARY

May 15, 1985
Started construction

October 23, 1986
Boiler hydrostatic test.

March 29, 1987
Boil-out.

April 2, 1987
Steam blows (66 total blows).

May 28, 1987
Steam to turbine with sand bed.
Completed vibration and trip logic checkout of 74 MWe (No. 4) turbine/generator.

May 29, 1987
Synchronized No. 4 generator and on-line at 7 MWe firing propane.

June 10, 1987
First coal fires in boiler supported with propane start-up burners.

Figure 2-1. Monthly Coal Hours for the Nucla CFB

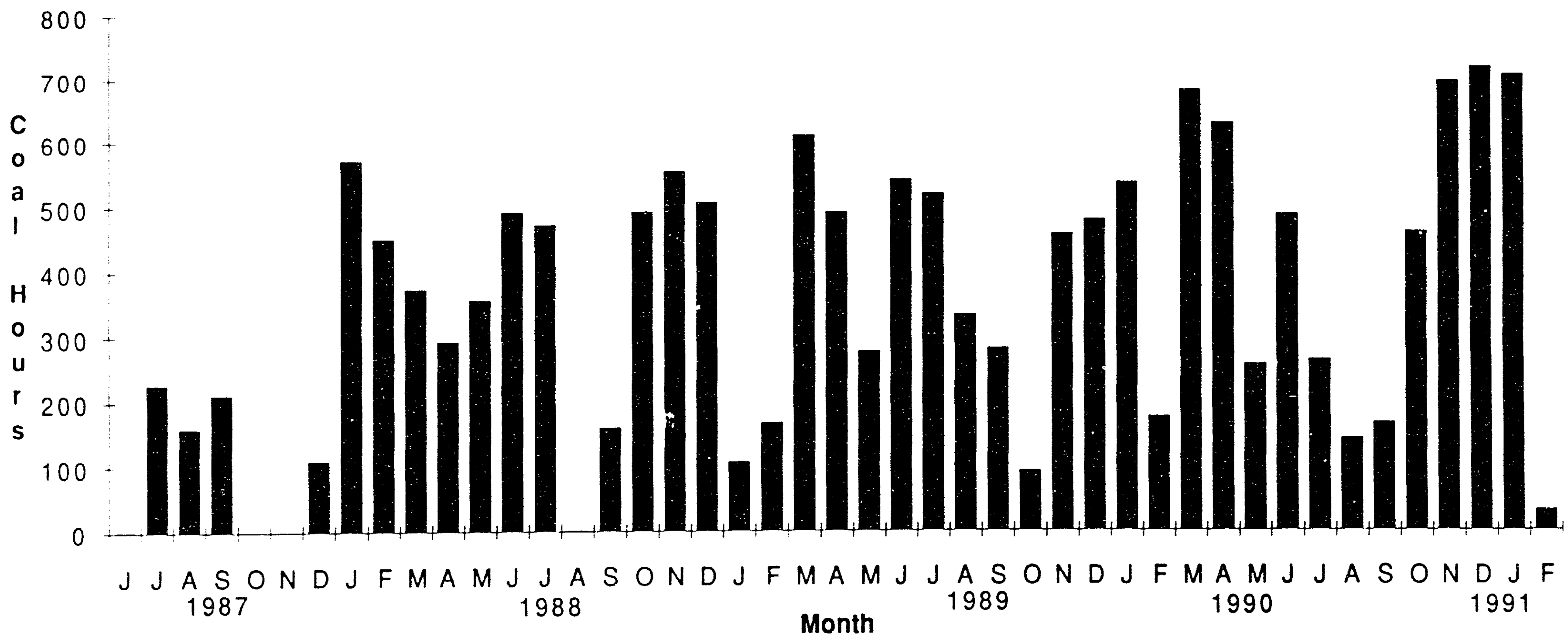


Figure 2-2. Breakdown of Outage Hours.

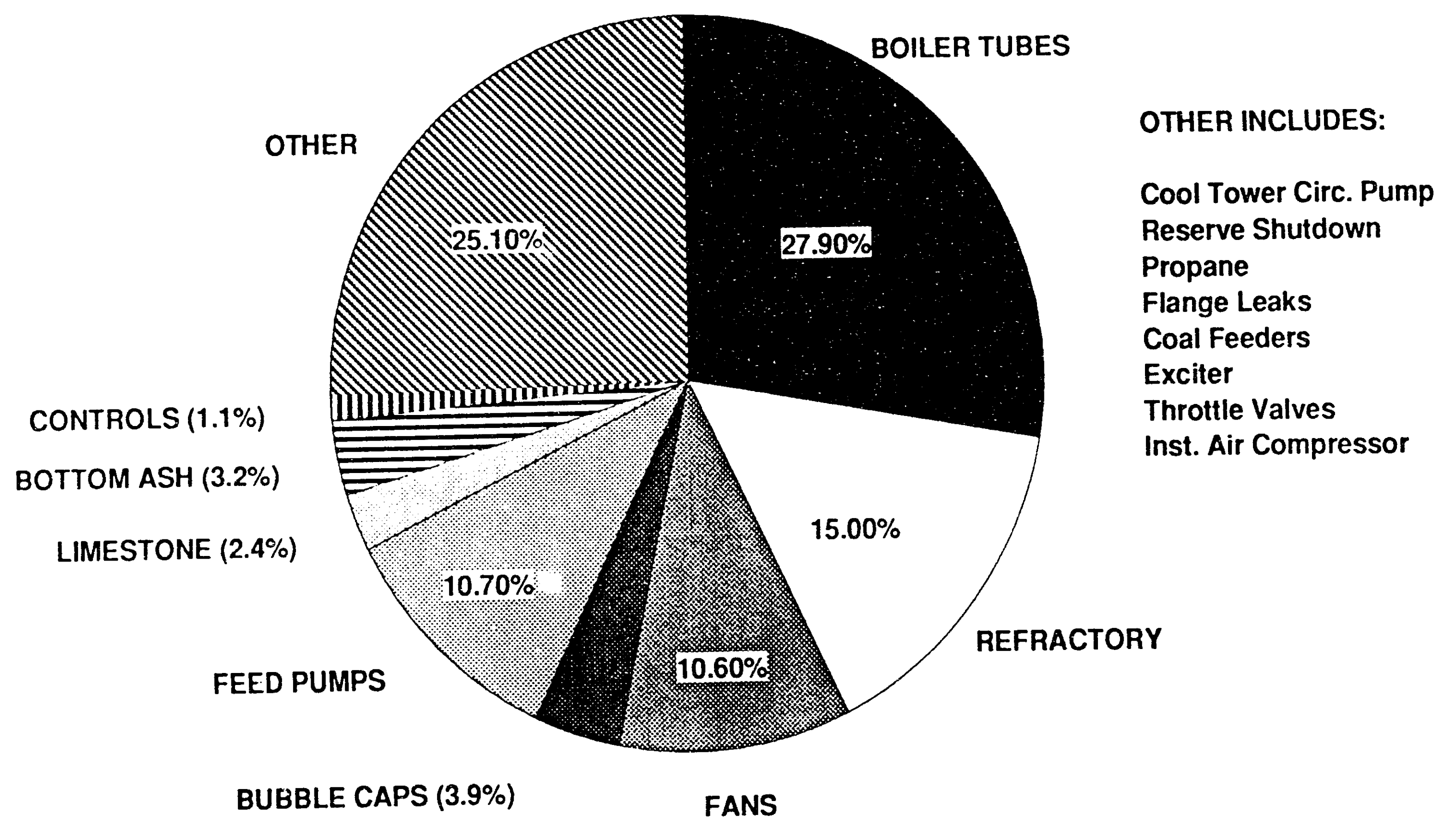


Figure 2-3. Comparison of Outage and In-Service Operation from Completion of Acceptance Tests (October 1988 Through January 1991).

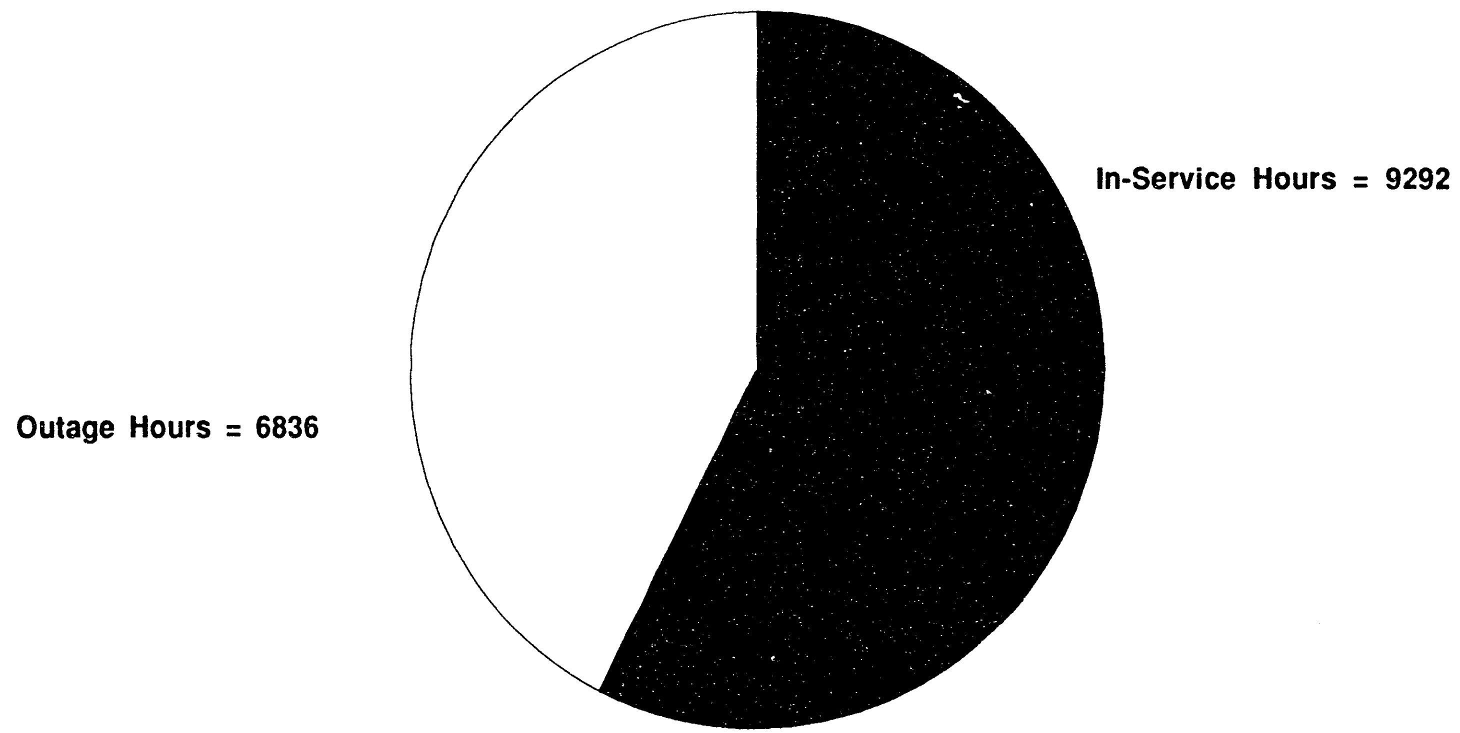


Table 2-1. OUTAGE SUMMARY

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
1-Oct-88	14:30	2-Oct-88	5:00	14.5	FAILURE OF AN INPUT/OUTPUT MODULE POWER SUPPLY ON THE DCS CAUSED MAIN FUEL TRIP (MFT).
2-Oct-88	12:00	3-Oct-88	15:00	27	CONTROLLED SHUTDOWN AS A RESULT OF LOW BED TEMPERATURES FROM HIGH ASH, LOW HHV COAL SUPPLY. UNIT HELD OFF LINE TO RESTORE PROPANE INVENTORY.
6-Oct-88	14:00	6-Oct-88	16:00	2	INDUCED DRAFT (ID) FAN TRIP FROM A SYSTEM GROUND FAULT DURING A LIGHTNING STORM.
17-Oct-88	20:00	26-Oct-88	2:00	198	CONTROLLED SHUTDOWN RESULTING FROM UNIT BEING OUT OF SO2 COMPLIANCE ON HIGH SULFUR COAL TEST. WENT INTO EXTENDED OUTAGE TO REPLACE MISSING BUBBLE CAPS AND TO WORK ON LIMESTONE FEEDERS.
28-Oct-88	8:00	28-Oct-88	9:30	1.5	TWO OF THREE COAL FEEDERS OUT OF SERVICE ON FURNACE B. BOILER TRIPPED WHEN THIRD COAL FEEDER TRIPPED ON BELT MISALIGNMENT.
4-Nov-88	11:30	10-Nov-88	4:00	136.5	CONTROLLED SHUTDOWN TO INSPECT COMBUSTORS FOR SUSPECTED REFRACTORY BLOCKAGE IN LOOP SEALS AND ASH CLASSIFIERS.
19-Nov-88	12:00	19-Nov-88	22:30	10.5	CONTROLLED SHUTDOWN TO REPAIR PACKING LEAK ON STEAM DRUM BLOW DOWN VALVE.
20-Nov-88	12:00	20-Nov-88	12:30	0.5	ID FAN TRIP DURING DELTA/WYE SWITCH.
24-Nov-88	14:00	24-Nov-88	18:30	4.5	MFT FROM MALFUNCTION OF FURNACE 4A PRESSURE SWITCHES FOR DRAFT CONTROL.
3-Dec-88	9:00	3-Dec-88	11:30	2.5	MFT DUE TO HIGH PRIMARY AIR (PA) FAN AMPS.
11-Dec-88	21:00	20-Dec-88	10:30	205.5	FAILURE OF GENERATOR 4A EXCITOR COLLECTOR RING.
26-Dec-88	2:30	26-Dec-88	10:30	8	MFT FROM FAULTY PRESSURE SWITCH ON ID FAN INLET.
27-Dec-88	12:00	27-Dec-88	17:30	5.5	MFT FROM OVERHEAT OF VARIABLE SPEED DRIVE (VSD) CONTROL CARD ON SECONDARY AIR (SA) FAN DUE TO ROOM AIR CONDITIONING PROBLEMS.
5-Jan-89	10:45	13-Feb-89	7:41	933	CONTROLLED SHUTDOWN DUE TO HOT SPOT AT LOOP SEAL 4B WELDED JOINT. DECISION MADE TO START PPCO OUTAGE TO REPAIR DAMAGED REFRACTORY IN THE LOOP SEALS AND CONES OF THE CYCLONES.

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
13-Feb-89	16:36	16-Feb-89	2:33	58	UNIT TRIP ON FUEL/AIR RATIO MISMATCH. THE MFT RESULTED FROM SYSTEM SOFTWARE UPDATE PROBLEM. ALSO FOUND LEAKING FLANGE GASKET ON SH SAFETY VALVE.
16-Feb-89	2:33	16-Feb-89	3:44	1	UNIT TRIP IMMEDIATELY AFTER SYNCHCRONIZATION ON MFT DUE TO ID FAN UNDERVOLTAGE TRIP.
17-Feb-89	15:15	23-Feb-89	12:14	141	CONTROLLED SHUTDOWN TO REPAIR SEIZED 4B CIRCULATING WATER PUMP . INLET AND DISCH. VALVES LEAKING BY TOO MUCH TO ISOLATE PUMP AND REPAIR ON LINE.
3-Mar-89	12:24	3-Mar-89	19:40	7	UNIT TRIP ON MFT DUE TO LOW PA FLOW TO 'B' FURNACE. THE LOW PA FLOW WAS CAUSED BY A SUDDEN LOOP SEAL SURGE WHICH INCREASED BED PRESSURE TO APPROXIMATELY 60" WC.
24-Mar-89	23:23	29-Mar-89	22:46	119	SCHEDULED SHUTDOWN TO INSPECT COMBUSTORS AFTER COMPLETING TEST BURN WITH 'SALT CREEK' COAL. REPAIRED 4A BOILER FEED PUMP MECHAN-ICAL SEAL DURING THIS OUTAGE.
12-Apr-89	16:53	18-Apr-89	17:31	145	CONTROLLED SHUTDOWN DUE TO ASH REMOVAL PROBLEMS IN "A" FURNACE RESULTING FROM A BENT FLUIDIZING TUBE AT THE ENTRANCE TO EACH BOTTOM ASH COOLER.
21-Apr-89	17:02	21-Apr-89	21:17	4	UNIT TRIP ON MFT DUE TO LOSS OF THE ID FAN RESULTING FROM A TRANSMISSION SYSTEM DISTURBANCE.
27-Apr-89	22:00	10-May-89	7:06	297	CONTROLLED SHUTDOWN DUE TO MECHANICAL SEAL LEAKS ON BOTH 4A AND 4B FEEDWATER PUMPS. 4B FEED PUMP ALSO REQUIRED CASING REPAIRS WHICH WERE COMPLETED OFF SITE.
10-May-89	7:21	10-May-89	23:25	16	UNIT TRIP ON MFT DUE TO LOSS OF THE ID FAN RESULTING FROM LOOSE ELECTRICAL CONNECTION WHICH CAUSED THE COMMUTATOR TO SHORT OUT.
14-May-89	11:22	22-May-89	17:30	198	UNIT TRIP ON MFT DUE TO SA FAN TRIP. REPLACED BAD FAN CONTROL CARD. DURING OUTAGE REINSTALLED 4B FEEDWATER PUMP. UNIT ON RESERVE SHUTDOWN AT 20:50 ON 5/19.
22-May-89	20:00	23-May-89	6:31	11	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
23-May-89	13:17	23-May-89	16:47	3	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
30-May-89	9:17	30-May-89	10:33	1	UNIT TRIP ON MFT DUE TO 'PHANTOM' SA FAN TRIP REASON UNDER INVESTIGATION.
9-Jun-89	13:57	9-Jun-89	18:12	4	CONTROLLED SHUTDOWN TO REMOVE "CLINKER" FROM 4C BOTTOM ASH COOLER. THREE BUBBLE CAPS WERE ALSO FOUND ADRIFT IN THIS COOLER AND REPLACED.
23-Jun-89	19:47	9-Jul-89	3:29	368	SCHEDULED SHUTDOWN AT THE COMPLETION OF ALTERNATE FUEL TESTING TO COMPLETE PA FAN INLET BOX AND LIMESTONE FEED SYSTEM MODIFICATIONS.
28-Jul-89	14:47	28-Jul-89	16:49	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE. 4A BFP SIEZED DURING THE UNIT ROLLDOWN WHEN ITS RECIRCULATION VALVE DID NOT PROPERLY OPERATE.
30-Jul-89	22:47	7-Aug-89	18:24	188	CONTROLLED SHUTDOWN TO ISOLATE 4A BFP FOR REMOVAL AND OFF-SITE REPAIR. UNIT STATUS CHANGED TO RESERVE SHUTDOWN FROM 12:00 HRS ON 8/2 TO 16:10 ON 8/4. THE INSTRUMENT AIR COMPRESSOR CHECK VALVE BETWEEN THE HIGH AND LOW PRESSURE STAGES FAILED AND WAS REPLACED.
20-Aug-89	0:45	26-Aug-89	4:43	148	CONTROLLED SHUTDOWN TO REINSTALL 4A BFP. OUTAGE EXTENDED TO REPLACE 23 DISTRIBUTOR PLATE "BUBBLE CAPS" IN A COMBUSTOR AND TO COMPLETE ADDITIONAL INSTRUMENT AIR COMPRESSOR REPAIRS.
26-Aug-89	5:43	26-Aug-89	16:28	11	CONTROLLED SHUTDOWN DUE TO LACK OF PROPANE
28-Aug-89	11:35	11-Sep-89	13:25	338	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK AT WALL BOX CONNECTION ON OUTSIDE OF BOILER. THE UNIT MFT'd DURING RESTART DUE TO A TRIP ON EXCITER VOLTAGE CABINET FAN FAILURE. THE NO. 2 THROTTLE VALVE REMAINED 11 % OPEN AFTER THE UNIT TRIP. THE VALVE WAS DISASSEMBLED AND THE UPPER STEM GUIDE BUSHING WAS REMACHINED TO THE MANUFACTURER'S SPECIFICATIONS. TWO ADRIFT NOZZLE CAPS NEAR THE LOOP SEAL IN 4B COMBUSTOR WERE ALSO CAPPED FROM THE WINDBOX SIDE AS A TEMPORARY REPAIR.

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE DATE	START OUTAGE TIME	STOP OUTAGE DATE	STOP OUTAGE TIME	DURATION (APPROX.) HRS.	CAUSE
13-Sep-89	3:03	13-Sep-89	11:50	9	UNIT TRIP ON MFT DUE TO LOSS OF THE SA FAN ON "PHANTOM" TRIP. AFTER SEVERAL UNSUCCESSFUL ATTEMPTS TO RESART THE FAN IN A NORMAL FASHION, THE FAN WAS RESTARTED "ACROSS THE LINE". A CONDENSER TUBE LEAK WAS ISOLATED AND REPAIRED BEFORE UNIT 1 WAS RETURNED TO SERVICE.
17-Sep-89	14:01	17-Sep-89	14:46	1	UNIT MFT ON LOW DRUM LEVEL DUE TO IMPROPER OPERATION OF THE MAIN FEEDWATER CONTROL VALVE.
23-Sep-89	22:21	9-Oct-89	22:29	384	UNIT MFT DUE TO LOSS OF THE PA FAN ON "PHANTOM" TRIP. STARTED SCHEDULED OUTAGE FOR PYROPOWER TO REPLACE THE PA FAN WHEEL.
13-Oct-89	19:41	11-Nov-89	18:08	694	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4B FURNACE. WATER FROM THE TUBE CAUSED AGGLOMERATION OF THE BED MATERIAL IN 4B COMBUSTOR, 4B WINDBOX, AND 4D BOTTOM ASH COOLER. SUBSEQUENT INSPECTION OF THE SUPERHEATER II PLATENS IN BOTH COMBUSTORS REVEALED MANY AREAS OF LOCALIZED EROSION WHICH WERE REPAIRED.
12-Nov-89	18:27	12-Nov-89	20:27	2	UNIT MFT ON LOW AIR/FUEL RATIO DUE TO AN IMPROPER BTU BIAS SETTING.
4-Dec-89	10:33	4-Dec-89	11:36	1	UNIT MFT ON LOW ELECTRO-HYDRAULIC CONTROL (EHC) SYSTEM PRESSURE. PROBLEM OCCURRED WHILE I&C TECHNICIAN WAS VALVING AN EHC ACCUMULATOR BACK IN-SERVICE AFTER BEING RECHARGED.
8-Dec-89	4:37	15-Dec-89	14:00	177	CONTROLLED SHUTDOWN DUE TO HIGH BED PRESSURE IN 4A COMBUSTOR DURING TYPE "B" COAL ACCEPTANCE TESTING USING A HIGH SULFUR COAL (1.8% S). SUB-SEQUENT INSPECTIONS REVEALED A TOTAL OF TWENTY SEVEN BUBBLE CAPS ADRIFT IN 4A COMBUSTOR (25), 4B COMBUSTOR (1), AND 4B LOOP SEAL (1).
17-Dec-89	23:26	18-Dec-89	5:27	6	UNIT MFT DUE TO UNIT 4 EXCITER FIRING CIRCUIT CARD FAILURE.
18-Dec-89	6:42	20-Dec-89	17:27	59	UNIT MFT DUE TO UNIT 4 EXCITER AFTER AN UNSUC-CESSFUL ATTEMPT TO RESTART THE UNIT. CUEA OBTAINED ENOUGH GOOD CARDS BETWEEN THE TWO REDUNDENT FIRING CIRCUITS TO RETURN THE UNIT TO SERVICE.

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
30-Dec-89	5:08	30-Dec-89	8:56	4	UNIT MFT ON LOW DRUM LEVEL DUE TO A UNIT 4 TURBINE UPSET. THE UPSET WAS THE RESULT OF A TURBINE CONTROL PROBLEM CAUSED BY AN IMPROPERLY CALIBRATED MW TRANSDUCER.
30-Dec-89	9:11	30-Dec-89	18:34	9	CONTROLLED SHUTDOWN DUE TO LEAK IN UNIT 4 GOVERNOR OIL CIRCUIT.
7-Jan-90	18:14	9-Jan-90	20:40	50	CONTROLLED SHUTDOWN DUE TO LOSS OF THE COAL PREP SYSTEM FROM A 4A COAL CRUSHER MOTOR BEARING FAILURE. THE OUTAGE WAS EXTENDED BECAUSE OF A STEAM LEAK ON THE WEST STEAM LEAD FLANGE BETWEEN THE WEST THROTTLE VALVE AND THE GOVERNOR VALVE WHICH DEVELOPED DURING RESTART.
18-Jan-90	14:10	19-Jan-90	18:51	29	UNIT MFT ON GENERATOR LOW FREQUENCY RESULTING FROM A RELAY WIRING ERROR. DURING RESTART A SH SAFETY VALVE FLANGE LEAK WAS DISCOVERED AND REPAIRED AFTER THE BOILER WAS COOLED DOWN.
26-Jan-90	18:37	6-Feb-90	21:16	267	CONTROLLED SHUTDOWN TO REPAIR THE "VORTEX FINDER" IN 4B COMBUSTOR CYCLONE AND TO CLEAN OUT BACKSIFTED MATERIAL FROM 4A AND 4B COMBUSTOR WINDBOXES.
9-Feb-90	4:18	9-Feb-90	21:36	17	CONTROLLED SHUTDOWN DUE TO VIBRATION IN THE SA FAN INLET DUCT. TWO STIFFENERS WERE ADDED TO A FAN INLET TURNING VANE TO RESOLVE THE PROBLEM.
9-Feb-90	22:36	10-Feb-90	2:36	4	UNIT MFT DUE TO LOW VACUUM ON UNIT 4 CONDENSER.
10-Feb-90	17:23	21-Feb-90	6:55	254	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4A FURNACE. WATER FROM THE TUBE CAUSED AGGLOMERATION OF THE BED MATERIAL IN 4A COMBUSTOR AND WINDBOX. 4A BFP WAS FOUND SEIZED WHILE ATTEMPTING BOILER HYDROSTATIC TEST AFTER COMPLETING TUBE REPAIRS.
26-Feb-90	0:08	3-Mar-90	9:41	130	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK OUTSIDE THE BOILER. THE LEAK WAS LOCATED IN A FLOOR TUBE WHERE THE WINDBOX TIES INTO THE FLOOR TUBES. THE OUTAGE WAS EXTENDED TO REPAIR A SECTION OF ABRASION RESISTANT REFRACTORY IN 4B CYCLONE CONE SECTION.
22-Mar-90	13:36	22-Mar-90	15:23	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE.

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
3-Apr-90	18:02	3-Apr-90	20:20	2	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE.
18-Apr-90	19:00	22-Apr-90	10:30	88	UNIT TRIP ON MFT DUE TO LOSS OF EXCITATION DUE TO EXCITER TRANSFORMER FAILURE.
2-May-90	6:29	20-May-90	6:16	432	UNIT MFT ON LOW DRUM LEVEL AT THE TIME OF THE TRIP,OPERATIONS PERSONNEL WERE REDUCING LOAD TO REMOVE THE BOILER FROM SERVICE VIA A CONTROLLED SHUTDOWN SEQUENCE AFTER AN INDICATION OF A TUBE LEAK IN 4A COMBUSTOR.
20-May-90	6:29	20-May-90	15:33	9	UNIT TRIP ON MFT DUE TO LOSS OF SA FAN RESULTING FROM A 4 KV LINE VOLTAGE. THE GENERATOR BREAKER HAD TO BE OPENED MANUALLY.
20-May-90	15:59	22-May-90	6:19	38	UNIT TRIP ON MFT DUE TO LOSS OF SA FAN RESULTING FROM A 4 KV VOLLTAGE LINE SURGE. THE GENERATOR REVERSE CURRENT RELAY HAD TO BE MANUALLY TRIPPED. THE BOILER WAS BOTTLED UP WHILE A RELAY WIRING FAULT WAS IDENTIFIED AND CORRECTED.
28-May-90	14:24	28-May-90	15:31	1	DURING A CONTROLLED SHUTDOWN DUE TO HIGH VIBRATION READINGS ON NO. 3 TURBINE BEARING, SWITCHYARD BREAKER N-521 TRIPPED THE HIHG VIBRATION SOURCE WAS DETERMINED TO BE TRANSIENT AND A HOT RESTART FOLLOWED.
31-May-90	9:16	7-Jun-90	1:38	160	UNIT MFT ON LOW DRUM LEVEL DUE TO A BOILER WW TUBE LEAK IN 4A COMBUSTOR.
7-Jun-90	8:11	7-Jun-90	20:21	12	CONTROLLED SHUTDOWN - PROPANE SUPPLY < 22%
7-Jun-90	22:21	7-Jun-90	23:37	1	PROPANE VAPORIZER TRIP
27-Jun-90	20:14	28-Jun-90	0:47	5	SA INVERTER FAULT
28-Jun-90	14:27	10-Jul-90	4:48	278	SHII 4A COMBUSTOR TUBE LEAK
17-Jul-90	18:25	28-Jul-90	8:56	255	UNIT MFT ON HIGH FURNACE DRAFT DUE TO A BOILER TUBE LEAK IN 4A COMBUSTOR. AT THE TIME OF THE TRIP,OPERATIONS PERSONNEL WERE REDUCING LOAD TO REMOVE THE BOILER FROM SERVICE VIA A CONTROLLED SHUTDOWN SEQUENCE.

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE DATE	START OUTAGE TIME	STOP OUTAGE DATE	STOP OUTAGE TIME	DURATION (APPROX.) HRS.	CAUSE
1-Aug-90	18:08	19-Aug-90	17:06	431	CONTROLLED SHUTDOWN DUE TO WATERWALL TUBE LEAK IN 4A COMBUSTOR. REPAIRS WERE COMPLETED AND THE UNIT WAS AVAILABLE FOR SERVICE AT 15:00 ON 8/16. HOWEVER, THE UNIT WAS PLACED ON RESERVE SHUTDOWN UNTIL 8/19
25-Aug-90	0:12	7-Sep-90	12:09	324	CONTROLLED SHUTDOWN FOR RESERVE SHUTDOWN
8-Sep-90	1:43	8-Sep-90	6:32	5	UNIT MFT ON PHANTOM PA FAN TRIP. A BLOWN FUSE IN THE FAN Y SIDE CONTROLLER WAS REPLACED.
12-Sep-90	0:12	13-Sep-90	4:05	28	CONTROLLED SHUTDOWN DUE TO A WATERWALL TUBE LEAK IN 4B COMBUSTOR. THE LEAK WAS EXTERNAL TO THE BOILER AT THE LOOPSEAL WALLBOX CONNECTION.
13-Sep-90	21:27	13-Sep-90	23:46	2	UNIT MFT ON PHANTOM PA FAN TRIP.
14-Sep-90	0:34	14-Sep-90	1:53	1	UNIT MFT ON HIGH DRUM LEVEL DURING START-UP SHORTLY AFTER SYNCHRONIZATION.
16-Sep-90	5:52	6-Oct-90	15:47	490	UNIT MFT ON HIGH FURNACE DRAFT PRESSURE DUE TO A BOILER TUBE LEAK IN 4A COMBUSTOR. DURING THE REPAIR OUTAGE B&W CONDUCTED A REMAINING USE-FUL LIFE ANALYSES ON THE RADIANT SUPERHEATER TUBES (SH II) AN TUBE METAL TEMPERATURE THERMO-COUPLES WERE INSTALLED.
6-Oct-90	17:06	7-Oct-90	0:36	8	CONTROLLED SHUTDOWN DUE TO A FLANGE LEAK BETWEEN THE THROTTLE AND CONTROL VALVES. DUR-ING START-UP.
19-Oct-90	2:04	19-Oct-90	5:45	4	UNIT MFT ON PHANTOM ID FAN TRIP.TWO CONTROL FUSES IN THE FAN DELTA SIDE CONTACTOR WERE REPLACED PRIOR TO RESTART.
23-Oct-90	13:00	23-Oct-90	14:16	1	UNIT MFT ON LOW AIR FUEL RATIO DUE TO A STUCK 4B UNDERBED DAMPER. DESSICANT DUST FROM THE CONTROL AIR DRYER CAUSED THE DAMPER TO STICK.
26-Oct-90	17:13	1-Nov-90	20:05	147	CONTROLLED SHUTDOWN FOR PYROPOWER TO INSPECT 4A AND 4B COMBUSTOR REFRACTORY AS PART OF THE CONTRACT CLOSEOUT. CUEA HIRED UNITED ENGINEERS AND CONSTRUCTORS TO PERFORM AN INDEPENDENT EVALUATION OF THE BOILER REFRACTORY.
14-Dec-90	5:01	14-Dec-90	12:27	7	UNIT TRIP ON MFT DUE TO LOSS OF ID FAN RESULTING FROM SYSTEM DISTURBANCE. THE FAN TRIP OCCURRED DURING A RECLOSURE ON 69KV BREAKER N-931.

Table 2-1. OUTAGE SUMMARY (Continued)

START OUTAGE		STOP OUTAGE		DURATION (APPROX.)	CAUSE
DATE	TIME	DATE	TIME	HRS.	
17-Dec-90	10:29	17-Dec-90	12:24	2	UNIT TRIP ON MFT DUE TO MYSTERY TRIP OF ID FAN
20-Dec-90	17:19	20-Dec-90	19:59	3	UNIT MFT ON LOW DRUM LEVEL DURING DYNAMIC LOAD RAMP TESTING AS PART OF THE DOE TEST PROGRAM.
22-Dec-90	16:19	22-Dec-90	20:08	4	UNIT MFT ON SA FAN TRIP DUE TO LOSS OF WDPF DROP 2. THE DROP WAS LOST DUE TO PROBLEMS WITH THE WDPF LOGIC ROOM HVAC SYSTEM.
2-Jan-91	15:05	2-Jan-91	18:32	3	CONTROLLED SHUTDOWN TO INSPECT A SWITCH ON THE #4 GENERATOR TRANSFORMER RAPID PRESSURE RELAY ALARM WHICH HAD ANNUNCIATED ON 12/31/90 AND DID NOT CLEAR. THE SWITCH WAS FOUND TO BE DEFECTIVE AND REPAIRED.
8-Jan-91	12:04	8-Jan-91	13:48	2	UNIT MFT ON HIGH ID FAN INLET PRESSURE DUE TO AN OUT-OF-CALIBRATION PRESSURE TRANSMITTER.
13-Jan-91	1:36	13-Jan-91	3:00	1	UNIT MFT ON LOSS OF COAL FEED TO 4A COMBUSTOR. THE MFT WAS DETERMINED TO BE THE RESULT OF COAL FEEDER ROTARY VALVE PLUGGAGE RESULTING FROM THE USE OF "DORCHESTER" COAL
13-Jan-91	3:38	13-Jan-91	12:12	9	CONTROLLED SHUTDOWN, AFTER AND MFT ON LOW DRUM LEVEL, DUE TO A SUSPECTED TUBE LEAK IN 4A COMBUSTOR. UPON FURTHER INVESTIGATION, THE INDICATIONS OF A TUBE LEAK WERE FOUND TO BE FALSE AND UNIT START-UP WAS RE-INITIATED.
16-Jan-91	12:18	17-Jan-91	2:30	14	UNIT MFT ON LOW-LOW UNDERBED PA AIR FLOW TO 4B COMBUSTOR DUE TO A STUCK CONTROL DAMPER. DESSICANT DUST FROM THE CONTROL AIR SYSTEM DRYER CAUSED THE DAMPER TO STICK. REPAIRS WERE MADE TO THE WARM UP LINE FOR 4B BOILER FEED PUMP DURING THE SHUTDOWN.
18-Jan-91	11:44	18-Jan-91	12:35	1	UNIT MFT ON PHANTOM SA FAN TRIP.

July 9, 1987
First coal fires without propane.
First limestone feed to boiler.
Baghouse #4 in service for the first time.
74 MWe turbine/generator on-line at 30 MWe.

July 1987
Continuous operation for 91 hours on coal at 35 to 45 MWe.
Completed steam blow to old turbines.
Started commissioning old turbines.

August and September 1987
Continued commissioning of old turbines and raising load.
Maximum load to date - 65 MWe.
Overheat incident occurred on evening of 9/29/87, unit off-line for inspection and repairs.

October, November and December 1987
Repair outage for overheat incident.

January 1988
571 hours on coal firing.
Outage to replace drum safety gasket.
Control tuning at 35%, 50%, 75% and 100% MCR.

February 1988
468 hours on coal firing.
Outage to repair coal conveyor C gearbox.
Outage to repair floor tube failure in combustor A.
Outage to repair floor tube failure in combustor B.

March 1988
354 hours on coal firing.
Outage due to secondary air fan trip.
Outage due to bed pressure swings.
Outage due to 74 MWe turbine exciter transformer failure.

April 1988
293 hours on coal firing.
Unit outage for No. 4 turbine fine screen removal and repair of exciter transformer.
Refractory repairs made to hot cyclones and furnaces.

May 1988
356 hours on coal firing.
Completed No. 4 turbine fine screen and exciter transformer outage.
Completed stack monitoring certification test.
Unit outage to replace demisters in drum.
Unit outage due to secondary air fan trip.

June 1988
492 hours on coal firing.
Completed dry run boiler acceptance test.
Test high ash design "B" coal; test abandoned due to bottom ash conveying capacity limitations.
Test high sulfur design "B" coal; test abandoned due to failure of limestone feed system.

July 1988
446 hours on coal firing
Full load acceptance test conducted on design "A" coal.
Completed 2 hour dry run turbine acceptance test. Maximum unit load of 116.4 MWe achieved.
Increased frequency of bubble cap loss.

August 1988
1.5 hours on coal firing.
Outage for modifications of bottom ash conveying system.
Refractory repair in loop seals, hot cyclones and furnaces.
Replacement of all bubble cap locking washers.

September 1988
184 hours on coal firing.
Test high sulfur design "B" coal; test abandoned due to limestone feeder failures.
Outage to repair combustor B tube leak at loop seal wall box.
Outage due to loop seal flow surges.

October 1988
492 hours on coal firing.
Completed second boiler acceptance test using design "A" coal.
Completed baghouse pressure drop test.
Completed 750 klb/hr, 500 klb/hr and 350 klb/hr emissions compliance tests.
Test on high sulfur design "B" coal; test abandoned due to limestone feeder failures.
Outage to inspect for loose refractory in combustors, ash coolers and loop seals.
Test on high ash design "B" coal with water sprays in two bottom ash coolers.

November 1988
552 hours on coal firing.
Outage to inspect refractory and add water sprays to bottom ash coolers.
Test on high sulfur design "B" coal; test abandoned due to limestone feeder failures.

December 1988
504 hours on coal firing.
Load curtailment due to limestone feeder failures.
Test on high ash design "B" coal with bottom ash cooler sprays in service.
Load curtailment due to high PA fan amps.
Unit outage due to No.4 generator exciter collector ring failure.

January 1989
106.5 hours on coal firing.
Unit outage for major refractory repairs to hot cyclones, loop seals, and furnaces.

February 1989
180 hours on coal firing.
4B circulating water pump failure.

March 1989
610 hours on coal firing.
Completed Salt Creek coal test burn and hot-mode shakedown test.

April 1989
493 hours on coal firing.
Test on high sulfur design "B" coal; test abandoned due to limestone feeder problems.
Test on high ash design "B" coal with water sprays in two bottom ash coolers. Test was terminated due to pluggage of bottom ash coolers from over-spraying.
Testing on high ash design "B" coal with modified bottom ash cooler sprays. Test was terminated due to plant outage caused by boiler feed pump problems.

May 1989
277 hours on coal firing.
Plant limited to 50% MCR due to 4B boiler feed pump problems.
Conducting freeboard gas traverse (FGAS) tests on Peabody coal at 50% MCR.
Bottom ash screw cooler 4A out of service.

June 1989
541 hours on coal firing.
Peabody coal deliveries extended to allow test program to complete test series AO2 thru AO8 and FGAS test B-6.
Plant off-line to allow modifications to PA fan inlet box.

July 1989
518 hours on coal firing.
PA fan inlet box modifications completed and fan tests conducted by PPC/Howden-Sirocco.
Westinghouse tuning turbine controls.
Switch to Salt Creek coal.
Test program ran test P49 and P50.
MFT due to ID fan trip caused by system disturbance.
4A boiler feed pump seized up; unit derated to 50% MCR.

August 1989
333 hours on coal firing.
Unit derated to 50% MCR due to loss of 4A boiler feed pump.
Test program testing at 50% MCR on Salt Creek coal.
Unit in outage to replace 4A boiler feed pump and to replace 23 bed nozzles in combustor A.
Unit in outage due to water-wall tube leak at 4F coal feed wall box in combustor B.

September 1989
281 hours on coal firing.
Unit off-line to repair sticking throttle valve on No. 2 (12.5 MWe) turbine.
All units on-line at 98 MWe; MFT due to SA fan trip.
All units on-line at 82 MWe; MFT due to malfunction of main feed water control valve.
Tests on various bed pressures to determine effect on bed temperature.
EPRI contractor conducted series of baghouse tests.
Unit down for installation of new PA fan wheel.

October 1989
91 hours on coal firing.
Completed installation of new PA fan wheel and PPC added shelf between superheat panels 2 and 3 in both furnaces.
Experiencing high opacity; several bags replaced.

December 1989
480 hours on coal firing.
All units on-line and the test program conducting tests .
Testing on high sulfur design "B" coal.
Tube leak in bottom ash cooler 4B due to water sprays.
Unit had to be shut down due to inability to remove ash from combustor A.
Twenty-five nozzles off in combustor A and 1 off in combustor B.
Inspected cyclone B vortex finder, 9 panels badly warped.
Unit back on-line but problem developed with No. 4 generator exciter firing circuit and unit down again.
All units on-line and test program conducting tests.

January 1990
543 hours on coal firing.
All units on-line at 108 MWe and test program conducting tests.
Dynamic testing successfully completed.
Unit outage to clear blockage in coal feed system to in-plant silos and repair superheater safety flange leak.
Combustion chamber bed temperature difference of approximately 100 °F.
Unit in scheduled outage to repair combustor B cyclone vortex finder.

February 1990
178 hours on coal firing.
UT inspection of SHII panels in both combustors.
Air flow tests conducted.
Multiple tube leak in combustor A SHII and water wall.
4A boiler feed pump seized.
Low load test conducted.
Leak in bottom southwest corner of combustor B.

March 1990
681 hours on coal firing.
Expansion joints installed in windbox corners.
Test program performance testing conducted.
Fan power test conducted.
Test program soot blowing test conducted.

April 1990
629 hours on coal firing.
Test program performance tests conducted.
Unit 4 generator exciter transformer explosion and MFT.
Inspection during outage.

May 1990
258 hours on coal firing.
Unit off-line for water-wall tube weld repair on outside wall box.
3 SA fan trips
High dP's in baghouses 1-4.

June and July 1990
752 hours on coal firing.
All units out of service due to SH II tube leak.
59 bubble caps missing in combustor A; 3 in combustor B.
4 bottom ash cooler nozzles replaced.
EPRI concluded testing on June 15.

August 1990
143 hours on coal firing.
Unit shut down due to water-wall tube leaks due to bed material blockage in combustor A.
Cemented bed material in tubes and headers hydro-blasted.
Boiler chemistry problems persisted.

September 1990

167 hours on coal firing.

4 bubble caps replaced in combustor A; 1 bubble cap replaced in combustor B.

External leak found at the loop seal wall box connection to combustor B.

There were two PA fan trips.

Unit shut down due to SHII and water-wall tube leaks.

Inspections of SHII, refractory, water walls, bubble caps.

100 bubble caps replaced in combustor A; 20 bubble caps replaced in combustor B.

Large chunks of refractory missing from combustor A bull nose and cyclone cone and from scroll piece in both combustors.

Combustor B center wall refractory interface pad welded in places.

October 1990

461 hours on coal firing.

Water-wall tube leak discovered during boiler fill after outage.

Flange leak on main steam line.

Leaking bags in baghouse 3.

DOE testing conducted.

Clinkers developed during DOE coal size testing.

Combustor B primary air damper stuck twice.

Controlled shutdown in preparation for inspections.

Six nozzles replaced in combustor A; one nozzle replaced in combustor B.

November 1990

697 hours on coal firing.

DOE testing conducted.

High pressure across baghouse 3 due to accumulated fly ash.

Attemperator tests conducted.

December 1990

718 hours on coal firing.

Test conducted to determine the effect of high bed inventory.

Stack testing conducted to verify previous particulate measurements taken as part of the environmental characterization plan.

Alternate coal (Dorchester) deliveries begun.

4A coal feeder drag conveyor bearing failure.

MFT due to ID fan trip.

DOE dynamic testing conducted.

Three MFT's due to loss of WDPF drops and subsequent SA fan trips.

January 1991

706 hours on coal firing.

Controlled shut down to repair switch on #4 generator transformer rapid pressure relay alarm.

4C limestone conveyor was taken out of service due to a bad rotary valve motor.

Alternate fuels testing conducted at half load.

MFT due to loss of coal feed resulting from high coal moisture content.

Orchard Valley (gob) coal deliveries started.

4C limestone rotary valve repairs completed.

2 MFT's due to PA and SA fan trips.

Successful operation on a combination of Salt Creek and gob coals.

DOE testing concluded on January 18, 1991.

2.3 ACCEPTANCE TESTS

In June of 1988, a dry run acceptance test was completed at full load with Design Coal A, followed by operability tests with high ash and high sulfur Design Coals B. Although the dry run acceptance was successful in establishing operating and sampling procedures, the high ash and high sulfur coal tests were unsuccessful due to capacity limitations with the original bottom ash transport system. Modifications that were made to the bottom ash system to increase transport capacity are discussed in Section 13.

The first acceptance tests on Design Coal A were completed on July 7, 1988. Fan power consumption in excess of contract guarantees at full load was identified prior to the test. Other boiler performance guarantees were met at full load operation except the calcium to sulfur ratio and total draft loss. The guarantee value for the former is 1.5 (excluding calcium in the coal ash), while the actual value for the test was 3.0. There were four reasons that were cited for failure to meet the guaranteed value:

- High combustion chamber temperatures. For the performance period of 16 hours, combustor A and B temperatures averaged 1647 °F and 1707 °F, respectively (as measured approximately 20 inches above the distributor plate around the perimeter of the combustor). These temperatures should have been in the vicinity of 1550 °F to 1600 °F.
- Low ash content. The ash content of the coal averaged 16.8 percent versus the value for design A coal of 26.9%. This resulted in a deficiency of calcium and other potential sorbents in the ash.
- Improper limestone sizing, particularly excessive fines fraction. The small particles pass through the hot cyclones and do not recirculate.
- Poor combustion balance between the two chambers. Better matching of air and coal flows may improve performance and reduce mean bed temperatures.

The acceptance test was originally scheduled for 24 hours, with solids sampling covering a 12-hour interval in the middle of this period. Sixteen hours into the test period and 9 hours into the solids sampling interval, coal feeder 4A tripped and caused a significant-enough boiler upset that the run was terminated 8 hours earlier than the 24-hour agreement. However, CUEA and PPC agreed that the two complete isokinetic samples and five sets of solids samples that were taken would suffice.

On July 8, 1988, following the full-load acceptance test, load was increased to a gross output of 116.4 MWe to establish equipment and design limitations on the plant. In this case, a drop in drum water level suggested a possible limitation with the feed water system. This was subsequently found to be controls related.

Load was subsequently ramped between 925 klb/h and 750 klb/h steam flow. Maximum rate of change was limited to approximately 8.4 klb/min (1 MWe/min). This limitation is dictated by turbine control settings which require final tuning by Westinghouse before this rate can be significantly increased. Nearly full load was maintained through July 11 when load was shed at an improved rate of 1.5 MWe/min to approximately 750 klb/h steam flow. This was achieved without final tuning of the turbine controls by Westinghouse.

Stack emissions were also verified at the 750 klb/h load. The Ca/S ratio limit for meeting the SO_2 emission limit of 0.4 lb/10^6 Btu at these reduced loads is not stipulated contractually. Emissions were satisfactory at 750 klb/h.

On July 12, turbine testing was completed with the unit 4 governor valves 100% open and gross plant output at 117 MWe. Load was then reduced to 80 MWe to test various schemes for reducing bed temperatures, which were in the range of 1650 °F to 1700 °F at the peak load. At the reduced load, there is enough fan margin for adjusting the primary air to secondary air ratios. Adjustment of the relative air flows appeared to have little effect on bed temperatures. The tests, however, were not conducted in a controlled fashion for a sufficient duration to reach positive conclusions. Ash cooler/classifier air flows were also adjusted between 4 ft/s and 10 ft/s fluidizing velocities to determine if bed particle sizing could be altered enough to influence bed temperature. Again, these tests were inconclusive due to inadequate test duration.

Although acceptance tests for Design Coal A were repeated in October 1988 at lower operating temperatures, process conditions for the July 7, 1988 test were as follows:

Table 2-2. Acceptance Test Process Conditions

Boiler performance item	Design Value	Data, 7/7/88
steam flow, lb/hr	925,000	922,600
steam temp, °F	1005	1005.3
dP superheater, psi	150	147
dP economizer, psi	12	14.6
air resistance(PA/SA) in wg.	62/37	61.1/39.9
draft loss, in wg.	16.2	16.76
air heater leakage (air-gas)	0	0
boiler efficiency	88.3	88.8
steam purity	0.1	ok
control range SH %	54-100	ok
PA fan kW	1620	2689
circ. pump, kW	N/A	N/A
soot blower steam demand, lb/h	2034	ok
SA fan kw	400	649
ID fan kw	1400	1961
Ca/S ratio	1.5	3.03
particulate emission, #/MBtu	0.03	0.0245
NOx emission, #/MBtu	0.5	0.37
SO2 emission, #/MBtu	0.4	0.401
#4 Baghouse Performance		
stack gas dust loading:		
grain loading, gr/acf	0.01	0.0075
#/million Btu	0.03	0.0245
dP 4 compartments out, in wg.	7.5	7.3
dP 2 compartments out, in wg.	7.0	6.4
dP all compartments in, in wg.	6.8	5.8
bag life	2 yr. min.	not tested
stack opacity	20%	< 20%
dT baghouse, °F	15	unreliable data

Notes:
- all data by Colorado-Ute
- Ca/S ratio guaranteed at full load only
- SO2 emission guarantee is without a limit on the Ca/S ratio

On October 7, 1988, a repeat of the July 7 Design Coal A boiler performance acceptance test was run. The calcium to sulfur ratio was substantially lower during the second acceptance test than during the first test. The ratio was 1:4 when only the calcium present in the limestone was considered (1:7 when the calcium in the coal was also included). Both of these values correspond to an SO2 retention rate of 72 percent. Factors that may have contributed to the improvement in Ca/S ratio included lower overall combustor temperature, better temperature balance between the two combustors, and change in limestone size distribution as indicated by a larger median size in the second test.

Process conditions during this Design Coal A acceptance test in October, 1988 were as follows:

Table 2-3. Acceptance Test Process Conditions

Boiler performance item	Design Value	Data, 10/88
steam flow, lb/hr	925,000	959,672
steam temp, °F	1005	1003
air resistance(PA/SA) in wg.	62/37	54.0/37.3
draft loss, in wg.	16.2	
boiler efficiency	88.3	88.55
PA fan kW	1620	
Ca/S ratio	1:5	3:03
particulate emission, #/MBtu	0.03	0.0245
NOx emission, #/MBtu	0.5	0.37
SO2 emission, #/MBtu	0.4	0.401
Particulate, #/MBtu		
925 Klb steam flow	0.03	0.018
750	0.03	<0.03
500	0.03	<0.03
350	0.03	<0.03
NOx, #/MBtu		
925	0.5	0.2
750	0.5	0.18
500	0.5	0.17
350	0.5	0.08
SO2, #/MBtu		
925	0.4	0.39
750	0.4	0.28
500	0.4	0.27
350	0.4	0.19
#4 Baghouse Performance		
Grains/cf of gas	0.01	0.0094
dP (2x2), in wg.	7.5	7.1
dP (2x2) soot blow, in wg.	7.5	7.6
dP all compartments in, in wg.	6.8	6.6
stack opacity	20%	6.3-9.4

Notes:
all data by Colorado-Ute
Ca/S ratio guaranteed at full load only
SO2 emission guarantee is without a limit on the Ca/S ratio

Concerning acceptance tests with high ash coal, demonstrations of sustained operability on the high ash coal were initially unsuccessful due to excessive temperatures of bed material discharging from the ash classifiers at full load. The high temperatures were reduced to acceptable operational levels by operating two ash classifiers and the water-cooled screw cooler on each combustion chamber. The two ash classifiers operate in parallel and the water-cooled screw cooler operates in series with either or both of the ash classifiers. By design, only two of the three ash cooling systems should be in service on each combustion chamber simultaneously. Modifications to the fluidizing air flow control logic also helped reduce bed material drain temperatures and improve bottom ash disposal flow rate. However, PA fan limitations terminated the tests in during the fourth quarter of 1988.

High sulfur coal testing was also attempted at full load on several occasions through the fourth quarter of 1988. Limitations in limestone feed flow rate of feeder failures prevented the successful completion of these tests.

2.4 SUMMARY OF EQUIPMENT AND OPERATING PROBLEMS

Problems with equipment and operation of the Nucla CFB facility are summarized below (and are discussed in the sections in parentheses and/or in the Annual Reports):

- September 1987 overheat incident (1987-1988 Annual Report)
- Leaks in the secondary superheater and water-wall tubes (Section 16)
- Temperature differential between combustors (Section 11)
- Distortion of the cyclone vortex finders (Section 16)
- Air distributor bubble cap / nozzle wear and loss (Section 16)
- Refractory breakage, particularly in the cyclones, loop seals, and at the water wall/refractory interface (Section 16)
- High initial rate of replacement required for baghouse bags (Section 15)
- Bottom ash cooler limitations (Sections 13 and 16)
- Primary air fan limitations (1989 Annual Report)
- Limestone feed system limitations (Section 12)
- Loop seal flow instabilities
- Boiler feed water pump failures (non CFB-related)
- Drum level swings
- Backsifting of bed material into the windboxes (Section 16)

After plant start-up, many problems encountered were routine in nature, including a number of equipment trips before fine tuning of the controls system , minor steam leaks at flanges and relief valves, and generator synchronization difficulties. A second group of problems could be traced back to design or construction inadequacies. Steam line expansion interference, steam leaks at field welds, boiler casing leaks, primary and secondary air cross-leakage in the air heater, plugging of various pressure taps, faulty O_2 and SO_2 analyzers, and faulty air dampers and actuators fall into this category. A third group of difficulties may be ascribed to the new technology and scale-up uncertainties. Items such as drum level instability, back-sifting of bed material into the primary air plenum, and initial poor performance of the ash coolers are included in this group.

While the correction of many of these problems caused relatively short outages (days), repairs after the overheat incident of September 1987 required an outage of 10 weeks. This incident is described in Section 16 of this report and in more detail in the 1987-1988 Annual Report. However, the persistent problem of secondary superheater tube leaks has caused the largest amount of CFB-related outage time through January 1991. This issue is also discussed in Section 16.

One serious problem that has disrupted unit operation is that of secondary superheater tube leaks. From October 1989 to January 1991, there have been seven separate tube failures, contributing significantly to total outage hours. Causes for these failures include particle erosion, long term overheat, and short term overheat from flow restrictions. Erosion-caused tube leaks were addressed by installation of horizontal shelves along the top tube of the second superheater panel. To address superheater II tube failures due to long term overheat, the attemperator spray flow logic was modified, and there have not been any additional tube failures since October 1990. Failures attributed to short term overheat due to flow restrictions have been addressed by modifications to shutdown procedures in an effort to reduce the likelihood of solids ingestion into failed tubes.

One operational problem that has proved difficult to resolve is a temperature differential between combustors, primarily during full-load operation. Since initial startup, combustors A and B have operated with a temperature differential in the lower combustor zone of as high as 150 °F. Although the root cause of the temperature differential is still not fully understood, sufficient tests and normal operating data exist for characterizing the behavior of the boiler when the differential is present.

Summarizing the operating characteristics of the Nucla CFB boiler during periods of high combustor temperature differential:

- Combustor B generally has the higher operating bed temperature and cycle inlet temperature.
- Furnace water-wall differential pressure is lowest in the combustor with the higher temperature. The differential pressure is a direct indication of solids loading and is generally lower in combustor 4B compared to 4A
- Circulating material is consistently coarser in combustor 4B as indicated by samples taken from each loop seal. At full load operation, this material generally gets coarser after three of four days following a startup until and equilibrium is achieved.

Loss of air distributor bubble caps has occurred frequently during the first years of operation. Design changes to the bubble caps and retentions washers have helped to minimize bubble cap loss. Bubble cap erosion has also been pronounced in the region in front of the recycle return line and extending three quarters of the distance across the air distributor to the front wall. Erosion has been severe enough that replacement of many bubble caps has been required.

Refractory breakage has also been an operational problem. In the lower combustion chambers, "gunned-on" refractory has broken and spalled over most surfaces, particularly around the lower 2 to 3 feet above the air distribution plate, near the water-wall interface, around the recycle return line, and around the start-up burners and manways. In the cyclones, the abrasion resistant layers of refractory on the inlet spirals, cyclone barrels, and conical sections have also suffered breakage and spalling. Modified refractory anchors were installed in some regions and refractory "stops" were placed around the bull nose to reduce movement and breakage. In the loop seals, the original archways suffered severe breakage after 5500 hours of service and were subsequently cast using a combination of brick, castable refractory, and gunned-on refractory.

During the first four years of operation, the Nucla baghouses have experience numerous bag failures, equal to approximately 8 % of the total number of installed bags. Baghouse 2 experiences a particularly high rate of failure, with was found to be due to high deflate air flow rates. The deflate flow rate to the older baghouses was subsequently adjusted to equal the deflate pressure in baghouse 4, the new baghouse. Although the bag failure rate is still higher than acceptable, this may be due to damage to the bags during initial operation at the higher deflate air flow rate. The majority of failures have occurred in the bottom of the bag, where the dirty gas enters, and are believed to be caused by abrasion of the bag by the entering ash.

Bottom ash cooler problems have not been severe. Minor problems included the infrequent loss of bubble caps and warping of and packing of bed material around manual isolation gates. The most significant problem has been that the drains from the combustors have occasionally blocked with refractory and large pieces of bed material. In addition, the auxiliary hardware for fluidizing the inlet drains have suffered from blockage by bed material, erosion, and damage from air lances.

Concerning primary air fan flow limitations, full load had been restricted to approximately 105 MWe to allow some margin for control of excess air. Air flow tests on the fans were conducted in the fourth quarter of 1988 to determine causes for performance shortfalls. After these tests, the fan vendor concluded that there were major air flow distribution problems in the PA fan inlet boxes. Inlet fan box modifications were made, followed by additional air flow testing. These modifications produced only limited improvement in PA fan performance.

In the fourth quarter of 1989, the wheel and inlet cones of the PA fan were replaced with a more aerodynamic design as shown in Figures 2-4 and 2-5. Subsequent testing indicated that approximately two thirds of the desired improvement in performance was achieved.

Limestone feeder problems have included multiple eccentric weight bearing failures, motor burnouts, and feeder instability. The motor systems were replaced with totally enclosed motors, integral bearing, and eccentric weights, and have experienced no additional failures. Feeder stability has been poor due to pressurization of the charge hopper from transport air leaking past the rotary valves, and to a high pressure drop across the feeder cone. The addition of vent lines seems to have improved feeder stability.

Concerning loop seal flow instabilities, considerable time was spent on measuring pressure profiles and adjusting air flow distribution to the loop seals in an initially unsuccessful effort to resolve this problem. During inspection of the internals of the solids recycle system in March 1988, loose refractory pieces in the bottom of the loop seal and bent aeration nozzles in the recycle downcomers were discovered. Refractory pieces were removed, damaged nozzles were replaced, and the loop seal air distribution geometry was modified. These modifications resolved this problem.

Drum level control MFT's frequently caused difficulties during boiler restarts. This places a strain on the propane startup system both mechanically and in keeping propane inventories ready for startup. Drum level MFT's also resulted in high consumption of boiler makeup water because of delays in start-up when blowdown and drain rates are highest. This places an increased burden on the demineralizer train. This problem has never been completely corrected.

Concerning backsifting, bed material backsifts through the air distributor bubble caps into the windbox and accumulates on the windbox floor. This occurs particularly during start-up, shutdown, and low-load operation at low underbed air flow. Most of the material backsifts through bubble caps located in front of the recycle return, at the entrance to the bottom ash coolers, and along the front wall corners. Modifications to correct this problem included an accumulated bed material reinjection line and collection canisters to

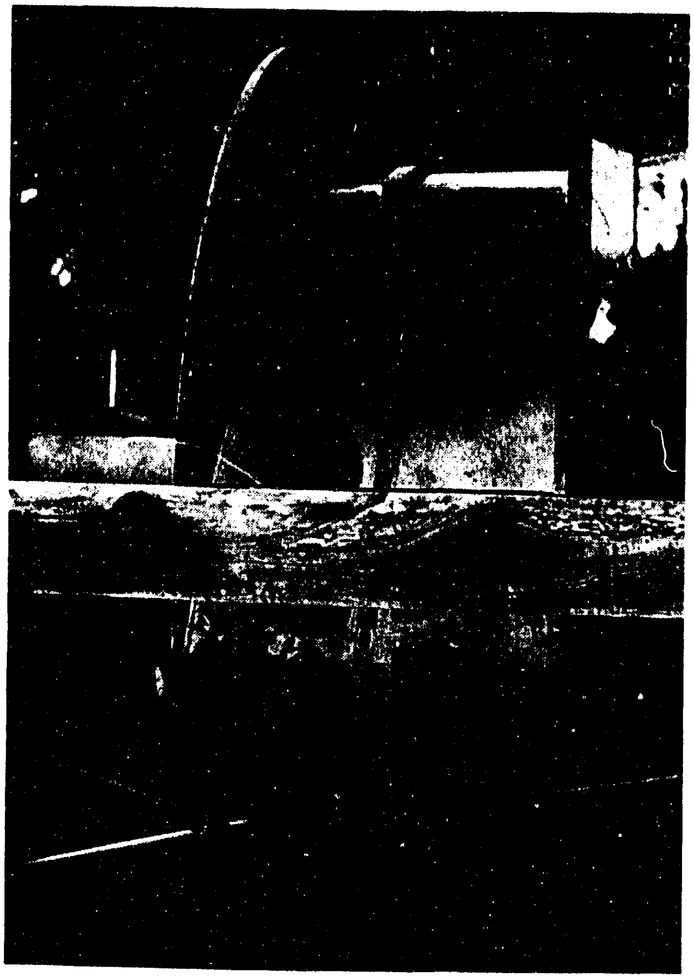


Figure 2-4. Original PA Fan Wheel Design.

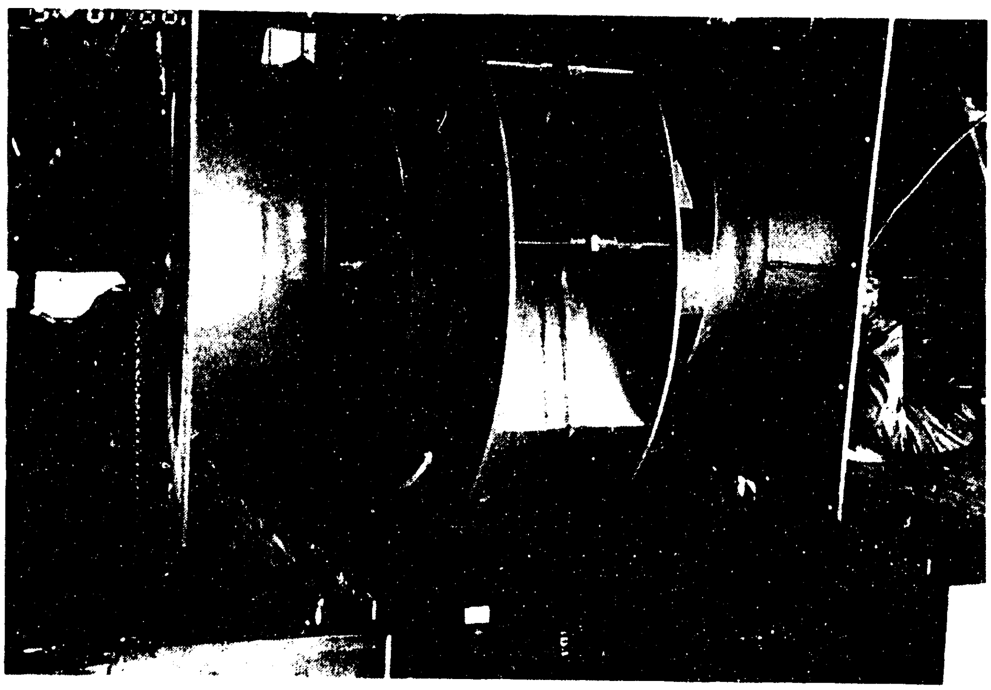


Figure 2-5. Modified PA Fan Wheel Design.

collect bed material accumulations in front of the windbox. These modifications did not effectively resolve the problem.

Section 3

PLANT COMMERCIAL PERFORMANCE STATISTICS

3.1 SUMMARY

This section describes plant commercial performance statistics for the period July 1988 through January 1991. During this time period, the plant operated with an average operating availability of 58.3% and a capacity factor of 39.6%. The average equivalent availability for the period July 1989 through January 1991 is 56.5%. The average net plant heat rate for the period September 1988 through January 1991 is 12055 Btu/Nkwh. Typical averages for non-CFB coal-fired units in the size range of the Nucla plant between 1984 and 1988 showed an availability of 83.9% and a capacity factor of 49.7%. This is according to NERC GADS data for units in the 100-199 MWe size range.

Although average availability and capacity factors are below the typical averages, there are several factors that can account for some of the differences. The demonstration nature of the project required outages for inspections of materials as detailed in Section 16. Equipment modification outages were also required for some non-design fuel tests.

CFB technology-related outages also contributed to the low average availability and capacity factors. These CFB-related problems are described in Section 2. Section 2 also contains the following information relevant to plant commercial performance statistics:

- Figures 2-2 and 2-3 show total outage time compared to in-service time and percentage contributions of various boiler components to these outages.

- Table 2-1, a detailed description of outages for the period October 1988 through January 1991.

Table 3-1 shows monthly plant commercial performance statistics including operating availability, equivalent availability, capacity factor and net plant heat rate. These items are also shown graphically in Figures 3-1 through 3-4. Tables 3-2 through 3-33 show detailed plant commercial performance statistics for each month from July 1988 through February 1991. Section 3.2 presents the definitions used in determining these statistics. More detailed plant commercial performance statistics information is available in each Annual Report.

Table 3-1. Nucla CFB Plant Commercial Performance Statistics

MONTH	OPERATING AVAIL (%)	EQUIVALENT AVAIL (%)	CAPACITY FACTOR (%)	HEAT RATE (Btu/Nkwh)
Jul-88	65.2	N/A	51.8	N/A
Aug-88	0.5	N/A	0.1	N/A
Sep-88	23.5	N/A	12.6	12427
Oct-88	68.1	N/A	47.6	12168
Nov-88	78.9	N/A	48.5	11673
Dec-88	81.6	N/A	46.1	12301
Jan-89	14.3	N/A	9.3	11883
Feb-89	26.0	N/A	13.0	13424
Mar-89	83.0	N/A	60.2	11710
Apr-89	69.1	N/A	46.2	12069
May-89	48.5	N/A	17.0	13131
Jun-89	75.5	N/A	53.3	11800
Jul-89	70.1	64.9	50.4	11911
Aug-89	52.5	29.2	23.8	12429
Sep-89	40.0	36.0	30.4	12064
Oct-89	12.5	12.5	10.0	11876
Nov-89	63.9	60.3	57.9	11854
Dec-89	65.5	64.8	56.2	11934
Jan-90	72.5	57.0	54.3	11817
Feb-90	27.3	18.4	14.9	11638
Mar-90	92.1	79.9	78.3	11672
Apr-90	87.8	75.1	83.9	11596
May-90	33.1	30.9	26.2	12127
Jun-90	69.4	69.0	54.2	12313
Jul-90	36.1	29.9	21.4	12456
Aug-90	51.8	51.7	11.4	12585
Sep-90	45.8	45.7	18.3	11992
Oct-90	63.0	62.5	31.3	12258
Nov-90	97.2	97.0	85.7	11604
Dec-90	97.9	97.6	56.2	11767
Jan-91	96.0	92.0	57.5	11102
AVG	58.3	56.5	39.6	12054.5

Figure 3-1. Nucla CFB Operating Availability
July 1988 through January 1991

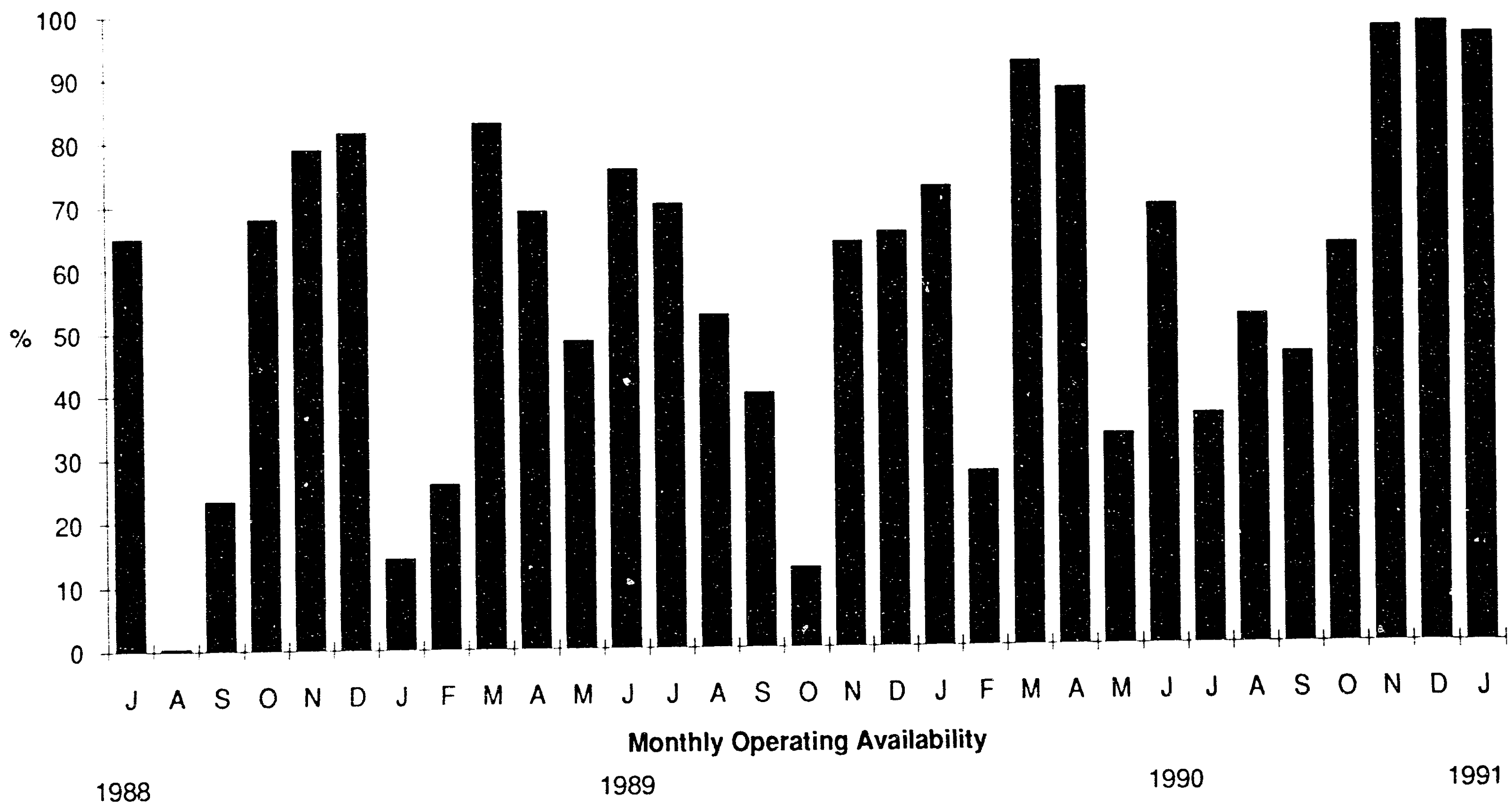


Figure 3-2. Nucla CFB Equivalent Availability July 1988 through January 1991

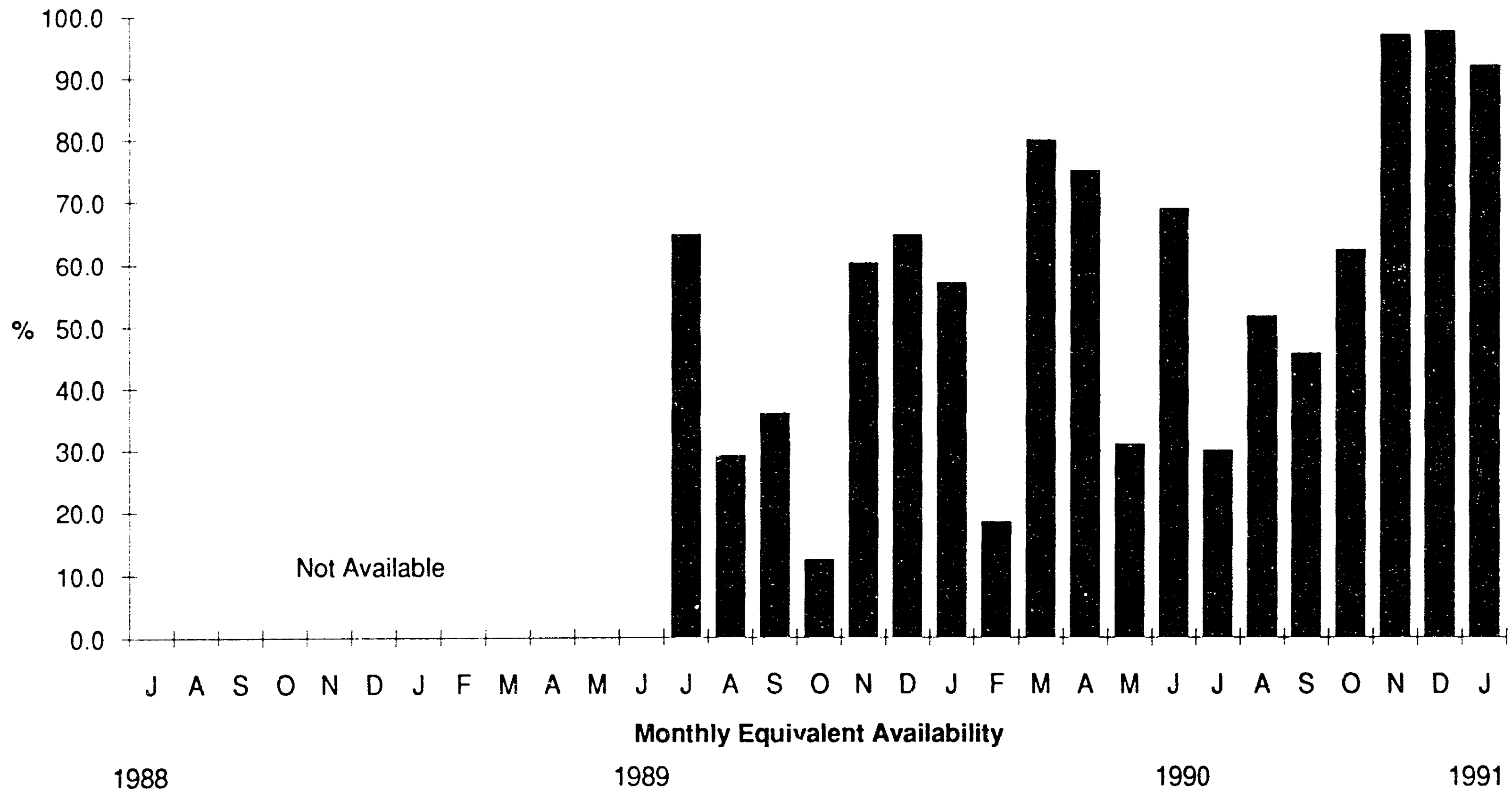


Figure 3-3. Nucla CFB Capacity Factor July 1988 through January 1991

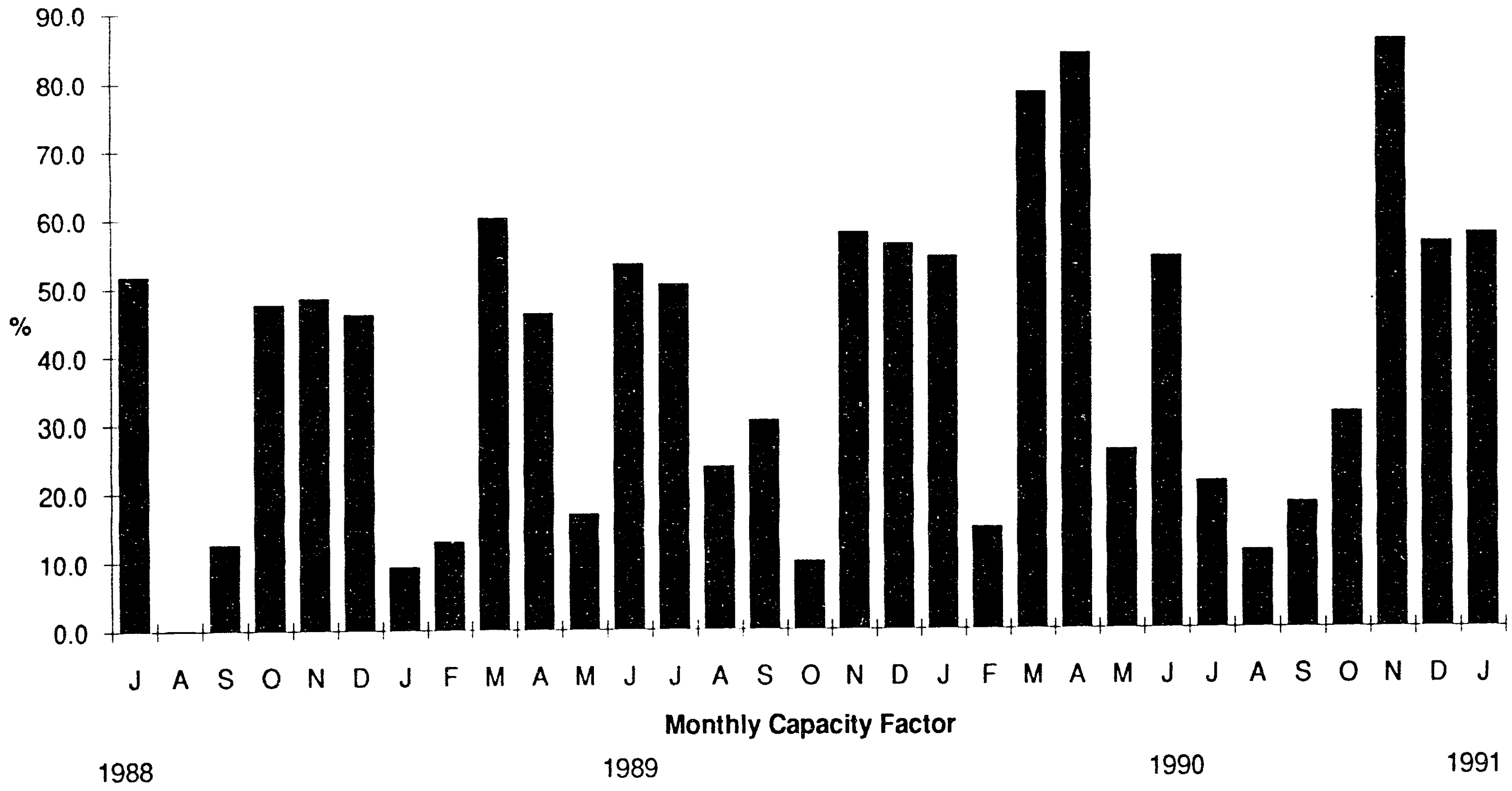


Figure 3-4. Nucla CFB Net Plant Heat Rate
July 1988 through January 1991

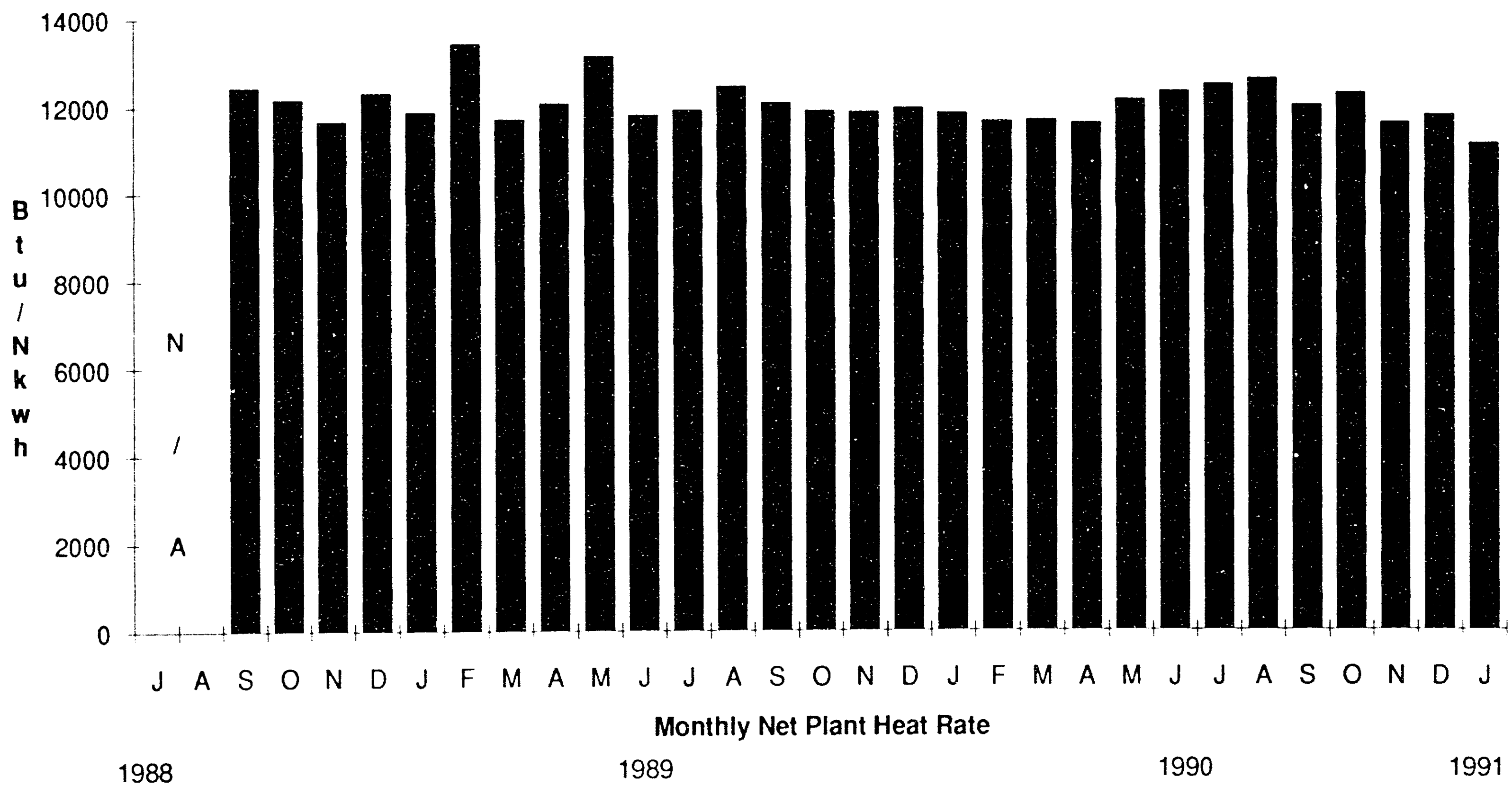


Table 3-2
PLANT COMMERICAL PERFORMANCE STATISTICS
July 1988

1. Plant Outputs and Consumptions

• Gross generation:	41705	mWhr
• Net generation:		
- Period	37042	mWhr
- On line	37500	mWhr
• Aux power use:		
- Period	4663	mWhr
- On line	4205	mWhr
• Aux power use (in %):		
- Period	11.18	%
- On line	10.08	%

2. Operating Hours

• Period hours:	744
• In Service:	485
• Coal hours:	470
• On standby:	0
• Scheduled outage:	0
• Unscheduled outage:	259

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	46642	10.50	442
2	4848	11.04	439
3	3865	9.86	392
4	28,250	59.06	480

4. Operating Availability

• Percent: 65.19 %

5. Capacity Factor

• Percent: 51.84 %

6. Major Equipment Usages

• Boiler feed pumps:	1,091,100	kWhr
• Primary air fan:	1,077,400	kWhr
• Secondary air fan:	283,500	kWhr
• Induced draft fan:	665,600	kWhr
• High pressure blowers:	63,000	kWhr
• Bottom ash cooler fan:	84,900	kWhr

7. Material Consumptions

• Total coal f' ow:	20,491	tons
• Total limestone flow:	2,087	tons
• Total warm-up gas (propane) flow:	2,514.142	kscf

* This report includes hand-calculated performance statistics for the 160 hr period between 7/22/88, 1700 hrs, and 7/29/88, 0900 hrs, when the VAX computer was out of services

Table 3-3
PLANT COMMERICAL PERFORMANCE STATISTICS
August 1988

1. Plant Outputs and Consumptions

• Gross generation:	50	mWhrs
• Net generation:		
- Period	904	mWhrs
- On line	38	mWhrs
• Aux power use:		
- Period	954	mWhrs
- On line	12	mWhrs
• Aux power use (in %):		
- Period	1,908.00	%
- On line	23.40	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	4	hrs
• Coal hours:	1.4	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	740	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	0	0.00	0
2	0	0.00	0
3	0	0.00	0
4	50	12.5	4

4. Operating Availability

• Percent:	0.54	%

5. Capacity Factor

• Percent:	0.06	%

6. Major Equipment Usages

• Boiler feed pumps:	41,500	kWhr
• Primary air fan:	172,600	kWhr
• Secondary air fan:	30,100	kWhr
• Induced draft fan:	48,500	kWhr
• High pressure blowers:	13,200	kWhr
• Bottom ash cooler fan:	8,500	kWhr

9. Material Consumptions

• Total coal flow:	5.25	tons
• Total limestone flow:	.58	tons
• Total warm-up gas (propane) flow:	2,276.594	kscf

Table 3-4
PLANT COMMERICAL PERFORMANCE STATISTICS
September 1988

1. Plant Outputs and Consumptions

• Gross generation:	9,978	mWhrs
• Net generation:		
- Period	7,900	mWhrs
- On line	8,819	mWhrs
• Aux power use:		
- Period	2,078	mWhrs
- On line	1,159	mWhrs
• Aux power use (in %):		
- Period	20.83	%
- On line	11.62	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	169	hrs
• Coal hours:	161	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	551	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	759	10.12	75
2	660	8.80	75
3	980	10.32	95
4	7,580	44.85	169

4. Operating Availability

• Percent:	23.47	%

5. Capacity Factor

• Percent:	12.60	%

6. Major Equipment Usages

• Boiler feed pumps:	413,300	kWhr
• Primary air fan:	428,300	kWhr
• Secondary air fan:	74,00	kWhr
• Induced draft fan:	190,200	kWhr
• High pressure blowers:	34,700	kWhr
• Bottom ash cooler fan:	38,900	kWhr

7. Material Consumptions

• Total coal flow:	4,527	tons
• Total limestone flow:	405	tons
• Total warm-up gas (propane) flow:	7,436	kscf

Table 3-5
PLANT COMMERICAL PERFORMANCE STATISTICS
October 1988

1. <u>Plant Outputs and Consumptions</u>

• Gross generation:	38,974	mWhr
• Net generation:		
- Period	34,310	mWhr
- On line	34,755	mWhr
• Aux power use:		
- Period	4,663	mWhr
- On line	4,219	mWhr
• Aux power use (in %):		
- Period	12.0	%
- On line	10.8	%

2. <u>Operating Hours</u>

• Period hours:	744	hrs
• In Service:	507	hrs
• Coal hours:	492	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	237	hrs

3. <u>Individual Unit Outputs</u>

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3,783	8.8	430
2	4,067	10.0	405
3	3,602	8.1	444
4	27,521	54.3	507
Unit Total	38,874	76.9	507

4. <u>Operating Availability</u>:	68.1	%
5. <u>Equivalent Availability</u>:	63.1	%
6. <u>Capacity Factor</u>:	47.6	%
7. <u>Average Heat Rate for Period</u>:	12168.1	btu/nkwh

8. <u>Major Equipment Usages</u>

• Boiler feed pumps:	1,119	mWhr
• Primary air fan:	1,067	mWhr
• Secondary air fan:	222	mWhr
• Induced draft fan:	572	mWhr
• High pressure blowers:	70	mWhr
• Bottom ash cooler fan:	81	mWhr

9. <u>Material Consumptions</u>

• Total coal flow:	20,320	tons
• Total limestone flow:	849	tons
• Total warm-up gas (propane) flow:	4,632	kscf
• Avg higher heating value of propane gas:	2,516	btu/scf

10. <u>Average Coal Analysis</u>

• Higher heating value:	10218	btu/lb
• Sulfur:	0.8	%
• Ash:	23.7	%
• Moisture:	4.9	%

11. <u>Solid waste to disposal (wet)</u>:	7482	tons

Table 3-6
PLANT COMMERICAL PERFORMANCE STATISTICS
November 1988

1. Plant Outputs and Consumptions

• Gross generation:	38,414	mWhrs
• Net generation:		
- Period	33,659	mWhrs
- On line	34,040	mWhrs
• Aux power use:		
- Period	4,756	mWhrs
- On line	4,374	mWhrs
• Aux power use (in %):		
- Period	12.4	%
- On line	11.4	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	568	hrs
• Coal hours:	496	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	152	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3,533	7.2	492
2	3,311	8.5	391
3	3,750	7.7	485
4	27,819	49.0	568
Unit Total	38414	67.6	568

4.	Operating Availability:	78.9	%
5.	Equivalent Availability:	71.5	%
6.	Capacity Factor:	48.5	%
7.	Average Heat Rate for Period:	11673.4	btu/kwh

8. Major Equipment Usages

• Boiler feed pumps:	1,249	mWhrs
• Primary air fan:	1,061	mWhrs
• Secondary air fan:	187	mWhrs
• Induced draft fan:	487	mWhrs
• High pressure blowers:	81	mWhrs
• Bottom ash cooler fan:	84	mWhrs

9. Material Consumptions

• Total coal flow:	20,732	tons
• Total limestone flow:	1,237	tons
• Total warm-up gas (propane) flow:	3,902	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	9,424	btu/lb
• Sulfur:	0.9	%
• Ash:	26.5	%
• Moisture:	6.1	%

11.	Solid waste to disposal (wet):	9,798	tons

Table 3-7
PLANT COMMERICAL PERFORMANCE STATISTICS
December 1988

1. Plant Outputs and Consumptions

• Gross generation:	37,744	mWhrs
• Net generation:		
- Period	33056	mWhrs
- On line	33537	mWhrs
• Aux power use:		
- Period	4687	mWhrs
- On line	4207	mWhrs
• Aux power use (in %):		
- Period	12.4	%
- On line	11.1	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	522	hrs
• Coal hours:	505	hrs
• On standby:	85	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	137	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	3,618	8.6	419
2	2,880	8.5	339
3	4,104	8.9	460
4	27,142	52.0	522
Unit Total	37,744	72.2	522

4. Operating Availability:	81.6	hrs
5. Equivalent Availability:	71.3	hrs
6. Capacity Factor:	46.1	hrs
7. Average Heat Rate for Period:	12,304.1	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1,167	mWhrs
• Primary air fan:	1,039	mWhrs
• Secondary air fan:	157	mWhrs
• Induced draft fan:	516	mWhrs
• High pressure blowers:	53	mWhrs
• Bottom ash cooler fan:	76	mWhrs

9. Material Consumptions

• Total coal flow:	20,895	tons
• Total limestone flow:	1,425	tons
• Total warm-up gas (propane) flow:	5,050	kscf
• Avg higher heating value of propane gas	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	9,717	btu/lb
• Sulfur:	1.0	%
• Ash:	18.2	%
• Moisture:	9.9	%

11. Solid waste to disposal (wet):	8,181	tons

Table 3-8
PLANT COMMERICAL PERFORMANCE STATISTICS
January 1989

1. Plant Outputs and Consumptions

• Gross generation:	7580	mWhrs
• Net generation:		
- Period	6013	mWhrs
- On line	6736	mWhrs
• Aux power use:		
- Period	1567	mWhrs
- On line	844	mWhrs
• Aux power use (in %):		
- Period	20.7	%
- On line	11.1	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	106	hrs
• Coal hours:	106	hrs
• On standby:	0	hrs
• Scheduled outage:	608	hrs
• Unscheduled outage:	30	hrs
• Number of Unit Starts:	0	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	700	6.7	105
2	689	6.6	105
3	665	6.3	106
4	5527	51.9	106
Unit Total	7580	71.2	106

4. Operating Availability:	14.3	%
5. Equivalent Availability:	14.3	%
6. Capacity Factor:	9.3	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11883.1	btu/nkwh
• On line (coal):	11886.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	228	mWhrs
• Primary air fan:	202	mWhrs
• Secondary air fan:	33	mWhrs
• Induced draft fan:	106	mWhrs
• High pressure blowers:	17	mWhrs
• Bottom ash cooler fan:	16	mWhrs

9. Material Consumptions

• Total coal flow:	4140	tons
• Total limestone flow:	444	tons
• Total start-up burner gas (propane) flow:	23	kscf
• Avg higher heating value of propane gas:	2550	btu/scf

10. Average Coal Analysis

• Higher heating value:	9659	btu/lb
• Sulfur:	1.7	%
• Ash:	16.5	%
• Moisture:	11.0	%

Table 3-9
PLANT COMMERICAL PERFORMANCE STATISTICS
February 1989

1. Plant Outputs and Consumptions

• Gross generation:	9580	mWhrs
• Net generation:		
- Period	7663	mWhrs
- On line	8380	mWhrs
• Aux power use:		
- Period	1917	mWhrs
- On line	1199	mWhrs
• Aux power use (in %):		
- Period	20.0	mWhrs
- On line	12.5	mWhrs

2. Operating Hours

• Period hours:	672	hrs
• In Service:	175	hrs
• Coal hours:	167	hrs
• On standby:	0	hrs
• Scheduled outage:	296	hrs
• Unscheduled outage:	201	hrs
• Number of Unit Starts:	4	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	667	6.3	105
2	835	7.7	108
3	1387	9.3	150
4	6690	38.3	175
Unit Total	9580	54.8	175

4. Operating Availability:	26.0	%
5. Equivalent Availability:	19.2	%
6. Capacity Factor:	13.0	%

7. Average Heat Rate for Period:

• On line (coal and gas):	13424.7	btu/nkwh
• On line (coal):	12660.0	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	419	mWhrs
• Primary air fan:	364	mWhrs
• Secondary air fan:	48	mWhrs
• Induced draft fan:	148	mWhrs
• High pressure blowers:	26	mWhrs
• Bottom ash cooler fan:	36	mWhrs

9. Material Consumptions

• Total coal flow:	5294	tons
• Total limestone flow:	487	tons
• Total start-up burner gas (propane) flow:	3922	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10178	btu/lb
• Sulfur:	1.0	%
• Ash:	18.0	%
• Moisture:	8.6	%

Table 3-10
PLANT COMMERICAL PERFORMANCE STATISTICS
March 1989

1. Plant Outputs and Consumptions
   - Gross generation: 49278 mWhrs
   - Net generation:
     - Period 43741 mWhrs
     - On line 44070 mWhrs
   - Aux power use:
     - Period 5537 mWhrs
     - On line 5208 mWhrs
   - Aux power use (in %):
     - Period 11.2 %
     - On line 10.6 %

2. Operating Hours
   - Period hours: 744 hrs
   - In Service: 618 hrs
   - Coal hours: 611 hrs
   - On standby: 0 hrs
   - Scheduled outage: 119 hrs
   - Unscheduled outage: 7 hrs
   - Number of Unit Starts: 2 hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	5524	9.5	582
2	4897	8.7	561
3	5248	9.0	581
4	33609	54.4	618
Unit Total	49278	79.8	618

4. Operating Availability: 83.0 %

5. Equivalent Availability: 75.4 %

6. Capacity Factor: 60.2 %

7. Average Heat Rate for Period:
   - On line (coal and gas): 11710.1 btu/nkwh
   - On line (coal): 11645.9 btu/nkwh

8. Major Equipment Usages
   - Boiler feed pumps: 1378 mWhrs
   - Primary air fan: 1275 mWhrs
   - Secondary air fan: 272 mWhrs
   - Induced draft fan: 729 mWhrs
   - High pressure blowers: 57 mWhrs
   - Bottom ash cooler fan: 84 mWhrs

9. Material Consumptions
   - Total coal flow: 25230 tons
   - Total limestone flow: 1209 tons
   - Total start-up burner gas (propane) flow: 2299 kscf
   - Avg higher heating value of propane gas: 2516 btu/scf

10. Average Coal Analysis:
    - Higher heating value: 10163 btu/lb
    - Sulfur: 0.7 %
    - Ash: 18.8 %
    - Moisture: 8.6 %

Table 3-11
PLANT COMMERICAL PERFORMANCE STATISTICS
April 1989

1. Plant Outputs and Consumptions

• Gross generation:	92648	mWhrs
• Net generation:		
- Period	81616	mWhrs
- On line	82827	mWhrs
• Aux power use:		
- Period	11032	mWhrs
- On line	9821	mWhrs
• Aux power use (in %):		
- Period	11.9	%
- On line	10.6	%

2. Operating Hours

• Period hours:	2184	hrs
• In Service:	1334	hrs
• Coal hours:	130	hrs
• On standby:	69	hrs
• Scheduled outage:	173	hrs
• Unscheduled outage:	609	hrs
• Number of Unit Starts:	9	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	5709	8.3	692
2	6780	8.9	765
3	10423	8.4	1239
4	69736	52.3	1334
Unit Total	92648	69.5	1334

4. Operating Availability: 64.2 %

5. Equivalent Availability: 36.5 %

6. Capacity Factor: 38.6 %

7. Average Heat Rate for Period:

• On line (coal and gas):	12099.4	btu/nkwh
• On line (coal):	12080.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	2541	mWhrs
• Primary air fan:	2437	mWhrs
• Secondary air fan:	266	mWhrs
• Induced draft fan:	1278	mWhrs
• High pressure blowers:	130	mWhrs
• Bottom ash cooler fan:	207	mWhrs

9. Material Consumptions

• Total coal flow:	48841	tons
• Total limestone flow:	2651	tons
• Total start-up burner gas (propane) flow:	6931	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10153	btu/lb
• Sulfur:	0.9	%
• Ash:	20.4	%
• Moisture:	6.7	%

Table 3-12
PLANT COMMERICAL PERFORMANCE STATISTICS
May 1989

1. Plant Outputs and Consumptions

• Gross generation:	13894	mWhrs
• Net generation:		
- Period	11663	mWhrs
- On line	12293	mWhrs
• Aux power use:		
- Period	2231	mWhrs
- On line	1601	mWhrs
• Aux power use (in %):		
- Period	16.1	%
- On line	11.5	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	292	hrs
• Coal hours:	276	hrs
• On standby:	69	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	383	hrs
• Number of Unit Starts:	6	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	0	ERR	0
2	0	ERR	0
3	1800	7.0	257
4	12094	41.4	292
Unit Total	13894	47.6	292

4. Operating Availability:	48.5	%
5. Equivalent Availability:	30.7	%
6. Capacity Factor:	17.0	%

7. Average Heat Rate for Period:

• On line (coal and gas):	13130.7	btu/nkwh
• On line (coal):	12680.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	403	mWhrs
• Primary air fan:	461	mWhrs
• Secondary air fan:	35	mWhrs
• Induced draft fan:	191	mWhrs
• High pressure blowers:	36	mWhrs
• Bottom ash cooler fan:	49	mWhrs

9. Material Consumptions

• Total coal flow:	7822	tons
• Total limestone flow:	337	tons
• Total start-up burner gas (propane) flow:	4742	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	9890	btu/lb
• Sulfur:	0.9	%
• Ash:	23.7	%
• Moisture:	5.3	%

Table 3-13
PLANT COMMERICAL PERFORMANCE STATISTICS
June 1989

1. Plant Outputs and Consumptions

• Gross generation:	42175	mWhrs
• Net generation:		
- Period	37613	mWhrs
- On line	37965	mWhrs
• Aux power use:		
- Period	4562	mWhrs
- On line	4210	mWhrs
• Aux power use (in %):		
- Period	10.8	%
- On line	10.0	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	544	hrs
• Coal hours:	541	hrs
• On standby:	0	hrs
• Scheduled outage:	173	hrs
• Unscheduled outage:	4	hrs
• Number of Unit Starts:	1	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	2454	9.8	250
2	3559	10.5	338
3	5077	9.9	511
4	31085	57.2	544
Unit Total	42175	77.6	544

4. Operating Availability:	75.5	%
5. Equivalent Availability:	41.2	%
6. Capacity Factor:	53.3	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11800.3	btu/nkwh
• On line (coal):	11780.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1035	mWhrs
• Primary air fan:	1077	mWhrs
• Secondary air fan:	131	mWhrs
• Induced draft fan:	611	mWhrs
• High pressure blowers:	59	mWhrs
• Bottom ash cooler fan:	84	mWhrs

9. Material Consumptions

• Total coal flow:	21677	tons
• Total limestone flow:	987	tons
• Total start-up burner gas (propane) flow:	394	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10313	btu/lb
• Sulfur:	0.7	%
• Ash:	19.4	%
• Moisture:	7.1	%

Table 3-14
PLANT COMMERICAL PERFORMANCE STATISTICS
July 1989

1. Plant Outputs and Consumptions

• Gross generation:	41285	mWhrs
• Net generation:		
- Period	36688	mWhrs
- On line	36982	mWhrs
• Aux power use:		
- Period	4597	mWhrs
- On line	4303	mWhrs
• Aux power use (in %):		
- Period	11.1	%
- On line	10.4	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	521	hrs
• Coal hours:	519	hrs
• On standby:	0	hrs
• Scheduled outage:	195	hrs
• Unscheduled outage:	27	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Avg Load (mW)	Hours
1	4035	9.0	449
2	4280	9.4	455
3	3855	9.5	406
4	29116	55.9	521
Unit Total	41285	79.2	521

4. Operating Availability:	70.1	%
5. Equivalent Availability:	64.9	%
6. Capacity Factor:	50.4	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11911.1	btu/nkwh
• On line (coal):	11877.5	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1105	mWhrs
• Primary air fan:	975	mWhrs
• Secondary air fan:	138	mWhrs
• Induced draft fan:	585	mWhrs
• High pressure blowers:	59	mWhrs
• Bottom ash cooler fan:	73	mWhrs

9. Material Consumptions:

• Total coal flow:	20414	tons
• Total limestone flow:	1342	tons
• Total start-up burner gas (propane) flow:	1304	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	10757	btu/lb
• Sulfur:	0.5	%
• Ash:	14.2	%
• Moisture:	9.1	%

Table 3-15
PLANT COMMERICAL PERFORMANCE STATISTICS
August 1989

1. Plant Outputs and Consumptions

• Gross generation:	19509	mWhrs
• Net generation:		
- Period	16600	mWhrs
- On line	17467	mWhrs
• Aux power use:		
- Period	2909	mWhrs
- On line	2042	mWhrs
• Aux power use (in %):		
- Period	14.9	%
- On line	10.5	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	338	hrs
• Coal hours:	333	hrs
• On standby:	52	hrs
• Scheduled outage:	59	hrs
• Unscheduled outage:	294	hrs
• Number of Unit Starts:	3	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	267	10.4	26
2	3198	9.8	326
3	327	10.2	32
4	15718	46.4	338
Unit Total	19509	57.6	338

4. Operating Availability:	52.5	%
5. Equivalent Availability:	29.2	%
6. Capacity Factor:	23.8	%

7. Average Heat Rate for Period:

• On line (coal and gas):	12429.1	btu/nkwh
• On line (coal):	12325.0	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	482	mWhrs
• Primary air fan:	770	mWhrs
• Secondary air fan:	56	mWhrs
• Induced draft fan:	326	mWhrs
• High pressure blowers:	55	mWhrs
• Bottom ash cooler fan:	49	mWhrs

9. Material Consumptions

• Total coal flow:	9860	tons
• Total limestone flow:	587	tons
• Total start-up burner gas (propane) flow:	3501	kscf
• Avg higher heating value of propane gas:	2615	btu/scf

10. Average Coal Analysis

• Higher heating value:	10907	btu/lb
• Sulfur:	0.6	%
• Ash:	13.0	%
• Moisture:	9.9	%

Table 3-16
PLANT COMMERICAL PERFORMANCE STATISTICS
September, 1989

1. Plant Outputs and Consumptions

• Gross generation:	24095	mWhrs
• Net generation:		
- Period	21108	mWhrs
- On line	21607	mWhrs
• Aux power use:		
- Period	2988	mWhrs
- On line	2488	mWhrs
• Aux power use (in %):		
- Period	12.4	%
- On line	10.3	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	288	hrs
• Coal hours:	281	hrs
• On standby:	0	hrs
• Scheduled outage:	170	hrs
• Unscheduled outage:	262	hrs
• Number of Unit Starts:	3	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	2092	9.4	222
2	2526	9.9	256
3	2738	10.5	260
4	16738	58.1	288
Unit Total	24095	83.6	288

4. Operating Availability:	40.0	%
5. Equivalent Availability:	36.0	%
6. Capacity Factor:	30.4	%

7. Average Heat Rate for Period:

• On line (coal and gas):	12064.2	btu/nkwh
• On line (coal):	11936.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	643	mWhrs
• Primary air fan:	651	mWhrs
• Secondary air fan:	68	mWhrs
• Induced draft fan:	377	mWhrs
• High pressure blowers:	35	mWhrs
• Bottom ash cooler fan:	36	mWhrs

9. Material Consumptions

• Total coal flow:	12069	tons
• Total limestone flow:	871	tons
• Total start-up burner gas (propane) flow:	2123	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis:

• Higher heating value:	10674	btu/lb
• Sulfur:	0.6	%
• Ash:	15.5	%
• Moisture:	8.8	%

Table 3-17
PLANT COMMERICAL PERFORMANCE STATISTICS
October 1989

1. Plant Outputs and Consumptions

• Gross generation:	8184	mWhrs
• Net generation:		
- Period	6705	mWhrs
- On line	7326	mWhrs
• Aux power use:		
- Period	1479	mWhrs
- On line	858	mWhrs
• Aux power use (in %):		
- Period	18.1	%
- On line	10.5	%

2. Operating Hours

• Period hours:	745	hrs
• In Service:	93	hrs
• Coal hours:	91	hrs
• On standby:	0	hrs
• Scheduled outage:	214	hrs
• Unscheduled outage:	437	hrs
• Number of Unit Starts:	1	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	767	10.0	76
2	853	10.5	81
3	784	9.9	79
4	5779	61.8	93
Unit Total	8184	87.6	93

4. Operating Availability:	12.5	%
5. Equivalent Availability:	12.5	%
6. Capacity Factor:	10.0	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11875.7	btu/nkwh
• On line (coal):	11752.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	210
• Primary air fan:	237
• Secondary air fan:	27
• Induced draft fan:	160
• High pressure blowers:	11
• Bottom ash cooler fan:	12

9. Material Consumptions:

• Total coal flow:	4812	tons
• Total limestone flow:	274	tons
• Total start-up burner gas (propane) flow:	1038	kscf
• Avg higher heating value of propane gas:	2516	btu/lb

10. Average Coal Analysis:

• Higher heating value:	8933	btu/lb
• Sulfur:	0.6	%
• Ash:	28.0	%
• Moisture:	7.6	%

Table 3-18
PLANT COMMERICAL PERFORMANCE STATISTICS
November 1989

1. Plant Outputs and Consumptions

• Gross generation:	45854	mWhrs
• Net generation:		
- Period	40999	mWhrs
- On line	41317	mWhrs
• Aux power use:		
- Period	4856	mWhrs
- On line	4538	mWhrs
• Aux power use (in %):		
- Period	10.6	%
- On line	9.9	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	460	hrs
• Coal hours:	452	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	260	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	4443	10.1	442
2	4783	10.9	437
3	5057	11.3	448
4	31570	68.7	460
Unit Total	45854	99.7	460

4. Operating Availability:	63.9	%
5. Equivalent Availability:	60.3	%
6. Capacity Factor:	57.9	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11853.9	btu/nkwh
• On line (coal):	11811.1	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1083	mWhrs
• Primary air fan:	976	mWhrs
• Secondary air fan:	178	mWhrs
• Induced draft fan:	867	mWhrs
• High pressure blowers:	43	mWhrs
• Bottom ash cooler fan:	60	mWhrs

9. Material Consumptions

• Total coal flow:	24532	tons
• Total limestone flow:	1420	tons
• Total start-up burner gas (propane) flow:	1443	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10051	btu/lb
• Sulfur:	0.6	%
• Ash:	20.4	%
• Moisture:	7.8	%

Table 3-19
PLANT COMMERICAL PERFORMANCE STATISTICS
December 1989

1. Plant Outputs and Consumptions

• Gross generation:	46023	mWhrs
• Net generation:		
- Period	40847	mWhrs
- On line	41417	mWhrs
• Aux power use:		
- Period	5176	mWhrs
- On line	4606	mWhrs
• Aux power use (in %):		
- Period	11.2	%
- On line	10.0	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	488	hrs
• Coal hours:	479	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	256	hrs
• Number of Unit Starts:	6	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	4812	11.4	422
2	4828	11.3	426
3	5022	11.1	451
4	31360	64.3	488
Unit Total	46023	94.4	488

4. Operating Availability:	65.5	%
5. Equivalent Availability:	64.8	%
6. Capacity Factor:	56.2	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11933.8	btu/nkwh
• On line (coal):	11826.9	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1128	mWhrs
• Primary air fan:	1170	mWhrs
• Secondary air fan:	120	mWhrs
• Induced draft fan:	816	mWhrs
• High pressure blowers:	51	mWhrs
• Bottom ash cooler fan:	77	mWhrs

9. Material Consumptions

• Total coal flow:	23972	tons
• Total limestone flow:	1600	tons
• Total start-up burner gas (propane) flow:	3499	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10223	btu/lb
• Sulfur:	0.6	%
• Ash:	18.1	%
• Moisture:	9.1	%

Table 3-20
PLANT COMMERICAL PERFORMANCE STATISTICS
January 1990

1. Plant Outputs and Consumptions

• Gross generation:	44,441	mWhrs
• Net generation:		
- Period	39,791	mWhrs
- On line	40,091	mWhrs
• Aux power use:		
- Period	4,649	mWhrs
- On line	4,349	mWhrs
• Aux power use (in %):		
- Period	10.5	%
- On line	9.8	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	540	hrs
• Coal hours:	536	hrs
• On standby:	0	hrs
• Scheduled outage:	126	hrs
• Unscheduled outage:	79	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	5970	11.3	527
2	3599	12.1	297
3	3702	12.3	300
4	31170	57.7	540
Unit Total	44441	82.3	540

4. Operating Availability:	72.5	%
5. Equivalent Availability:	57.0	%
6. Capacity Factor:	54.3	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11817.2	btu/nkwh
• On line (coal):	11757.4	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	991	mWhrs
• Primary air fan:	1069	mWhrs
• Secondary air fan:	98	mWhrs
• Induced draft fan:	661	mWhrs
• High pressure blowers:	60	mWhrs
• Bottom ash cooler fan:	71	mWhrs

9. Material Consumptions

• Total coal flow:	23509	tons
• Total limestone flow:	1141	tons
• Total start-up burner gas (propane) flow:	2172	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10013	btu/lb
• Sulfur:	0.5	%
• Ash:	19.2	%
• Moisture:	9.5	%

Table 3-21
PLANT COMMERICAL PERFORMANCE STATISTICS
February 1990

1. Plant Outputs and Consumptions

• Gross generation:	11046	mWhrs
• Net generation:		
- Period	9397	mWhrs
- On line	9886	mWhrs
• Aux power use:		
- Period	1649	mWhrs
- On line	1160	mWhrs
• Aux power use (in %):		
- Period	14.9	%
- On line	10.5	%

2. Operating Hours

• Period hours:	672	hrs
• In Service:	183	hrs
• Coal hours:	176	hrs
• On standby:	0	hrs
• Scheduled outage:	164	hrs
• Unscheduled outage:	325	hrs
• Number of Unit Starts:	4	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	469	8.9	53
2	329	9.9	33
3	1302	9.4	138
4	8945	48.8	183
Unit Total	11046	60.3	183

4. Operating Availability:	27.3	%
5. Equivalent Availability:	18.4	%
6. Capacity Factor:	14.9	%

7. Average Heat Rate for Period:

• On line (gas and coal):	11637.7	btu/nkwh
• On line (coal):	11432.4	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	101	mWhrs
• Primary air fan:	131	mWhrs
• Secondary air fan:	4	mWhrs
• Induced draft fan:	26	mWhrs
• High pressure blowers:	31	mWhrs
• Bottom ash cooler fan:	10	mWhrs

9. Material Consumptions

• Total coal flow:	5882	tons
• Total limestone flow:	271	tons
• Total start-up burner gas (propane) flow:	3160	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10268	btu/lb
• Sulfur:	0.5	%
• Ash:	18.1	%
• Moisture:	9.1	%

* - AUX POWER CONSUMPTION VALUES FOR THE MONTH WERE APPROXIMATED DUE TO PROBLEMS WITH THE ASSOCIATED MEGAWATT METER.

Table 3-22
PLANT COMMERICAL PERFORMANCE STATISTICS
March 1990

1. Plant Outputs and Consumptions

• Gross generation:	64088	mWhrs
• Net generation:		
- Period	58020	mWhrs
- On line	58131	mWhrs
• Aux power use:		
- Period	6069	mWhrs
- On line	5958	mWhrs
• Aux power use (in %):		
- Period	9.5	%
- On line	9.3	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	685	hrs
• Coal hours:	682	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	59	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	5845	11.8	493
2	5956	11.9	499
3	8067	11.9	677
4	44221	64.5	685
Unit Total	64088	93.5	685

4. Operating Availability:	92.1	%
5. Equivalent Availability:	79.9	%
6. Capacity Factor:	78.3	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11672.0	btu/nkwh
• On line (coal):	11643.7	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1382	mWhrs
• Primary air fan:	1358	mWhrs
• Secondary air fan:	152	mWhrs
• Induced draft fan:	994	mWhrs
• High pressure blowers:	99	mWhrs
• Bottom ash cooler fan:	90	mWhrs

9. Material Consumptions

• Total coal flow:	32528	tons
• Total limestone flow:	1757	tons
• Total start-up burner gas (propane) flow:	1294	kscf
• Avg high heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10405	btu/lb
• Sulfur:	0.5	%
• Ash:	17.3	%
• Moisture:	8.8	%

Table 3-23
PLANT COMMERICAL PERFORMANCE STATISTICS
April 1990

1. Plant Outputs and Consumptions

• Gross generation:	66417	mWhrs
• Net generation:		
- Period	60050	mWhrs
- On line	60244	mWhrs
• Aux power use:		
- Period	6367	mWhrs
- On line	6173	mWhrs
• Aux power use (in %):		
- Period	9.6	%
- On line	9.3	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	632	hrs
• Coal hours:	629	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	88	hrs
• Number of Unit Starts:	2	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Avg Load (mW)	Hours
1	7205	12.4	583
2	7365	12.3	599
3	7430	11.9	625
4	44417	70.3	632
Unit Total	66417	105.1	632

4. Operating Availability:	87.8	%
5. Equivalent Availability:	75.1	%
6. Capacity Factor:	83.9	%

7. Average Heat Rate for Period:

• On line (coal and gas):	11596.0	btu/nkwh
• On line (coal):	11576.6	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1422	mWhrs
• Primary air fan:	1523	mWhrs
• Secondary air fan:	174	mWhrs
• Induced draft fan:	1134	mWhrs
• High pressure blowers:	109	mWhrs
• Bottom ash cooler fan:	92	mWhrs

9. Material Consumptions

• Total coal flow:	33504	tons
• Total limestone flow:	1956	tons
• Total start-up burner gas (propane) flow:	1092	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10407	btu/lb
• Sulfur:	0.5	%
• Ash:	17.2	%
• Moisture:	8.7	%

Table 3-24
PLANT COMMERICAL PERFORMANCE STATISTICS
May 1990

1. Plant Outputs and Consumptions

• Gross generation:	21412	mWhrs
• Net generation:		
- Period	18558	mWhrs
- On line	19286	mWhrs
• Aux power use:		
- Period	2854	mWhrs
- On line	2126	mWhrs
• Aux power use (in %):		
- Period	13.3	%
- On line	9.9	%

2. Operating Hours

• Period hours:	744	hrs
• In Service:	246	hrs
• Coal hours:	240	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	498	hrs
• Number of Unit Starts:	4	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	2370	10.8	220
2	2116	10.0	212
3	2189	10.4	211
4	14737	59.8	246
Unit Total	21412	86.9	246

4. Operating Availability:	33.1	%
5. Equivalent Availability:	30.9	%
6. Capacity Factor:	26.2	%

7. Average Heat Rate for Period:

• On line (coal and gas):	12127.1	btu/nkwh
• On line (coal):	12091.1	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	538	mWhrs
• Primary air fan:	541	mWhrs
• Secondary air fan:	63	mWhrs
• Induced draft fan:	354	mWhrs
• High pressure blowers:	98	mWhrs
• Bottom ash cooler fan:	38	mWhrs

9. Material Consumptions

• Total coal flow:	11232	tons
• Total limestone flow:	903	tons
• Total start-up burner gas (propane) flow:	1213	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10369	btu/lb
• Sulfur:	17.8	%
• Ash:	0.6	%
• Moisture:	8.4	%

Table 3-25
PLANT COMMERICAL PERFORMANCE STATISTICS
June 1990

1. Plant Outputs and Consumptions

• Gross generation:	42965	mWhrs
• Net generation:		
- Period	38249	mWhrs
- On line	38652	mWhrs
• Aux power use:		
- Period	4716	mWhrs
- On line	4313	mWhrs
• Aux power use (in %):		
- Period	11.0	%
- On line	10.0	%

2. Operating Hours

• Period hours:	720	hrs
• In Service:	500	hrs
• Coal hours:	486	hrs
• On standby:	0	hrs
• Scheduled outage:	0	hrs
• Unscheduled outage:	220	hrs
• Number of Unit Starts:	4	hrs

3. Individual Unit Outputs

Unit	Output (mWhr)	Ave Load (mW)	Hours
1	4587	9.5	481
2	4644	9.9	469
3	4516	9.8	463
4	29218	58.5	500
Unit Total	42965	86.0	500

4. Operating Availability:	69.4	%
5. Equivalent Availability:	69.0	%
6. Capacity Factor:	54.2	%

7. Average Heat Rate for Period:

• On line (coal and gas):	12313.9	btu/nkwh
• On line (coal):	12272.3	btu/nkwh

8. Major Equipment Usages

• Boiler feed pumps:	1088	mWhrs
• Primary air fan:	986	mWhrs
• Secondary air fan:	122	mWhrs
• Induced draft fan:	703	mWhrs
• High pressure blowers:	133	mWhrs
• Bottom ash cooler fan:	69	mWhrs

9. Material Consumptions

• Total coal flow:	22290	tons
• Total limestone flow:	1960	tons
• Total start-up burner gas (propane) flow:	2517	kscf
• Avg higher heating value of propane gas:	2516	btu/scf

10. Average Coal Analysis

• Higher heating value:	10596	btu/lb
• Sulfur:	0.6	%
• Ash:	16.6	%
• Moisture:	7.8	%

Table 3-26
PLANT COMMERICAL PERFORMANCE STATISTICS
July 1990

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	17,846	268,301	414,020	969,108
NET, MWh	15,920	243,462	374,594	867,982
STATION SERVICE				
MWh	1,926	24,839	39,426	101,126
PERCENT OF GROSS	10.8	9.3	9.5	10.4
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	744.00	5,087.00	8,760.00	27,768.00
SERVICE HOURS	268.28	3,047.75	4,712.32	15,386.22
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	0	28,937	73,288	246,343
HOURS	0.00	289.37	732.88	2,463.43
FORCED OUTAGES				
NET GEN. LOSS, MWh	47,572	174,988	356,263	971,258
HOURS	475.72	1,749.88	3,262.63	9,712.58
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	4,604	34,433	54,618	205,763
HOURS	149.42	753.15	1,515.58	5,513.83
FACTORS (NET)				
AVAILABILITY, %	36.1	59.9	54.4	56.2
EQUIV. AVAILABILITY, %	29.9	53.1	48.2	48.6
CAPACITY, %	21.4	47.9	42.8	31.3
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	11,111.9	10,697.8	10,649.3	10,797.4
NET, Btu/kWh	12,456.3	11,789.2	11,770.2	12,055.4

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-27
PLANT COMMERICAL PERFORMANCE STATISTICS
August 1990

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	9,494	277,795	403,943	978,602
NET, MWh	8,458	251,920	365,521	876,440
STATION SERVICE				
MWh	1,036	25,875	38,422	102,162
PERCENT OF GROSS	10.9	9.3	9.5	10.4
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	744.00	5,831.00	8,760.00	28,512.00
SERVICE HOURS	145.33	3,193.08	4,519.40	15,531.55
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	0	28,937	67,348	246,343
HOURS	0.00	289.37	673.48	2,463.43
FORCED OUTAGES				
NET GEN. LOSS, MWh	35,830	210,818	332,675	1,007,088
HOURS	358.30	2,108.18	3,326.75	10,070.88
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	135	34,567	40,038	205,897
HOURS	12.23	765.38	1,233.53	5,526.07
FACTORS (NET)				
AVAILABILITY, %	51.8	58.9	54.3	56.0
EQUIV. AVAILABILITY, %	51.7	53.0	49.8	48.7
CAPACITY, %	11.4	43.2	41.7	30.7
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	11,211.1	10,715.3	10,645.5	10,801.4
NET, Btu/kWh	12,584.7	11,815.9	11,764.5	12,060.5

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-28
PLANT COMMERICAL PERFORMANCE STATISTICS
September 1990

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	14,692	292,487	394,182	993,294
NET, MWh	13,206	265,126	356,800	889,646
STATION SERVICE				
MWh	1,486	27,361	37,382	103,648
PERCENT OF GROSS	10.1	9.4	9.5	10.4
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	720.00	6,551.00	8,760.00	29,232.00
SERVICE HOURS	173.63	3,366.72	4,405.62	15,705.18
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	0	28,937	50,363	246,343
HOURS	0.00	289.37	503.63	2,463.43
FORCED OUTAGES				
NET GEN. LOSS, MWh	39,022	249,840	345,423	1,046,110
HOURS	390.22	2,498.40	3,454.23	10,461.10
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.0
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	41	34,609	37,383	205,939
HOURS	3.45	768.83	981.47	5,529.52
FACTORS (NET)				
AVAILABILITY, %	45.8	57.4	54.8	55.8
EQUIV. AVAILABILITY, %	45.7	52.2	50.6	48.6
CAPACITY, %	18.3	40.5	40.7	30.4
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,778.8	10,718.5	10,653.3	10,801.1
NET, Btu/kWh	11,991.7	11,824.7	11,769.5	12.059.5

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-29
PLANT COMMERICAL PERFORMANCE STATISTICS
October 1990

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	26,347	318,834	412,209	1,019,641
NET, MWh	23,560	288,685	372,904	913,205
STATION SERVICE				
MWh	2,787	30,149	39,305	106,435
PERCENT OF GROSS	10.6	9.5	9.5	10.4
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	745.00	7,296.00	8,760.00	29,977.00
SERVICE HOURS	469.35	3,836.07	4,781.67	16,174.53
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	12,738	41,675	41,675	259,082
HOURS	127.38	416.75	416.75	2,590.82
FORCED OUTAGES				
NET GEN. LOSS, MWh	14,827	264,667	316,507	1,060,937
HOURS	148.27	2,646.67	3,165.07	10,609.37
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	339	34,947	37,721	206,277
HOURS	33.87	802.70	1015.33	5,563.38
FACTORS (NET)				
AVAILABILITY, %	63.0	58.0	59.1	56.0
EQUIV. AVAILABILITY, %	62.5	53.2	54.8	49.0
CAPACITY, %	31.6	39.6	42.6	30.5
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,961.5	10,738.6	10,679.8	10,805.2
NET, Btu/kWh	12,254.4	11,860.1	11,805.5	12,064.6

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-30
PLANT COMMERICAL PERFORMANCE STATISTICS
November 1990

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	67,614	386,448	432,947	1,087.255
NET, MWh	61,449	350,134	392,023	974,654
STATION SERVICE				
MWh	6,165	36,314	40,924	112,600
PERCENT OF GROSS	9.1	9.4	9.5	10.4
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	720.00	8,016.00	8,760.00	30,697.00
SERVICE HOURS	699.92	4,535.98	5,021.75	16,874.45
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	2,008	43,683	43,683	261,090
HOURS	20.08	436.83	436.83	2,610.90
FORCED OUTAGES				
NET GEN. LOSS, MWh	0	264,667	290,490	1,060,937
HOURS	0.00	2,646.67	2,904.90	10,609.37
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	175	35,122	35,730	206,452
HOURS	13.00	815.70	853.67	5,576.38
FACTORS (NET)				
AVAILABILITY, %	97.2	61.5	61.9	56.9
EQUIV. AVAILABILITY, %	97.0	57.2	57.8	50.1
CAPACITY, %	85.3	43.7	44.8	31.8
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,546.4	10,705.0	10,677.6	10,789.2
NET, Btu/kWh	11,604.5	11,815.2	11,792.3	12,035.6

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-31
PLANT COMMERICAL PERFORMANCE STATISTICS
December 1990

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	60,860	447,308	447,308	1,148,115
NET, MWh	55,039	405,174	405,174	1,029,694
STATION SERVICE				
MWh	5,821	42,134	42,134	118,421
PERCENT OF GROSS	9.6	9.4	9.4	10.3
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	744.00	8,760.00	8,760.00	31,441.00
SERVICE HOURS	728.18	5,264.17	5,264.17	17,602.63
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	0	43,683	43,683	261,090
HOURS	0.00	436,83	436.83	2,610.90
FORCED OUTAGES				
NET GEN. LOSS, MWh	1,582	266,248	266,248	1,062,518
HOURS	15.82	2,662.48	2,662.48	10,625.18
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	165	35,288	35,288	206,618
HOURS	11.3	827.00	827.00	5,587.68
FACTORS (NET)				
AVAILABILITY, %	97.9	64.6	64.6	57.9
EQUIV. AVAILABILITY, %	97.7	60.6	60.6	51.2
CAPACITY, %	74.0	46.3	46.3	32.8
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,641.9	10,696.4	10,696.4	10,781.3
NET, Btu/kWh	11,767.3	11,808.7	11,808.7	12,021.3

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-32
PLANT COMMERICAL PERFORMANCE STATISTICS
January 1991

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	47,774	47,774	450,293	1,195.889
NET, MWh	42,767	42,767	407,509	1,072,461
STATION SERVICE				
MWh	5,007	5,007	42,784	123,428
PERCENT OF GROSS	10.5	10.5	9.5	10.3
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	744.00	744.00	8,760.00	32,185.00
SERVICE HOURS	713.95	713.95	5,438.67	18,316.58
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	345	345	31,482	261,435
HOURS	3.45	3.45	314.82	2,614.35
FORCED OUTAGES				
NET GEN. LOSS, MWh	2,660	2,660	261,000	1,065,178
HOURS	26.60	26.60	2,610.00	10,651.78
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	2,957	2,957	26,723	209,575
HOURS	62.92	62.92	659.48	5,650.60
FACTORS (NET)				
AVAILABILITY, %	96.0	96.0	66.6	58.8
EQUIV. AVAILABILITY, %	92.0	92.0	63.6	52.2
CAPACITY, %	57.5	57.5	46.5	33.3
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	11,102.0	11,102.0	10,762.7	10.795.0
NET, Btu/kWh	12,401.8	12,401.8	11,892.7	12,037.4

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

Table 3-33
PLANT COMMERICAL PERFORMANCE STATISTICS
February 1991

	CURRENT MONTH	YEAR TO DATE	TWELVE MONTHS	LIFE TO DATE
PRODUCTION				
GENERATION				
GROSS, MWh	2,955	50,729	442,343	1,198,844
NET, MWh	2,664	45,431	399,668	1,075,125
STATION SERVICE				
MWh	291	5,298	42,675	123,719
PERCENT OF GROSS	9.8	10.4	9.6	10.3
MAX. NET CAPACITY, MW	100	100	100	100
UNIT OPERATION				
PERIOD HOURS	672.00	1,416.00	8,760.00	32,857.00
SERVICE HOURS	32.18	746.13	5,288.05	18,348.77
SCHEDULED OUTAGES				
NET GEN. LOSS, MWh	58,472	58,817	73,563	319,907
HOURS	584.72	588.17	735.63	3,199.07
FORCED OUTAGES				
NET GEN. LOSS, MWh	0	2,660	228,470	1,065.178
HOURS	0.00	26.60	2,284.70	10,651.78
SCHEDULED CURTAILMENTS				
NET GEN. LOSS, MWh	0	0	0	2,850
HOURS	0.00	0.00	0.00	100.00
FORCED CURTAILMENTS				
NET GEN. LOSS, MWh	0	2,957	20,776	209,575
HOURS	0.000	62.92	528.68	5,650.60
FACTORS (NET)				
AVAILABILITY, %	13.0	56.6	65.5	57.8
EQUIV. AVAILABILITY, %	13.0	54.5	63.1	51.4
CAPACITY, %	4.0	32.1	45.6	32.7
PERFORMANCE DATA				
UNIT HEAT RATE				
GROSS, Btu/kWh	10,434.2	11,063.1	10,758.2	10,794.2
NET, Btu/kWh	11,573.3	12,353.2	11,907.0	12,036.3

NOTE: GENERATION IS IN MWh; CAPACITY IS IN MW

3.2 DEFINITIONS FOR PLANT COMMERCIAL PERFORMANCE STATISTICS

The following definitions are used by CUEA in generating plant commercial performance statistics that are presented and discussed in Section 3.1. These definitions are adopted from those used by the North American Electric Reliability Council in their report "Data Reporting Instructions for the Generating Availability Data System", October, 1990.

The definition for equivalent availability does not include seasonally adjusted derate hours which is included with planned and unplanned derate hours in the NERC GADS definition.

Availability Factor:	(Available Hours/Period Hours)*100%
Available:	State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.
Available Hours (AH):	Sum of all Service Hours and Reserve Shutdown Hours;
	Period Hours less Planned Outage Hours, Forced Outage Hours, and Maintenance Outage Hours.
Average Period Heat Rate (On Line, Net):	[Coal HHV * Coal Consumed] + [(Gas HHV * Gas Consumed (On-Line)) / Net Generation]
Capacity Factor:	(Gross Generation / Gross Maximum Capacity) * 100%

Note: In Section 3 tables and figures, Capacity Factors are calculated using the capacity factor equation prior to July, 1990 and using the net capacity factor equation from July, 1990 to present.

Equivalent Availability :	[(Available Hours - (Planned Derate + Unplanned Derate))/Period Hours]*100%

Note: In Section 3 tables and figures, Equivalent Availabilities are calculated using the gross equivalent availability equation prior to July, 1990 and using the equivalent availability equation from July, 1990 to present.

Forced Derating/Curtailment: An unplanned component failure or other condition that requires the load on the unit be reduced immediately or before the next weekend.

Forced Outage: An unplanned component failure or other condition that requires the unit be removed from service immediately or before the next weekend.

Gross Actual Generation: Actual number of electrical megawatt hours generated by the unit during the period being considered.

Gross Capacity Factor: (Gross Actual Generation / (Period Hours * Gross Maximum Capacity)) * 100%

Gross Equivalent Availability: (Gross Maximum Capacity * Available Hours - MWh loss due to Derating) / (Gross Maximum Capacity * Period Hours)

Note: In Section 3 tables and figures, Equivalent Availabilities are calculated using the gross equivalent availability equation prior to July, 1990 and using the equivalent availability equation from July, 1990 to present.

Gross Maximum Capacity: Maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal, or other deratings.

Maintenance Derating: The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Maintenance Outage: The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a maintenance outage may occur anytime during the year, have flexible start dates, and may or may not have a predetermined duration.

Net Actual Generation (MWh): Actual number of electrical megawatt hours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

Net Capacity Factor: [Net Actual Generation/(Period Hours * Net Maximum Capacity)]*100%

Note: In Section 3 tables and figures, Capacity Factors are calculated using the capacity factor equation prior to July, 1990 and using the net capacity factor equation from July, 1990 to present.

Net Maximum Capacity: Gross maximum capacity less the unit capacity utilized for that unit's station service or auxiliaries.

Number of Unit Starts: The number of times Unit 4 was electrically connected to the system during the reporting period.

Period Hours: Number of hours a unit was in the active state.

Planned Derating: The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage: The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).

Reserve Shutdown: A state in which a unit is available but not in service for economic reasons.

Scheduled Derating Extension: The extension of a maintenance or planned derating.

Scheduled Deratings/ Curtailments: Scheduled deratings are a combination of maintenance and planned deratings.

Scheduled Outage Extension: The extension of a maintenance or planned outage.

Scheduled Outages: Scheduled outages are a combination of maintenance and planned outages.

Service Hours: Total number of hours a unit was electrically connected to the system.

Unavailable: State in which a unit is not capable of operation because of the failure of a component, external restriction, testing, work being performed, or some adverse condition.

Unavailable Hours: Sum of all Forced Outage Hours, Maintenance Outage Hours, and Planned Outage Hours.

Unplanned Derated: Sum of all hours experienced during Forced Deratings, Maintenance Deratings and Scheduled Derating Extensions of any Maintenance Deratings.

Unplanned Outage: Sum of all hours experienced during Forced Outages, Maintenance Outages, and Scheduled Outage Extensions of any Maintenance Outages.

Section 4

COLD-MODE SHAKEDOWN AND CALIBRATION

During the period from February 1987 through March 1989, the cold-mode shakedown phase of the testing program was completed. The purpose of the cold-mode shakedown and calibration phase was to verify the manufacturer's calibration curves for the various instruments and to develop calibration curves for instruments that did not have calibration information provided. Furthermore, specialized instrumentation and computer programs were developed to support the test program. The solids preparation laboratory was also commissioned and sample preparation procedures were developed.

4.1 INSTRUMENTATION CALIBRATIONS

Calibrations were performed on the following instrument systems:

- Air Flow Instruments
- Coal Flow Weigh Belts
- Limestone Feeders
- Bottom Ash Weigh Bins
- Fly Ash Flow Measurements
- Test Instrumentation

Activities in each of these tasks are discussed below.

4.1.1 Air Flow Calibration

Figure 4-1 shows a schematic of the air system on the Nucla CFB. The primary air fan supplies air to the windbox, two sets of lower injection ports, three in-bed start-up burners, and miscellaneous air flows to one coal feeder, one loop seal expansion joint and one lower injection point for combustors A and B. Air flow to the primary air fan is manually measured at the inlet of the fan by an annubar (in 1990 this measurement was added to the data highway). Air foils are used to measure the air flow to the windbox (GFT1C & GFT1D), the Lower injection ports (GFT1W, GFT1X, GFT1Y, & GFT1Z), and the start-up burners (GFT2I, GFT2J, & GFT2K for combustor A and GFT2L, GFT2M, & GFT2N for combustor B). The miscellaneous air flows shown in Figure 4-1 are not measured. The air flows to the loop seal injection point contain rotometers that were not calibrated. The loop seal expansion joint air flow is also not measured. Other unmeasured air flows include the vortex finder cooling air, limestone transport air, and miscellaneous instrument air flows. Only

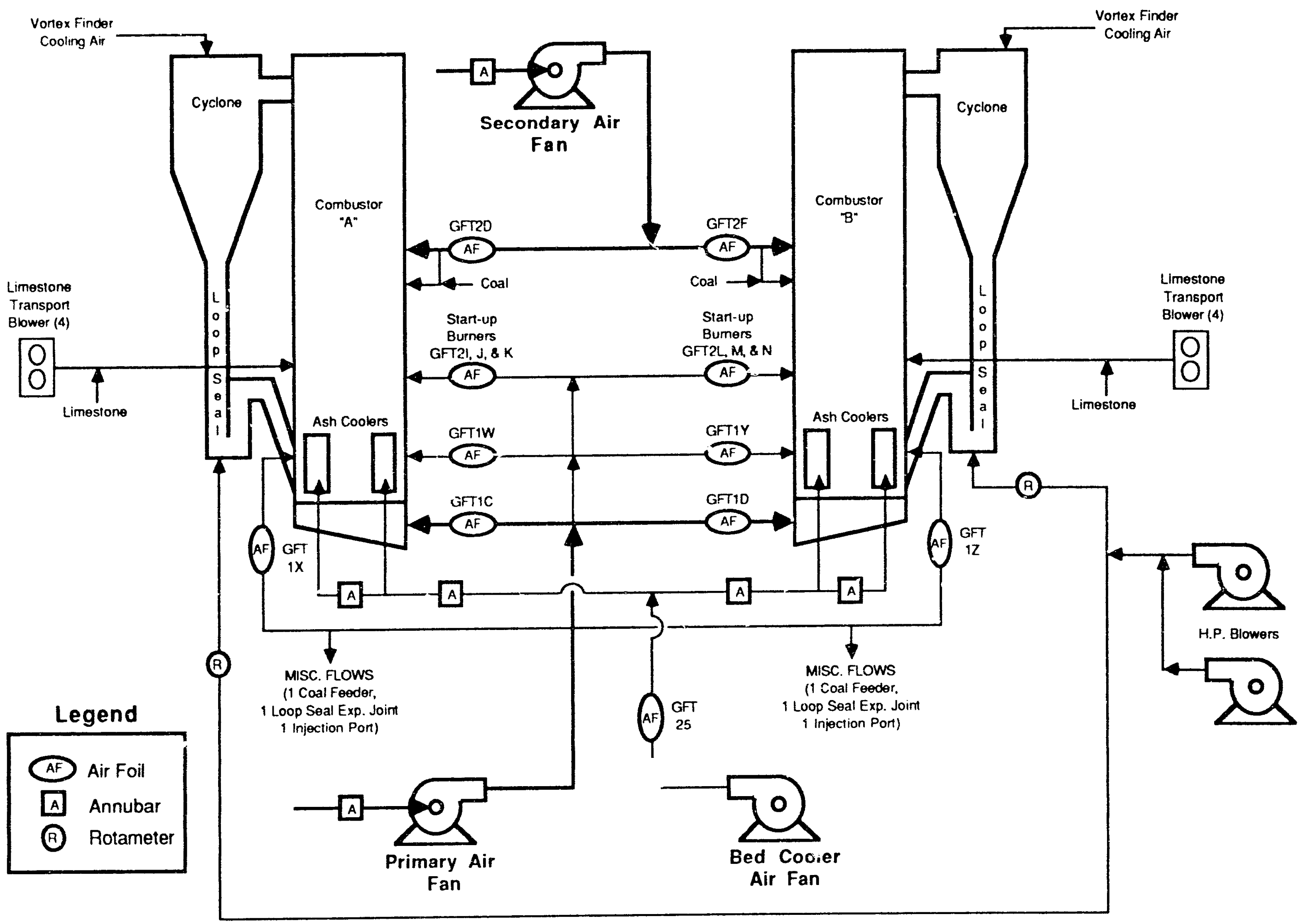


Figure 4-1. Schematic of Air Flow Measurement System at Nucla

one of the six start-up burner air foils were calibrated. These are similar in design and were assumed to have the same calibration. This is a safe assumption with regard to unit performance testing since the contribution to the total air flow from the start-up burners is small.

The secondary air fan provides air to the secondary air injection ports and to the front wall coal feeders. The air flow to the secondary air fan is measured manually at the fan inlet by an annubar (this measurement was also added to the data highway in 1990). Air foils measure the flow of secondary air to each of the combustors (GFT2D & GFT2F), including the coal feeder air. Two 100% high pressure blowers supply aeration air to the loop seals. Rotometers measure the air flow to the loop seals. The bottom ash cooling fan provides cooling air to the four bed ash coolers (two for each combustor). Air foil GFT25 measures the total air to all four bed ash coolers. Annubars measure the air flow to the individual ash coolers.

In addition to the air flow calibrations, an air foil is installed to measure the flue gas flow rate at the outlet of the new baghouse. This air foil was also calibrated as part of the air flow calibration program.

Air flow calibrations were performed using a Fechheimer probe which traverses the ducts upstream of the air foils. The Fechheimer probe is a air flow measuring device, similar to a pitot tube, that measures not only the velocity of the gas, but also measures the directional component of the flow. Because of the probe's ability to measure the directional component flow, the Fechheimer is considered more appropriate than a pitot tube for this type of application. Two Fechheimer probes of different lengths were used for the air flow calibrations. Both probes were calibrated at the Babcock & Wilcox Instrument Laboratory prior to use at Nucla.

Air flow calibrations were performed by measuring the velocity within the duct at several traverse points upstream of the air foil. Sample locations were installed in the ducts to conform to ASME Performance Test Code 4.4. Most of the traverses were performed at three flow rates in a V-notch load ramp, where the gas flow rate was first increased and then decreased. This flow pattern was used to look for possible hysteresis in the flow elements.

Calibrations were performed under hot conditions when the unit was operating and cold conditions when the unit was shut down with just the fans operating. The following flow traverse calibrations were made during the reporting period:

- Hot calibration of combustor A windbox flow (GFT1C) at 50% load during plant operation.

- Hot calibrations of lower injection ports for both combustors (GFT1W, GFT1X, GFT1Y, & GFT1Z) at 50% load during plant operation.

- Cold calibrations were performed for the secondary air airfoils GFT2D & GFT2F, and the combustor windbox flows GFT1C & GFT1D.

- Hot calibrations at 40 and 75 percent load for the secondary air airfoils GFT2D & GFT2F, for the combustor A & B windbox flows GFT1C & GFT1D, and for the lower injection nozzles GFT1W, GFT1X, GFT1Y, & GFT1Z.

- Hot calibration of the bottom ash cooling air airfoil, GFT25, at 40, 27, and 53 klb/hr.

- Hot calibration of the new baghouse outlet duct at 40 and 80 percent load.

- Cold calibration of the bottom ash cooling air airfoil, GFT25, at 50, 75, and 100 percent of design flow in a V-notch load ramp.

- Cold calibration of the primary air ducts to the lower air injection ports (GFT1W, GFT1X, GFT1Y, and GFT1Z) at minimum flow, 100 percent design flow, and halfway between minimum and design load in a V-notch ramp.

- Hot calibration of the air duct to start-up burner 4C. This air foil was considered to be representative of all of the start-up burner airfoils. Traverses were performed at approximately 50,75,100,75, and 50 percent of design air flow, in that order. An additional traverse was performed under cold conditions at 15 percent of design air flow. This flow corresponds to the amount of cooling air passing through the burners under normal operations of the boiler.

Based on these calibration runs, constants within the plant control system and the performance calculation package were changed to correspond to the new calibrations. Adjustments were made to the DCS calculations for secondary air readings from both combustors (GFT2D & GFT2F), the windbox primary air flow to both combustors (GFT1C and GFT1D), and the new baghouse outlet gas flow rate. The calibrated flow rate correlations were used to calculate the flow rate of all air streams in the performance calculation package used by the demonstration program. In addition, the air flow inputs to the performance calculation package were pressure compensated while those on the plant's distributed control system are not.

A hand-held anemometer was used to measure the cooling air flow to the two cyclone vortex finders during hot operations with the unit at 55 MW. The air flow to each vortex finder was measured to be approximately 3,550 lb/hr. Air flow into the vortex finder is drawn into the cyclones from the boiler house by the negative pressure in the cyclones. Therefore a constant value of 7,100 lb/hr was used for this flow rate in the performance calculations.

Most of the air flow instruments provided for the Nucla CFB are airfoil sensors. Figure 4-2 shows a schematic of an air foil. The configuration shown is typical of large ducts. In smaller ducts, such as the bottom ash cooling air duct, only the center foil is installed. The present installation at Nucla has a ΔP transmitter installed between the total pressure tap and only one of the static pressure taps. There was concern that the use of only one static pressure tap could introduce an unacceptable measurement error due to maldistribution of air flow between both sides of the central foil.

In order to assess the potential error of this installation, a test was performed on the bottom ash cooling airfoil, GFT25. During this test, a manometer was hooked up between the unused static pressure tap and the total pressure tap. Pressure drop readings were taken at four air flow rates. Air flow rate data were also taken from the DCS. Table 4-1 contains the results of this test. The recorded DCS flow rate was used to back-calculate the ΔP reading across the connected pressure taps. The actual flow rate shown in column 6 is based on the flow traverses that were described above and the ΔP in column 2 (the used tap ΔP). These tests were conducted prior to correcting the DCS constants.

The results in Table 4-1 show that there is some error associated with the use of only one static pressure tap. However, the error appears to be systematic and nearly linear. The air flow calculated from the average ΔP (column 5) is only slightly different than that obtained from the single pressure tap, and is not sufficient to account for differences between the indicated flow and actual flow. Nevertheless, since the error is systematic, the use of only one pressure tap with the new air flow calibrations should not introduce any new errors.

4.1.2 Coal Flow Measurements

The coal flow rate is used in several of the performance calculations and is an important input to boiler efficiency and material balances. Analysis of the performance calculations has shown that the coal feed rate should be measured to an accuracy of ±1 percent in order to achieve the desired accuracy of the performance calculations.

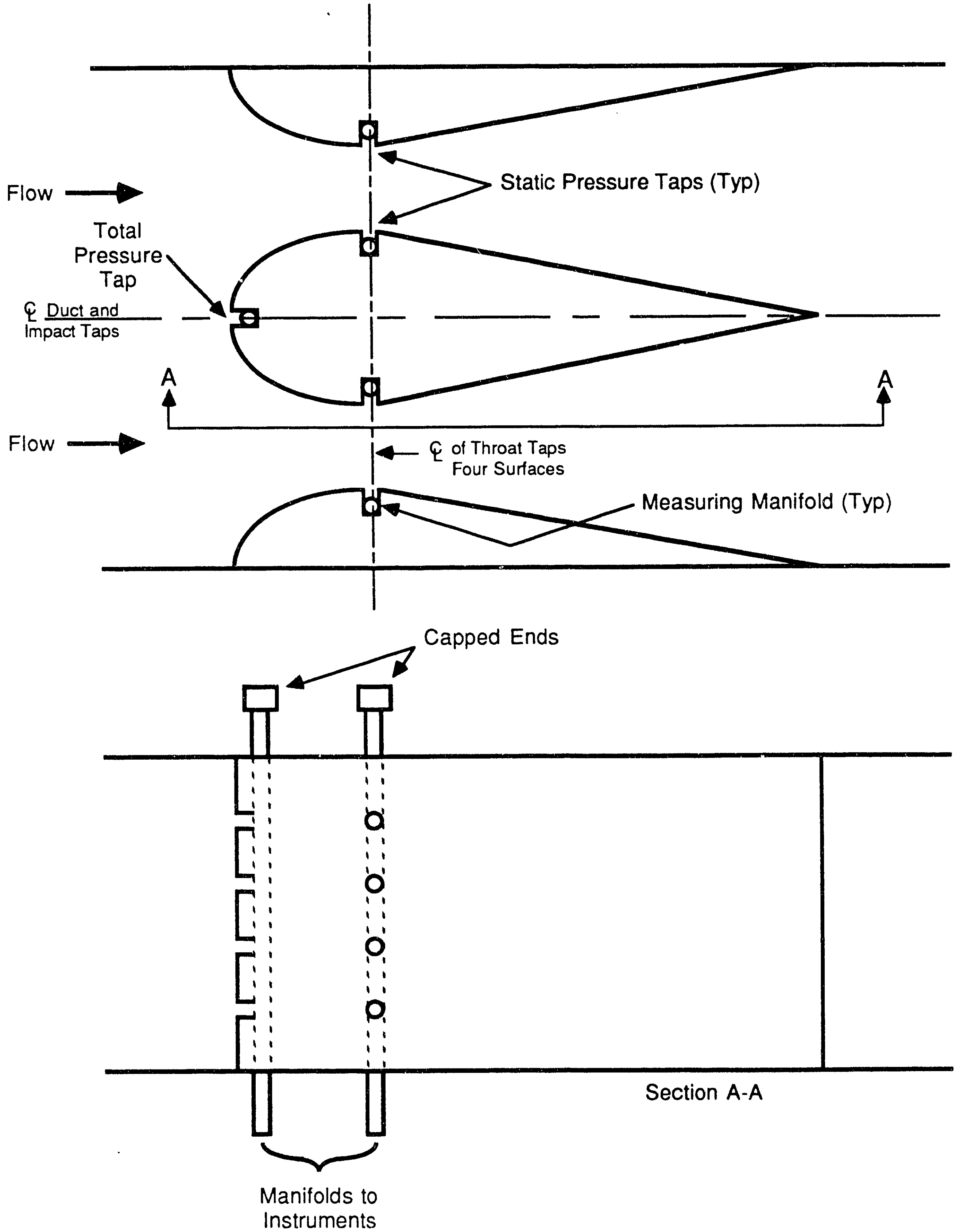


Figure 4-2. Typical Air Foil

Table 4-1

Bottom Ash Cooling Air Flow GFT25
(Airfoil Pressure Differential and Flow Data)

Unused Throat Tap ΔP, in H2O (Manometer)	Used[a] Throat Tap ΔP, In H2O	Avg. ΔP In. H2O	DCS Flow Klb/hr	Air Flow, (from Avg. ΔP) Klb/hr	Actual[b] Air Flow Klb/hr
1.31	1.67	1.49	24.1	22.8	20.8
2.70	3.62	3.16	35.6	33.2	29.2
6.90	6.90	6.90	49.1	49.1	43.7
8.65	7.85	8.25	52.4	53.7	46.5

(a) Back calculated from DCS flow rate.
(b) Based on flow traverse correlations and column 2.

The coal feed rate at Nucla is measured using six gravimetric weigh belt feeders. A review of three calibration options available for this type of feeder indicated that calibration using test chains was required to insure this level of accuracy. Subsequently, the demonstration program purchased a calibrated test chain. To facilitate the frequent calibrations required by the test program, a large wooden rolling dolly was built to assist installing and removing the test chain from the rear of each coal feeder. Furthermore, a centering device was built to facilitate alignment of the test chain during calibration.

After initial calibration trials, the calibration procedures were modified to include the following four step procedure:

- Tare calibration
- Test weight (chain)
- Electronic factoring to the test chain
- Electronic calibration with an applied voltage.

Initially this procedure was employed monthly during the demonstration program. Later it was found that the calibrations only needed to be performed once every 60 days to yield coal feed readings that were within the ±1 percent error band required by the test program. Data from the calibrations of the coal feeders were used to establish the measurement bias of the individual coal feeders.

4.1.3 Limestone Feeder Calibration

The limestone feed rate at Nucla is regulated by a variable-speed eccentric shaker that feeds limestone over a vibrating cone through an adjustable gap formed by sector plates (see Section 12). The flow rate is measured by a loss-in-weight system that uses load cells mounted on the hopper above the shaker cone. The weight change from two successive readings is divided by the time between the readings to produce the feed rate.

To calibrate the limestone feeders, weigh chains are hung onto the hoppers and the output signal of the load cells is adjusted to match the weight gain. A length of ship anchor chain was purchased and cut into lengths that could be handled by a technician. These chains were then weighed and tagged. Hangers were also installed onto the four legs of the limestone hoppers to hold the test chains.

After repeated efforts to correct various malfunctions in the weigh system, a final calibration confirmation was performed during June and July, 1988. Table 4-2 shows the results of these calibration runs. The calibrations showed that the limestone feeder for combustor B was more accurate than for combustor A. The average error for A feeder is 16 pounds and for B Feeder is 4.5 pounds. When compared to the capacity of the load cells, these errors correspond to a 0.5% error for feeder A and a 0.2% error for feeder B, which is within the accuracy limits required for the demonstration program of ± 1%.

Initially limestone calibrations were performed monthly during the demonstration program. It was later found that the calibrations could be performed once every 90 days. Errors recorded during these monthly calibrations were used to establish the measurement biases for the limestone feeders.

Table 4-2

LIMESTONE WEIGH FEEDER CALIBRATION
Feeder A June 30, 1988

Chains	Weigh Hopper Weight Reading	Actual Weight Added	|Difference|	Error %
0	0 Bouncing	0	0	-
4	353	374	21	5.6
0	0 Steady	0	0	-
4	350	374	24	6.4
8	693	705	12	1.7
4	347	366	19	5.2
0	13	0	13	-

Table 4-2 (cont.)

LIMESTONE WEIGH FEEDER CALIBRATION
Feeder B July 5, 1988

Chains	Weigh Hopper Weight Reading	Actual Weight Added	|Difference|	Error %
0	0.6	0	0.6	-
4	364	363	1	0.3
0	0 Bouncing	0	0	-
4	356	363	7	1.9
8	700	705	5	0.7
4	354	363	9	2.5
0	0 Steady	0	0	-

4.1.4 Bottom Ash Weigh Bin Calibration

The bottom ash flow rate is measured by using a weigh bin that receives bed material from both bed drain coolers on a combustor. The weigh bin fills with bed material to a pre-set weight and then begins an emptying cycle down to a pre-set level. The weight of ash is determined starting at the time when the emptying cycle is complete. The weight of the ash added during the fill cycle is measured every 15 minutes until the high level is reached and the emptying cycle begins. The total weight added and the total time between cycles is used to calculate the average bed drain rate for a performance test.

Calibration of the bed drain weigh bin involves checking the accuracy of the load cells in a similar fashion to the limestone feeders. Chains, weighing a total of 1,648 lbs, were added to each hopper when it was filled with three different quantities of bed material. The weight gain on the hopper was recorded, then the chains were removed and the weight recorded again. This process was repeated at least two times at each level of bed material. Table 4-3 shows the results of this calibration procedure. The average error on the weight readings for hopper A was 16 pounds, and the average error on the weight readings for hopper B was 19 pounds. These errors correspond to less than 0.3% of the full scale reading for each hopper.

Initially the bottom ash weigh hopper was calibrated on a monthly basis during the demonstration program. It was later found that the calibrations only needed to be performed once every 120 days. Errors in the weight readings were used to establish the instrument biases for these two weight measurement devices.

Table 4-3

BOTTOM ASH HOPPER CALIBRATION DATA

Hopper A April 22, 1988

Initial Weight	Weight After Chains Added or Removed	Weight Gain	|Difference|	% Error
480	2110	1630	18	1.09
2110	480	-1630	18	1.09
480	2130	1650	2	0.12
2130	480	-1650	2	0.12
Hopper Filled to 2100 lbs With Bed Material				
2100	3750	1650	2	0.12
3750	2065	-1685	37	2.25
2065	3750	1685	38	2.25
3750	2080	-1670	22	1.33
Hopper Filled to 3620 lbs With Bed Material				
3620	5280	1660	12	0.73
5280	3650	-1630	18	1.09
3650	5300	1650	2	0.12
5300	3650	-1650	2	0.12
Hopper Filled to 5340 lbs With Bed Material				
5304	7010	1670	22	1.33
7010	5340	-1670	22	1.33
5340	7010	1670	22	1.33

Hopper B February 22, 1988

Initial Weight	Weight After Chains Added or Removed	Weight Gain	|Difference|	% Error
-67	1630	1697	49	2.97
1630	-67	-1697	49	2.97
-67	1580	1647	1	0.06
1580	-67	-1647	1	0.06
Hopper Filled to 1550 lbs With Bed Material				
1550	3245	1695	47	2.85
3245	1600	-1645	3	0.18
1600	3260	1660	12	0.73
3260	1610	-1650	2	0.12
Hopper Filled to 3195 lbs With Bed Material				
3195	4895	1700	52	3.16
4895	3230	-1665	17	1.03
3230	4910	1680	32	1.94
4910	3245	1665	17	1.03
Hopper Filled to 4740 lbs With Bed Material				
4740	6390	1650	2	0.12
6390	4740	-1650	2	0.12
4740	6390	1650	2	0.12

4.1.5 Fly Ash Flow Measurement

During the Phase I test period, the fly ash metering system was modified extensively in an effort to obtain an accurate measurement of the flow rate and a representative sample of fly ash. Figure 4-3 shows a schematic of the fly ash system at Nucla following modifications. The problem with measurement of the flow rate and with the representativeness of the sample stems from the fact that fly ash is collected at 34 separate locations throughout the plant. The air heater and economizer each have two hoppers that collect fly ash. The new baghouse has 12 hoppers and baghouses 1, 2, and 3 each have six hoppers that collect fly ash. Each of these hoppers is equipped with a gate valve that periodically dumps fly ash into a vacuum ash transport system where it is delivered to the fly ash weigh bin. The hoppers are sequentially emptied into the vacuum ash transport system.

Experience has shown that the composition and quantity of ash collected in each of the ash hoppers differs sufficiently, such that none of the hoppers are representative of all of the fly ash. Therefore, a full-cut sampler was installed to continuously sample the fly ash leaving the weigh bin.

The fly ash flow rate meter is a Schenck impact flow meter. This meter measures the flow rate of fly ash that hits a deflector plate as it falls out of the fly ash weigh bin. Numerous attempts to obtain a reliable calibration of the fly ash flow meter failed to produce a reliable and repeatable signal.

In order to overcome the difficulties in obtaining a fly ash flow rate, an alternative method of calculating the flow rate was developed. The calculation involves an inerts balance around the boiler. Inerts are defined as all constituents except CO_2 and SO_3 in the limestone, coal ash, bottom ash, and fly ash. Inerts enter the boiler through the coal stream and the limestone stream.

Inerts In

$$\text{Coal inerts, lb/hr} = \frac{CI}{100} \times \text{coal flow}$$

$$\text{Limestone inerts, lb/hr} = \frac{LI}{100} \times \text{limestone flow}$$

Where: CI = % ash, as fired coal
$LI = 100 - CO2_l$
$CO2_l$ = % CO_2 in limestone

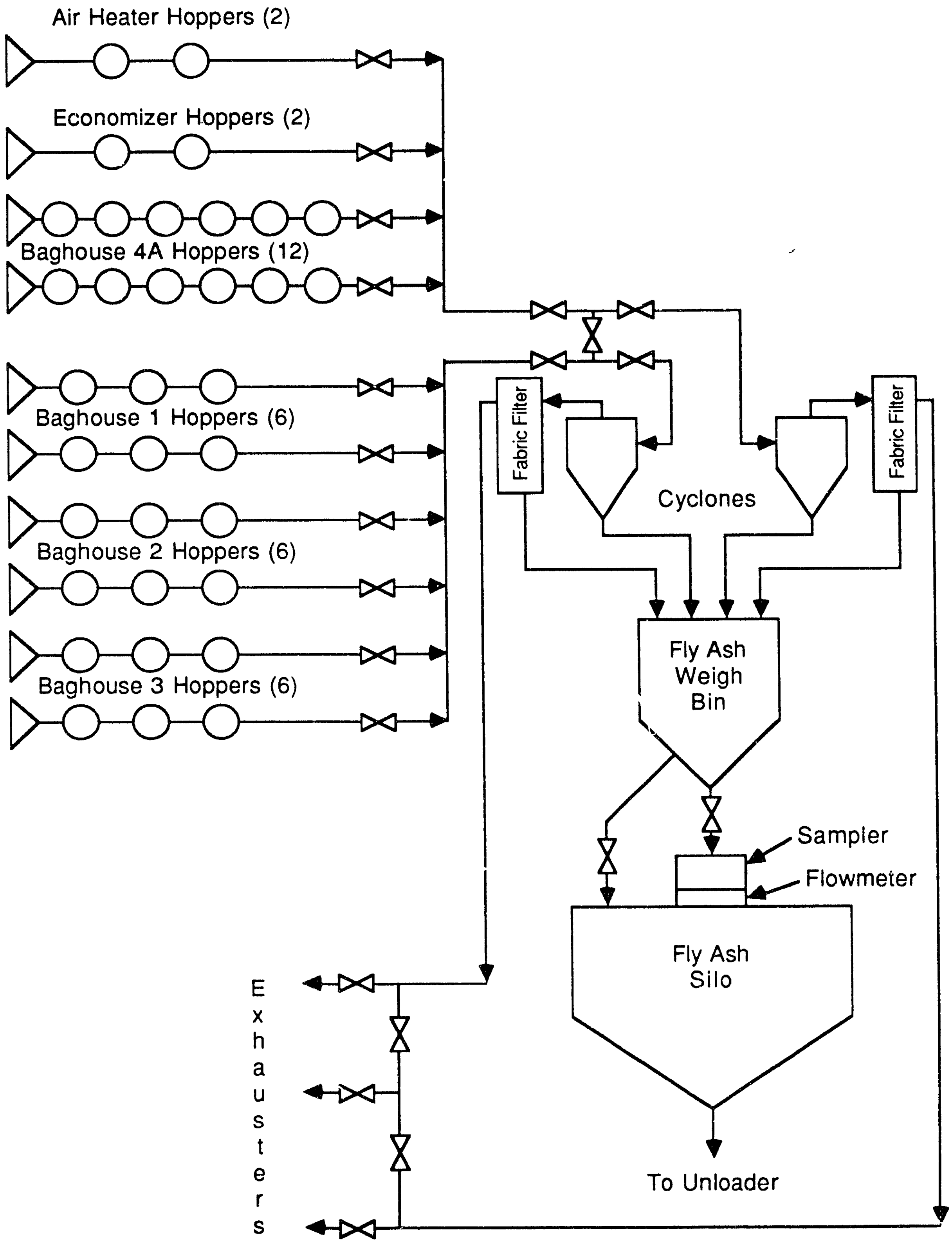


Figure 4-3. Schematic of Revised Fly Ash Collection and Measurement System

Inerts leave the boiler via the bed ash stream and the fly ash stream.

Inerts Out

$$\text{Bottom ash inerts, lb/hr} = \frac{BI}{100} \times \text{Bottom Ash Flow}$$

$$\text{Fly ash inerts, lb/hr} = \text{coal inerts} + \text{limestone inerts} - \text{bottom ash inerts}$$

$$\text{Fly Ash flow rate, lb/hr} = 100 \times \frac{\text{fly ash inerts}}{FAI}$$

Where: $BI = 100 - CO2_b - \frac{80}{32} S_b - (C_b - \frac{12}{44} CO2_b)$

$FAI = 100 - CO2_{fa} - \frac{80}{32} S_{fa} - (C_{fa} - \frac{12}{44} CO2_{fa})$

$CO2_{b,fa}$ = % CO_2 in bed ash or fly ash

$S_{b,fa}$ = % Sulfur in bed ash or fly ash

$C_{b,fa}$ = % Carbon in bed ash or fly ash

Note that the carbon in the bed material and fly ash is reported as total carbon and includes carbon contained in the CO2.

This calculation procedure has been incorporated into the performance calculations. The uncertainty analysis performed during the hot mode shakedown tests showed that the above equations gave a satisfactory estimate of the fly ash flow rate within the accuracy required for performance testing.

4.1.6 Test Instrumentation

A detailed list of all of the instrumentation required by the demonstration program was developed during the reporting period. This list included all instrumentation needed for steady-state performance tests and for dynamic load following tests. Included in the list is the required accuracy for each instrument, the calibration schedule for that instrument, the measurement range, and the last calibration date. Appendix A contains a copy of the instrumentation calibration schedule.

In developing the calibration schedule, consideration was given to the contribution of a particular instrument to calculated results uncertainties in the performance calculation package. The calibration schedule was modified on several occasions during the test program after it was found that certain instruments remained in calibration or were not significant contributors to the final results uncertainties.

The calibration data from the instruments also provided an estimate of the instrument bias, which is used in the performance calculation software to calculate the final results uncertainties. The instrument drift between calibration periods was averaged on a sum squared basis to determine the average drift of the instrument. This value was substituted for the instrument bias that was originally based on manufacturer's specification data. In many cases, this average drift exceeded the manufacturer's accuracy claim. In others, the instrument drift was found to be less than the manufacturer's accuracy.

4.2 SYSTEM COMMISSIONING

As a prelude to the demonstration program, several specialized sampling systems were developed and/or commissioned. Isokinetic sampling probes were needed to measure the baghouse inlet and outlet dust loadings as part of the baghouse monitoring program. Freeboard gas analysis probes were required to sample the flue gas at various points within the combustor as part of the solids and gas mixing test plan discussed in Section 9. A gas analysis system was required to analyze flue gas for oxygen, carbon dioxide, nitrogen oxides, sulfur dioxide, and carbon monoxide at the exit of the control boundary used in the performance calculations to calculate boiler efficiency. Several systems were developed to sample the various solid streams in the plant to ensure that representative samples were obtained. A sample preparation laboratory was established to process the samples prior to off-site analysis. Finally, the VAX computer was commissioned and software was developed in support of the demonstration program. This section documents the commissioning of these systems for the demonstration program, and provides details of each system.

4.2.1 Sampling Probes

The demonstration program utilizes three specialized sample systems to test either the solids loading or the chemical composition of the flue gas. These three systems are:

- Isokinetic sampling probes to periodically measure the solids loading in the flue gas.
- Freeboard Gas Analysis System (FGAS) probes to periodically measure the gas composition in the freeboard of the combustor.
- Economizer Exit Gas Analysis System (EGAS) probes to continuously measure the flue gas concentrations at the economizer exit.

During the initial phases of the test program all three systems were designed, procured, and placed into service.

4.2.1.1 Isokinetic Sampling Probes

The isokinetic sampling probes were used to measure the dust loading at the inlet and outlet of the baghouse. At the baghouse inlet, the dust loading was expected to be quite high (on the order of 10 to 12 gr/dscf). Two filtration options were evaluated for the isokinetic sampling probes: an in-duct filtration method, and an external filtration method. The in-duct filtration method is simpler to operate and less expensive. However, there was some concern that this type of probe would be subject to plugging due to the high dust loadings. In order to evaluate the applicability of this option, an in-duct filtration probe was obtained on loan from an off-site contractor for trial tests.

The sampling tests have shown that in-duct filtration performs satisfactorily without plugging for a substantial portion of the expected test duration. Accordingly, a complete sampling train was purchased for the demonstration program. The train consisted of the following equipment:

- 1 sampling console
- 1 sample pump
- 1 umbilical cord
- 3 stainless steel condensers
- 1 sample probe
- 2 thimble filter holders
- 1 Gelman filter holder
- 4 nozzles

Figure 4-4 shows a schematic of the isokinetic sampling train.

Two plant technicians were trained to operate the sampling equipment and to perform the isokinetic sampling. After approximately two weeks of training and working with the equipment, the sampling crew attained full proficiency with the isokinetic equipment. Once training was complete, the sampling team was subjected to a detailed audit of their procedures and techniques. The audit did not reveal any problems that would affect the accuracy of the results.

To demonstrate the repeatability of the sampling process, the sampling team performed two separate runs back-to-back while the unit was at a stable load. The results of these runs are shown in Table 4-4. These tests showed that results are repeatable to within 1%.

4.2.1.2 Freeboard Gas Analysis System (FGAS)

The FGAS probe is designed to sample the gas composition across two traverse planes inside combustor B at elevations 44'6" or 86'6". Gas sampling is possible from near the

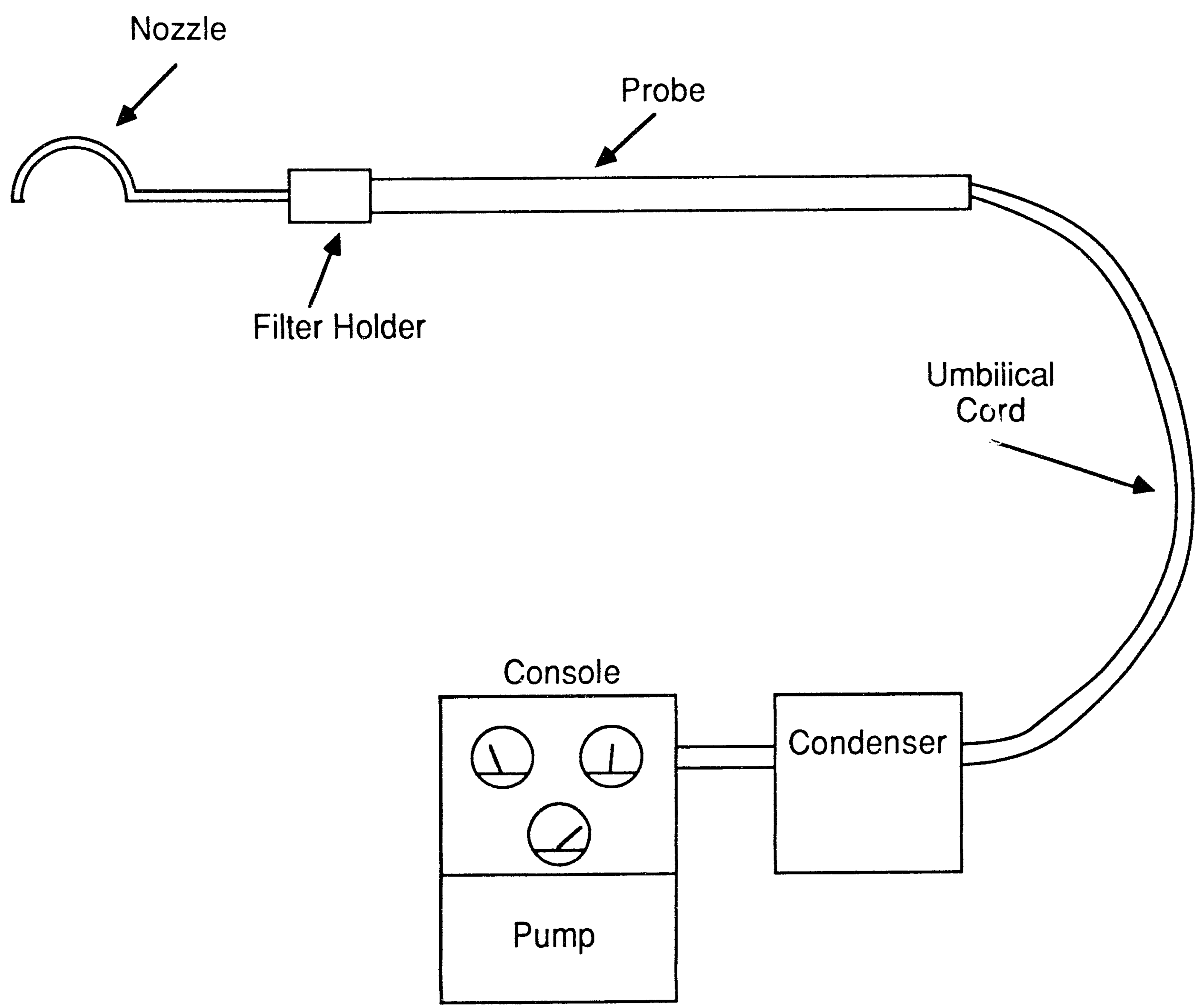


Figure 4-4. Isokinetic Sample Probe

outside wall to the centerline of the combustion chamber, for a total traverse distance of 10'2". The probes are water-cooled and were originally developed by TVA and EPRI for use in the analysis of a bubbling bed combustor freeboard. The current probe has been modified to incorporate site specific conditions of the Nucla CFB.

Table 4-4
ISOKINETIC SAMPLING REPEATABILITY TEST RESULTS
Location: Air Heater Exit

Date	1/3/89	1/3/89
Start Time	12:00	14:30
Flue Gas Moisture, %	7.29	7.3
Velocity, ft/sec	33.69	34.43
Volumetric Flow, DSCFM	147,268	149,874
Particulate Loading, gr/dscf	10.31	10.44
Particulate Mass Flow, lb/hr	13,645	13,412
Percent Isokinetic	100.6	100.5

The probe has a water-cooled outside shell and an electrically heated gas sample tube which is connected to the gas analyzers (described in Section 4.2.2) via a heated sample line. Suction is provided by the gas sample pump in the gas analyzer cabinet and pulls the combustion gasses from the combustion chamber. An air aspirated knife gate isolates the penetration through the water walls at the two locations.

In operation, the combustion gasses first pass through an unheated quench tube where the gas temperature is reduced to less than 400 °F, the maximum operating temperature of the sample line. The electrically heated sample line then maintains the sample temperature above the acid dew point of the gas (set point is 350 °F) to minimize condensation and corrosion of the sample line. The gas is sampled at a flow rate of approximately 7 liters/min. The sample passes through a cyclone separator and a fabric filter to remove any entrained solids. Both filters are contained within a heated cabinet. The gas sample then passes through another heated sample line to the gas analyzers.

A cooling water flow rate of between five and twenty gpm is required to maintain internal temperatures below 175 °F. Seven thermocouples are included in the system to allow the sampling team to monitor the operating conditions inside the probe. Cooling water passes through the length of the probe and returns to the outlet nozzle before being disposed of in the plant drain system. Water flow control is maintained by a manual control valve on the cooling water inlet line.

Initial use of the FGAS probes met with some difficulty due to plugging of the probe. This was traced to two separate causes. The first was a buildup of particles in the diaphragm valve located in the sample line. This was resolved by moving the valve downstream of the cyclone separator where the particulates are significantly lower. The second problem was caused by blockage of the line by a single large particle. This was solved by adding an orifice at the inlet and by replacing some of the teflon tubing with stainless tubing. With these modifications, the FGAS probe was capable of operating for over two hours without plugging, which is the time needed to complete a traverse.

Results of the FGAS traverses are contained in Section 9 of this report.

4.2.1.3 Economizer Exit Gas Analysis System (EGAS)

The economizer exit gas sample is an average of sixteen sample points which are mechanically interconnected in a heated valve averaging enclosure which is located between the two inlet ducts to the tubular air heater at an elevation of 94'. The two inlet ducts to the air heater are divided into eight 2'x 4' grids with a gas sample point located in the center of each grid. The samples are withdrawn by heated lines that terminate in the sample averaging cabinet. The EGAS averaging cabinet, and all of the sample lines, are heated to prevent acid dew point formation in the sample train. A single heat-traced line carries the gas sample to the gas analyzers.

Gas sample flow rates through each of the 16 probes are equalized by matching the vacuum on each sample line with a Hastelloy needle valve. The system also allows any individual probe, or any combination of probes to be sampled. For "split" combustor tests described in Section 6, gas samples were collected separately for each air heater inlet duct, i.e. each sample was the average of 8 probes.

Each of the sixteen gas sample points also has a thermocouple installed next to the sample probe. The eight temperatures in each duct are averaged locally in a thermocouple averaging box. The two averages are available as separate values on the DCS. The outlet of the tubular air heater contains eighteen thermocouples arrayed in a similar configuration to the inlet temperature grid. The two average temperatures are also available on the DCS.

4.2.2 Gas Analyzers

The gas analyzer equipment is located at elevation 24' on the turbine deck. The equipment includes a gas conditioning cabinet, and an air conditioned cabinet that contains the gas analyzers and a six pen strip chart recorder. An electrical output signal from each analyzer corresponding to the gas concentration is sent to the DCS. The strip chart recorder also displays the outputs from the analyzers. Other output signals are available for alarms and range settings of the various analyzers. The gas analyzers used in this installation are listed below along with their measurement method. The instruments are listed for the purposes of providing complete information regarding the test program and do not necessarily represent an endorsement of this equipment by CUEA or the DOE.

- Oxygen
  Beckman Industrial Corporation Model 755
  Paramagnetic measurement system.

- Carbon Monoxide and Carbon Dioxide
  Beckman Industrial Corporation Model 864
  Infrared absorption measurement system.

- NO_x
  Beckman Industrial Corporation Model 951A
  Chemiluminescence measurement system.

- Sulfur Dioxide
  Western Research Model 721A
  Energy absorption by a sample cell.

Calibration of the gas analyzers is performed by flowing premixed calibration gasses through the sample system at regular intervals. The calibration gasses are stored in high pressure cylinders and are connected to the analyzers by a manifold provided with the equipment. Five gas cylinders are required to store all of the required gas mixtures. Table 4-5 lists the calibration gas mixtures.

4.2.3 Solid Sampling System

For the performance calculations, all of the solid streams entering and leaving the boiler were sampled and analyzed. In order to sample these streams, either full-cut or full-cross sampling devices were used except for limestone sampling.

Table 4-5. E/FGAS Analyzer Calibration Gasses

Bottle	Gas	Range
1	N_2 for zero reference	N_2 >99.8%
2	Low span O_2, CO, CO_2	O_2 8% CO 400 ppm CO_2 4% Balance N_2
3	High span O_2, CO, CO_2	O_2 20% CO 4000 ppm CO_2 16% Balance N2
4	Low span SO_2, NO_x	SO_2 400 ppm NO_x 400 ppm Balance N_2
5	High span SO_2, NO_x	SO_2 1200 ppm NO_x 800 ppm Balance N_2

Coal is sampled using full-cut flow diverters installed on the front of each of the six weigh belt feeders. Initial operation of the full-cut diverter sampler revealed some problems associated with fines accumulation in the sample line and with fine loss due to the dust suppression system. These problems were solved by the addition of close clearance seals on the sample valve, and an air actuated damper on the dust suppression vacuum line to isolate the feeder being sampled.

Limestone is sampled using two thief samplers that withdraw a sample from the limestone weigh bins. The sample point was originally located near the bottom of the weigh bins. However, problems with pressurization of the weigh bins caused the sample points to be relocated near the top of the weigh bins.

Bed ash is sampled using thief probes located below each of the four bottom ash coolers. No major problems were experienced with these sample points.

The fly ash sampler was described in Section 4.1.5 of this report. The continuous sampler has been found to give a reliable, representative sample of the fly ash.

4.2.4 Sample Preparation Laboratory

In order to measure the performance of a fluidized bed boiler, a number of solid samples need to be taken during the performance tests. These samples include:

- Coal
- Limestone
- Bed ash
- Fly ash

Section 4.2.3 described the manner in which the solid samples are withdrawn from the boiler during the performance tests. In this section, the steps taken to prepare and analyze the solid samples will be discussed.

In order to minimize the cost of the sample laboratory at Nucla, it was decided that most of the chemical analyses required by the performance calculations would be performed at an off-site laboratory. Nevertheless, several steps were needed to insure that a representative sample reached the chemical laboratory. The Chemical Analysis Report and the Physical Analysis Report contained in Table 4-6 of Section 4.2.5.1 lists the chemical and physical analyses required by the performance calculations. The sample preparation laboratory at Nucla performs the analyses for:

- Size distribution
- Air dry moisture
- Bulk density
- Particle density
- Sulfur

The remainder of the analyses listed in Table 4-6 are performed by an outside analytical laboratory. Sulfur is also determined by the outside laboratory.

4.2.4.1 Coal Preparation

Figure 4-6 shows the coal preparation flow sheet. Coal is sampled from the six coal feeders at Nucla. Approximately 5 gallons of coal are sampled from each feeder. All six samples taken at the same time are composited to form one coal sample for the test period. The sample is then riffled down to form a 20 pound analytical sample and a 5 pound physical analysis sample.

The 20 pound analytical sample is crushed to minus 30 mesh. Five pounds of this sample are then allowed to air dry at 40°C for six hours. Next the air dried analytical sample is riffled and one quart is stored in a sealed, labeled container as an archive sample. The remaining 200-300 grams are pulverized to minus 200 mesh and blended. A small amount

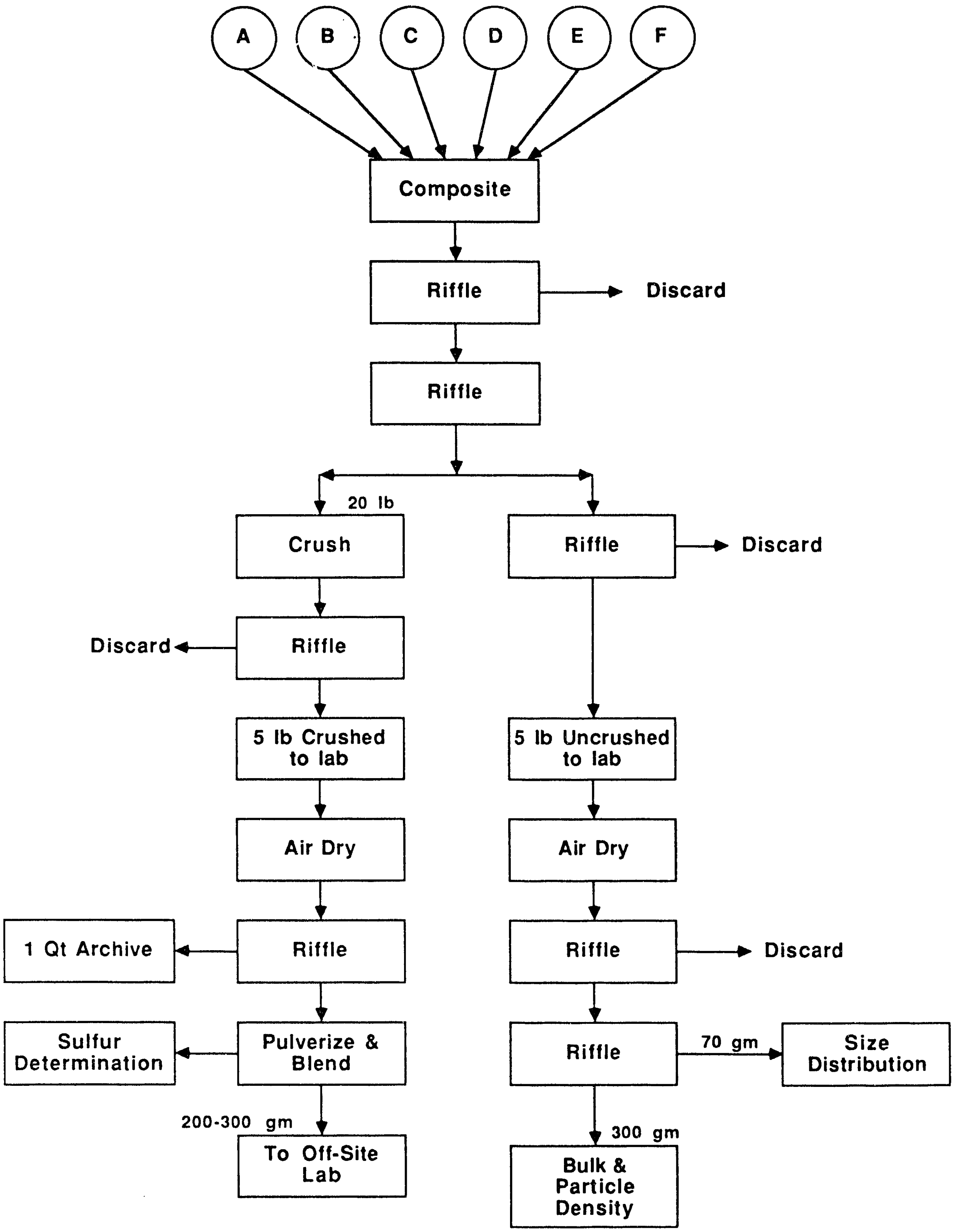


Figure 4-5. Coal Preparation Flow Sheet

of this sample is periodically analyzed in a Leco sulfur analyzer. The remainder of the sample is shipped to the analytical laboratory in a sealed container.

The five pound physical analysis sample is weighed and air dried for 6 hours at 40 °C. The air dried sample is then reweighed and the air dry moisture is determined. Next the sample is riffled to give a 70 gram sample that is analyzed for size distribution and a 300 gram sample that is used for bulk and particle density determinations.

4.2.4.2 Limestone Preparation

Figure 4-6 shows the flow sheet for the laboratory preparation of the limestone sample. Approximately five pounds of limestone are withdrawn from each of the two limestone feeders. These two samples are composited to give the limestone gross composite sample for the time period. The ten pound sample is then oven dried to determine the total moisture of the limestone.

Next the limestone sample is passed through a series of riffles to produce a 1 quart archive sample, a 300 gram sample for particle and bulk density determination, a 70 gram sample for size distribution analysis, and a 200 to 300 gram analytical sample. The analytical sample is pulverized to minus 200 mesh, blended, and sent to the outside laboratory for analysis.

4.2.4.3 Bottom Ash Preparation

Figure 4-7 shows the flow sheet for the preparation of the bottom ash sample. Five pound samples are withdrawn from each of the four bed ash discharge points. These four samples are composited to form the gross composite bottom ash sample for the sampling period. The gross composite sample is riffled to give about 400 grams of material for the physical analyses. The remainder of the bottom ash sample is crushed to minus 30 mesh. The crushed sample is then riffled to yield a 1 quart archive sample and a 200-300 gram analytical sample. The 200-300 gram analytical sample is pulverized to minus 200 mesh. Some of this material is analyzed in the Leco sulfur analyzer at Nucla, and the rest is sent off site for chemical analysis.

4.2.4.4 Fly Ash Preparation

Figure 4-8 shows the flow sheet for the preparation of the fly ash sample. A single fly ash sample is obtained from the continuous fly ash sampler during a sample time period. This sample is riffled to yield a 1 quart archive sample, a 300 gram sample for bulk and particle density determination, and a 200-300 gram analytical sample. The analytical sample is

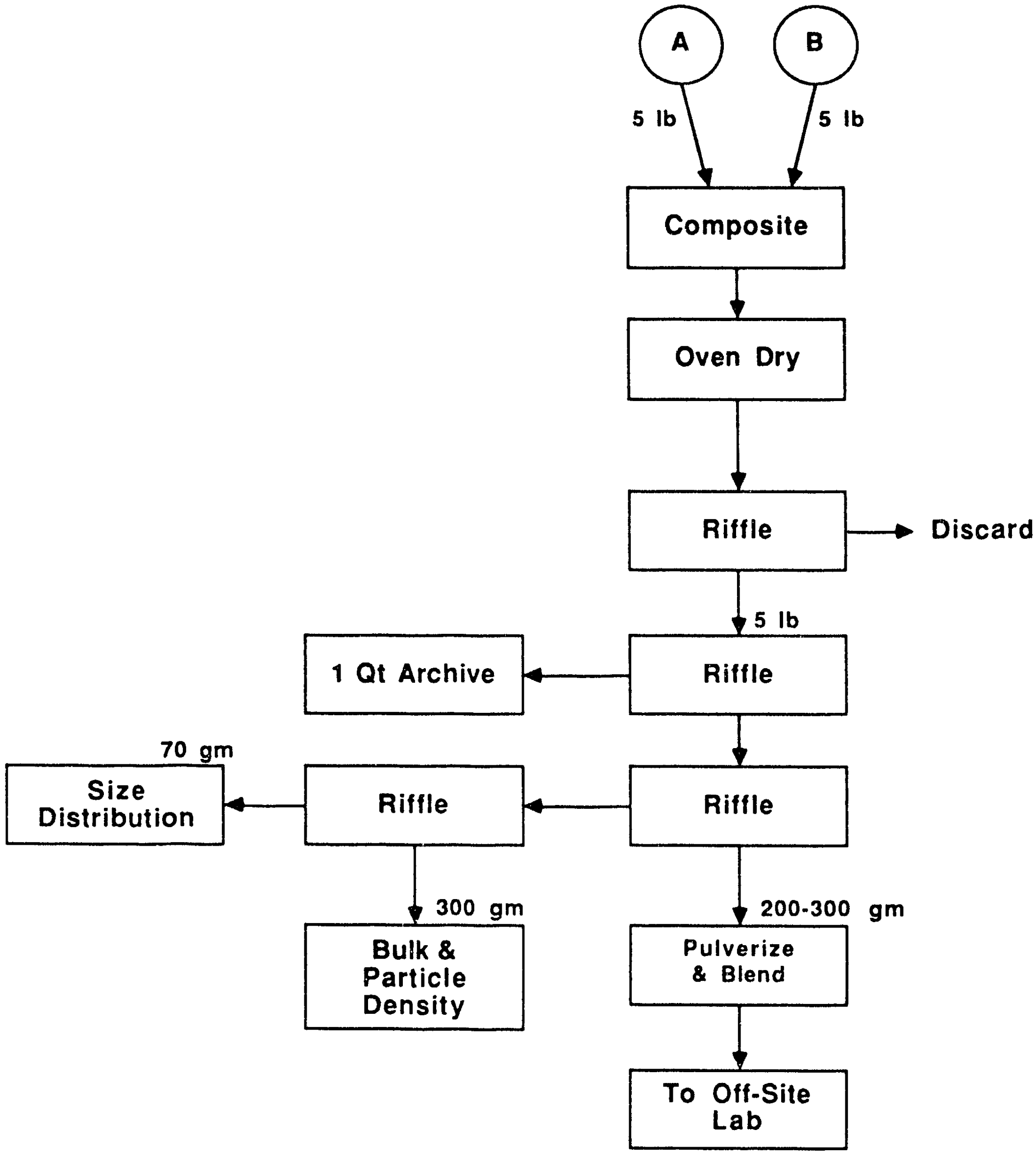


Figure 4-6. Limestone Preparation Flow Sheet

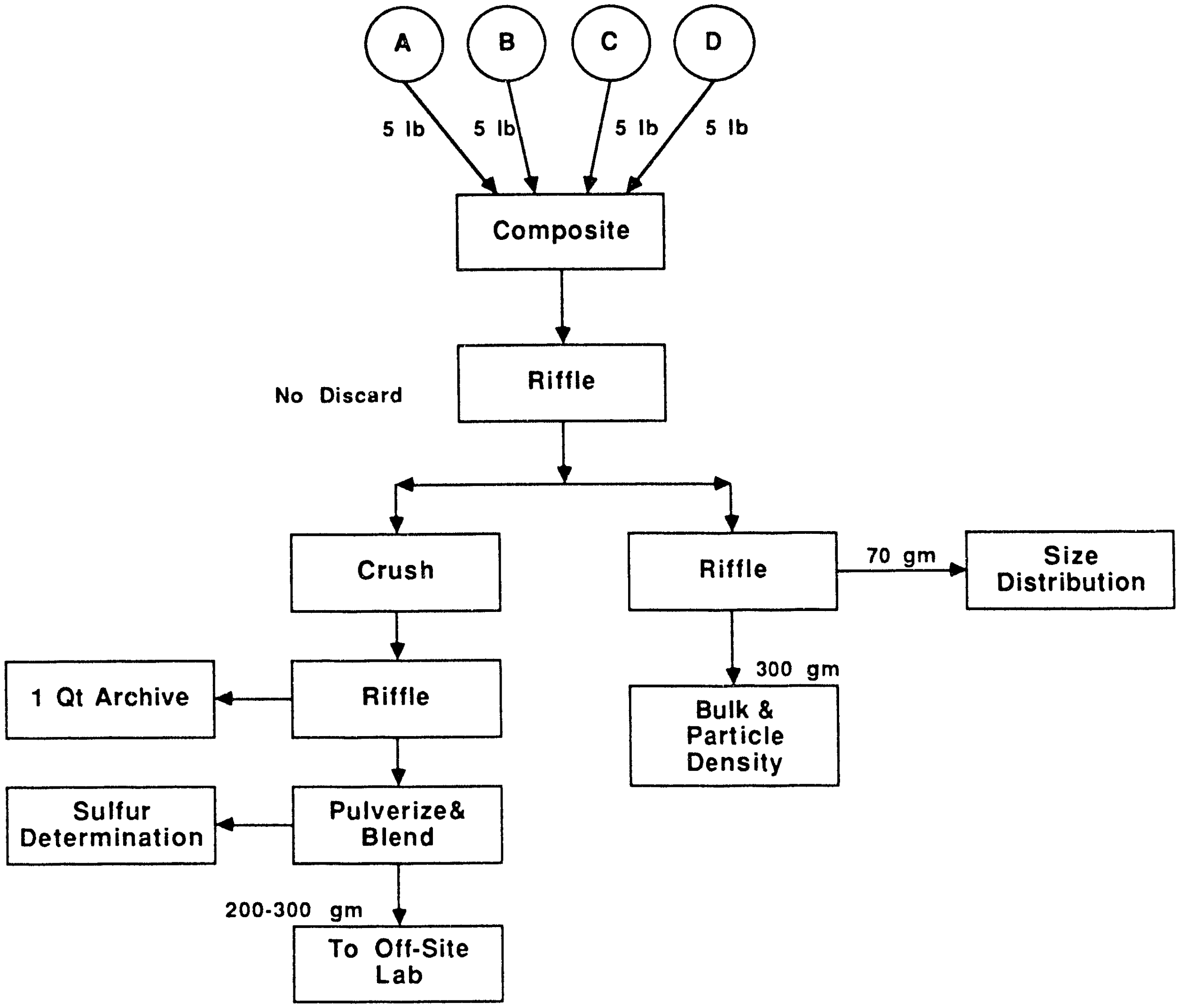


Figure 4-7. Bottom Ash Preparation Flow Sheet

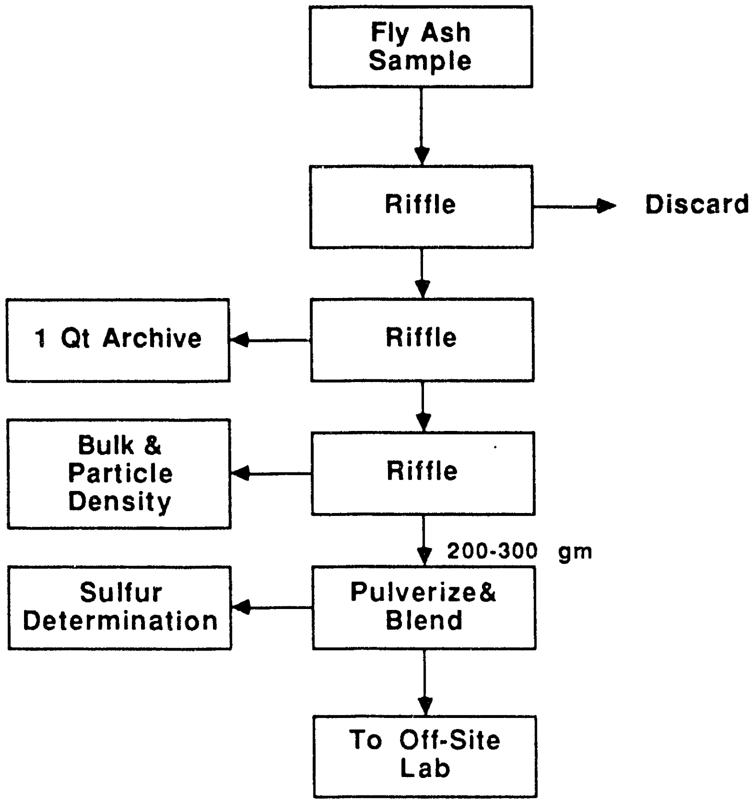


Figure 4-8. Fly Ash Preparation Flow Sheet

pulverized to minus 200 mesh. Part of this sample is analyzed in the Leco sulfur analyzer at Nucla. The remainder is sent to the off-site laboratory for chemical analysis.

4.2.4.5 Quality Control

The Nucla laboratory personnel developed a rigorous program to insure quality control in the preparation and analysis of the solid samples. For each performance test, one of the samples sent to the laboratory was a duplicate of another sample. In addition, several tests were conducted to determine the division of analysis variance. Duplicate samples were also sent to other laboratories on a round-robbin basis to serve as a check on the outside laboratory's procedures. Careful record keeping was also employed.

4.2.5 VAX Computer

The data acquisition system used for the test program was a Digital Equipment Corporation (DEC) VAX 8200 computer with eight megabytes of Random Access Memory. Specialized software was developed for real-time and historical data monitoring on this system. The VAX computer reads plant data directly off the plant's Westinghouse digital control system. The software then averages and stores the data for retrieval and analysis. Software can produce historical trend plots, run the performance calculations and uncertainty analysis for performance tests, and other file maintenance procedures from a menu driven master program. Both laser and graphics printers are attached to the VAX for hard copy output.

The VAX computer is connected to IBM PC's and the Macintosh computers via a serial cable. Files can be transferred to or from the VAX using the Kermit protocol.

The historical data storage and retrieval programs of the VAX are far superior to the capabilities of the plant distributed control system. As such, the VAX was beneficial to the plant in evaluating process upsets and trips, and to the test program for management of test conditions during the performance tests. Measurement points accessed by the VAX computer are listed in Appendix A along with calibration information for the transmitters.

4.2.5.1 Performance Calculations

The performance calculations for the test program are carried out on the VAX computer. The algorithms to perform the calculations were developed by EPRI and their contractors. The calculations include an implementation of PTC 4.1, the ASME boiler test code, heat and material balances around the boiler envelope, calculations of Ca/S molar ratio, calcium utilization, superficial velocities, and particle sizes of the various solid streams. Details of the performance calculations are contained in the 1988 Annual Report.

The performance calculations were checked extensively by EPRI and their contractors. The calculation results were checked against an Excel spread sheet calculation developed by the test team.

Results of the performance calculations are printed out on eight summary sheets. These summary sheets contain all of the relevant data obtained during a performance test. The eight summary sheets for test PS17 are shown in Table 4-6.

4.2.5.2 Uncertainty Analysis

ASME PTC 19.1 provides guidelines for determining the measurement uncertainty of the various plant measurements that feed the performance calculation program. PTC 19.1 also provides guidelines for propagating these uncertainties throughout the performance calculations.

The procedure for calculating the uncertainty of the results of a given calculation can be summarized as follows:

1. Determine the average values of the independent parameters ($\overline{P}_i$) that enter into the result (r) of the calculation.
2. Determine the precision index of the average value ($S_{\overline{P}_i}$) for each $\overline{P}_i$.
3. Determine the bias limit for each of the measured parameters ($B_{\overline{P}_i}$).
4. Determine the degrees of freedom associated with each $\overline{P}_i$ ($\nu_{\overline{P}_i}$).
5. Use the perturbation method to determine the bias limit of the result (B_r).
6. Use the perturbation method to determine the precision index of the result (S_r).
7. Calculate the degrees of freedom of the result (ν_r).
8. Find the Student's t factor (t) corresponding to ν_r.
9. Calculate the total uncertainty of the result by the root-sum-square method ($U_{r_{RSS}}$).

Table 4-6. Summary Sheets for Test PS17

--------------- PROCESS OPERATING SUMMARY REPORT -----------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:16:57.00

	Combustor A	Combustor B	Unit
Gross Plant Output (MWe)			55.69
Final SH Stm. Flow (klb/hr)			490.83
Final SH Out. Press (psig)			1451.47
Final SH Out. Temp. (F)			971.16
Coal Rate Frnt-Wst (klb/hr)	9.98	11.71	
Coal Rate Frnt-Est (klb/hr)	9.72	9.40	
Coal Rate Rear (klb/hr)	11.33	10.63	
Total (klb/hr)	31.03	31.74	62.77
Limestone Rate (klb/hr)	1.40	1.02	2.42
Bed Drain Rate (klb/hr)	2.13	1.97	4.10
Flyash Flow (klb/hr)			
Calculated			11.71
Superficial Velocity (ft/sec)			
Distributor Plate (Inl Air)	6.99	7.20	
Freeboard (Inlet Air)	10.06	10.16	
Dist. Plate (02 Method)	6.73	6.94	
Freeboard (02 Method)	9.75	9.85	
Avg. Bed Temp. (F) 20"	1546.54	1501.40	
Avg. Bed Temp. (F) 66"	1525.81	1514.90	
Avg. Bed Temp. (F) 118"	1462.37	1487.11	
Wet Flue Gas Flow - 02 Method (klb/hr)			696.59
Flue Gas Composition (AH Inlet)			
02 (v%)			6.33
C02 (v%)			13.00
CO (ppmv)			98.36
NOX (ppmv)			40.77
(lbs/10^6 btu)			0.07
S02 (ppmv)			102.23
(lbs/10^6 btu)			0.23
Total Air Flow (klb/hr)			647.62
Primary Air Flow (klb/hr)			388.28
Sec. Air Flow (klb/hr)			259.34
SA/PA Ratio			0.67

Table 4-6. (Cont't)

-------------- PROCESS OPERATING SUMMARY REPORT -----------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:16:57.00

	Combustor A	Combustor B	Unit
PA Fan Out. Press. (in WG)			0.00
SA Fan Out. Press. (in WG)			51.65
PA AH Out. Press. (in WG)	46.48	46.59	
SA AH Out. Press. (in WG)	31.78	31.88	
Windbox Press. (in WG)	42.56	41.91	
Bed Press. 18" Above Grid (in WG)	23.59	20.88	
Freeboard Press. (in WG)	-0.34	-0.22	
Cyclone Out. Press. (in WG)			-2.71
SH 1 & 3 Flue Gas DP (in WG)			0.00
Economizer Flue Gas DP (in WG)			0.53
AH DP (in WG)			3.22
Baghouse In. Press. (in WG)			-6.59
ID Fan In. Press. (in WG)			-12.78
Cyclone In. Temp. (F)	1387.82	1386.31	
Cyclone Out. Temp. (F)	1405.95	1402.59	
Loop Seal Solids Temp. (F)	1464.26	1500.24	
AH Gas In. Temp. (F)	501.26	504.85	
AH Gas Out. Temp. (F)	288.48	286.01	
Pri. Air AH In. Temp. (F)			139.34
Pri. Air AH Out. Temp. (F)	384.70	387.58	
Sec. Air AH In. Temp. (F)			175.85
Sec. Air AH Out. Temp. (F)	413.27	410.06	
Feedwater Flow (klb/hr)			469.21
SH2 Attemp. Flow (klb/hr)			21.92
SH3 Attemp. Flow (klb/hr)			0.71
Drum Press. (Psig)			1504.93
Ambient Temp. (F)			117.25
Baro. Press. (In Hg)			24.59
Rel. Humidity (%)			11.17

Table 4-6. (Cont't)

------------ PERFORMANCE SUMMARY REPORT ------------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:17:10.00

	VALUE	UNC*
CHEMICAL PROCESS SUMMARY		
Ca Utilization % (Sorbent Only)	38.61	2.02
Ca Utilization % (Coal and Sorbent)	28.37	2.36
Alkali Utilization % (Coal and Sorbent)	25.07	2.01
Ca To S (Sorbent Only)	2.04	0.09
Ca To S (Coal and Sorbent)	2.78	0.23
Alkali To S (Coal and Sorbent)	3.15	0.25
SO2 Retention %	78.95	2.12
Combustion Efficiency %	98.49	0.10
BOILER PERFORMANCE SUMMARY		
Boiler Efficiency (Loss Method) %	86.72	0.32
Boiler Efficiency (I/O Method) %	85.81	3.03
Excess Air %	42.28	1.42
Air Heater Effectiveness	0.76	0.02
Boiler Load %MCR	54.62	0.93
Wet flue gas flow - 02 Method (klbs/hr)	696.59	18.28
MATERIAL BALANCE		
Total balance %	99.94	0.55
Carbon balance %	96.61	8.11
Hydrogen balance %	100.35	0.06
Oxygen balance %	98.89	4.72
Nitrogen balance %	100.62	1.39
Sulfur balance %	95.63	7.47
Calcium balance %	117.82	11.10
UNIT HEAT RATE		
Gross Heat Rate (btu/kwhr)	10947.	275.
Net Heat Rate (btu/kwhr)	12236.	333.

* Uncertainty, +/- in same units as variable.

Table 4-6. (Cont't)

----- MATERIAL BALANCE REPORT (02 METHOD) -----

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:17:12.00

METHOD "A" MEASURED AIR FLOWS

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	62.77	2.42	709.13	774.32
C	35.87	0.28		36.15
H	2.69	0.00	0.72	3.41
N	0.22		539.99	540.21
O	10.55	1.12	168.41	180.09
S	0.34	0.00		0.34
Ca	0.32	0.87		1.19

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	% Acc For
Total	696.59	11.71	4.10	712.39	92.00
C	34.32	0.55	0.05	34.92	96.61
H	3.35	0.01	0.00	3.36	98.50
N	496.43			496.43	91.89
O	162.62	0.60	0.43	163.64	90.87
S	0.07	0.14	0.12	0.33	95.63
Ca		0.83	0.57	1.40	117.82

METHOD "B" CALCULATED AIR FLOW

INPUTS(klb/hr)	Coal	Sorbent	Air	Total Input
Total	62.77	2.42	647.62	712.81
C	35.87	0.28		36.15
H	2.69	0.00	0.66	3.35
N	0.22		493.16	493.37
O	10.55	1.12	153.80	165.48
S	0.34	0.00		0.34
Ca	0.32	0.87		1.19

OUTPUTS(klb/hr)	Flue Gas	Fly Ash	Bed Drain	Total Output	% Acc For
Total	696.59	11.71	4.10	712.39	99.94
C	34.32	0.55	0.05	34.92	96.61
H	3.35	0.01	0.00	3.36	100.35
N	496.43			496.43	100.62
O	162.62	0.60	0.43	163.64	98.89
S	0.07	0.14	0.12	0.33	95.63
Ca		0.83	0.57	1.40	117.82

Table 4-6. (Cont't)

---------- CHEMICAL ANALYSIS REPORT --------------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:17:14.00

	Coal	Sorbent	Fly Ash	Bed Drain Matl
HHV (Btu/lb)	9711.67			
Total Moisture (%)	8.87	0.08		
Air Dry Loss (%)	3.39			
Blk Den (#/cft)	0.00			
Volatiles (%)	31.57			
Fixed C (%)	38.70			
Ash (%)	20.86			
CONSTITUENTS (%)				
C	57.15		4.68	1.23
H	3.29	0.00	0.06	0.10
O	8.93			
N	0.33			
S	0.55	0.00	1.17	2.89
Ca	0.50	36.13	7.09	13.94
Mg	0.13	0.44	0.57	0.56
Fe	0.34	0.19	1.61	0.96
CO2		42.43	0.69	0.82

NOTE: Only constituents used in the Performance
Calculations are reported.

Table 4-6. (Cont't)

---------- PHYSICAL ANALYSIS REPORT --------------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:17:17.00

		Percentage Less Than		
Mesh	Actual Microns	Coal	Sorbent	Bed Drain
1.50	37500	100.00	100.00	100.00
1.00	25000	100.00	100.00	100.00
0.75	19000	100.00	100.00	100.00
0.50	12500	100.00	100.00	100.00
0.25	6300	86.92	100.00	96.25
4	4750	80.22	100.00	93.45
6	3350	70.76	100.00	88.45
8	2360	60.90	100.00	83.70
10	1700	50.76	100.00	77.20
14	1180	41.30	100.00	69.15
20	850	33.28	100.00	58.45
28	600	27.14	81.00	46.70
48	300	16.44	69.50	18.75
100	150	9.26	60.70	3.10
150	106	6.96	57.00	1.15
200	75	6.96	52.40	0.35
325	45	6.96	46.40	0.35
400	38	6.96	43.80	0.35
Median diameter		1649.05	61.10	661.34

Table 4-6. (Cont't)

---------- HEAT BALANCE REPORT ----------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:17:19.00

BOILER EFFICIENCY (%)(LOSSES METHOD)		86.72
	Value(KBtu/hr)	% of total *
CHEMICAL HEAT INPUT OF THE COAL:	610127.06	97.22
I. CREDITS		
1. Heat credit for sensible heat in entering moist air	12255.75	1.95
2. Sensible heat in entering as-fired coal	-153.28	-0.02
3. Sensible heat in entering wet sorbent	11.72	0.00
4. Heat credit for sulfation reaction	1817.15	0.29
5. Bottom ash cooling water input	3518.03	0.56
6. Sootblowing steam	0.00	0.00
II. LOSSES		
1. Heat loss from unburned coal	8921.83	1.42
2. Heat loss from sensible heat in dry flue gas	34104.66	5.43
3. Heat loss due to moisture in as-fired fuel and sorbent	6377.08	1.02
4. Latent heat loss due to moisture from burning of hydrogen	21121.05	3.37

* Total equals: Chemical input of coal plus credits

Table 4-6. (Cont't)

-- ------- HEAT BALANCE REPORT ----------

TEST : PS17

Start.......10/11/90 9: 0: 0
End.........10/11/90 15: 0: 0
Printed.....17-JAN-1991 14:17:19.00

	Value(KBtu/hr)	% of total *
II. LOSSES (CONT)		
5. Latent heat loss due to moisture in the air	563.30	0.09
6. Heat loss due to calcination of sorbent	1497.00	0.24
7. Heat loss due to formation of CO	262.86	0.04
8. Heat loss due to unburned hydrocarbons in flue gas	0.00	0.00
9. Heat loss due to radiation and convection	5000.00	0.80
10. Heat loss due to sensible heat in flue dust	492.27	0.08
11. Heat loss due to sensible heat in bed drain	252.80	0.04
12. Heat loss due to sootblower steam	0.00	0.00
13. Heat loss to bottom ash cooler cooling water	4778.28	0.76
SUM OF LOSSES TERMS	83371.13	13.28

* Total equals: Chemical input of coal plus credits

A more detailed description follows.

STEP 1: Find $\overline{P}i$

The average value for each of the inputs is given by:

$$\overline{P}_i = \frac{1}{N} \sum_{k=1}^{N} P_{i-k} \qquad (4-1)$$

Where: P_{i-k} = the kth measurement of the ith input variable.
N = the number of repeat measurements

STEP 2: Find $S\overline{P}_i$

The precision error, or random error, for a given input parameter is assumed to be made up entirely of the precision index of the average of the measurements of that parameter. As described in PTC 19.1, the precision index, S, is an estimate of the standard deviation and is defined as:

$$S = \left\{ \frac{\sum_{k=1}^{N} (P_{i-k} - \overline{P}_i)^2}{(N - 1)} \right\}^{.5} \qquad (4-2)$$

The quantity S is a measure of the error that can be expected if any one measurement, P_{i-k}, is used to estimate the true average of the population sampled. However, if the average value ,$\overline{P}_i$, is used, the precision index of the average is defined as:

$$S\overline{P}_i = \frac{S}{\sqrt{N}} \qquad (4-3)$$

Thus the precision error is reduced by using the average instead of any of the individual measurements. Equations 4-2 and 4-3 are used to determine the precision index of the average chemical analyses.

For the data points taken from the data highway, a slightly different procedure is required. Points on the data highway are stored as average values over a short time period, usually 15 minute averages, $\overline{P}_{i-j}$, along with a standard deviation, S_{i-j}, calculated for that average time period.

When the test period is defined, the M values of $\overline{P}_{i-j}$ are averaged to obtain $\overline{P}_i$. The estimate of the pooled precision index for the individual $\overline{P}_{i-j}$'s is given by:

$$S_{pooled} = \left\{\frac{\sum_{j=1}^{M} S_{i-j}^2}{M}\right\}^{.5} \tag{4-4}$$

The precision index of the grand average $\overline{P}_i$ is then given by:

$$S_{\overline{P}_i} = \frac{S_{pooled}}{\sqrt{H*M}} \tag{4-5}$$

Where H is the number of measurements that are averaged to give $\overline{P}_{i-j}$ and M is the number of stored readings that are averaged to give $\overline{P}_i$.

STEP 3: Determine $B_{\overline{P}_i}$

Bias limits for the input parameters are estimated from the manufacturers' performance specifications. There are six main types of measurements that are used as inputs to the performance calculations:

- Pressure (or differential pressure)
- Temperature
- Fluid flow rate
- Solid flow rate
- Gas chemical analysis
- Solid chemical analysis

The bias limits for the pressure and pressure differential measurements are obtained from the calibration data and the amount of drift observed between calibrations. Bias limits for temperatures are available from the vendors' catalogs. Bias limits on the air heater exit gas temperature thermocouples were determined by inserting each thermocouple into boiling water, and measuring the difference between the reading and 212 °F. No bias error is assumed to be associated with the location of the thermocouples.

Fluid flow measurements, such as those for feed water, steam, and air are based on the output from differential pressure (ΔP) instruments. These instruments measure the ΔP across and orifice plate or other similar flow device. The signal from the ΔP transmitter is processed through a square-root extractor, which puts out a signal that is proportional to the square root of the signal entering it. This square-root extractor output signal is then a linear function of the flo rate. Because of this, the bias limit on the fluid flow rat measurements are not only a function of the bias limit on th ΔP reading, but also a function of flow rate as well. The bias limits for these instruments were obtained from the calibration data.

The bias limit for the solid flow rate measurements is obtained from the calibration data of each instrument. The bias limits for the gas analyzers are also obtained from the calibration data. The gas analyzers were calibrated on a regular schedule to eliminate any other sources of bias error. Chemical analyses biases were obtained from the calibration data obtained from the laboratory.

STEP 4: Determine $\nu\overline{P}_i$

The degrees of freedom associated with the calculation of each $S\overline{P}_i$ is given by

$$\nu\overline{P}_i = N-1 \tag{4-6}$$

Where N is the total number of measurements that went into the average value (N is equal to H*M for values on the data highway).

STEP 5: Calculate Br

The bias limit of the result Br is the uncertainty of the result that is due to the bias limits of the input parameters. The value of Br is given by:

$$Br = \left[\sum_{i=1}^{N}(\theta_i \ B\overline{P}_i)^2\right]^{.5} \tag{4-7}$$

Where θ_i is the relative sensitivity coefficient for the i^{th} parameter. θi is defined in PTC 19.1 as follows:

$$\theta_i = \frac{\partial r}{\partial \overline{P}_i .} \tag{4-8}$$

θ_i is the partial derivative of the result with respect to the i^{th} input parameter. The value of θ_i can be calculated by taking the partial derivatives of all of the mathematical expressions used to calculate the result. This method is called the analytical method. A simpler way to determine the partial derivatives is to use the perturbation method, where the value of $\overline{P}_i$. is replaced in the calculation with $(\overline{P}_i + \Delta\overline{P}_i)$, where $\Delta\overline{P}_i$ is a small increment of $\overline{P}_i$ (usually 1% of $\overline{P}_i$), and a value of $r(\overline{P}_i + \Delta\overline{P}_i)$ is calculated. The value of θ_i is then given by:

$$\theta_i = \frac{r(\overline{P}_i + \Delta\overline{P}_i) - r}{\Delta\overline{P}_i} \qquad (4\text{-}9)$$

for each input parameter. This calculation has been found to give the same result as the analytical method, and while it requires considerably more calculations, is much easier to implement on the VAX computer than the analytical method.

STEP 6: Calculate S_r

The precision index of the calculated result, S_r, is the uncertainty of the result that is due to the precision indexes of the input parameters. The calculation of S_r is identical to B_r, except that $S_{\overline{P}_i}$ is substituted for $B_{\overline{P}_i}$ in equation 4-7.

STEP 7: Calculate ν_r

The degrees of freedom of the calculated result is a function of the precision index of the result, the precision index of the input variables, and the degrees of freedom of the input variables. The Welch-Satterwaite formula given in PTC 19.1 is used to calculate ν_r as follows:

$$\nu_r = \frac{S_r^{\,4}}{\displaystyle\sum_{i=1}^{N} \frac{(\theta_i \, S_{\overline{P}_i})^4}{n_{\overline{P}_i}}} \qquad (4\text{-}10)$$

The perturbation results for θi are used in both equations 4-7 and 4-10.

STEP 8: Find the Student's t value

The precision index of the result, Sr, is related to the precision error of the calculated result by a factor known as Student's t value. The precision error of the calculated result is ($t*S_r$). The value of t is a function of the number of degrees of freedom and the probability that the true value of r will be inside of the range of $r \pm t*S_r$. The value of t was evaluated at a probability interval of 95%. Table 4-7 lists values of t for the 95% probability interval as a function of ν degrees of freedom.

STEP 9: Calculate U_{rRSS}

The last step in the calculation of the uncertainty of the result is to combine the values of B_r and S_r to obtain U_{rRSS}. PTC 19.1 recommends using the root-sum-square model for combining the bias error and the precision error. The equation for the overall uncertainty is:

$$U_{rRSS} = [B_r^2 + (t\ S_r)^2]^{.5} \qquad (4\text{-}11)$$

Using the values of t from Table 4-7 gives an uncertainty interval of 95%. The final result can be expressed with its uncertainty interval as:

$$r \pm U_{rRSS} \qquad (4\text{-}12)$$

Table 4-7. Student's t Values at the 95% Probability Level

n	t	n	t
1	12.71	16	1.120
2	4.303	17	2.110
3	3.182	18	2.101
4	2.776	19	2.093
5	2.571	20	2.086
6	2.447	21	2.080
7	2.365	22	2.074
8	2.306	23	2.069
9	2.262	24	2.064
10	2.228	25	2.060
11	2.201	26	2.056
12	2.179	27	2.052
13	2.160	28	2.048
14	2.145	29	2.045
15	2.131	30	2.042
		40	2.021
		60	2.000
		120	1.980
		∞	1.960

Section 5

HOT-MODE SHAKEDOWN

The purpose of hot-mode testing is to establish the conduct for future steady-state performance testing as discussed in Section 6. Specifically, the test plan is designed to establish 1) the required times to reach steady-state conditions following changes in unit load and bed chemistry, 2) the quantity of solids samples and process data required to assure acceptable accuracy in calculated results, and 3) the required duration for each performance test. These tests were conducted from March 6 to 18, 1989.

Prior to these tests, a one week series of operational tests were conducted to establish "design" operating conditions for the boiler by which the hot-mode tests would be conducted. These tests were termed pre-hot-mode tests. In particular, bed temperatures and pressures, ash cooler fluidizing velocities, and primary to secondary air ratios were established for the hot-mode test plan. In addition, the pre-hot-mode tests provided a run-in calibration and training period prior to the start of the hot-mode test plan.

5.1 PRE-HOT-MODE TEST RESULTS

During a one week period prior to hot-mode testing, all solids feed and disposal systems were calibrated, including the six coal feeders, two limestone feeders, two bottom ash weigh bins, and the fly ash weigh bin. The calibrations were performed according to procedures developed during the cold mode shakedown period described in Section 4. Due to difficulties calibrating the fly ash flow meter, a methodology was developed for calculating the flow rate based on a mass balance of inerts in the input coal and limestone streams and the output bottom ash stream. This method was used for the remainder of all performance testing described in Section 6.

In addition, all solids sampling hardware was tested and a partial set of solids samples were withdrawn from the boiler according to the sampling scenario established for the hot-mode test plan. These samples were prepared in the on-site solids preparation laboratory as a final check on all equipment, procedures, and manpower availability.

The operational tests designed to establish "design" operating conditions for the hot-mode test plan revealed the following:

1. The ability to pre-set combustor operating temperatures was not possible. Temperatures were found to vary with load, excess air, and bed pressures. The latter are measured along each of three walls in the lower combustion chambers approximately one foot above the air distributor plate. The value is an indication of the solids inventory in the bed.

2. At similar loads, excess air levels, and bed pressures, the operating temperatures between combustion chambers could be significantly different. Temperatures could also vary within the same combustion chamber between repeat tests under seemingly identical operating conditions. This suggested that solids distribution in the upper freeboard region of the combustion chambers may be different between the two combustors and between duplicate tests. This distribution of solids is not indicated by the measurement of bed pressure at the one foot level in the combustor. However, the pressure profile is measured at 10 foot intervals along the rear wall of combustor B. Data from these pressure taps suggested differences in profiles under nearly identical operating conditions.

3. Ash cooler fluidizing velocities did little to affect changes in combustor operating temperatures. The original intent of this design was to classify bed material and return the finer size fraction to the combustion process while removing the larger material from the boiler as bottom ash. Although size data did indicate that higher fluidizing velocities in the ash coolers produced a coarser bed drain, this change had little impact on the overall solids distribution in the boiler and hence, on operating temperatures.

4. Changes in primary to secondary air ratio had no immediate impact on combustor operating temperatures. Changes in bed temperatures over 4 to 8 hour periods following these changes were consistent with the normal drift observed during the unit operational period prior to these tests. No definite conclusions could be made regarding the impact of PA/SA ratio of temperature.

5. Increasing excess air at constant load decreased combustor operating temperatures, as expected. This is caused by the increase in combustor stoichiometry and the associated reduction in adiabatic flame temperature. However, excess air adjustments are limited due to the requirement at half load to maintain a minimum underbed air flow to each combustion chamber to reduce backsifting into the windbox, and at full load by primary air fan limitations.

Based on results from these tests, only unit load and excess air were determined to be significant controllable parameters affecting operating temperatures and hence, test results. To establish repeatability of test results, setpoints for the following operating variables were established prior to testing:

- Unit load
- Excess air at 3.3 vol. % O_2
- PA/SA ratio as established at a given load by the design flow curves provided by the boiler vendor
- Bed pressures set to 18 in wg. average in each chamber
- Ash cooler velocities set to 6 ft/s
- All coal and limestone feeders in service

Also based on results from these tests, an effort was undertaken to develop a correlation for predicting combustor operating temperatures based on measured controllable and uncontrollable operating parameters. This resulted in the installation of pressure taps on each combustion chamber to measure the differential pressure along the water walls between the lower combustor refractory/water-wall interface and the top of the combustion chamber. This led to a relatively accurate correlation, as discussed in greater detail in Section 10. Combustor operating temperatures are predicted based on the differential pressure measurement, which is uncontrollable, and unit load and excess air.

5.2 OBJECTIVES AND PROCEDURES FOR HOT-MODE TESTING

The hot-mode test plan consisted of a series of five special tests designed to:

- Determine the number of solids samples which must be taken during a performance test to achieve a desired degree of output accuracy.
- Establish the duration for steady-state performance testing.
- Demonstrate the accuracy of solids preparation procedures according to ASTM standards.
- Determine the times required for the boiler to reach chemical equilibrium after a step change in Ca/S ratio and to reach thermal equilibrium following a step change in load.

5.2.1 Determination of the Number of Solids Samples Required

ASTM procedures outline a method for determining the number of samples required to achieve a specified accuracy in an output variable, based on the uncertainty of a single input variable. Since feed and waste streams are not uniform throughout a test, the chemical composition of solids streams is expected to vary over the course of a test run. Therefore, it is necessary to collect and analyze several samples to accurately represent the chemical composition of each stream. Because fewer solids samples can be collected relative to the number of readings that can be recorded from on-line instrumentation, the solids data have a much greater effect on performance calculation result uncertainties than data from the data highway.

The uncertainty analysis software subroutine, incorporated into the performance calculations in the second quarter of 1988, calculates the uncertainty in each of the outputs from the performance calculations, given the uncertainty in each of the measurements used as inputs to the performance calculations. This was discussed in more detail in Section 4.2.5.2. The uncertainties depend upon the actual values, standard deviations (precision errors), and bias errors associated with the input variables to the performance calculations. The original algorithm used for calculating uncertainties involved taking partial derivatives of each performance equation. This required that the uncertainty analysis code be changed every time a change was made to the performance calculation code. To avoid this, the test team developed a "perturbation method" to calculate the uncertainty in test results based on the uncertainty of all input measurements. The contributions to the uncertainty in the result by the uncertainty of the input parameter is found by perturbing each input parameter value by the amount of the input uncertainty and evaluating the result at the new value of the input parameter. Thus, there is no need to change the uncertainty calculations to match revisions in the performance calculations. This method establishes the total uncertainty of all calculated results for a test run based on the contributions of precision and bias errors of all input variables. The uncertainty analysis can also be used to establish output variable sensitivity (sensitivity analysis) to changes in input variables. Sensitivity analysis is helpful in highlighting critical process instrumentation and for establishing required instrument accuracy (i.e., calibration frequency).

To determine the number of samples required, the test team performed the uncertainty analysis on hot-mode test SD1 for various 2-hour increments. Each additional 2-hour increment adds one additional set of coal, limestone, fly ash and bottom ash samples. The variance of other process variables, such as temperature and pressure measurements, also change as the duration of the test run increases. As the number of samples included in a test run increases, the uncertainty in the results is expected to decrease. Target accuracies for calculated test results were established during cold mode shakedown testing. For example, four of these target accuracies for calculated results are:

- Boiler efficiency ± 0.5%
- Calcium balance ± 10%
- Combustion efficiency ± 0.2%
- Sulfur retention ± 5%

It is possible to choose the number of solids samples required to achieve these target uncertainties. This, in turn, establishes the test duration, since it is difficult to collect a set of solids samples more frequently than once every 2 hours.

5.2.2 Determination of the Accuracy of Solids Preparation Procedures

The validation process for the solids sampling, preparation, and analysis procedures began during cold-mode shakedown, when an extensive review of the sampling locations and procedures was performed to identify and eliminate any sources of systematic bias. Quantification of the error due to preparation and analysis was completed during the hot-mode test sequence by measuring the variance of the analytical results of four identically prepared samples, each derived from a single initial sample. The variance of the results is called the division and analysis variance (S_{da}^2), and is a measure of the random error introduced by preparing and analyzing samples.

ASTM procedures provide guidelines for determining the acceptability of the division and analysis variance. The acceptability depends upon two criteria. First, the variance should not change when measured repeatedly. Statistical tests are used to determine if a change in the variance is real (i.e., caused by problems with the preparation procedures or the result of measurement inaccuracies).

To determine S_{da}^2, a single sample is collected according to normal sampling procedures. The sample is then split into four subsamples. Each of these subsamples is reduced according to standard procedures to a lab sample which is then analyzed. The variance of the four analyses is then calculated and reported as S_{da}^2.

The number of samples called for by the ASTM procedure was modified to use 8 samples requiring 32 analyses. This modified plan was used for coal and bottom ash samples, and greatly reduced the cost of the procedure without compromising results.

The second criterion for determining acceptability is that the variance of division and analysis should not be more than 20 percent of the overall variance (S_o^2). The overall variance includes the variability of the material as well as the preparation and analysis variability. The first step in determining S_o^2 involves collecting an incremental sample, which is one acquired through a single operation of the sampling device. This sample is not composited with other increments but is prepared as a separate lab sample. The

ASTM plan was modified so that 42 incremental samples were collected for coal and 40 were collected for bottom ash during the 48 hours allotted for the test.

To calculate S_o^2, the analytical results were divided into two groups, and a variance was calculated for each group. The variances of the two groups were averaged and then multiplied by an "F" factor from statistical tables to calculate a "probable maximum" value of S_o^2. This is the number upon which ASTM requirements are based.

5.2.3 Determination of the Time Required to Steady State

The time requirement to steady state is defined as the time period over which the plant must operate at constant conditions to ensure chemical and thermal equilibrium with all reacting variables. This information is valuable for test scheduling in that it indicates the time required between tests for the plant to reach equilibrium at the new conditions. For this test plan, major first-order transient times were determined by making changes in the boiler load and the Ca/S ratio. Boiler load for the Ca/S ratio transient test was 100% MCR. The Ca/S ratio transient was introduced by shutting off the limestone feeders. After 12 hours of operation, the limestone feed rate was returned to twice its initial setting. Operation was observed for another 12 hours prior to proceeding to the load change transients.

For the load ramp test, main turbine load was adjusted down in a controlled ramp (not less than 1% per minute and not more than the maximum rate of load reduction which had been demonstrated from an initial value of 100% MCR down to the minimum load at which all turbine/generators remained in service. After 24 hours, load was increased in a controlled ramp back to the initial 100% MCR value.

5.3 TEST MATRIX

The test matrix for the hot-mode-shakedown tests is as shown below:

Test Number	Transient Test Variable	Target Boiler Load	Ca/S	Forecast Test Time (hr)
SD0	Startup and load Stabilization			48
SD1	Base Case	100%	D	48
SD2	Ca/S	100%	0	12
SD3	Ca/S	100%	D*	12
SD4	Load	50%	D	24
SD5	Load	100%	D	24

D = Design
* Minimum load with all turbine/generators

Hot-mode tests SD0 through SD5 were performed from 08:00 on March 12 through 10:00 on March 18. The unit switched from Peabody coal to the test coal, Salt Creek, one day prior to the initiation of test SD0. Test SD0 was actually a 24-hour hold period at steady-state conditions prior to the start of solids sampling. Test SD1 was a baseline performance test whose primary objective was to determine the minimum test duration required to achieve an acceptable level of uncertainty in performance calculation results. Tests SD2 and SD3 determined the response time of SO_2 emissions following a complete stoppage of limestone flow into the boiler, and after resumption of limestone feed at twice the previous rate. Tests SD4 and SD5 measured the plant response to a load change.

The plant was operated at steady-state at close to full load (105 MWe) from 08:00 on March 13, 1989 to 08:00 on March 15, 1989. During this time, instrument readings from the plant control system data highway were recorded by the data acquisition system every 30 seconds and solids samples were collected every 2 to 4 hours.

5.4 HOT-MODE TEST RESULTS

5.4.1 Determination of the Number of Solids Samples Required

There are four solids streams to consider in uncertainty analyses: coal and limestone entering the boiler and bottom ash and fly ash exiting the boiler. Plots in the 1987-1988 Annual Report graphically show the variation in the composition of the four solids streams over the duration of the test. Generally, solids analyses from test SD1 indicate that Salt Creek coal has a low composition variability. Plots of scatter in solids analysis can also be useful in troubleshooting the solids sampling and preparation procedures; for example, unusually high readings of carbon content in some bottom ash samples led to the realization that samples had been prepared in a crusher that had not been rinsed with bottom ash prior to use.

The six main types of measurements used as inputs to the performance calculations are:

- Pressure (or pressure difference)
- Temperature
- Fluid flow rate
- Solid flow rate
- Gas chemical analysis
- Solid chemical analysis

The uncertainty in a measured variable has two components - a precision component and a bias component. Precision error is a function of the number of readings and the scatter in those readings. A larger number of readings during a steadier process will generally lead to a smaller precision error. Bias error is that component of the uncertainty which is fixed from one reading to the next. Also known as systematic error, it is a function of instrument accuracy and is estimated using equipment specifications and engineering judgement. See Section 4.2.5.2 for more information on measurement uncertainty.

Shown in Table 5-1 are the major contributors to uncertainty in the calculation of boiler efficiency by the losses method. Figure 5-1 shows how the uncertainty in boiler efficiency (loss method) decreases with time.

In Table 5-1, the input variables for a given result are shown in the order of maximum contribution for the results calculated over the 48-hour run period. The numbers shown for the contribution are equivalent to the terms Br^2 (bias limit of the result) and tSr^2 (Student t factor multiplied by the precision index of the result) as described in Section 3.2.5.2. Contributions shown are those whose values are greater than one percent of the value of the maximum contribution. The total uncertainty (shown near the top of the table) is the square root of the sum of all the contributions.

The major contributors to uncertainty in six other important performance calculation results are shown in Tables 5-2 through 5-7 and the corresponding plots of the uncertainty of results with time are shown in Figures 5-2 through 5-7. The tables and plots are shown for the following performance calculation results:

- Boiler efficiency (I/O method)
- Ca/S molar ratio
- SO_2 retention (%)
- Ca utilization
- Net heat rate
- Combustion efficiency

In Tables 5-1 through 5-7, a bias error is always the largest contributor to the uncertainty for the period. The only precision errors that appear are those associated with solids analysis, and a larger number of readings will generally lead to a smaller precision error. This leads to the conclusion that results uncertainties are reduced by increasing the number of solids samples. Also, the uncertainty obtained by taking 16 solids samples over a 48-hour steady-state period can be replicated by taking 16 solids samples over a shorter period of time. However, factors such as manpower, sample processing equipment requirements, and residence time of material in the boiler impose practical limitations on the

Table 5-1

BOILER EFFICIENCY (LOSS METHOD)

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		88.17		88.04		88.09		88 11		88 27		88 38	
TOTAL UNCERTAINTY		0.77		0.38		0.33		0 29		0 26		0 23	
UNC CONTRIBUTIONS													
O2 @ econmizer flue gas outlet	BIAS	0.012	5	0.0125	3	0.0125	2	0.0124	2	0.0119	2	0.0119	1
HHV of fuel AF basis	P.E.	0.419	1	0.0725	1	0.0415	1	0 0304	1	0.014	1	0.0079	2
Hydrogen in coal AF basis	BIAS	0.0063	6	0 00633	5	0.00633	5	0.00631	4	0.00623	3	0 0062	3
Carbon in fly ash	BIAS	0.00445	7	0.00449	7	0 00448	7	0 00456	6	0 0045	5	0 0043	4
Hydrogen in fly ash	BIAS	-		0.00405	8	0 00407	9	0.00414	7	0.00408	6	0 0039	5
Hydrogen in coal AF basis	P.E	0.0182	4	0.00566	6	0 00426	8	0.00316	9	0.00466	4	0.0033	6
Carbon in fly ash	P.E.	-		-		0.0111	3	0.00733	3	0.00251	9	0 0030	7
HHV of fuel AF basis	BIAS	-		0.0032	9	0.00316	10	0.00314	10	0.00305	7	0.0030	8
Radiant and convective losses	BIAS	-		0.00211	10	0 0021	11	0.0021	11	0.0021	11	0 0021	9
Carbon in coal AF basis	P.E.	0.0406	3	0.00913	4	0.00533	6	0.00365	8	0 00268	8	0 0015	10
Ash in coal AF basis	BIAS	.		0.00165	11	0.00156	12	0.00154	12	0 00153	12	0 0014	11
Moisture in fuel AF basis	BIAS	.		0.00107	12	0 00106	13	0.00106	13	0.00105	13	0.0011	12
Ash in coal AF basis	P.E	0.0653	2	0.0135	2	0.00724	4	0.00494	5	0.00244	10	0.0010	13

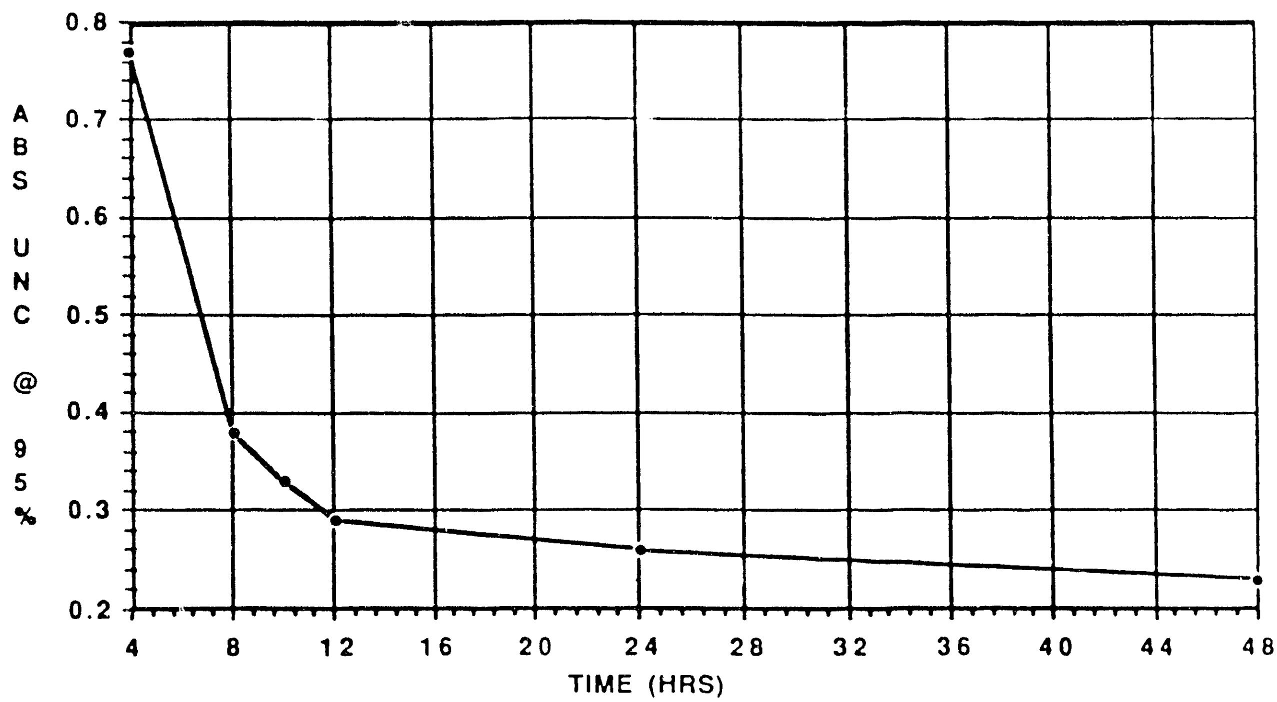


Figure 5-1. Absolute Uncertainty in Boiler Efficiency (Loss Method) vs. Time.

Table 5-2

BOILER EFFICIENCY (I/O METHOD)

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		86.39		86.12		86.01		85.95		86.07		86.14	
TOTAL UNCERTAINTY		6.87		3.34		2.99		2.83		2.62		2.54	
UNC CONTRIBUTIONS													
Feedwater flow (TMP CMP)	BIAS	4.99E+00	2	4.95E+00	2	4.94E+00	1	4.94E+00	1	4.99E+00	1	4.99E+00	1
HHV of fuel AF basis	P.E.	4.09E+01	1	5.18E+00	1	3.01E+00	2	2.10E+00	2	9.22E-01	2	4.90E-01	2
SH IIB attemperator flow	BIAS			1.91E-01	3	1.90E-01	3	1.90E-01	3	1.91E-01	3	1.92E-01	3
HHV of fuel AF basis	BIAS			1.66E-01	4	1.65E-01	4	1.64E-01	4	1.64E-01	4	1.65E-01	4
Coal flow cmb B, rear wall(4D)	BIAS			8.47E-02	5	8.45E-02	5	8.46E-02	5	8.50E-02	5	8.55E-02	5
Coal flow cmb A, fr wll,east(4C)	BIAS			8.43E-02	6	8.41E-02	6	8.41E-02	7	8.44E-02	6	8.49E-02	6
Coal flow cmb A, rear wall (4A)	BIAS			8.27E-02	8	8.26E-02	7	8.26E-02	8	8.29E-02	7	8.32E-02	7
Coal flow cmb B, fr wll,east(4E)	BIAS			8.24E-02	9	8.23E-02	8	8.23E-02	9	8.26E-02	8	8.30E-02	8
Coal flow cmb A, fr wll,west(4B)	BIAS			8.12E-02	10	8.10E-02	9	8.10E-02	10	8.15E-02	9	8.20E-01	9
Coal flow cmb B, fr wll,west(4F)	BIAS			8.08E-02	11	8.06E-02	10	8.06E-02	11	8.10E-02	10	8.14E-02	10
Feedwater Temp	BIAS			8.41E-02	7	6.99E-02	11	8.44E-02	6	5.87E-02	11	6.38E-01	11

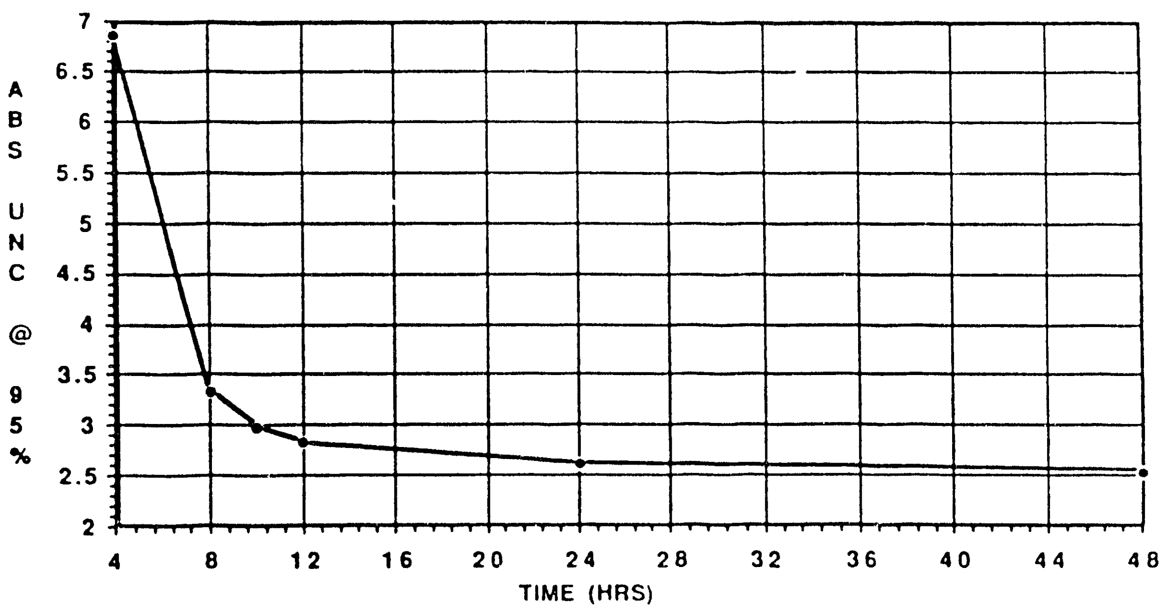


Figure 5-2. Absolute Uncertainty in Boiler Efficiency (I/O Method) vs. Time.

Table 5-3

Ca/S MOLAR RATIO (SORBENT ONLY)

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		1.41		1.38		1.39		1.41		1.41		1.48	
TOTAL UNCERTAINTY		0.44		0.22		0.19		0.18		0.17		0.17	
UNC CONTRIBUTIONS													
Sulfur in coal AF basis	BIAS	1.96E-02	2	1.94E-02	2	1.97E-02	1	2.05E-02	1	2.09E-02	1	2.31E-02	1
Sulfur in coal AF basis	PE	1.69E-01	1	2.36E-02	1	1.41E-02	2	9.62E-03	2	4.33E-03	2	2.19E-03	2
Sorbent feed rate CMB 4A	BIAS	-		1.24E-03	3	1.27E-03	3	1.30E-03	3	1.30E-03	3	1.44E-03	3
Sorbent feed rate CMB 4B	BIAS	-		1.18E-03	4	1.17E-03	4	1.19E-03	4	1.20E-03	4	1.34E-03	4
Calcium in lime AF basis	PE	-		6.48E-04	5	5.86E-04	5	9.83E-04	5	4.45E-04	5	2.34E-04	5

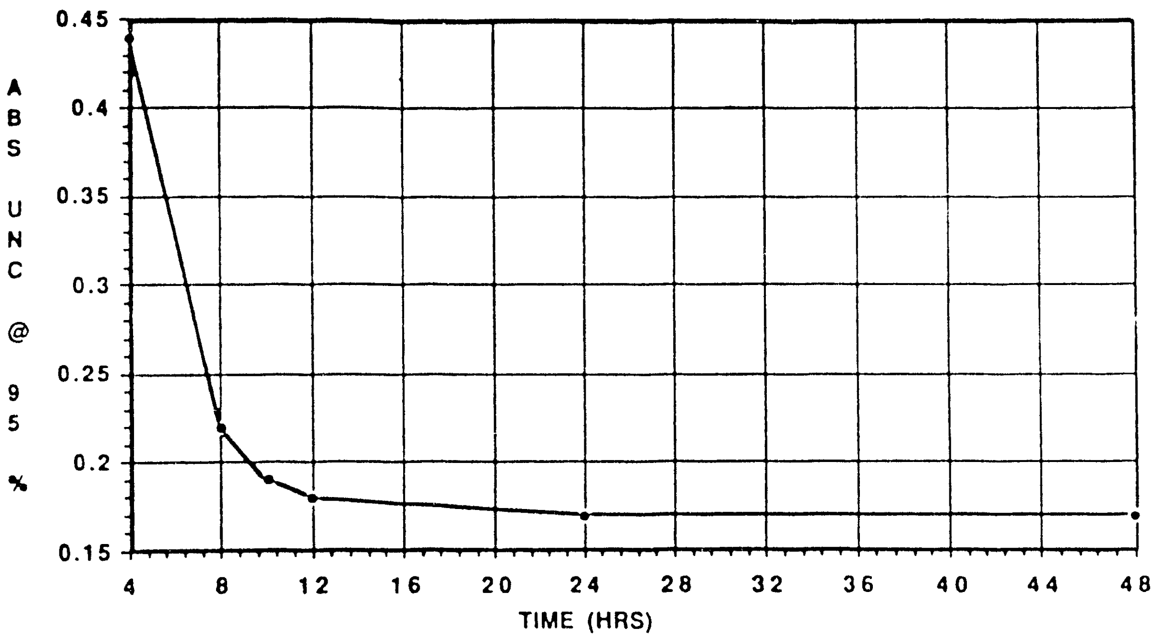


Figure 5-3. Absolute Uncertainty in Ca/S Molar Ratio (Sorbent) vs. Time.

Table 5-4

SULFUR DIOXIDE RETENTION PERCENT

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		70.2		69.28		69.13		68.83		68.66		68.48	
TOTAL UNCERTAINTY		9.62		5.23		4.76		4.59		4.31		4.18	
UNC CONTRIBUTIONS													
Sulfur in coal AF basis	BIAS	8.69E+00	2	9.49E+00	2	9.65E+00	1	9.98E+00	1	1.03E+01	1	1.04E+01	1
SO2 (LO) @ econ flue gas	BIAS	4.92E+00	3	5.13E+00	3	5.15E+00	3	5.22E+00	2	5.35E+00	2	5.39E+00	2
Sulfur in coal AF basis	P.E.	7.51E+01	1	1.16E+01	1	6.90E+00	2	5.02E+00	3	2.18E+00	3	9.89E-01	3
O2 at econ flue gas outlet	BIAS	-		5.43E-01	5	5.48E-01	4	5.58E-01	4	5.65E-01	4	5.74E-01	4
Carbon in coal AF basis	P.E.	3.19E+00	4	5.53E-01	4	3.29E-01	5	2.19E-01	5	1.52E-01	5		

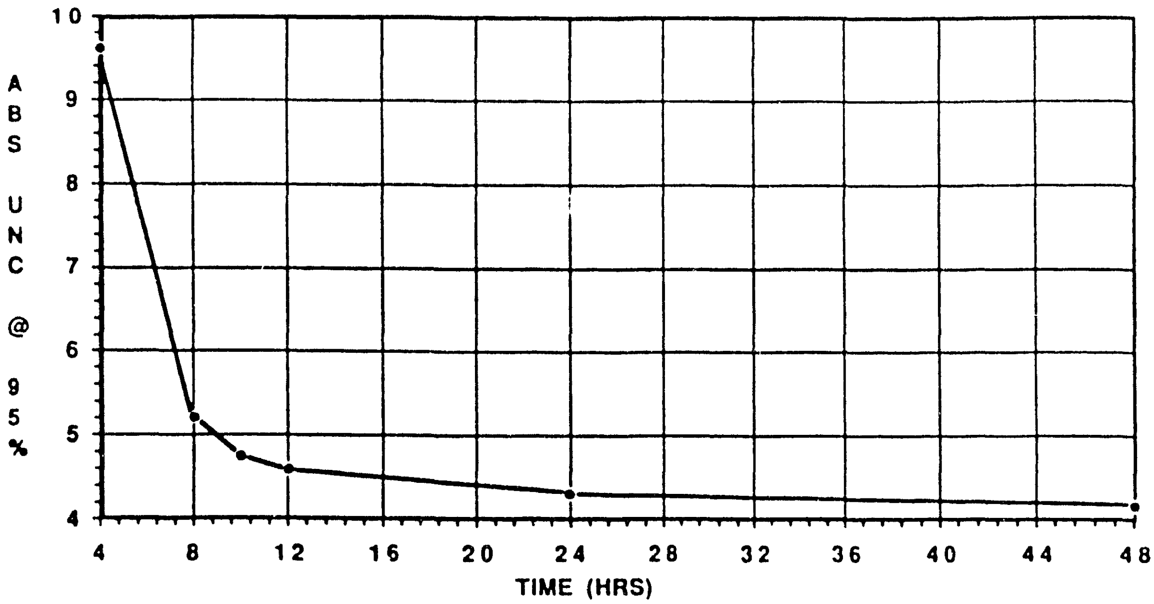


Figure 5-4. Absolute Uncertainty in Sulfur Dioxide Retention vs. Time.

Table 5-5

CALCIUM UTILIZATION (SORBENT ONLY)

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		49.81		50.04		49.71		48.87		48.72		46.12	
TOTAL UNCERTAINTY		23.73		11.95		10.62		9.99		9.17		8.09	
UNC CONTRIBUTIONS													
Sulfur in coal AF basis	BIAS	6.10E+01	2	6.51E+01	2	6.50E+01	1	6.45E+01	1	6.55E+01	1	5.90E+01	1
Sulfur in coal AF basis	P.E.	4.92E+02	1	6.96E+01	1	4.02E+01	2	2.77E+01	2	1.17E+01	2	4.72E+00	2
SO2 (LO) @ econ flue gas	BIAS	-		2.68E+00	3	2.66E+01	3	2.63E+00	3	2.69E+00	3	2.44E+00	3
Sorbent feed rate CMB 4A	BIAS	-		1.53E+00	4	1.54E+00	4	1.49E+00	4	1.48E+00	4	1.32E+00	4
Sorbent feed rate CMB 4B	BIAS	-		1.46E+00	5	1.42E+00	5	1.37E+00	5	1.37E+00	5	1.23E+00	5

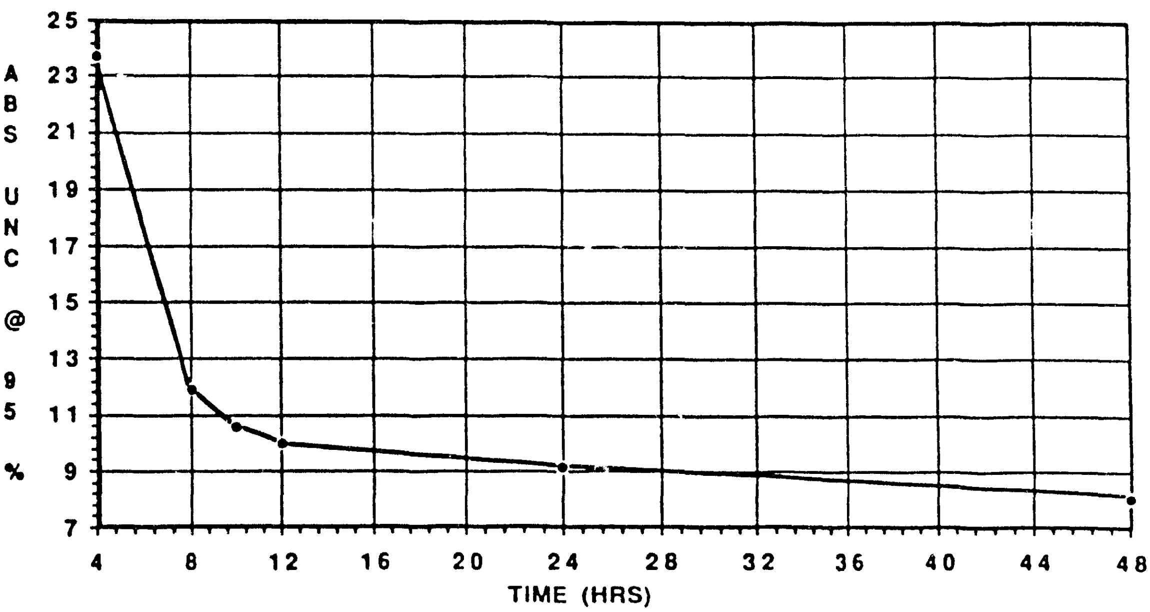


Figure 5-5. Absolute Uncertainty in Calcium Utilization (Sorbent) vs. Time.

Table 5-6

NET PLANT HEAT RATE

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		11260.5		11301.5		11314.1		11325.2		11297.7		11256.5	
TOTAL UNCERTAINTY		878		351		291		260		214		194	
UNC CONTRIBUTIONS													
Total load in MW 1,2,3,4	BIAS	17200	2	1.74E+04	2	1.74E+04	2	1.75E+04	2	1.73E+04	1	1.71E+04	1
HHV of fuel AF basis	P.E.	73900	1	9.35E+04	1	5.46E+04	1	3.80E+04	1	1.64E+04	2	8.62E+03	2
HHV of fuel AF basis	BIAS	-		2.97E+03	3	2.97E+03	3	2.96E+03	3	2.93E+03	3	2.91E+03	3
Coal flow cmb B, rear wall(4D)	BIAS	-		1.47E+03	4	1.47E+03	4	1.48E+03	4	1.47E+03	4	1.47E+03	8
Coal flow cmb A, fr wll,east(4C)	BIAS	-		1.46E+03	5	1.46E+03	5	1.47E+03	5	1.46E+00	5	1.46E+03	7
Coal flow cmb A, rear wall (4A)	BIAS	-		1.43E+03	6	1.44E+03	6	1.44E+03	6	1.44E+00	6	1.43E+03	6
Coal flow cmb B, fr wll,east(4E)	BIAS	-		1.43E+03	7	1.43E+03	7	1.44E+03	7	1.43E+03	7	1.42E+03	5
Coal flow cmb A, fr wll,west(4B)	BIAS	-		1.40E+03	8	1.41E+03	8	1.41E+03	8	1.41E+03	8	1.41E+03	4
Coal flow cmb B, fr wll,west(4F)	BIAS	-		1.40E+03	9	1.40E+03	9	1.41E+03	9	1.40E+03	9	1.40E+03	3
Unit auxiliary transformer MW	BIAS	-				5.78E+02	10	5.79E+02	10	5.72E+02	10	5.66E+02	10

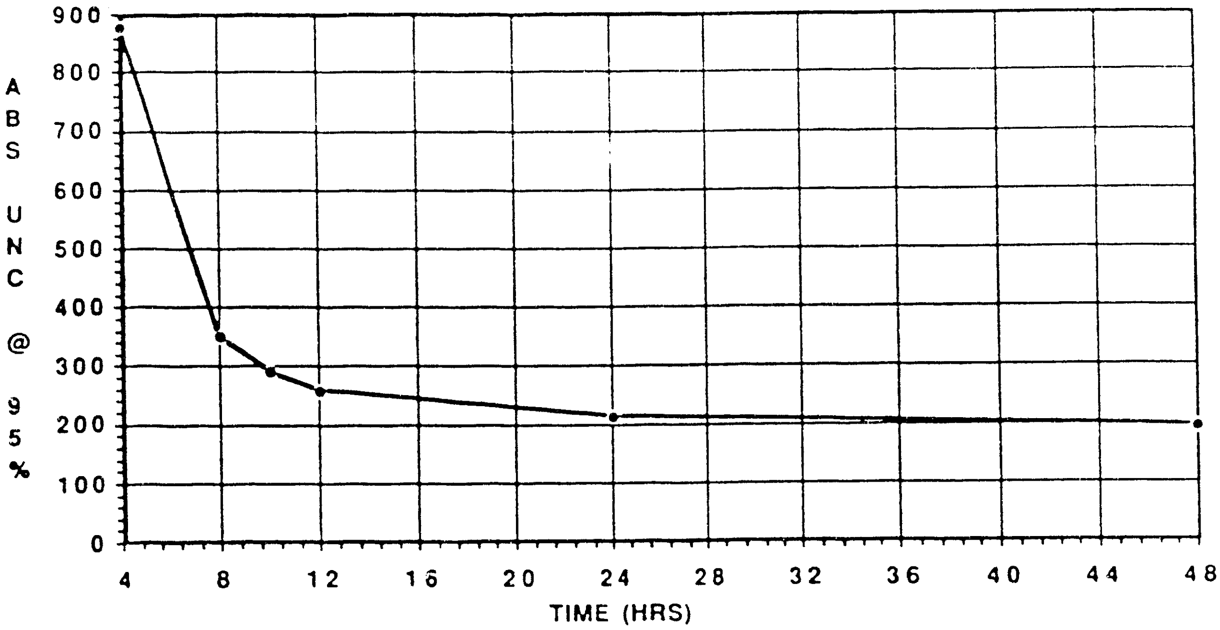


Figure 5-6. Absolute Uncertainty in Net Plant Heat Rate vs. Time.

Table 5-7

COMBUSTION EFFICIENCY

Description	ERROR TYPE	4 HR	RANK	8 HR	RANK	10 HR	RANK	12 HR	RANK	24 HR	RANK	48 HR	RANK
MEAN VALUE		98.04		98 04		98.08		98.07		98 09		98 18	
TOTAL UNCERTAINTY		0.32		0 18		0.19		0 17		0 14		0 13	
UNC CONTRIBUTIONS													
Carbon in flyash	BIAS	5.04E-03	3	5.10E-03	2	5.10E-03	3	5.19E-03	3	5.08E-03	1	4 84E-03	1
Hydrogen in flyash	BIAS	4.11E-03	4	4.16E-03	3	4.18E-03	4	4.26E-03	4	4 17E-03	2	4 00E-03	2
Carbon in flyash	P.E.	1.71E-03	8	7.67E-04	7	3.60E-02	1	8.72E-03	1	2.90E-03	3	3 65E-03	3
Ash in coal AF basis	BIAS	1.79E-03	7	1.78E-03	5	1.68E-03	5	1.67E-03	5	1.64E-03	5	1 53E-03	4
Ash in coal AF basis	P E	7.06E-02	1	1.56E-02	1	8.44E-03	2	5.58E-03	2	2 68E-03	4	1 14E-03	5
Bed drain rate CMB 4B	BIAS	-		5.52E-04	9	4.94E-04	7	4.11E-04	7	4 10E-04	6	4 49E-04	6
Carbon in bed drain	BIAS	-		2.49E-04	11	2.37E-04	10	2 18E-04	11	2.12E-04	9	2 42E-04	7
Bed drain rate CMB 4A	BIAS	-		2.51E-04	10	2.36E-04	11	2.30E-04	10	2.19E-04	8	2.30E-04	8
HHV of fuel AF basis	P E	1.18E-02	2	2.15E-03	4	1.19E-03	6	8.63E-04	6	3.87E-04	7	2 05E-04	9
Hydrogen in bed drain	BIAS	-		2.05E-04	12	1.80E-04	12	1.80E-04	12	1 75E-04	10	2.02E-04	10
CO2 in flyash	BIAS	-		1.67E-04	13	1.75E-04	13	1 75E-04	13	1 72E-04	12	1 69E-04	11
Hydrogen in flyash	P E	3 40E-03	5	8.79E-04	6	4.63E-04	8	2.96E-04	8	1.52E-04	13	1 00E-04	12
Carbon in bed drain	P E	2 52E-03	6	5 76E-04	8	3.68E-04	9	2 80E-04	9	1 73E-04	11	9 45E-05	13
HHV of fuel AF basis	BIAS	-		-		-		-		8 26E-05	14	7 45E-05	14

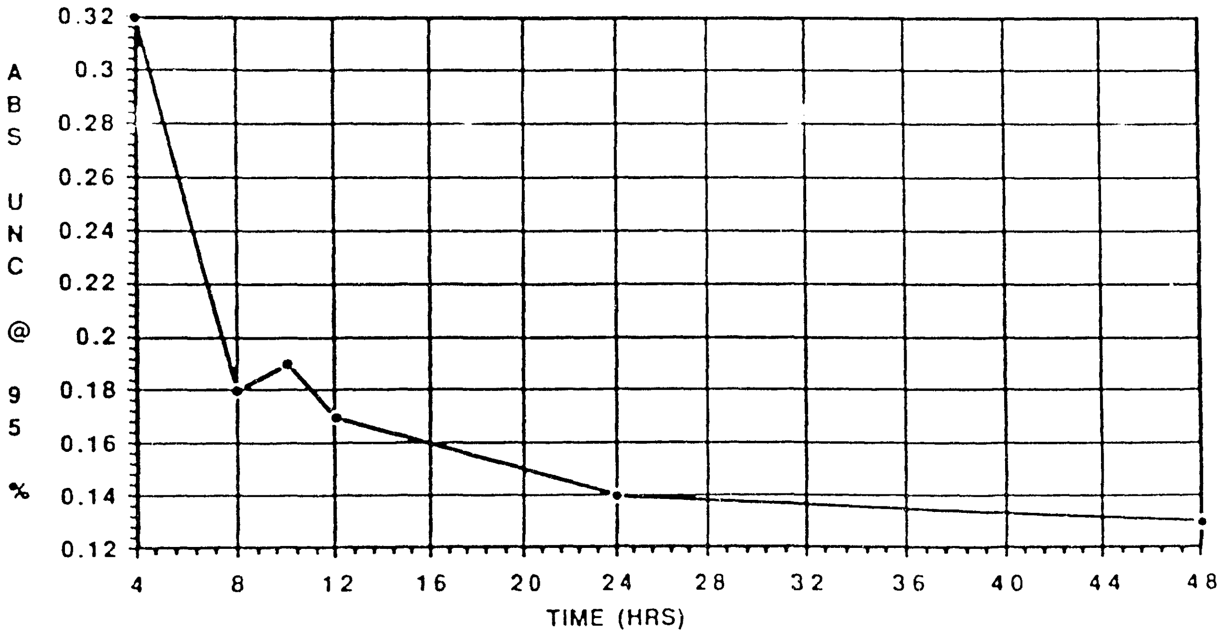


Figure 5-7. Absolute Uncertainty in Combustion Efficiency vs. Time.

feasible increases in sampling frequency and corresponding decreases in test duration.

For four out of the seven major calculated results, (Ca/S ratio, SO_2 retention, calcium utilization, and boiler efficiency (I/O method)) the contribution of the largest precision error was reduced below that of the largest bias error after 10 hours (six solids samples) for test SD1. Therefore, for those variables, the point of diminishing returns has been reached with regard to minimizing uncertainty from increasing the number of samples. For combustion efficiency and net heat rate, this point is reached after 24 hours of sampling (10 samples). For boiler efficiency by loss method, it takes 48 hours (16 samples). However, since the uncertainties associated with these results are acceptably low after only 10 hours of sampling, it is not necessary to increase the number of solids samples taken to achieve a further reduction in uncertainty.

In Figures 5-2 through 5-7, it can be seen that a point of diminishing returns for uncertainty minimization is reached when a bias error becomes the top ranking contributor to the uncertainty in a given result. To further reduce the uncertainty, reduction in this top ranking bias error is required.

5.4.2 Accuracy of Solids Preparation Procedures

Concerning the accuracy of solids preparation procedures, three tests are available for determining the acceptability of the variance of division and analysis, S_{da}^2: excessive variation, division and analysis variance limit (from ASTM procedures), and high uncertainties in performance analysis results (from ASME PTC 19.1).

With respect to meeting the first criteria, values obtained during repeated determinations of S_{da}^2 may not vary excessively. Whether the amount of variation is excessive is based on the statistical "F" test, which limits the amount of the ratio of each individual measurement of S_{da}^2 to the average of all the measurements within the group. Another check is provided by comparing the average value of each group to the overall average again using the statistical "F" factors.

Table 5-8 shows the results of the variance ratio tests for coal and bottom ash for each of the eight samples, which were divided into two groups of 4 samples each.

Table 5-8. Results of Variance Analysis

Item	Total Moisture	Dry Ash	As-fired HHV	Carbon	Calcium
	Coal Variance			Bottom Ash Variance	
Sda^2 (Group 1)	0.045	0.175	3446	0.038	0.457
	0.076	0.034	2464	0.015	0.133
	0.343	0.016	7525	0.097	0.458
	0.061	0.021	2699	0.008	0.069
(Group 2)	0.047	0.232	5660	0.029	0.066
	0.004	0.052	5783	0.019	0.121
	0.014	0.01	11805	0.014	0.164
	0.272	0.068	911	0.008	0.028
Avg Sda^2 (Group 1)	0.131	0.062	4033	0.04	0.279
Avg Sda^2 (Group 2)	0.084	0.09	6040	0.017	0.095
Sda^2 Avg Overall	0.108	0.076	5037	0.029	0.187
Variance Ratios, Maximum limit from "F" factor tables = 3.49					
Group 1	0.34	2.84	0.85	0.96	1.64
	0.58	0.55	0.61	0.39	0.47
	2.61	0.27	1.87	2.45	1.64
	0.46	0.35	0.67	0.2	0.25
Group 2	0.56	2.57	0.94	1.67	0.7
	0.05	0.57	0.96	1.07	1.28
	0.17	0.11	1.95	0.79	1.73
	3.22	0.75	0.15	0.46	0.29
Group Variance ratios, Maximum = 2.18					
	1.22	0.81	0.8	1.39	1.49
	0.78	1.19	1.2	0.61	0.51
Overall Variance, So^2					
Group 1	0.1	0.164	8783	0.058	0.502
Group 2	0.131	0.107	6581	0.08	0.693
Probable Maximum:					
	0.175	0.205	11600	0.104	0.902
Comparisons:					
Sda^2	0.108	0.076	5037	0.029	0.187
So^2	0.175	0.205	11600	0.104	0.902
Sda^2/So^2	0.62	0.37	0.43	0.27	0.21

The ratio of each individual S_{da}^2 to the average of the group of four must not exceed 3.49 (from "F" factor tables); none of the ratios exceed this limit. The ratio of each group average to the overall average must not exceed 2.18; none of the ratios exceed this limit, either. If any of the ratio tests fail the "F" factor criteria, ASTM methodology would have required that the techniques of preparation and analysis be improved.

The division/analysis variance limit test requires that the division and analysis variance be no more than 20% of the overall variance. The probable maximum value of S_o^2, which is used for comparison of S_o^2 and S_{da}^2, is shown. From the table, the division and analysis variance exceeds 20% of the overall variance in all instances. Since the value for S_{da}^2 represents a precision error for solids sampling and analysis, the 20% criteria set by ASTM code becomes more difficult to achieve as the coal properties become more uniform. Improving the precision error may require more sample increments, larger sample lot sizes, and/or sample crushing at earlier stages of preparation.

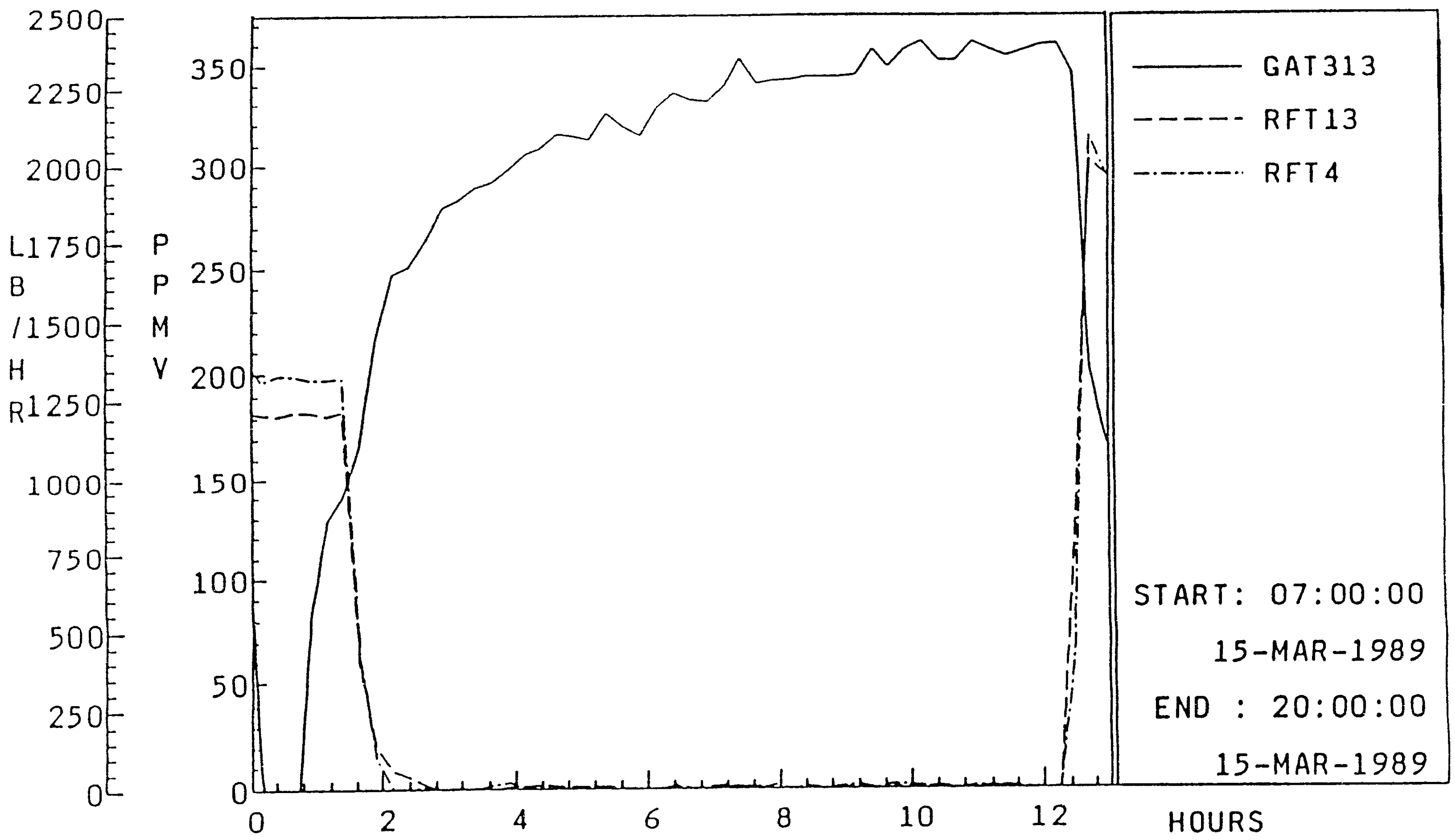
5.4.3 Determination of the Time to Steady State

Concerning transient tests, tests SD2 and SD3 determined the response time of SO_2 emissions following a complete stoppage of limestone flow into the boiler, and after resumption of limestone feed at twice the previous rate. Results are shown in Figures 5-8 through 5-10.

Tests SD4 and SD5 measured the plant response to a fairly rapid load change. Of primary concern is the rate of change in refractory temperatures. These represent the longest lag time to thermal equilibrium of any variable. A representative cyclone refractory temperature is displayed for the load decrease and increase, respectively, in Figures 5-11 through 5-13. A noticeable difference in the response time for decreasing and increasing loads was observed. This represents the effect of higher heat transfer coefficients at higher loads.

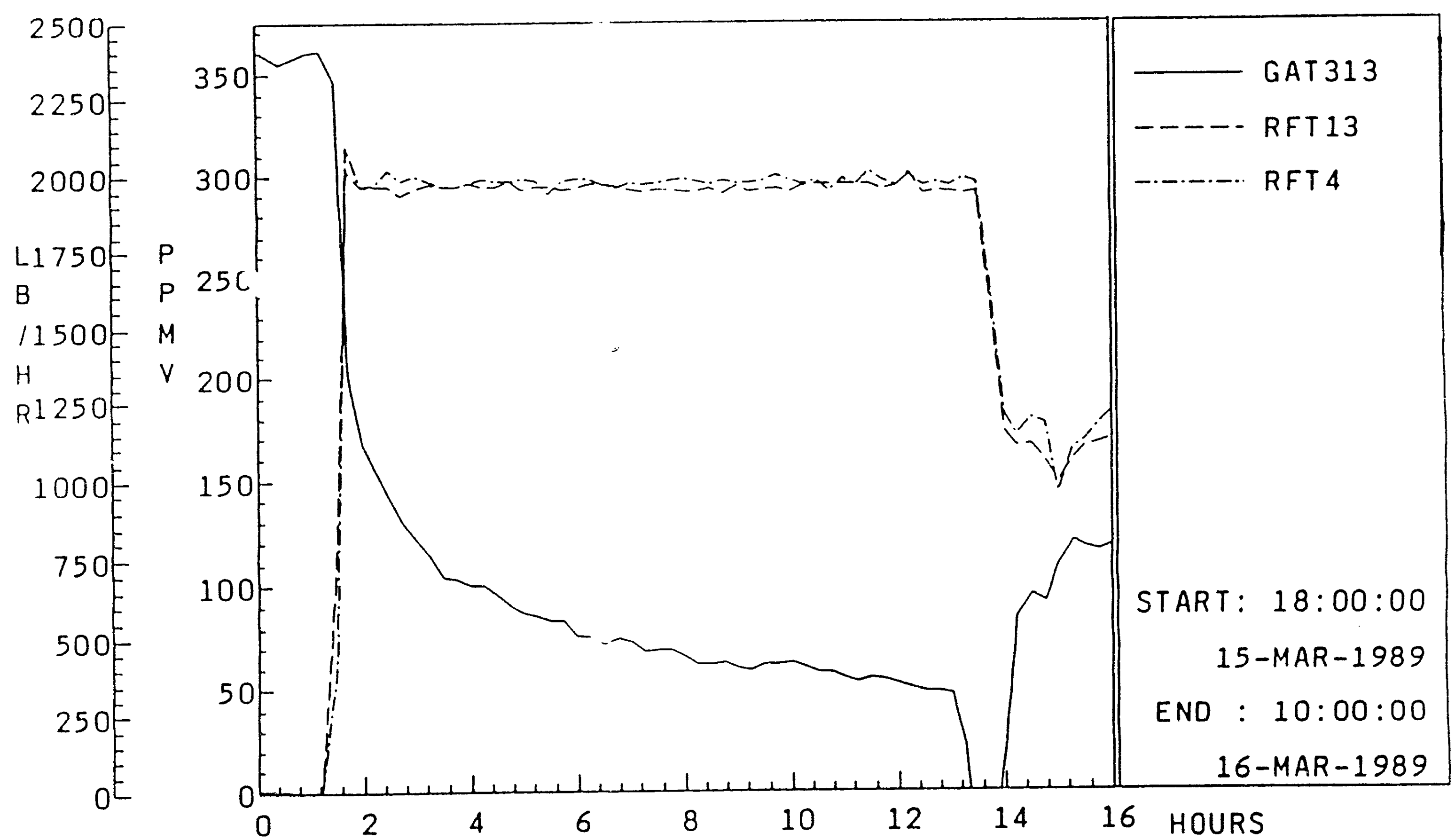
5.5 CONCLUSIONS

Ultimately, the overall uncertainty in the final performance results dictates requirements for precision error for all input parameters. The uncertainty analysis program used on the test results ties the uncertainties of all input parameters to the uncertainties in the results.



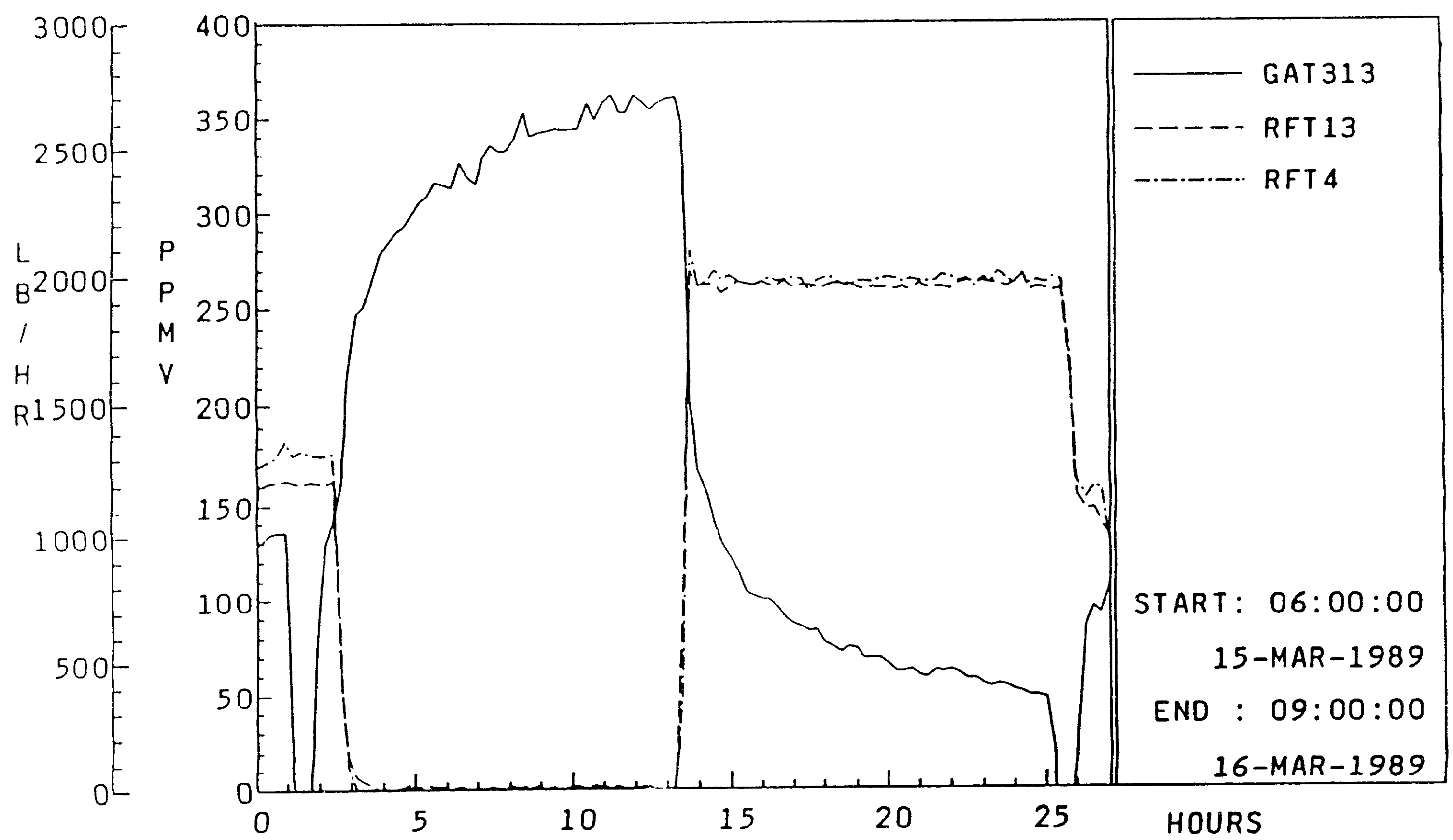
GAT313-SO2(LO) ECON FLUE GAS OUTLET RFT13-SORBENT FEED RATE CMB 4B
RFT4-SORBENT FEED RATE CMB 4A

Figure 5-8. Sorbent Feed Rate and SO_2 Output.



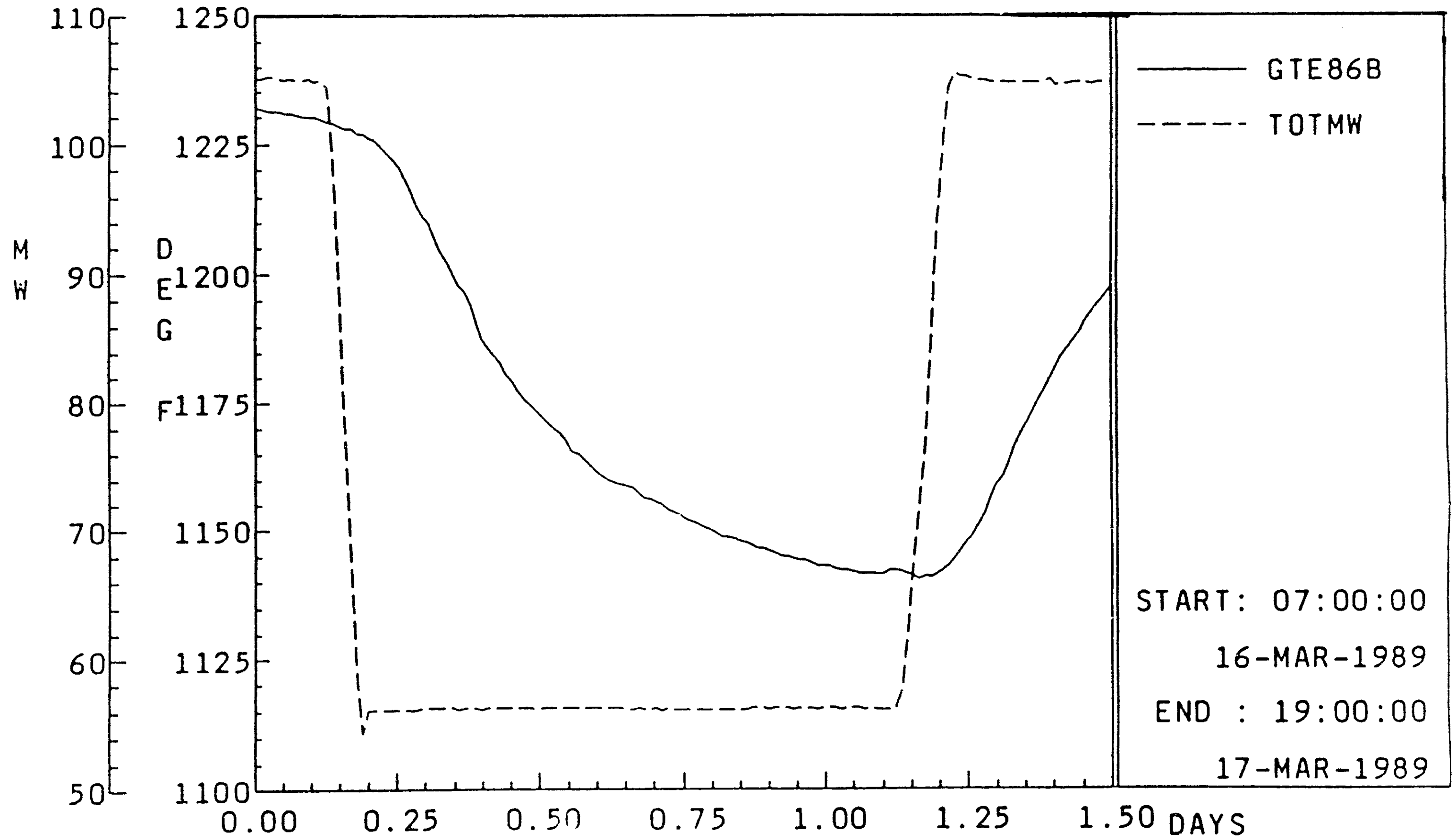
GAT313-SO2(LO) ECON FLUE GAS OUTLET RFT13-SORBENT FEED RATE CMB 4B
RFT4-SORBENT FEED RATE CMB 4A

Figure 5-9. Sorbent Feed Rate and SO_2 Output.



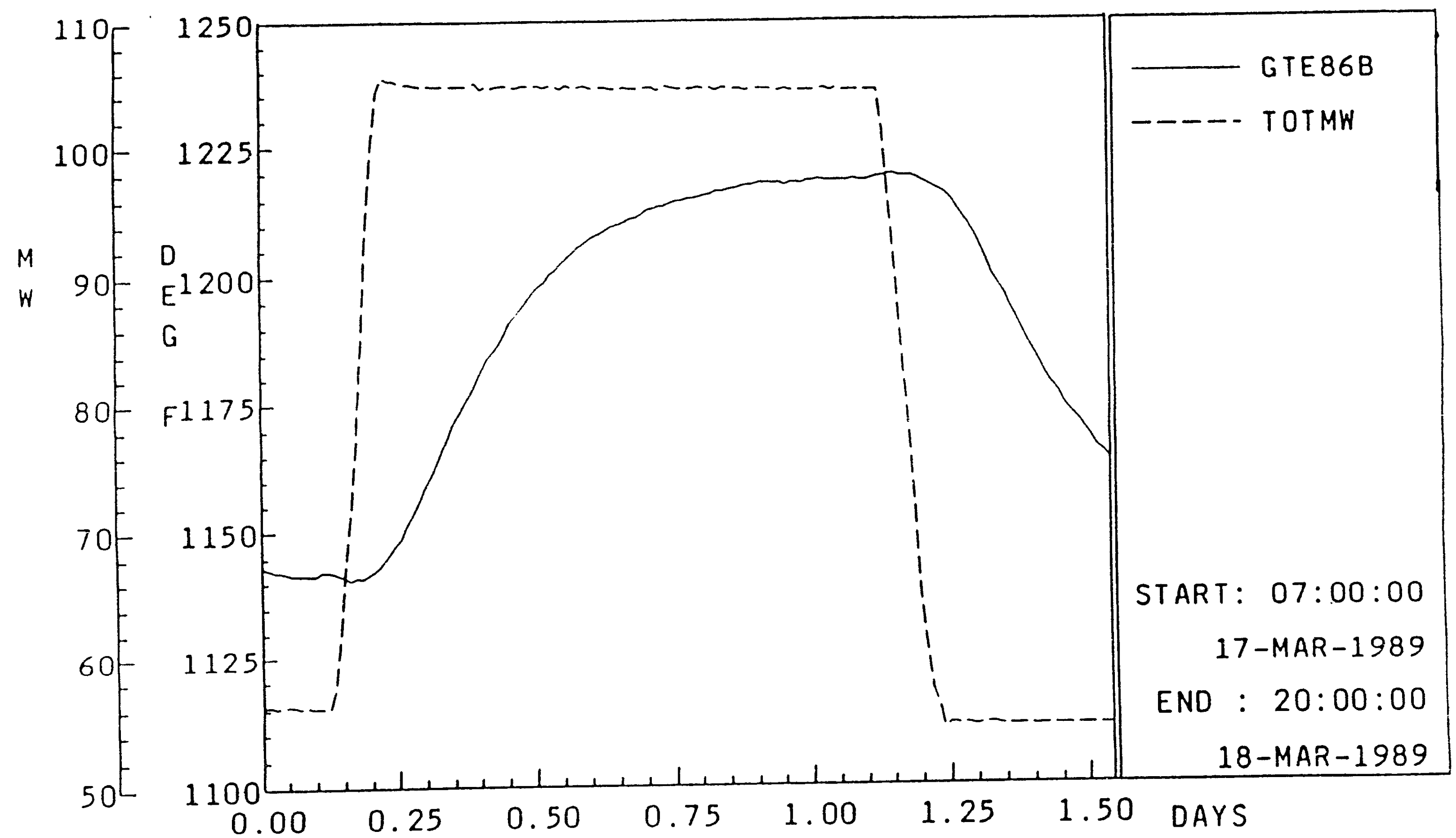
GAT313-SO2(LO) ECON FLUE GAS OUTLET RFT13-SORBENT FEED RATE CMB 4B
RFT4-SORBENT FEED RATE CMB 4A

Figure 5-10. Sorbent Feed Rate and SO_2 Output.



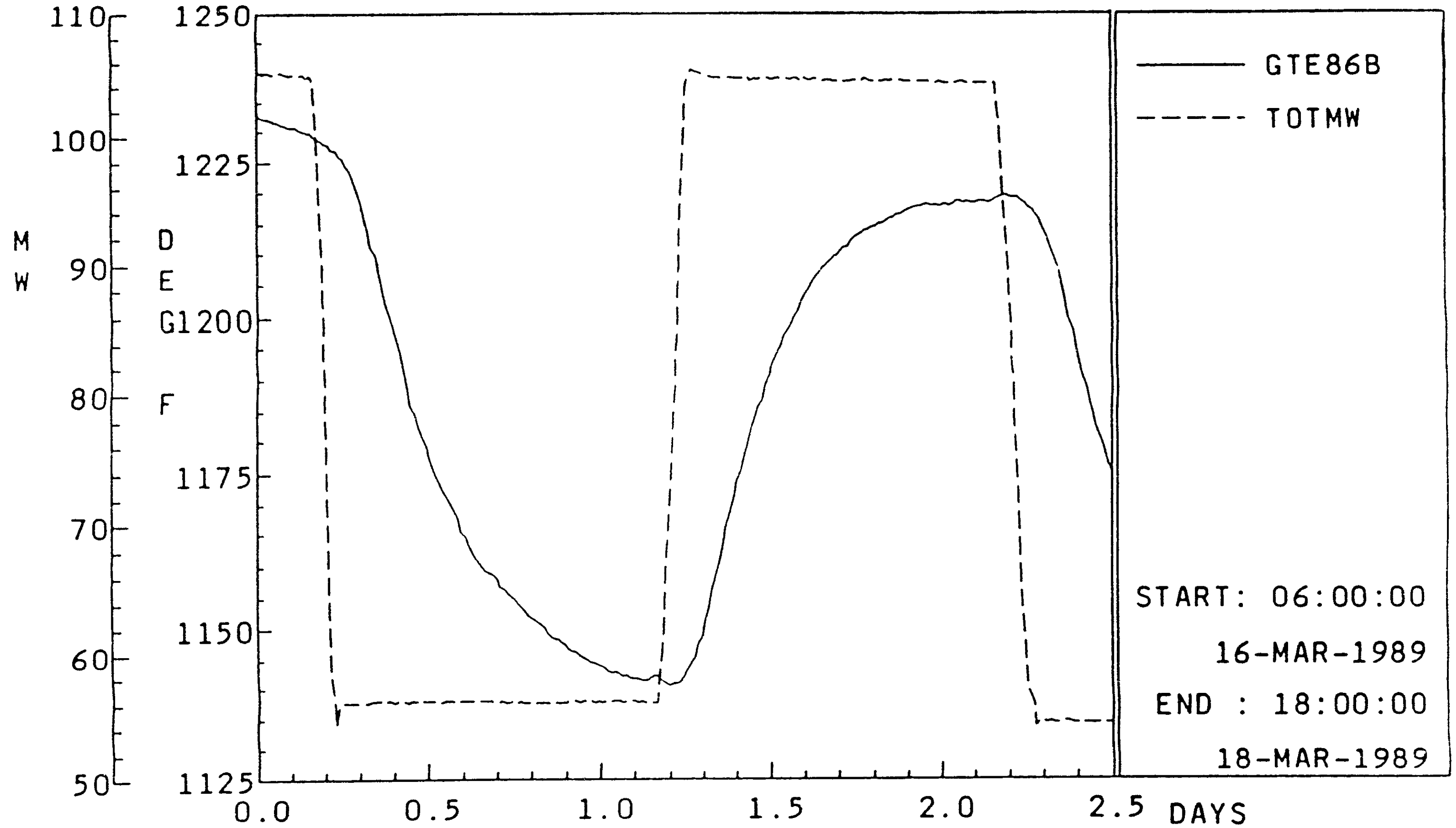
GTE86B-CYCLONE 4B LOWER REFACTORY T TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 5-11. Cyclone B Refractory Temperature.



GTE86B-CYCLONE 4B LOWER REFACTORY T TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 5-12. Cyclone B Refractory Temperature.



GTE86B-CYCLONE 4B LOWER REFACTORY T TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 5-13. Cyclone B Refractory Temperature.

After test SD1, uncertainty analysis was used by the test team to establish the numbers of solids samples required to minimize the uncertainties of important results. These were determined to be six samples each of coal, fly ash, limestone, and bottom ash. The test duration required to physically collect these samples is 10 hours. Better estimates of bias error also became available and were included in the uncertainty analysis. Solids sampling requirements were updated with the bias errors.

In addition, the test team chose to target minimum uncertainty rather than targeting a specific uncertainty. In addition, calcium balance was replaced by calcium to sulfur ratio as a key performance result. Minimum uncertainty is defined as that obtained when a reduction in measurement precision errors has a negligible impact on the total results uncertainties.

As performance test results were evaluated, a better understanding developed of what measurements contributed the most to results uncertainty. Four of the most important are identified here:

1. Solids sample chemical data
2. Coal feed rates
3. Limestone feed rates
4. Gas analyzer data

The bias error values used originally for solids chemical data were overestimated for most of the chemical species. Discussion with the off-site laboratory resulted in the revised values currently in use. These are shown in the 1990 Annual Report.

The bias determined from 10 coal feed calibrations agreed well with the original bias estimate. A 1% span error and a 0.3 Klb/hr zero error are used.

The bias determined from calibration data for limestone feed rates was much larger than the original estimate, as shown in below:

Limestone feeder bias estimates

	Original		Revised	
Combustor	4A	4B	4A	4B
Span error, %	5	5	20	12
Zero error, lb/hr	50	50	50	50

The bias estimates for NO_x, CO, and SO_2 gas analyzers remained at the originally estimated 10 ppmv. The O_2 estimated bias was reduced to 0.15% from 0.40%, and the CO_2 bias was increased from 0.40% to 1.1%. A temperature-related drift is responsible for the higher CO_2 bias.

Impact of revised bias error estimates: The revisions made to the bias estimates did not have a substantial impact on the performance results uncertainties. Increases in some bias estimates were offset by decreases in others. The effect on each of the four key results uncertainties after changes in the bias estimates after test SD1 is shown below:

Calculated result	Original Test Plan Unc, %	Revised Uncertainty, %
Boiler efficiency	± 0.5	± 0.3
Combustion efficiency	± 0.2	± 0.2
Ca/S	± 10	± 14
Sulfur retention	± 5	± 5

In conjunction with the revised bias estimates, the solids sampling requirements were reassessed. The solids sampling requirements for dual and split combustor tests were determined as follows:

Split combustor tests:
Fly ash samples are taken at a point that is common to both combustors. Since a difference in fly ash carbon is expected between the combustors, combustion and boiler efficiency results for a single combustor are not valid. Ca/S and sulfur retention are the remaining key results uncertainties and will determine the number of solids samples required.

With only Ca/S and sulfur retention uncertainty to contend with, sulfur in the coal becomes the most significant precision error. By varying the number of coal samples included in completed test uncertainty analyses, it was determined that four samples will yield minimum results uncertainty for most of the tests completed to date. Only two each of limestone, fly ash, and bottom ash samples are required.

Combined combustor tests:
For combined combustor tests the boiler and combustion efficiency can be evaluated. To minimize the uncertainty in these results, coal ash and fly ash carbon precision errors must be kept low. Analyses have shown that five coal and six fly ash samples consistently minimized uncertainty in these results for performance tests completed to date. Again, only two limestone and two bottom ash samples are required per test. The five coal samples required for minimum boiler and combustion efficiency uncertainty exceed the four samples necessary to minimize Ca/S uncertainty and sulfur retention uncertainty.

Expected uncertainties for the four key results with the present bias estimates and with five coal samples, six fly ash samples, two limestone samples, and two bottom ash samples are:

Performance Result	Uncertainty, %
Boiler efficiency	± 0.3
Combustion efficiency	± 0.1
Ca/S	± 5
Sulfur retention	± 3

Concerning the time to chemical or thermal equilibrium after step changes in Ca/S ratio or load, respectively, due to scheduling and coal supply constraints, the tests were not run long enough to reach full equilibrium. Initially, this was deemed sufficient as it was assumed that extrapolations could be made from collected data yielding equilibrium values and times to steady state. However, this was not the case and analyses showed that the time required for the plant to reach equilibrium after a step change in limestone flow rate is longer than 12 hours. To ensure equilibrium conditions, at least one day of operation at the new Ca/S setting should be scheduled before testing after a step change in limestone feed rate.

Analysis of the transient effects of step changes in load also lead to the conclusion that at least one day of unit operation is required for process stabilization between steady-state performance tests at different loads.

For both types of transient responses, a longer period of time than 24 hours is recommended before the start of testing following significant changes in load and/or Ca/S ratio.

Section 6

PERFORMANCE TEST RESULTS

Performance calculations were run for a total of 72 steady-state tests over the course of the Phase I and Phase II test programs. The baseline fuel for both test phases was Salt Creek coal. Tests were run on two alternate fuels, Peabody coal and Dorchester coal.

Because of the large operating temperature differential that exists between combustors at full load, tests run at these conditions were conducted as split combustor tests, in which each combustion chamber is tested separately. In addition, some tests were run as split combustor tests due to limestone feeder problems that resulted in different feed configurations for the two combustors. Three data sets are produced for each split combustor test. One data set provides combustion and boiler efficiency results for the entire boiler, while each of the other two data sets provide emissions data for an individual combustor. Therefore, performance calculations were run for a total of 124 data sets. A listing of these data sets is shown in Table 6-1, along with the associated dates and important unit operating parameters. Summary reports for all data sets analyzed to date appear in the in the volume of performance summary reports.

In this section, emissions data and boiler and combustion efficiencies obtained from the performance tests are described. The effects of the following plant parameters were investigated:

- Load
- Alternate fuels
- Coal feed configuration
- Limestone feed configuration
- Excess air
- Secondary air to primary air ratio
- Coal size
- Limestone size

Over the range of operating parameters at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exceptions of coal feed configuration and excess air at elevated temperatures, it is the only parameter which had a measurable impact on emissions or efficiencies. Emissions of SO_2 and NO_x were found to increase with increased combustor temperatures while CO emissions decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased. No means for effective control of bed temperature were found during the course of

Table 6-1. SUMMARY OF PERFORMANCE TEST RESULTS

Page (1 of 3)

COAL TYPE	LOAD (MWe)	BED TEMPERATURE (DEG F)	** COAL FEED CONFIGURATION	* LIMESTONE FEEDERS OUT OF SERVICE	EXCESS AIR (%)	SECONDARY TO PRIMARY AIR RATIO	CALCIUM TO SULFUR RATIO	SULFUR RETENTION (%)	NOX EMISSIONS (PPMV DRY @3% O2)	CO EMISSIONS (PPMV DRY @3% O2)	COMBUSTION EFFICIENCY (%)	BOILER EFFICIENCY (%)
SALT CREEK	105	1558	BALANCED	NONE	23	0.7	1.4	69	62	104	98.1	87.7
SALT CREEK	55	1491	BALANCED	-	36	0.7	2.1	78	30	113	98.7	87.8
SALT CREEK	82	1552	BALANCED	-	22	0.6	2.0	83	58	83	98.6	88.0
PEABODY	105	1611	BALANCED	-	21	0.7	1.8	73	146	83	97.6	87.6
PEABODY	55	1495	BALANCED	NONE	39	0.7	1.5	78	52	111	97.6	87.4
PEABODY	82	1607	BALANCED	NONE	25	0.6	1.7	75	141	78	98.3	88.2
PEABODY	82	1597	BALANCED	NONE	25	0.7	3.9	98	189	72	97.9	87.6
PEABODY	83	1599	BALANCED	NONE	24	0.7	0.6	37	103	80	97.9	87.9
PEABODY	104	1627	BALANCED	NONE	19	0.7	3.7	98	208	72	98.0	87.9
PEABODY	104	1614	BALANCED	NONE	20	0.6	0.7	45	136	67	97.8	88.3
PEABODY	104	1625	BALANCED	NONE	19	0.7	1.8	73	154	61	97.7	87.7
SALT CREEK	98	1643	BALANCED	NONE	20	0.6	0.9	14	118	61	98.6	88.6
SALT CREEK	98	1636	BALANCED	NONE	20	0.6	3.5	78	156	65	98.7	88.2
SALT CREEK	55	1537	BALANCED	NONE	39	0.8	2.6	80	61	98	98.8	87.1
SALT CREEK	55	1518	BALANCED	NONE	42	0.8	3.1	89	58	101	98.7	86.8
SALT CREEK	55	1516	LOOPSEAL	1 FW & 1 SW	42	0.8	2.8	81	46	88	98.9	87.1
SALT CREEK	108	1598	50-50	NONE	20	0.7	4.8	76	170	77	98.2	87.7
SALT CREEK	108	1535	50-50	NONE	20	0.7	4.7	92	138	87		
SALT CREEK	108	1659	50-50	NONE	20	0.8	4.8	61	199	68		
SALT CREEK	108	1619	50-50	NONE	13	0.7	5.1	74	157	72	97.9	87.6
SALT CREEK	108	1546	50-50	NONE	13	0.7	5.1	93	135	80		
SALT CREEK	108	1688	50-50	NONE	13	0.7	5.2	57	182	63		
SALT CREEK	55	1492	BALANCED	NONE	40	0.8	1.4	67	24	134	98.5	87.6
SALT CREEK	55	1466	BALANCED	ALL	42	0.8	0.0	22	16	141	98.3	87.7
SALT CREEK	55	1427	FRONT WALL	NONE	46	0.8	3.2	93	41	142	98.1	87.1
SALT CREEK	109	1653	BALANCED	NONE	13	0.7	4.9	85	190	69	97.9	88.0
SALT CREEK	109	1594	BALANCED	NONE	13	0.6	5.1	95	162	78		
SALT CREEK	109	1707	BALANCED	NONE	13	0.7	4.6	75	218	59		
SALT CREEK	109	1686	BALANCED	NONE	13	0.6	4.6	86	229	58	98.0	88.0
SALT CREEK	109	1661	BALANCED	NONE	13	0.6	4.7	92	220	61		
SALT CREEK	109	1710	BALANCED	NONE	13	0.7	4.4	79	237	54		
SALT CREEK	56	1463	BALANCED	NONE	45	0.7	3.8	98	79	132	98.5	87.9
SALT CREEK	56	1470	LOOPSEAL	NONE	45	0.7	3.4	94	77	109	98.5	87.4
SALT CREEK	56	1430	FRONT WALL	1 FW & 1 SW	45	0.7	3.1	92	44	125	97.9	87.0
SALT CREEK	111	1674	BALANCED	NONE	17	0.7	3.5	70	176	78		
SALT CREEK	111	1664	50-50	NONE	16	0.7	2.7	71	150	69	97.7	87.9
SALT CREEK	111	1649	50-50	NONE	16	0.7	2.7	73	139	74		
SALT CREEK	111	1675	50-50	NONE	17	0.7	2.6	69	162	63		
SALT CREEK	111	1654	FRONT WALL	NONE	16	0.7	4.7	68	236	66	97.8	87.8
SALT CREEK	111	1636	FRONT WALL	NONE	16	0.7	3.7	71	211	70		
SALT CREEK	110	1672	FRONT WALL	NONE	16	0.7	5.5	66	261	63		
SALT CREEK	110	1669	BALANCED	NONE	16	0.7	3.8	73	194	75	97.4	87.5
SALT CREEK	110	1642	BALANCED	NONE	16	0.7	3.0	76	152	79		
SALT CREEK	110	1695	BALANCED	NONE	16	0.7	4.6	70	236	70		
SALT CREEK	110	1671	LOOPSEAL	NONE	17	0.7	4.9	70	176	76	97.3	87.1
SALT CREEK	111	1640	LOOPSEAL	NONE	17	0.7	3.3	71	146	76		
SALT CREEK	110	1701	LOOPSEAL	NONE	16	0.7	6.8	69	205	76		
SALT CREEK	111	1686	BALANCED	NONE	10	0.7	5.9	74	171	70	97.5	87.5
SALT CREEK	111	1658	BALANCED	NONE	10	0.7	3.6	75	138	72		
SALT CREEK	111	1711	BALANCED	NONE	10	0.7	9.0	74	213	68		
SALT CREEK	111	1622	BALANCED	NONE	26	0.8	2.4	72	165	88	97.5	87.5
SALT CREEK	111	1610	BALANCED	NONE	26	0.8	2.3	72	154	92		

Table 6-1. SUMMARY OF PERFORMANCE TEST RESULTS

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COAL TYPE	LOAD (MWe)	BED TEMPERATURE (DEG F)	* * COAL FEED CONFIGURATION	* LIMESTONE FEEDERS OUT OF SERVICE	EXCESS AIR (%)	SECONDARY TO PRIMARY AIR RATIO	CALCIUM TO SULFUR RATIO	SULFUR RETENTION (%)	NOX EMISSIONS (PPMV DRY @3% O2)	CO EMISSIONS (PPMV DRY @3% O2)	COMBUSTION EFFICIENCY (%)	BOILER EFFICIENCY (%)
SALT CREEK	111	1636	BALANCED	NONE	26	0.8	2.5	72	177	84		
SALT CREEK	111	1661	BALANCED	NONE	16	0.7	3.5	75	168	79	97.9	87.8
SALT CREEK	111	1613	BALANCED	NONE	16	0.7	2.1	77	117	85		
SALT CREEK	111	1709	BALANCED	NONE	17	0.7	4.9	72	220	74		
SALT CREEK	111	1656	BALANCED	NONE	16	0.7	3.9	73	156	97	97.1	87.2
SALT CREEK	111	1623	BALANCED	NONE	16	0.7	2.3	74	115	102		
SALT CREEK	111	1689	BALANCED	NONE	17	0.7	5.4	72	198	93		
SALT CREEK	111	1657	BALANCED	NONE	17	0.7	3.2	74	164	87	97.3	87.3
SALT CREEK	111	1624	BALANCED	NONE	16	0.7	2.5	76	128	92		
SALT CREEK	111	1692	BALANCED	NONE	18	0.7	3.9	73	200	83		
SALT CREEK	111	1660	BALANCED	NONE	16	1.0	3.5	76	166	78	96.9	86.7
SALT CREEK	111	1626	BALANCED	NONE	16	1.0	2.6	78	120	84		
SALT CREEK	110	1692	BALANCED	NONE	17	1.0	4.8	74	211	72		
SALT CREEK	110	1664	BALANCED	NONE	16	1.0	2.9	67	135	74		
SALT CREEK	110	1615	BALANCED	NONE	17	0.5	3.6	78	147	87	97.2	87.0
SALT CREEK	110	1546	BALANCED	NONE	17	0.5	2.0	79	77	96		
SALT CREEK	109	1685	BALANCED	NONE	16	0.5	5.9	77	223	77		
SALT CREEK	110	1622	BALANCED	NONE	16	0.6	3.7	78	144	83	97.6	87.5
SALT CREEK	110	1549	BALANCED	NONE	16	0.6	2.1	79	78	89		
SALT CREEK	110	1689	BALANCED	NONE	16	0.6	5.7	78	228	75		
SALT CREEK	111	1654	BALANCED	NONE	16	1.0	3.8	72	157	81	97.3	87.2
SALT CREEK	111	1612	BALANCED	NONE	16	1.0	2.4	75	103	90		
SALT CREEK	111	1694	BALANCED	NONE	17	1.0	5.6	70	203	72		
SALT CREEK	110	1672	BALANCED	NONE	17	0.7	3.5	81	226	61	98.0	87.6
SALT CREEK	110	1643	BALANCED	NONE	17	0.7	3.0	82	181	65		
SALT CREEK	110	1700	BALANCED	NONE	18	0.7	3.7	80	266	57		
SALT CREEK	110	1679	BALANCED	NONE	17	0.8	4.1	80	238	68	98.1	87.1
SALT CREEK	110	1650	BALANCED	NONE	17	0.8	3.0	82	182	75		
SALT CREEK	109	1708	BALANCED	NONE	17	0.9	5.1	79	278	63		
SALT CREEK	110	1670	BALANCED	1 SW	17	0.7	4.4	77	236	68	98.3	87.7
SALT CREEK	110	1643	BALANCED	1 SW	16	0.7	2.6	78	175	72		
SALT CREEK	110	1698	BALANCED	1 SW	17	0.8	5.8	75	301	63		
SALT CREEK	110	1644	BALANCED	1FW & 1 LS	16	0.7	3.3	80	187	73		
SALT CREEK	56	1511	BALANCED	NONE	42	0.7	2.0	79	50	121	98.5	86.7
SALT CREEK	56	1517	50-50		43	0.7	1.8	79	48	81	98.5	87.3
SALT CREEK	56	1502	BALANCED	NONE	44	0.8	1.8	78	41	124	98.4	87.1
SALT CREEK	55	1475	FRONT WALL	NONE	43	0.8	2.1	77	41	113	98.2	86.6
SALT CREEK	55	1509	LOOPSEAL	NONE	43	0.7	1.8	77	42	107	98.8	86.8
SALT CREEK	55	1499	LOOPSEAL	NONE	43	0.8	1.8	76	41	103	98.6	86.5
SALT CREEK	56	1526	50-50	NONE	42	0.7	1.7	75	47	115	98.5	87.2
SALT CREEK	56	1510	BALANCED	1 SW	42	0.8	1.6	71	40	126	98.5	87.0
SALT CREEK	56	1516	50-50	1 FW & 1 SW	43	0.7	1.6	72	42	120	98.6	87.3
SALT CREEK	110	1647	BALANCED	NONE	17	0.7	3.3	72	156	68	98.0	87.4
SALT CREEK	110	1661	50-50	NONE	17	0.7	3.3	73	153	71	97.9	87.4
SALT CREEK	110	1629	FRONT WALL	NONE	17	0.7	4.3	71	214	73	98.0	87.4
SALT CREEK	111	1650	BALANCED	1 SW	17	0.7	3.0	72	168	69	98.1	88.0
SALT CREEK	111	1643	BALANCED	NONE	17	0.7	2.8	73	153	75	97.8	87.4
SALT CREEK	111	1633	50-50	1 FW & 1 SW	16	0.7	2.9	72	179	75		
SALT CREEK	110	1672	LOOPSEAL	1 SW	17	0.6	3.6	73	167	58	98.2	87.9
SALT CREEK	111	1652	BALANCED	NONE	18	0.7	3.3	72	185	55	98.0	87.5
SALT CREEK	109	1683	BALANCED	NONE	11	0.6	5.6	73	222	100	98.1	87.6

Table 6-1. SUMMARY OF PERFORMANCE TEST RESULTS

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COAL TYPE	LOAD (MWe)	BED TEMPERATURE (DEG F)	** COAL FEED CONFIGURATION	* LIMESTONE FEEDERS OUT OF SERVICE	EXCESS AIR (%)	SECONDARY TO PRIMARY AIR RATIO	CALCIUM TO SULFUR RATIO	SULFUR RETENTION (%)	NOX EMISSIONS (PPMV DRY @3% O2)	CO EMISSIONS (PPMV DRY @3% O2)	COMBUSTION EFFICIENCY (%)	BOILER EFFICIENCY (%)
SALT CREEK	109	1669	BALANCED	NONE	11	0.6	4.5	74	197	115		
SALT CREEK	109	1697	BALANCED	NONE	11	0.6	6.9	72	248	86		
SALT CREEK	109	1628	BALANCED	NONE	22	0.7	2.5	73	167	63	98.2	87.8
SALT CREEK	109	1632	BALANCED	NONE	22	0.7	2.7	72	158	75	98.1	87.8
SALT CREEK	109	1639	BALANCED	NONE	21	0.7	3.1	73	196	68	98.3	87.7
SALT CREEK	110	1667	LOOPSEAL	NONE	17	0.7	5.3	72	208	68	98.0	87.3
SALT CREEK	110	1642	LOOPSEAL	NONE	17	0.7	4.0	69	175	69		
SALT CREEK	110	1690	LOOPSEAL	NONE	16	0.6	7.3	75	241	67		
SALT CREEK	110	1666	LOOPSEAL	-	17	0.6	5.7	70	209	76	97.8	87.0
SALT CREEK	110	1646	LOOPSEAL	1 FW & 1 SW	17	0.6	4.2	73	187	78		
SALT CREEK	110	1686	LOOPSEAL	1 SW	17	0.6	6.6	67	230	74		
DORCHESTER	58	1482	FRONT WALL	-	43	0.7	2.1	90	104	126	98.2	86.5
DORCHESTER	58	1448	FRONT WALL	1 FW	44	0.7	2.4	90	107	128		
DORCHESTER	58	1515	BALANCED	NONE	43	0.7	2.2	89	100	124		
DORCHESTER	58	1480	BALANCED	-	42	0.7	2.5	95	87	136	97.8	85.6
DORCHESTER	58	1460	BALANCED	1 FW	41	0.6	2.6	95	82	138		
DORCHESTER	58	1508	BALANCED	NONE	42	0.7	2.4	95	91	134		
DORCHESTER	83	1529	BALANCED	-	24	0.5	2.1	87	96	106	97.9	86.6
DORCHESTER	83	1521	BALANCED	1 FW	24	0.5	2.4	88	90	108		
DORCHESTER	83	1533	BALANCED	NONE	24	0.6	2.1	87	103	104		
DORCHESTER	83	1531	BALANCED	NONE	25	0.5	2.4	92	113	104	97.8	86.4

* FW - FRONT WALL
SW - SIDE WALL

** BALANCED - EACH OF THREE COAL FEEDERS/COMBUSTOR FEEDING EQUALLY
LOOP SEAL - ALL COAL FLOW TO A COMBUSTOR THROUGH REAR WALL LOOP SEAL FEEDER
FRONT WALL - ALL COAL FLOW TO A COMBUSTOR SPLIT EQUALLY TO BOTH FRONT WALL FEEDERS
50-50 - 50% OF THE COAL FLOW TO THE LOOP SEAL COAL FEEDER AND 50% TO THE FRONT WALL

performance testing. This is discussed in more detail in Section 10 of this report.

Tests to examine the effects of coal and limestone size were limited at Nucla. This is because the existing equipment for sizing this material was not flexible enough to vary the size appreciably.

6.1 EMISSIONS DATA SUMMARY

Flue gas emissions data and associated operating parameters were tabulated for a total of 72 Phase I and Phase II tests and analyzed to establish trends and correlations. As two sets of emissions data can be obtained from each split combustor test, the 72 performance tests provide 98 sets of emissions data. Table 6-2 tabulates the results of the analyses performed on the emissions data obtained from these tests. Mean bed temperatures shown are the average of all thermocouple readings in the refractory-lined lower combustor section.

Since plant stack emissions data are readily available from the continuous emissions monitors (CEM), they are included in Table 6-3 as verification of the emissions data measured by the test program instrumentation at the air heater inlet. Table 6-4 presents additional data related to sulfur capture.

Analyses of the effects of various operating parameters on the emissions are presented in separate sub-sections for SO_2, NO_x, and CO.

6.1.1 Sulfur Retention

Figure 6-1 is a plot of SO_2 retention versus Ca/S molar ratio for all data points taken at mean bed temperatures lower than 1620 °F. Ca/S ratio requirements for a given sulfur retention are fairly consistent below 1620 °F, but increase rapidly with temperature above this point. The calculated uncertainty band-widths are displayed along with the points. Ca/S molar ratios were calculated based on the calcium content of the sorbent only and do not account for the calcium content of the coal.

Also shown in the figure is a curve which represents a correlation based on the points shown. The equation for the curve is:

$$\text{Sulfur Retention} = 100*(1-e^{-0.803*Ca/S})$$

In this figure, a Ca/S molar ratio of 1.5 to 2.0 is required for 75% sulfur retention and a ratio of between 4.0 and 5.0 is required for 95% retention.

The 1620 °F bed temperature limit was determined by plotting adjusted Ca/S molar ratios against bed temperature for tests with sulfur retentions between 65% and 85%. The Ca/S molar ratios were

Table 6-2. FLUE GAS ANALYSIS SUMMARY

Air heater inlet (Page 1 of 2)

Date	Time	Test no.	Coal Type	Load GMWe	Mean bed Temp. A Deg F	Mean bed Temp. B Deg F	SA/PA Ratio	O2 A Side Wet % Vol	O2 B Side Wet % Vol	O2 Dry % Vol	CO2 Dry % Vol	CO PPMV Dry	CO 3% O2	NOx PPMV Dry	NOx 3% O2	NOx Lb/ 10^6 Btu	SO2 PPMV Dry	SO2 3% O2	SO2 Lb/ 10^6 Btu	Ca/S (Sorbent) Ratio
4/2189	8:00-16:30	A01	P.B.	105	1574	1638	0.9	3.3	3.3	3.7	15.3	80	83	141	146	0.20	192	199	0.37	1.8
5/26/89	8:00-17:30	A07	P.B.	55	1492	1497	0.9	5.1	5.1	5.9	12.9	93	111	44	52	0.07	150	179	0.35	1.5
6/6/89	7:30-14:30	A04	P.B.	82	1601	1614	0.8	3.5	3.5	4.2	14.8	73	78	132	141	0.19	162	174	0.33	1.7
6/7/89	8:00-14:30	A05	P.B.	82	1582	1611	0.8	3.5	3.4	4.3	15.0	67	72	175	189	0.25	9	10	0.02	3.9
6/8/89	8:30-15:30	A06	P.B.	83	1586	1611	0.8	3.5	3.5	4.2	15.0	75	80	96	103	0.14	381	408	0.76	0.6
6/16/89	10:00-17:00	A02	P.B.	104	1609	1645	0.9	3.3	3.3	3.5	15.8	70	72	202	208	0.27	13	13	0.02	3.7
6/17/89	10:00-17:00	AO3	P.B.	104	1602	1625	0.8	3.3	3.4	3.5	15.8	65	67	132	136	0.18	388	398	0.73	0.7
6/19/89	10:00-17:00	A08	P.B.	104	1629	1621	0.8	3.2	3.3	3.4	15.9	59	61	150	154	0.20	188	193	0.35	1.8
3/13/89	8:00-20:00	SD1	S.C.	105	1567	1556	0.9	3.5	3.5	3.9	15.1	99	104	59	62	0.08	136	144	0.27	1.4
3/20/89	8:00-21:00	P30	S.C.	55	1469	1516	0.9	5.2	5.4	5.7	13.7	119	139	26	30	0.04	77	91	0.17	2.1
3/21/89	8:00-21:00	P31	S.C.	82	1534	1578	0.8	3.5	3.5	3.8	15.3	92	96	56	58	0.08	78	82	0.15	2.0
7/17/89	10:00-17:00	P49	S.C.	98	1633	1650	0.8	3.3	3.4	3.5	15.6	59	61	114	118	0.16	424	436	0.81	0.9
7/19/89	9:15-13:15	P50	S.C.	98	1617	1659	0.8	3.3	3.3	3.5	15.6	63	65	152	156	0.21	111	114	0.21	3.5
8/17/89	8:00-14:00	P52	S.C.	55	1526	1520	1.0	5.5	5.5	6.3	12.4	72	88	38	46	0.07	85	104	0.20	2.8
8/11/89	8:30-15:30	P21	S.C.	55	1526	1513	1.0	5.5	5.5	6.3	12.6	83	101	47	58	0.08	50	61	0.12	3.1
8/9/89	8:15-15:00	P39	S.C.	55	1533	1542	1.0	5.6	5.5	6.0	12.6	82	98	51	61	0.09	94	113	0.22	2.6
11/29/89	9:20-11:45	P55A	S.C.	108	1532	NA	1.0	3.3	3.3	3.5	14.9	85	87	134	138	0.19	37	38	0.07	4.8
11/29/89	12:30-15:10	P55B	S.C.	108	NA	1659	1.0	3.3	3.3	3.5	14.8	66	68	193	199	0.28	165	170	0.33	4.8
11/30/89	9:15-12:15	P56A	S.C.	108	1552	NA	0.9	2.3	2.3	2.5	15.9	82	80	139	135	0.19	42	41	0.08	5.2
11/30/89	12:35-15:35	P56B	S.C.	108	NA	1688	0.9	2.3	2.3	2.5	15.7	65	63	188	182	0.26	189	184	0.36	5.0
1/11/90	9:00-15:30	P20	S.C.	55	1484	1503	0.8	6.1	6.1	6.2	10.8	111	134	20	24	0.04	138	167	0.38	1.4
1/15/90	9:00-15:00	P57	S.C.	55	1451	1483	0.9	6.3	6.3	6.4	11.6	115	141	13	16	0.02	308	379	0.79	0.0
1/17/90	10:40-15:00	P58	S.C.	55	1420	1440	0.8	6.4	6.3	6.6	11.6	150	188	37	46	0.07	24	30	0.06	3.3
1/23/90	9:45-12:30	P60A	SC	109	1601	NA	0.8	2.3	2.4	2.5	16.4	80	78	167	162	0.22	26	25	0.05	5.1
1/23/90	13:00-15:30	P60B	S.C.	109	NA	1712	0.8	2.3	2.4	2.5	16.2	61	59	224	218	0.30	125	122	0.23	4.7
1/25/90	11:40-14:00	P61A	S.C.	109	1670	NA	0.7	2.3	2.4	2.5	16.3	63	61	227	220	0.30	39	37	0.07	4.7
1/25/90	14:30-17:00	P61B	S.C.	109	NA	1716	0.8	2.3	2.4	2.5	16.2	56	54	244	237	0.32	111	108	0.20	4.5
3/6/90	9:30-15:00	P62	S.C.	56	1454	1472	0.8	6.3	6.3	6.6	12.4	105	131	63	79	0.11	7	9	0.02	3.8
3/8/90	9:30-15:00	P63	S.C.	56	1464	1481	0.9	6.3	6.3	6.6	12.1	87	109	61	76	0.11	23	29	0.06	3.4
3/10/90	9:00-15:00	P64	S.C.	56	1417	1442	0.7	6.3	6.4	6.6	12.3	100	125	35	44	0.06	28	35	0.07	3.1
3/15/90	12:30-15:45	P65B	S.C.	111	NA	1674	0.7	2.8	2.8	3.0	15.9	78	78	176	176	0.24	133	133	0.25	3.5
3/16/90	10:00-12:45	M01A	S.C.	111	1649	NA	0.7	2.8	2.9	3.0	15.9	74	74	139	139	0.19	125	125	0.23	2.7
3/16/90	13:15-15:15	M01B	S.C.	111	NA	1675	0.7	2.8	2.9	3.0	15.9	63	63	162	162	0.22	145	145	0.27	2.6
3/20/90	9:00-11:55	M02A	S.C.	111	1636	NA	0.7	2.8	2.8	3.0	16.0	70	70	211	211	0.28	128	128	0.24	3.7
3/20/90	12:50-15:00	M02B	S.C.	110	NA	1672	0.7	2.8	2.8	3.0	16.0	63	63	261	261	0.35	159	159	0.30	5.5
3/23/90	9:00-11:00	P06A	S.C.	110	1642	NA	0.7	3.0	3.0	3.0	16.5	79	79	152	152	0.20	109	109	0.20	3.0
3/23/90	12:15-14:50	P06B	S.C.	110	NA	1695	0.7	2.8	2.8	3.0	16.6	70	70	236	236	0.31	138	138	0.25	4.6
3/27/90	10:25-12:15	M03A	S.C.	111	1640	NA	0.7	2.8	2.8	3.1	16.0	76	76	146	146	0.20	127	128	0.24	3.3
3/27/90	13:00-15:20	M03B	S.C.	110	NA	1701	0.7	2.8	2.8	3.0	16.0	76	76	204	205	0.27	138	138	0.26	6.8
3/29/90	10:16-13:00	P66A	S.C.	111	1658	NA	0.7	1.8	1.8	2.0	17.1	76	72	146	138	0.18	124	117	0.22	3.6
3/29/90	13:35-16:00	P66B	S.C.	111	NA	1711	0.7	1.8	1.8	2.0	17.1	72	68	225	213	0.28	127	120	0.22	9.0
3/30/90	12:45-15:00	P32A	S.C.	111	1610	NA	0.8	4.0	4.0	4.4	14.7	85	92	142	154	0.21	115	124	0.23	2.3
3/30/90	9:00-11:45	P32B	S.C.	111	NA	1636	0.8	4.1	4.1	4.4	14.7	78	84	164	177	0.24	112	121	0.23	2.5
4/2/90	8:15-10:45	P67A	S.C.	111	1613	NA	0.7	2.8	2.8	3.0	16.0	85	85	118	117	0.16	115	114	0.21	2.1
4/2/90	11:30-14:00	P67B	S.C.	111	NA	1708	0.7	2.8	2.8	3.1	16.0	73	74	219	220	0.29	129	129	0.24	4.9
4/5/90	9:00-11:45	P68A	S.C.	111	1623	NA	0.7	2.8	2.8	2.9	15.7	102	102	116	115	0.16	120	120	0.23	2.3
4/5/90	12:30-15:00	P68B	S.C.	111	NA	1689	0.7	2.8	2.8	3.1	15.6	93	93	198	198	0.27	130	130	0.25	5.4
4/6/90	12:30-15:00	P07A	S.C.	111	1624	NA	0.7	2.8	3.0	3.0	15.7	92	92	128	128	0.17	118	118	0.22	2.5
4/6/90	9:45-11:45	P07B	S.C.	111	NA	1692	0.7	2.7	2.9	3.2	15.6	82	83	198	200	0.27	129	130	0.25	3.9
4/11/90	9:15-11:45	P08A	S.C.	111	1626	NA	1.0	2.8	2.8	3.0	15.9	84	84	121	120	0.16	115	115	0.22	2.6
4/11/90	12:30-14:45	P08B	S.C.	110	NA	1692	1.0	2.8	2.8	3.1	15.8	72	72	210	211	0.28	135	136	0.25	4.8
4/13/90	12:15-15:00	P69B	S.C.	110	NA	1664	1.0	2.8	2.8	3.0	15.7	74	74	134	135	0.18	149	149	0.28	2.9
4/17/90	9:00-11:45	P36A	S.C.	110	1546	NA	0.5	2.8	2.8	3.0	15.8	96	96	77	77	0.10	115	115	0.22	2.0
4/17/90	12:30-14:50	P36B	S.C.	109	NA	1685	0.5	2.8	2.8	3.0	15.9	77	77	223	223	0.30	126	126	0.24	5.9

Table 6-2. FLUE GAS ANALYSIS SUMMARY

Air heater inlet (Page 2 of 2)

Date	Time	Test no.	Coal Type	Load GMWe	Mean bed Temp. A Deg F	Mean bed Temp. B Deg F	SA/PA Ratio	O2 A Side Wet % Vol	O2 B Side Wet % Vol	O2 Dry % Vol	CO2 Dry % Vol	CO PPMV Dry	CO PPMV 3% O2	NOx PPMV Dry	NOx 3% O2	NOx Lb/ 10^6 Btu	SO2 PPMV Dry	SO2 3% O2	SO2 Lb/ 10^6 Btu	Ca/S (Sorbent) Ratio
4/18/90	9:00-12:00	P70A	S.C.	110	1549	NA	0.6	2.8	2.8	3.0	15.7	89	89	78	78	0.11	127	127	0.24	2.1
4/18/90	12:45-15:45	P70B	S.C.	110	NA	1689	0.6	2.8	2.8	3.0	15.7	75	75	228	228	0.31	118	118	0.22	5.7
4/27/90	9:10-11:45	P71A	S.C.	111	1612	NA	1.0	2.8	2.8	2.9	15.9	91	90	104	103	0.14	121	121	0.23	2.4
4/27/90	12:30-15:30	P71B	S.C.	111	NA	1694	1.0	2.8	2.8	3.1	15.9	72	72	203	203	0.27	140	141	0.26	5.6
5/25/90	9:00-11:50	C01A	S.C.	110	1643	NA	0.7	2.8	2.8	3.0	15.9	65	65	181	181	0.25	107	107	0.20	3.0
5/25/90	12:30-15:30	C01B	S.C.	110	NA	1700	0.7	2.8	2.9	3.2	15.8	56	57	263	266	0.36	138	140	0.26	3.7
6/12/90	8:30-11:15	C02A	S.C.	110	1650	NA	0.8	2.8	2.8	3.0	15.9	75	75	181	182	0.24	117	117	0.22	3.0
6/12/90	12:00-16:00	C02B	S.C.	109	NA	1708	0.9	2.8	2.8	3.1	15.9	63	63	276	278	0.37	132	133	0.25	5.1
6/14/90	8:25-11:10	M05A	S.C.	110	1643	NA	0.7	2.9	2.9	3.0	16.0	72	72	175	175	0.23	144	144	0.27	2.6
6/14/90	12:00-14:45	M05B	S.C.	110	NA	1698	0.8	2.8	2.8	3.1	16.2	63	63	300	301	0.40	163	163	0.30	5.8
6/15/90	8:30-12:00	M04A	S.C.	110	1644	NA	0.7	2.8	2.8	3.0	16.0	73	73	187	187	0.25	126	126	0.23	3.3
10/11/90	9:00-15:00	PS17	S.C.	56	1547	1501	0.7	5.9	5.9	6.3	13.0	98	121	98	121	0.16	41	50	0.09	2.0
10/12/90	9:00-15:00	PS24	S.C.	56	1550	1508	0.7	6.0	6.0	6.4	13.0	66	81	66	81	0.11	38	48	0.09	1.8
10/17/90	10:30-16:30	PS18	S.C.	56	1534	1490	0.8	6.0	6.0	6.5	13.0	100	124	100	124	0.17	33	41	0.08	1.8
10/24/90	9:00-14:20	PS26	S.C.	55	1506	1448	0.8	6.1	6.0	6.4	12.7	91	113	91	113	0.15	33	41	0.08	2.1
10/25/90	9:30-15:00	PS25	S.C.	55	1543	1460	0.7	6.1	6.0	6.4	12.7	87	107	87	107	0.15	34	42	0.08	1.9
10/26/90	10:10-15:45	PS27	S.C.	55	1530	1439	0.8	6.1	5.9	6.4	12.7	84	103	84	103	0.14	33	41	0.08	1.8
11/6/90	9:00-15:00	PS24R1	S.C.	56	1562	1512	0.7	6.0	6.0	6.4	12.7	93	115	93	115	0.16	38	47	0.09	1.7
11/7/90	9:00-15:00	PS28	S.C.	56	1544	1498	0.8	6.0	6.0	6.3	13.0	102	126	102	126	0.17	32	40	0.07	1.7
11/8/90	9:30-15:30	PS29	S.C.	56	1545	1483	0.7	6.0	6.0	6.4	13.0	97	120	97	120	0.16	34	42	0.08	1.6
11/14/90	9:30-15:30	PS01	S.C.	110	1636	1658	0.7	2.8	2.8	3.1	15.7	68	68	155	156	0.21	131	132	0.25	3.3
11/15/90	9:00-15:00	PS08	S.C.	110	1643	1679	0.7	2.8	2.8	3.2	16.0	70	71	151	153	0.20	132	133	0.25	3.3
11/16/90	9:00-15:00	PS10	S.C.	110	1616	1642	0.7	2.8	2.8	3.1	15.8	72	73	212	214	0.29	142	143	0.27	4.3
11/21/90	9:00-14:55	PS12R1	S.C.	111	1624	1677	0.7	2.8	2.8	3.1	16.0	69	69	167	168	0.22	135	136	0.25	3.0
11/26/90	9:00-15:00	PS02	S.C.	111	1621	1666	0.7	2.8	2.8	3.1	15.8	75	75	153	153	0.21	136	136	0.26	2.8
11/28/90	9:00-13:00	PS13M1A	S.C.	111	1633	NA	0.7	2.8	2.8	2.9	15.9	75	75	180	179	0.24	139	138	0.26	2.9
11/30/90	9:00-15:00	PS09M1	S.C.	110	1648	1696	0.6	2.8	2.8	3.2	16.0	57	58	165	167	0.22	123	124	0.23	3.6
12/3/90	9:00-15:00	PS31	S.C.	111	1623	1681	0.7	2.8	2.8	3.2	15.7	54	55	182	185	0.25	130	132	0.25	3.3
12/5/90	13:00-15:30	PS14A	S.C.	109	1669	NA	0.6	1.8	1.8	2.1	16.5	120	115	206	197	0.27	127	121	0.23	4.5
12/5/90	9:15-12:15	PS14B	S.C.	109	NA	1697	0.6	1.8	1.8	2.1	16.7	90	86	261	248	0.34	149	142	0.27	6.9
12/6/90	9:00-15:00	PS15	S.C.	109	1617	1640	0.7	3.5	3.5	3.8	16.0	60	63	159	167	0.21	129	135	0.24	2.5
12/7/90	9:00-15:00	PS16	S.C.	109	1616	1647	0.7	3.5	3.5	3.8	15.9	71	75	151	158	0.20	126	132	0.24	2.7
12/10/90	9:00-15:00	PS32	S.C.	109	1629	1649	0.7	3.5	3.6	3.8	15.9	65	68	188	196	0.25	126	131	0.24	3.1
12/11/90	9:00-11:45	PS11A	S.C.	110	1642	NA	0.7	2.8	2.8	3.1	16.6	69	69	174	175	0.23	139	139	0.25	4.0
12/11/90	14:15-16:15	PS11B	S.C.	110	NA	1690	0.6	3.1	3.0	3.0	16.8	68	67	241	241	0.31	113	113	0.20	7.3
12/13/90	9:00-11:45	PS33A	S.C.	110	1646	NA	0.6	2.8	2.8	3.2	16.7	78	78	185	187	0.24	122	123	0.22	4.2
12/13/90	12:30-14:40	PS33B	S.C.	110	NA	1686	0.6	2.8	2.8	3.0	16.8	74	74	229	230	0.29	147	147	0.26	6.6
1/11/91	10:15-13:10	AF07A	D.	58	1448	NA	0.7	6.0	6.0	6.5	12.7	103	128	87	107	0.15	166	206	0.39	2.4
1/11/91	13:45-16:15	AF07B	D.	58	NA	1515	0.7	6.0	6.0	6.4	12.7	101	124	81	100	0.14	170	209	0.40	2.2
1/12/91	12:30-15:15	AF08A	D.	58	1460	NA	0.6	5.8	5.8	6.2	13.1	113	138	67	82	0.11	70	85	0.16	2.6
1/12/91	9:00-11:45	AF08B	D.	58	NA	1508	0.7	5.9	5.9	6.3	13.1	109	134	74	91	0.12	75	92	0.17	2.4
1/15/91	10:00-12:45	AF09A	D.	83	1521	NA	0.5	3.8	3.8	4.1	15.1	101	108	85	90	0.12	208	222	0.41	2.4
1/15/91	13:30-16:00	AF09B	D.	83	NA	1533	0.6	3.8	3.8	4.2	15.0	97	104	96	103	0.14	218	233	0.43	2.1
1/16/91	9:00-11:30	AF10	D.	83	1519	1543	0.5	3.8	3.8	4.2	15.2	97	104	105	113	0.15	135	145	0.26	2.4

Table 6-3. PLANT STACK EMISSION SUMMARY

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Date	Time	Test No.	Type of coal	Load GMWe	NOX Lb/ 10^6Btu	SO2 PPMV	SO2 LB/ 10^6Btu	SO2 A Side PPMV	SO2 B Side PPMV	Opacity %
3/13/89	8:00-20:00	SD1	S.C.	105.3	0.08	117	0.25	101	14	4
3/20/89	08:00-21:00	P30	S.C.	55.2	0.04	63	0.15	65	126	3
3/21/89	08:00-21:00	P31	S.C.	82.3	0.08	65	0.15	51	97	4
4/2189	8:00-16:30	A01	P.B.	105.2	0.20	174	0.39	170	67	0
5/26/89	8:00-17:30	A07	P.B.	54.9	0.07	141	0.35	137	107	3
6/6/89	7:30-14:30	A04	P.B.	82.4	0.18	151	0.30	135	125	6
6/7/89	8:00-14:30	A05	P.B.	82.4	0.26	9	0.02	4	10	9
6/8/89	8:30-15:30	A06	P.B.	82.6	0.14	355	0.84	322	313	10
6/16/89	10:00-17:00	A02	P.B.	103.6	0.28	3	0.00	4	9	7
6/17/89	10:00-17:00	AO3	P.B.	103.8	0.18	367	0.79	302	299	7
6/19/89	10:00-17:00	A08	P.B.	104	0.20	175	0.36	167	122	8
7/17/89	10:00-17:00	P49	S.C.	98.2	0.17	395	0.83	389	321	8
7/19/89	9:15-13:15	P50	S.C.	98.2	0.22	98	0.21	99	82	8
8/17/89	8:00-14:00	P52	S.C.	55.4	0.07	70	0.19	67	64	7
8/11/89	8:30-15:30	P21	S.C.	55.4	0.08	37	0.09	36	33	7
8/9/89	8:15-15:00	P39	S.C.	55.4	0.08	76	0.19	68	74	7
11/29/89	9:20-11:45	P55A	S.C.	107.7	0.24	84	0.18	22	116	9
11/29/89	12:30-15:10	P55B	S.C.	107.8	0.23	85	0.18	21	116	9
11/30/89	9:15-12:15	P56A	S.C.	108.2	0.21	101	0.21	27	142	9
11/30/89	12:35-15:35	P56B	S.C.	108.3	0.21	99	0.20	26	136	9
1/11/90	9:00-15:30	P20	S.C.	55.3	0.03	119	0.32	105	116	6
1/15/90	9:00-15:00	P57	S.C.	55.1	0.01	289	0.83	261	240	5
1/17/90	10:40-15:00	P58	S.C.	55.4	0.06	17	0.04	17	10	4
1/23/90	9:45-12:30	P60A	S.C	108.6	0.27	58	0.11	16	75	6
1/23/90	13:00-15:30	P60B	S.C.	108.5	0.27	63	0.13	16	80	6
1/25/90	11:40-14:00	P61A	S.C.	108.7	0.32	65	0.12	24	69	7
1/25/90	14:30-17:00	P61B	S.C.	108.8	0.31	65	0.13	27	68	7
3/6/90	9:30-15:00	P62	S.C.	55.6	0.11	0	0.00	0	13	3
3/8/90	9:30-15:00	P63	S.C.	55.7	0.10	10	0.02	8	26	4
3/10/90	9:00-15:00	P64	S.C.	55.7	0.06	15	0.03	22	23	3
3/15/90	12:30-15:45	P65B	S.C.	110.7	0.15	70	0.12	88	89	4
3/16/90	10:00-12:45	M01A	S.C.	110.9	0.20	109	0.22	99	101	4
3/16/90	13:15-15:15	M01B	S.C.	110.9	0.19	121	0.25	102	109	4
3/20/90	9:00-11:55	M02A	S.C.	110.7	0.30	128	0.26	95	96	3
3/20/90	12:50-15:00	M02B	S.C.	110.4	0.31	129	0.26	95	99	3
3/23/90	9:00-11:00	P06A	S.C.	110	0.26	109	0.23	83	83	3
3/23/90	12:15-14:50	P06B	S.C.	110.1	0.25	109	0.23	84	83	3
3/27/90	10:25-12:15	M03A	S.C.	110.6	0.23	122	0.26	94	95	5
3/27/90	13:00-15:20	M03B	S.C.	110.4	0.23	109	0.23	89	81	6
3/29/90	10:16-13:00	P66A	S.C.	110.7	0.22	114	0.23	89	85	3
3/29/90	13:35-16:00	P66B	S.C.	110.6	0.23	104	0.21	89	71	3
3/30/90	12:45-15:00	P32A	S.C.	110.8	0.22	94	0.21	82	64	5
3/30/90	9:00-11:45	P32B	S.C.	110.8	0.23	94	0.21	79	62	4
4/2/90	8:15-10:45	P67A	S.C.	111.1	0.22	107	0.21	88	70	4
4/2/90	11:30-14:00	P67B	S.C.	110.8	0.21	108	0.22	88	70	3
4/5/90	9:00-11:45	P68A	S.C.	111.0	0.20	105	0.22	89	71	3
4/5/90	12:30-15:00	P68B	S.C.	110.5	0.20	106	0.22	89	70	3
4/6/90	12:30-15:00	P07A	S.C.	110.7	0.22	107	0.22	88	71	4
4/6/90	9:45-11:45	P07B	S.C.	110.9	0.20	108	0.22	89	69	4
4/11/90	9:15-11:45	P08A	S.C.	110.9	0.21	122	0.24	110	0	4
4/11/90	12:30-14:45	P08B	S.C.	110.3	0.21	110	0.22	88	206	4
4/13/90	12:15-15:00	P69B	S.C.	110.3	0.11	108	0.23	80	66	6
4/17/90	9:00-11:45	P36A	S.C.	109.7	0.20	107	0.23	86	174	5
4/17/90	12:30-14:50	P36B	S.C.	109.4	0.20	95	0.21	81	78	3

Table 6-3. PLANT STACK EMISSION SUMMARY

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Date	Time	Test No.	Type of coal	Load GMWe	NOX Lb/ 10^6Btu	SO2 PPMV	SO2 LB/ 10^6Btu	SO2 A Side PPMV	SO2 B Side PPMV	Opacity %
4/18/90	9:00-12:00	P70A	S.C.	109.8	0.21	104	0.22	93	139	4
4/18/90	12:45-15:45	P70B	S.C.	109.7	0.21	103	0.22	94	133	4
4/27/90	9:10-11:45	P71A	S.C.	110.7	0.20	105	0.21	88	95	5
4/27/90	12:30-15:30	P71B	S.C.	110.7	0.20	106	0.22	87	91	4
5/25/90	9:00-11:50	C01A	S.C.	109.9	0.31	98	0.21	84	101	6
5/25/90	12:30-15:30	C01B	S.C.	109.6	0.29	106	0.24	91	104	6
6/12/90	8:30-11:15	C02A	S.C.	109.6	0.30	104	0.22	90	80	5
6/12/90	12:00-16:00	C02B	S.C.	109.5	0.32	102	0.22	89	82	5
6/14/90	8:25-11:10	M05A	S.C.	109.8	0.31	131	0.27	113	103	4
6/14/90	12:00-14:45	M05B	S.C.	109.6	0.31	124	0.26	98	104	4
6/15/90	8:30-12:00	M04A	S.C.	110.1	0.33	119	0.25	96	97	5
10/11/90	9:00-15:00	PS17	S.C.	55.7	0.07	87	0.24	79	82	3
10/12/90	9:00-15:00	PS24	S.C.	55.8	0.06	84	0.22	79	89	3
10/17/90	10:30-16:30	PS18	S.C.	56.2	0.05	86	0.22	86	88	4
10/24/90	9:00-14:20	PS26	S.C.	55.4	0.06	104	0.30	92	95	4
10/25/90	9:30-15:00	PS25	S.C.	55.2	0.06	93	0.23	91	95	3
10/26/90	10:10-15:45	PS27	S.C.	55.1	0.06	92	0.23	90	95	3
11/6/90	9:00-15:00	PS24R1	S.C.	55.7	0.06	96	0.24	86	76	3
11/7/90	9:00-15:00	PS28	S.C.	55.8	0.05	103	0.25	92	82	3
11/8/90	9:30-15:30	PS29	S.C.	55.8	0.06	80	0.20	98	50	4
11/14/90	9:30-15:30	PS01	S.C.	110.3	0.19	120	0.24	110	50	3
11/15/90	9:00-15:00	PS08	S.C.	110.3	0.19	118	0.24	110	50	3
11/16/90	9:00-15:00	PS10	S.C.	110.4	0.27	127	0.26	110	50	3
11/21/90	9:00-14:55	PS12R1	S.C.	110.9	0.20	123	0.24	110	57	4
11/26/90	9:00-15:00	PS02	S.C.	110.7	0.19	118	0.24	110	57	3
11/28/90	9:00-13:00	PS13M1A	S.C.	111.4	0.27	107	0.21	109	67	3
11/30/90	9:00-15:00	PS09M1	S.C.	110.2	0.21	115	0.25	102	96	3
12/3/90	9:00-15:00	PS31	S.C.	110.6	0.23	119	0.24	102	102	4
12/5/90	13:00-15:30	PS14A	S.C.	109.0	0.29	128	0.24	102	112	4
12/5/90	9:15-12:15	PS14B	S.C.	109.0	0.29	126	0.23	102	110	4
12/6/90	9:00-15:00	PS15	S.C.	109.3	0.21	118	0.25	102	101	4
12/7/90	9:00-15:00	PS16	S.C.	109.4	0.20	115	0.24	102	102	4
12/10/90	9:00-15:00	PS32	S.C.	109.3	0.25	113	0.25	98	100	3
12/11/90	9:00-11:45	PS11A	S.C.	110.5	0.24	134	0.28	109	118	3
12/11/90	14:15-16:15	PS11B	S.C.	110.0	0.28	93	0.19	101	105	3
12/13/90	9:00-11:45	PS33A	S.C.	109.9	0.13	110	0.22	96	83	3
12/13/90	12:30-14:40	PS33B	S.C.	109.8	0.11	119	0.25	95	97	3
1/11/91	10:15-13:10	AF07A	D.	58	0.15	166	0.39	136	125	3
1/11/91	13:45-16:15	AF07B	D.	58	0.14	170	0.40	134	127	2
1/12/91	12:30-15:15	AF08A	D.	58	0.11	70	0.16	55	51	3
1/12/91	9:00-11:45	AF08B	D.	58	0.12	75	0.17	51	52	2
1/15/91	10:00-12:45	AF09A	D.	83	0.12	208	0.41	163	161	3
1/15/91	13:30-16:00	AF09B	D.	83	0.14	218	0.43	146	161	3
1/16/91	9:00-11:30	AF10	D.	83	0.15	135	0.26	99	104	2

Table 6-4. AIR HEATER FLUE GAS ANALYSIS: SO2 EMISSION

(Page 1 of 2)

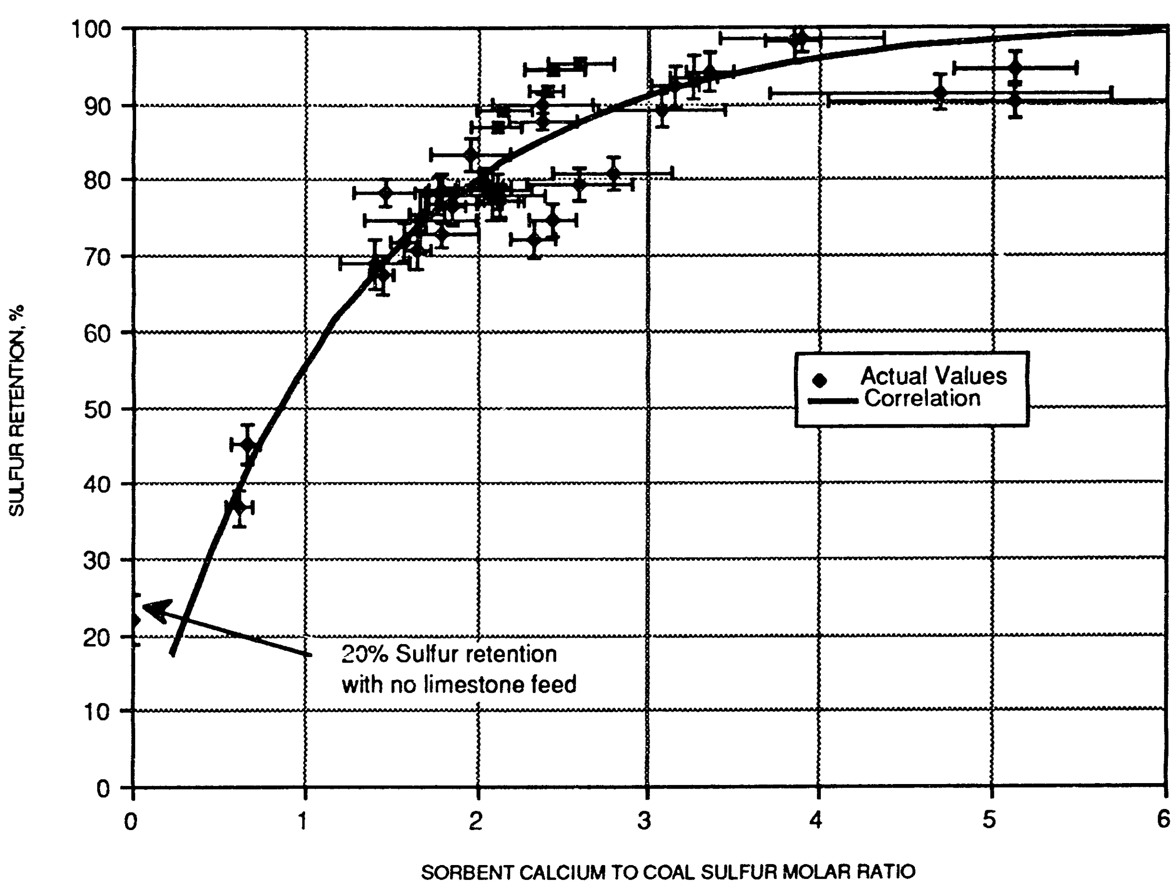
Date	Time	Test no.	Type of coal	Load in MW	Mean bed Temp. A in F	Mean bed Temp. B in F	PPMV	SO2 PPMV @ 3% O2	LB/ 10^6 BTU	Ratio Ca/S Sorbent	Ratio Ca/S Sorbent &coal	SO2 Retention %	Ca Utilization (%) Sorbent	Ca Utilization (%) Sorbent &coal
4/2189	8:00-16:30	A01	P.B.	105.2	1574	1638	192	199	0.37	1.8	2.0	73	41	36
5/26/89	8:00-17:30	A07	P.B.	54.9	1492	1497	150	179	0.35	1.5	2.3	78	54	34
6/6/89	7:30-14:30	A04	P.B.	82.4	1601	1614	162	174	0.33	1.7	2.5	75	45	30
6/7/89	8:00-14:30	A05	P.B.	82.4	1582	1611	9	10	0.02	3.9	4.7	98	25	21
6/8/89	8:30-15:30	A06	P.B.	82.6	1586	1611	381	408	0.76	0.6	1.3	37	60	29
6/16/89	10:00-17:00	A02	P.B.	103.6	1609	1645	13	13	0.02	3.7	4.0	98	26	24
6/17/89	10:00-17:00	AO3	P.B.	103.8	1602	1625	388	398	0.73	0.7	1.2	45	69	38
6/19/89	10:00-17:00	A08	P.B.	104	1629	1621	188	193	0.35	1.8	2.1	73	40	35
3/13/89	8:00-20:00	SD1	S.C.	105.3	1567	1556	136	144	0.27	1.4	2.1	69	49	34
3/20/89	08:00-21:00	P30	S.C.	55.2	1469	1516	77	91	0.17	2.1	2.9	78	37	27
3/21/89	08:00-21:00	P31	S.C.	82.3	1534	1578	78	82	0.15	2.0	2.5	83	42	34
7/17/89	10:00-17:00	P49	S.C.	98.2	1633	1650	424	436	0.81	0.9	1.3	14	15	10
7/19/89	9:15-13:15	P50	S.C.	98.2	1617	1659	111	114	0.21	3.5	3.9	78	22	20
8/17/89	8:00-14:00	P52	S.C.	55.4	1526	1520	85	104	0.20	2.8	3.2	81	29	25
8/11/89	8:30-15:30	P21	S.C.	55.4	1526	1513	50	61	0.12	3.1	3.5	89	29	26
8/9/89	8:15-15:00	P39	S.C.	55.4	1533	1542	94	113	0.22	2.6	3.0	80	31	27
11/29/89	9:20-11:45	P55A	S.C.	107.7	1532	NA	37	38	0.07	4.8	5.2	92	19	18
11/29/89	12:30-15:10	P55B	S.C.	107.8	NA	1659	165	170	0.33	4.8	5.2	61	13	12
11/30/89	9:15-12:15	P56A	S.C.	108.2	1552	NA	42	41	0.19	5.2	5.8	90	17	16
11/30/89	12:35-15:35	P56B	S.C.	108.3	NA	1688	189	184	0.36	5.0	5.6	57	11	10
1/11/90	9:00-15:30	P20	S.C.	55.3	1484	1503	138	167	0.38	1.4	2.0	68	47	34
1/15/90	9:00-15:00	P57	S.C.	55.1	1451	1483	308	379	0.79	0.0	0.4	22	----	60
1/17/90	10:40-15:00	P58	S.C.	55.4	1420	1440	24	30	0.06	3.3	4.0	94	29	24
1/23/90	9:45-12:30	P60A	S.C.	108.6	1601	NA	26	25	0.05	5.1	5.7	95	19	17
1/23/90	13:00-15:30	P60B	S.C.	108.5	NA	1712	125	122	0.23	4.7	5.2	75	16	14
1/25/90	11:40-14:00	P61A	S.C.	108.7	1670	NA	39	37	0.07	4.7	5.7	92	20	16
1/25/90	14:30-17:00	P61B	S.C.	108.8	NA	1716	111	108	0.21	4.5	4.9	79	18	16
3/6/90	9:30-15:00	P62	S.C.	55.6	1454	1472	7	9	0.02	3.8	4.7	98	26	21
3/8/90	9:30-15:00	P63	S.C.	55.7	1464	1481	23	29	0.06	3.4	3.8	94	28	25
3/10/90	9:00-15:00	PC*	S.C.	55.7	1417	1442	28	35	0.07	3.1	3.7	92	29	25
3/15/90	12:30-15:45	P65B	S.C.	110.7	NA	1674	133	133	0.25	3.5	3.9	70	20	18
3/16/90	10:00-12:45	M01A	S.C.	110.9	1649	NA	125	125	0.24	2.7	3.1	73	27	24
3/16/90	13:15-15:15	M01B	S.C.	110.9	NA	1675	145	145	0.27	2.6	3.1	69	26	23
3/20/90	9:00-11:55	M02A	S.C.	110.7	1636	NA	128	128	0.24	3.7	4.2	71	19	17
3/20/90	12:50-15:00	M02B	S.C.	110.4	NA	1672	159	159	0.30	5.5	5.9	66	12	11
3/23/90	9:00-11:00	P06A	S.C.	110	1642	NA	109	109	0.20	3.0	3.4	76	26	22
3/23/90	12:15-14:50	P06B	S.C.	110.1	NA	1695	138	138	0.25	4.6	5.0	70	15	14
3/27/90	10:25-12:15	M03A	S.C.	110.6	1640	NA	127	128	0.24	3.3	3.7	71	22	19
3/27/90	13:00-15:20	M03B	S.C.	110.4	NA	1701	138	138	0.26	6.8	7.2	69	10	10
3/29/90	10:16-13:00	P66A	S.C.	110.7	1658	NA	124	117	0.22	3.6	4.1	75	21	18
3/29/90	13:35-16:00	P66B	S.C.	110.6	NA	1711	127	120	0.22	9.0	9.4	74	8	8
3/30/90	12:45-15:00	P32A	S.C.	110.8	1610	NA	115	124	0.23	2.3	2.8	72	31	25
3/30/90	9:00-11:45	P32B	S.C.	110.8	NA	1636	112	121	0.23	2.5	3.0	73	29	24
4/2/90	8:15-10:45	P67A	S.C.	111.1	1613	NA	115	114	0.21	2.1	2.7	77	36	29
4/2/90	11:30-14:00	P67B	S.C.	110.8	NA	1708	129	129	0.24	4.9	5.4	72	14	13
4/5/90	9:00-11:45	P68A	S.C.	111.0	1623	NA	120	120	0.23	2.3	2.9	74	32	26
4/5/90	12:30-15:00	P68B	S.C.	110.5	NA	1689	130	130	0.25	5.4	5.9	72	13	12
4/6/90	12:30-15:00	P07A	S.C.	110.7	1624	NA	118	118	0.22	2.5	3.0	76	31	25
4/6/90	9:45-11:45	P07B	S.C.	110.9	NA	1692	129	130	0.25	3.9	4.3	73	19	17
4/11/90	9:15-11:45	P08A	S.C.	110.9	1626	NA	115	115	0.22	2.6	3.2	78	30	24
4/11/90	12:30-14:45	P08B	S.C.	110.3	NA	1692	135	136	0.26	4.8	5.4	74	15	14
4/13/90	12:15-15:00	P69B	S.C.	110.3	NA	1664	149	149	0.28	2.9	3.6	67	23	19
4/17/90	9:00-11:45	P36A	S.C.	109.7	1546	NA	115	115	0.22	2.0	2.7	79	39	30
4/17/90	12:30-14:50	P36B	S.C.	109.4	NA	1685	126	126	0.24	5.9	6.3	77	13	12

Table 6-4. AIR HEATER FLUE.GAS ANALYSIS: SO2 EMISSION

(Page 2 of 2)

Date	Time	Test no.	Type of coal	Load in MW	Mean bed Temp. A in F	Mean bed Temp. B in F	PPMV	SO2 PPMV @ 3% O2	LB/ 10^6 BTU	Ratio Ca/S Sorbent	Ratio Ca/S Sorbent &coal	SO2 Retention %	Ca Utilization (%) Sorbent	Ca Utilization (%) Sorbent &coal
4/18/90	9:00-12:00	P70A	S.C.	109.8	1549	NA	127	127	0.24	2.1	2.7	79	37	29
4/18/90	12:45-15:45	P70B	S.C.	109.7	NA	1689	118	118	0.22	5.7	6.1	78	14	13
4/27/90	9:10-11:45	P71A	S.C.	110.7	1612	NA	121	121	0.23	2.4	3.0	75	31	25
4/27/90	12:30-15:30	P71B	S.C.	110.7	NA	1694	140	141	0.26	5.6	6.0	70	13	12
5/25/90	9:00-11:50	C01A	S.C.	109.9	1643	NA	107	107	0.20	3.0	3.6	82	27	23
5/25/90	12:30-15:30	C01B	S.C.	109.6	NA	1700	138	140	0.26	3.7	4.2	80	21	19
6/12/90	8:30-11:15	C02A	S.C.	109.6	1650	NA	117	117	0.22	3.0	3.5	82	28	23
6/12/90	12:00-16:00	C02B	S.C.	109.5	NA	1708	132	133	0.25	5.1	5.6	79	15	14
6/14/90	8:25-11:10	M05A	S.C.	109.8	1643	NA	144	144	0.27	2.6	3.2	78	30	24
6/14/90	12:00-14:45	M05B	S.C.	109.6	NA	1698	163	163	0.30	5.8	6.3	75	13	12
6/15/90	8:30-12:00	M04A	S.C.	110.1	1644	NA	126	126	0.23	3.3	3.7	80	24	21
10/11/90	9:00-15:00	PS17	S.C.	55.7	1547	1501	102	99	0.23	2.0	2.8	79	39	28
10/12/90	9:00-15:00	PS24	S.C.	55.8	1550	1508	97	94	0.22	1.8	2.4	79	44	32
10/17/90	10:30-16:30	PS18	S.C.	56.2	1534	1490	98	95	0.23	1.8	2.7	78	44	29
10/24/90	9:00-14:20	PS26	S.C.	55.4	1506	1448	104	101	0.25	2.1	2.7	77	36	29
10/25/90	9:30-15:00	PS25	S.C.	55.2	1543	1460	104	100	0.24	1.9	2.5	77	42	31
10/26/90	10:10-15:45	PS27	S.C.	55.1	1530	1439	102	99	0.24	1.8	2.5	76	41	30
11/6/90	9:00-15:00	PS24R1	S.C.	55.7	1562	1512	114	111	0.27	1.7	2.4	75	44	32
11/7/90	9:00-15:00	PS28	S.C.	55.8	1544	1498	120	116	0.28	1.7	2.6	71	43	28
11/8/90	9:30-15:30	PS29	S.C.	55.8	1545	1483	113	109	0.26	1.6	2.2	72	46	33
11/14/90	9:30-15:30	PS01	S.C.	110.3	1636	1658	131	132	0.25	3.3	4.2	72	22	17
11/15/90	9:00-15:00	PS08	S.C.	110.3	1643	1679	132	133	0.25	3.3	3.9	73	22	18
11/16/90	9:00-15:00	PS10	S.C.	110.4	1616	1642	142	143	0.27	4.3	5.1	71	16	14
11/21/90	9:00-14:55	PS12R1	S.C.	110.9	1624	1677	135	136	0.25	3.0	3.7	72	24	19
11/26/90	9:00-15:00	PS02	S.C.	110.7	1621	1666	136	136	0.26	2.8	3.5	73	26	21
11/28/90	9:00-13:00	PS13M1A	S.C.	111.4	1633	NA	139	138	0.26	2.9	3.5	72	25	21
11/30/90	9:00-15:00	PS09M1	S.C.	110.2	1648	1696	123	124	0.23	3.6	4.3	73	20	17
12/3/90	9:00-15:00	PS31	S.C.	110.6	1623	1681	130	132	0.25	3.3	4.0	72	22	18
12/5/90	13:00-15:30	PS14A	S.C.	109.0	1669	NA	127	121	0.23	4.5	5.3	74	17	14
12/5/90	9:15-12:15	PS14B	S.C.	109.0	NA	1697	149	142	0.27	6.9	7.6	72	10	9
12/6/90	9:00-15:00	PS15	S.C.	109.3	1617	1640	129	135	0.24	2.5	3.3	73	29	22
12/7/90	9:00-15:00	PS16	S.C.	109.4	1616	1647	126	132	0.24	2.7	3.6	72	27	20
12/10/90	9:00-15:00	PS32	S.C.	109.3	1629	1649	126	131	0.24	3.1	3.6	73	24	20
12/11/90	9:00-11:45	PS11A	S.C.	110.5	1642	NA	139	139	0.25	4.0	4.7	69	17	15
12/11/90	14:15-16:15	PS11B	S.C.	110.0	NA	1690	113	113	0.20	7.3	8.0	75	10	9
12/13/90	9:00-11:45	PS33A	S.C.	109.9	1646	NA	122	123	0.22	4.2	4.7	73	17	15
12/13/90	12:30-14:40	PS33B	S.C.	109.8	NA	1686	147	147	0.26	6.6	7.4	67	10	9
1/11/91	10:15-13:10	AF07A	D.	58.4	1448	NA	166	206	0.39	2.4	2.5	90	38	35
1/11/91	13:45-16:15	AF07B	D.	58.2	NA	1515	170	209	0.40	2.2	2.5	89	41	36
1/12/91	12:30-15:15	AF08A	D.	58.3	1460	NA	70	85	0.16	2.6	2.9	95	37	33
1/12/91	9:00-11:45	AF08B	D.	58.4	NA	1508	75	92	0.17	2.4	2.8	95	39	33
1/15/91	10:00-12:45	AF09A	D.	83.3	1521	NA	208	222	0.41	2.4	2.6	88	37	34
1/15/91	13:30-16:00	AF09B	D.	83.0	NA	1533	218	233	0.43	2.1	2.5	87	41	35
1/16/91	9:00-11:30	AF10	D.	83.4	1519	1543	135	145	0.26	2.4	2.9	92	38	32

Figure 6-1. Effect of Ca/S Molar Ratio on Sulfur Retention (Bed Temp. < 1620 °F)



adjusted to 75% retention to compensate for the fact that Ca/S requirements vary with sulfur retention. The equation used to adjust the Ca/S parameter for 75% retention follows:

$$\text{Adjusted Ca/S} = \text{Ca/S} * \frac{(-1.386)}{\ln(1-\text{sulfur retention}/100)}$$

The plot of adjusted Ca/S molar ratios versus average bed temperature is illustrated in Figure 6-2. Included in the figure is a best fit curve, which was developed using the points shown. The equation for the best fit curve is:

$$\text{Ca/S} = 1.8 + e^{(T-1627)*0.0184}$$

where

Ca/S = Ca/S molar ratio, adjusted to 75% retention
T = Average bed temperature, °F

From the figure, it can be seen that the Ca/S molar requirement for 75% retention increases considerably above 1620 °F. Below 1620 °F, a Ca/S ratio of approximately 1.5 to 2.0 is required for 75% retention.

Figure 6-3 shows the Ca/S requirements for various sulfur retentions for tests run on Peabody, Salt Creek, and Dorchester coals at temperatures below 1620 °F. It can be seen that there is no detectable difference between the Peabody and Salt Creek coals, while the Dorchester coal appears to have slightly lower Ca/S requirements for a given retention. This is most likely due to the higher sulfur content of the Dorchester coal (ranging from 1.4% to 1.8%) which is 2 to 3 times that of the Peabody and Salt Creek coals (0.4% to 0.8%).

In Figure 6-4, the effect of load on tests run at bed temperatures less than 1620 °F on Salt Creek and Peabody Coal is shown. It appears from the figure that higher load tests are more likely to result in higher Ca/S requirements. However, these points were all split combustor tests where the other combustor was operating at a temperature well over 1620 °F. Thus, these SO_2 measurements may have been biased upwards by high SO_2 emissions from the other combustor. For example, in test P60A, SO_2 emissions from combustor A measured 25 ppm SO_2 at 3% O_2, while SO_2 emissions from combustor B measured 122 ppm SO_2 at 3% O_2. A small amount of flue gas mixing between the two combustors at the measurement location would have resulted in a higher SO_2 reading for combustor A. Since the split combustor measurements are taken at the air heater inlet where some gas mixing is possible, these points are most likely biased in the direction of lower sulfur capture.

The effect of coal feed configuration on Ca/S requirements for full-load tests can be seen in Figure 6-5. For these tests, the data shows that balanced (33% feed to each of the three feeders in

Figure 6-2. Effect of Bed Temperature on Calcium Requirements for 75% Sulfur Retention

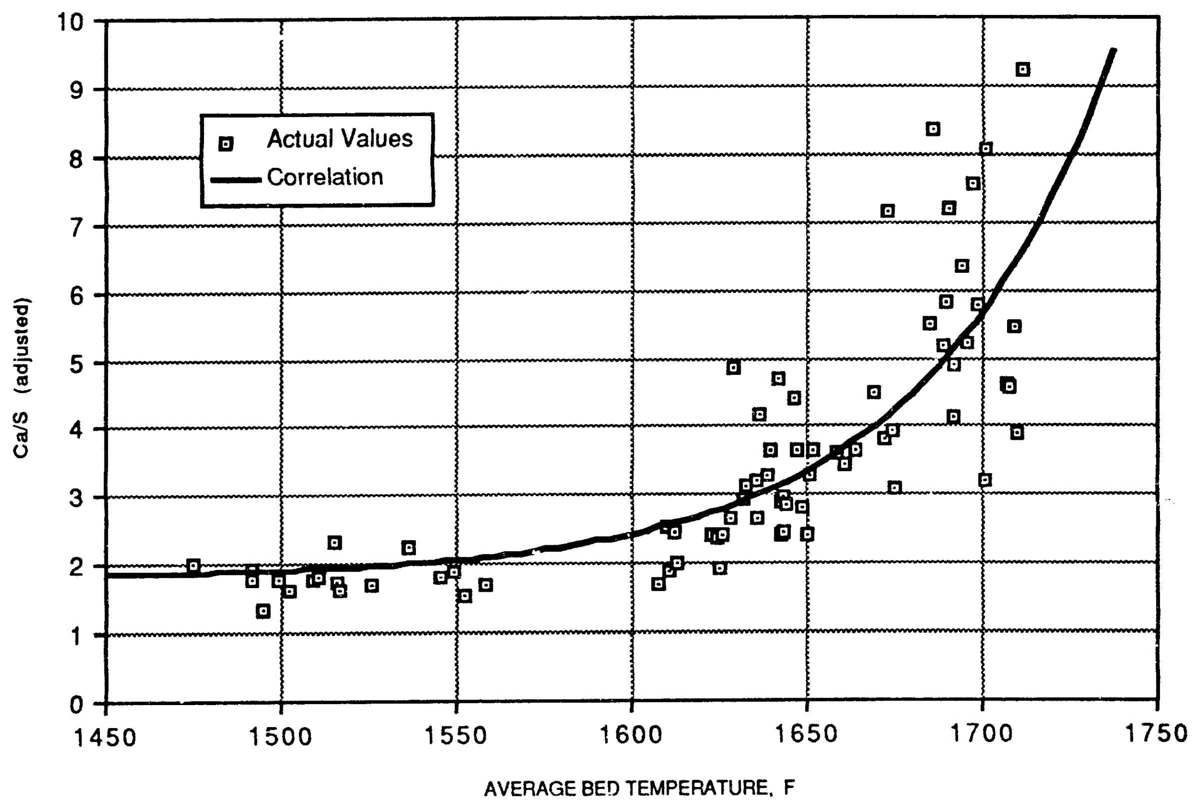


Figure 6-3. Calcium Requirements and Sulfur Retentions for Various Fuels

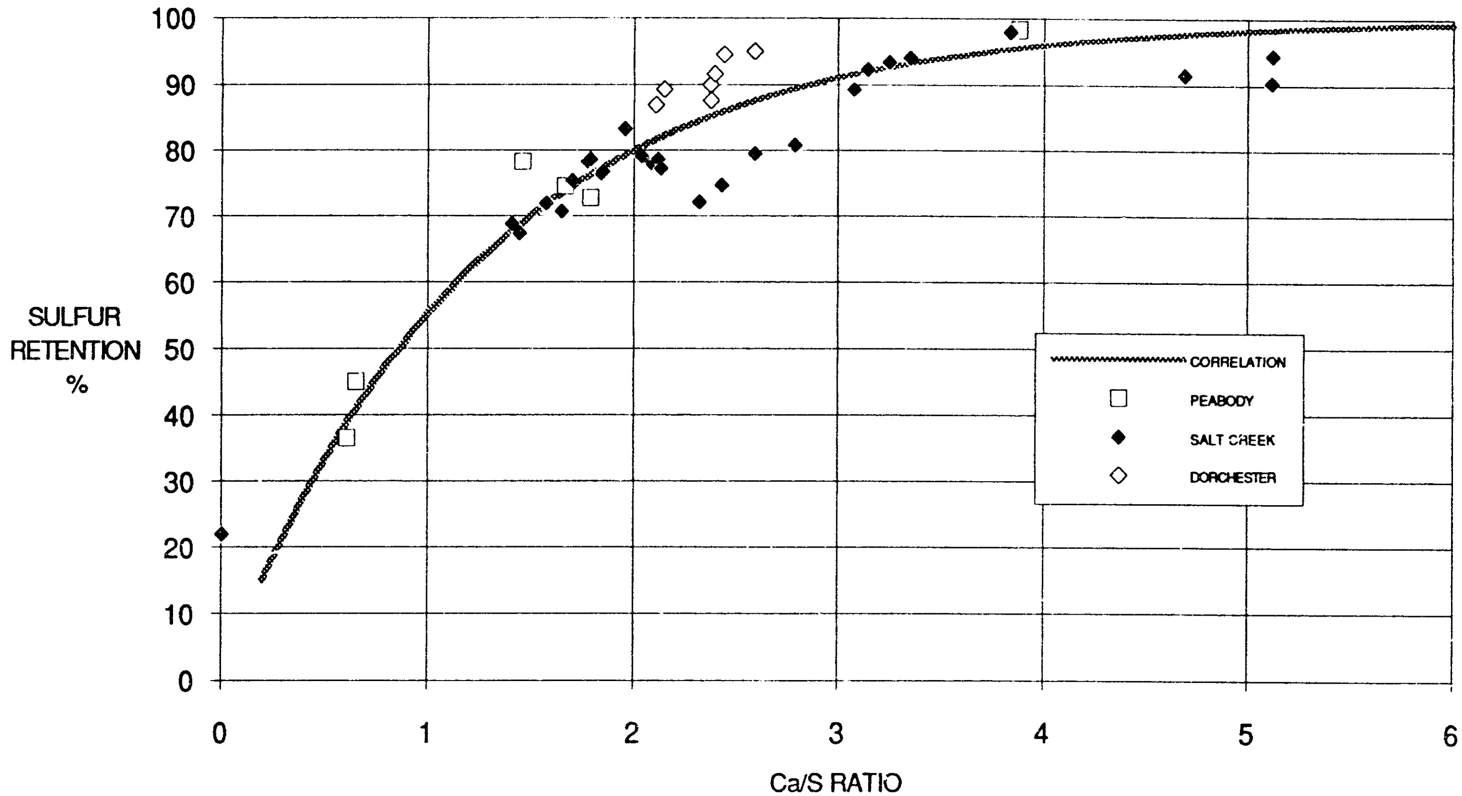


Figure 6-4. Effect of Load on Calcium Requirements

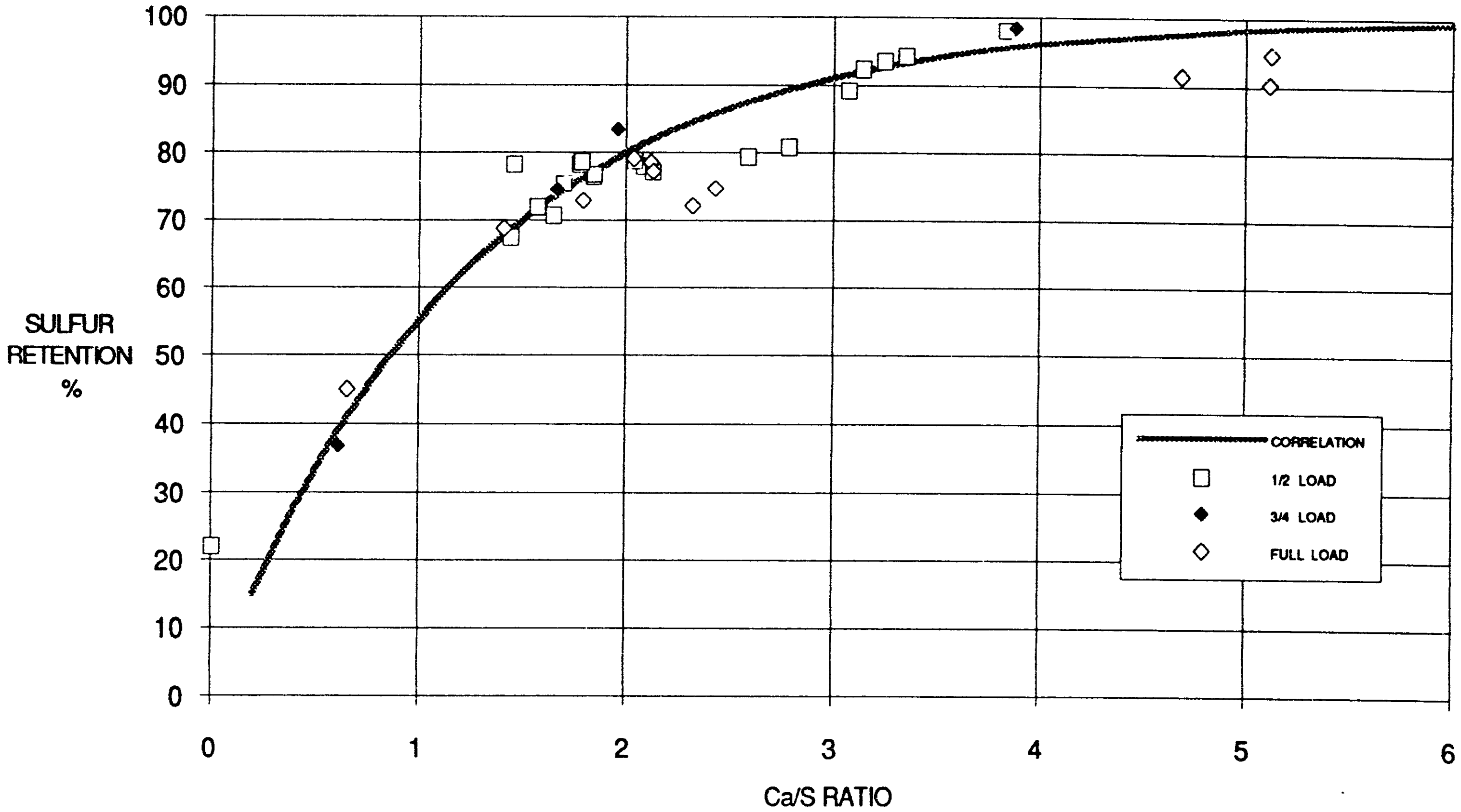
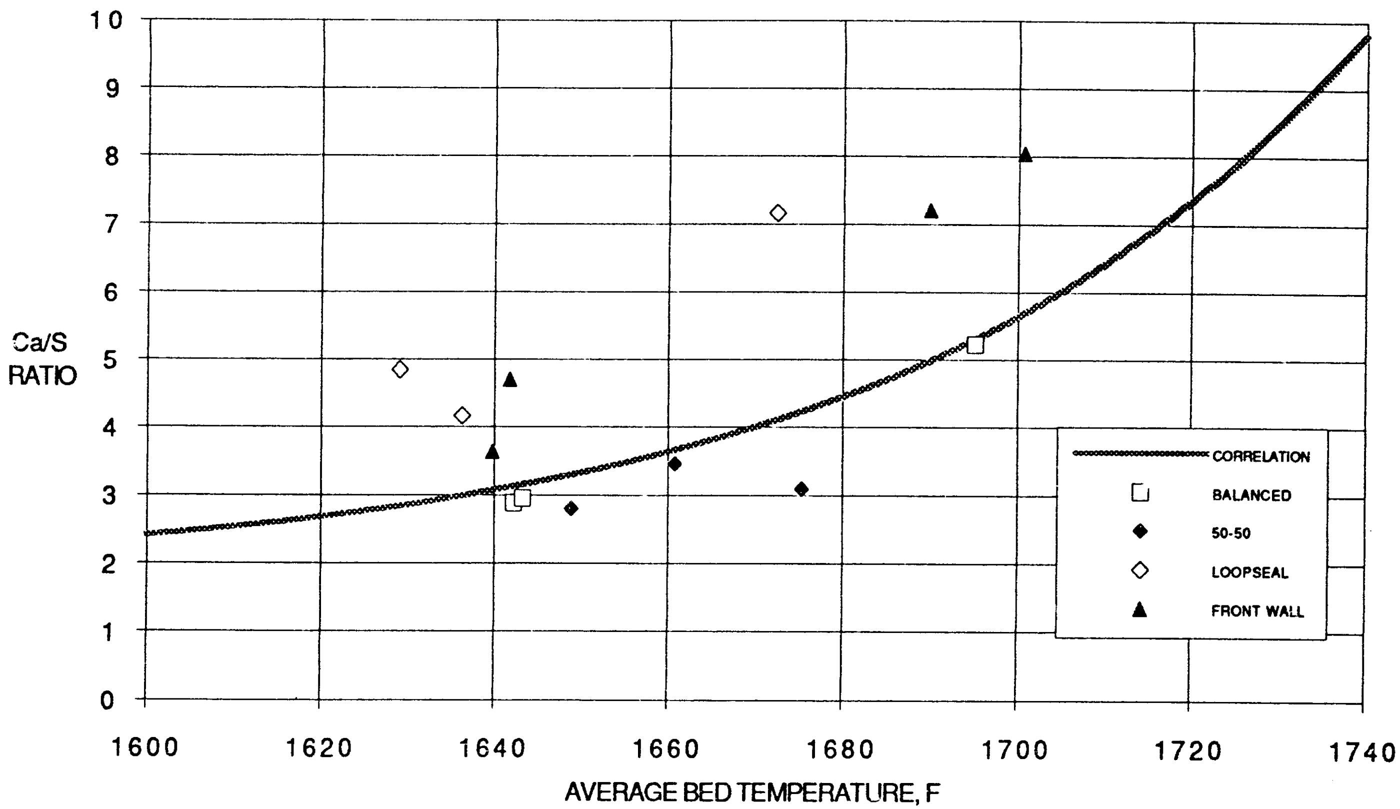


Figure 6-5. Effect of Coal Feed Configuration on Calcium Requirement for Salt Creek Coal



each combustor) and 50-50 (25% to each of the front wall feeders and 50% to the loop seal coal feeder) coal feed distributions yield lower Ca/S requirements. This effect becomes more pronounced at elevated bed temperatures. No effect of coal feed distribution on Ca/S requirements was found at half load.

As can be seen in Figure 6-6, results from testing indicate that calcium requirements are insensitive to changes in limestone feed configuration at full load. At lower loads, no indication of calcium requirement sensitivity to limestone feed configuration was found. The number of these configuration tests are limited due to mechanical limitations to the limestone feed system.

The results, shown in Figure 6-7, show the effect of excess air and temperature on the Ca/S ratio. At bed temperatures below 1680 °F, excess air does not appear to influence calcium requirements. Above this point, the data indicate that decreased excess air may have a negative impact on Ca/S requirements. The data above 1680 °F indicate that the 10% excess air points deviate from the correlation curve as the temperature increases, while the points above 13% excess air do not.

Attempts to determine the effect of SA/PA ratio on calcium requirements are documented in Figure 6-8. As is apparent from the figure, no effect can be seen when SA/PA ratio is varied over its full range (0.5 to 1.0) during full load operation. Also, no effect due to changes in the SA/PA ratio was found during half load testing.

It has been suggested that CO concentration may affect calcium requirements. This was investigated, and no relationship between flue gas air heater inlet CO concentrations and calcium requirements was found in data from the tests run at Nucla.

6.1.2 NO_x Emissions

NO_x emissions for all tests completed have been less than 0.34 lb/MMBtu (as measured by the CUEA stack emissions monitoring system), which is well within the emission limit of 0.50 lb/MMBtu. The average level of NO_x emissions for all tests is 0.18 lb/MMBtu. For fluidized bed boilers operating well below the thermal NO_x formation temperature of approximately 2500 °F, it is believed that NO_x emissions result from fuel-bound nitrogen being converted to NO_x followed by the destruction of the NO_x in the combustor. Mechanisms and reactions that lead to NO_x formation in fluidized bed combustion systems are complicated, and for a given coal and limestone, may be influenced by a number of factors.

Bed temperature is one of the most influential factors affecting NO_x emissions. The effect of this parameter on NO_x emissions has been well researched and documented. In general, NO_x emissions have been shown to increase with increasing bed temperature. A

Figure 6-6. Effect of Limestone Feed Configuration on Calcium Requirements

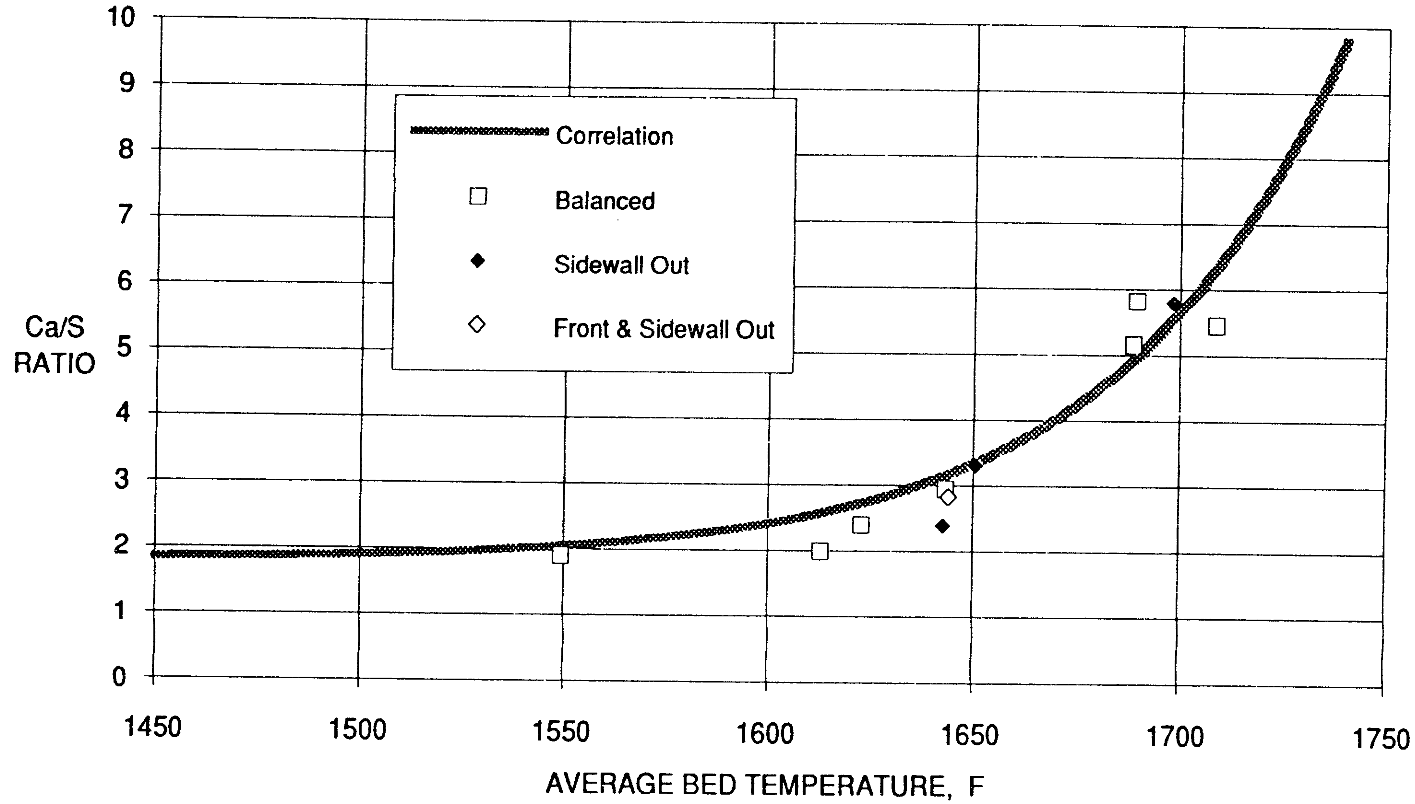


Figure 6-7. Effect of Excess Air on Calcium Requirements

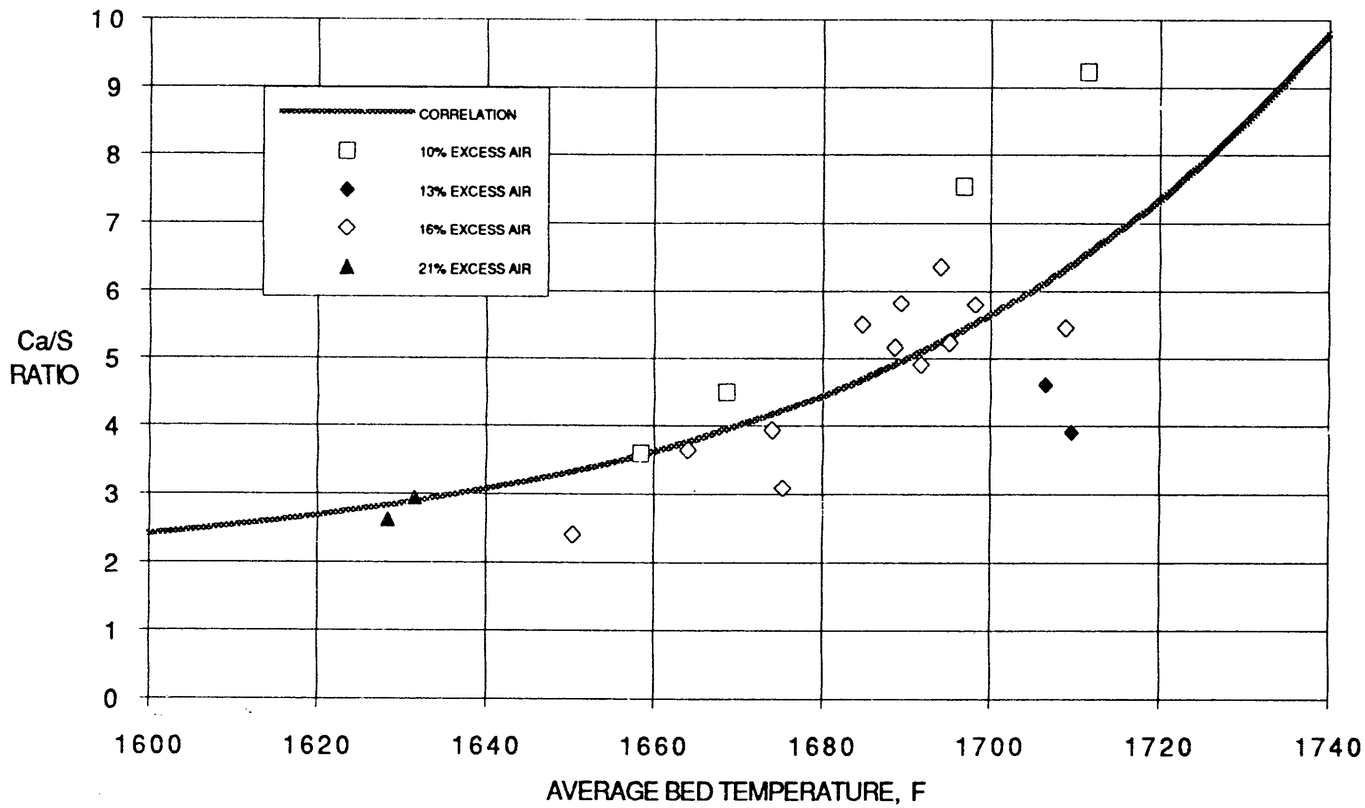
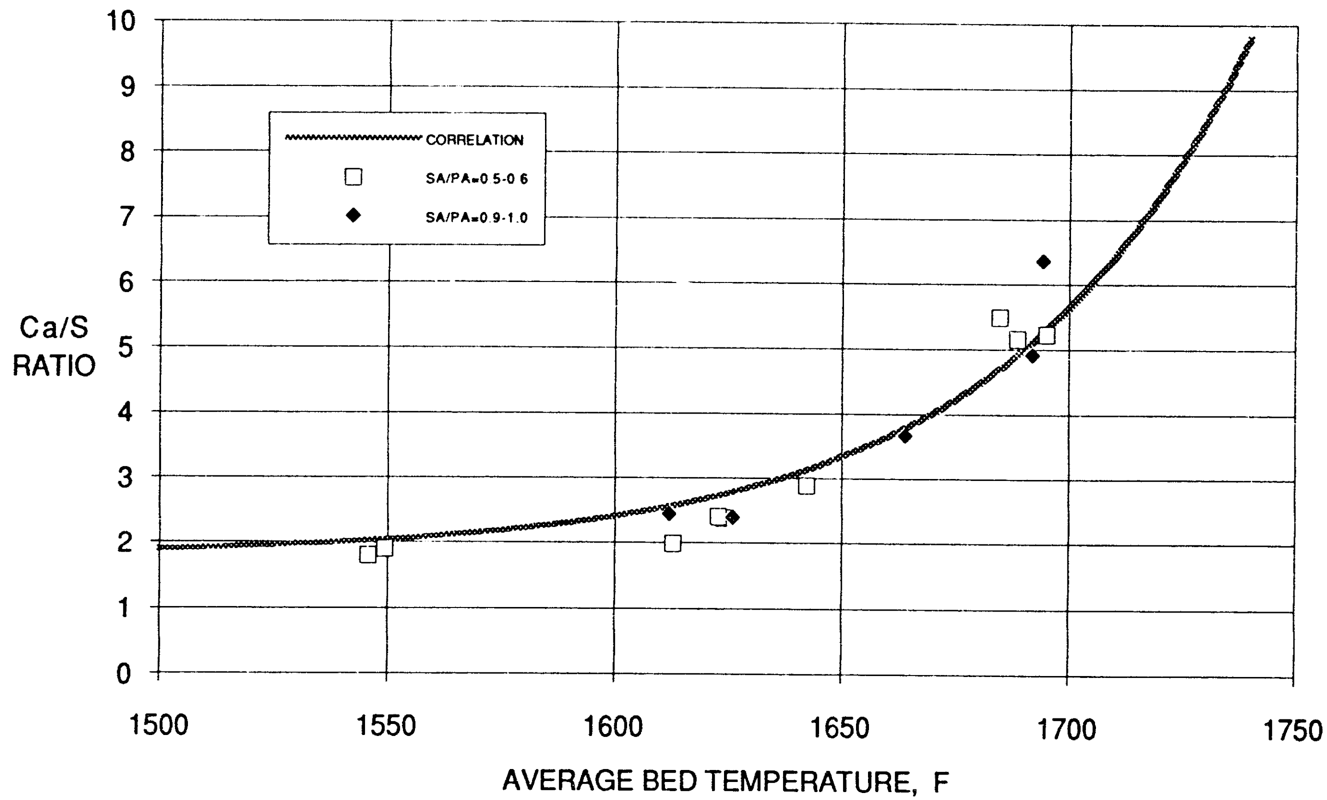


Figure 6-8. Effect of SA/PA Ratio on Calcium Requirements



plot showing this relationship for the Nucla CFB boiler is included here as Figure 6-9.

A second order polynomial relationship was used to fit a curve to the data points. This curve is also shown in Figure 6-9. The equation for the curve is:

$$[NO_x] = 4139 - 5.867 * T + 2.1E-3 * T^2$$

where:

$[NO_x]$ = NO_x concentration corrected to 3% O_2, ppmv
T = Mean bed temperature, °F

An attempt to explain the scatter in the NO_x versus bed temperature plot for all balanced coal feed configuration tests identified limestone feed rate as another variable affecting NO_x. Figure 6-10 shows NO_x plotted against bed temperature for different Ca/N weight ratios. Ca/N weight ratio serves as a measure of limestone feed normalized to the nitrogen input of the coal. Table 6-5 contains all data relevant to the development of Figure 6-10.

CaO has been known to influence both NO_x formation and reduction. Oxidation of volatile nitrogen, present in the form of NH_3, is catalyzed by CaO. This may explain why higher NO_x emissions result from increasing Ca/N weight ratios.

Figure 6-11 shows how the NO_x emissions varied with the use of alternate fuels. As shown in the figure, emissions during operation on Dorchester coal were consistently higher than the correlated values. This is most likely due to the fact that the sulfur content, and therefore limestone feed rate (and Ca/N ratio), was higher when operating on this fuel.

The effect of coal feed configuration on NO_x during full load operation is shown in Figure 6-12. It appears that feeding coal through the front wall only may lead to higher NO_x emissions. As was the case with the Dorchester coal, higher limestone feed requirements with front wall only coal feed lead to higher limestone feed rates, which increases the Ca/N ratio. It is significant to note that while coal feed to the loop seal feed point only results in higher Ca/S ratios, it does not appear to lead to higher NO_x emissions. No effect of coal feed configuration was found at lower temperatures and loads.

The influence of excess air on NO_x emissions was investigated, and the results of that investigation are shown in Figure 6-13. As the figure shows, excess air did not appear to have a significant effect on the emissions of NO_x over the range tested. This result is somewhat surprising as most researchers believe that increased excess air will lead to increased NO_x emissions. However, the range of excess air studied in these tests was somewhat limited.

Figure 6-9. Effect of Bed Temperature on NOx Emissions

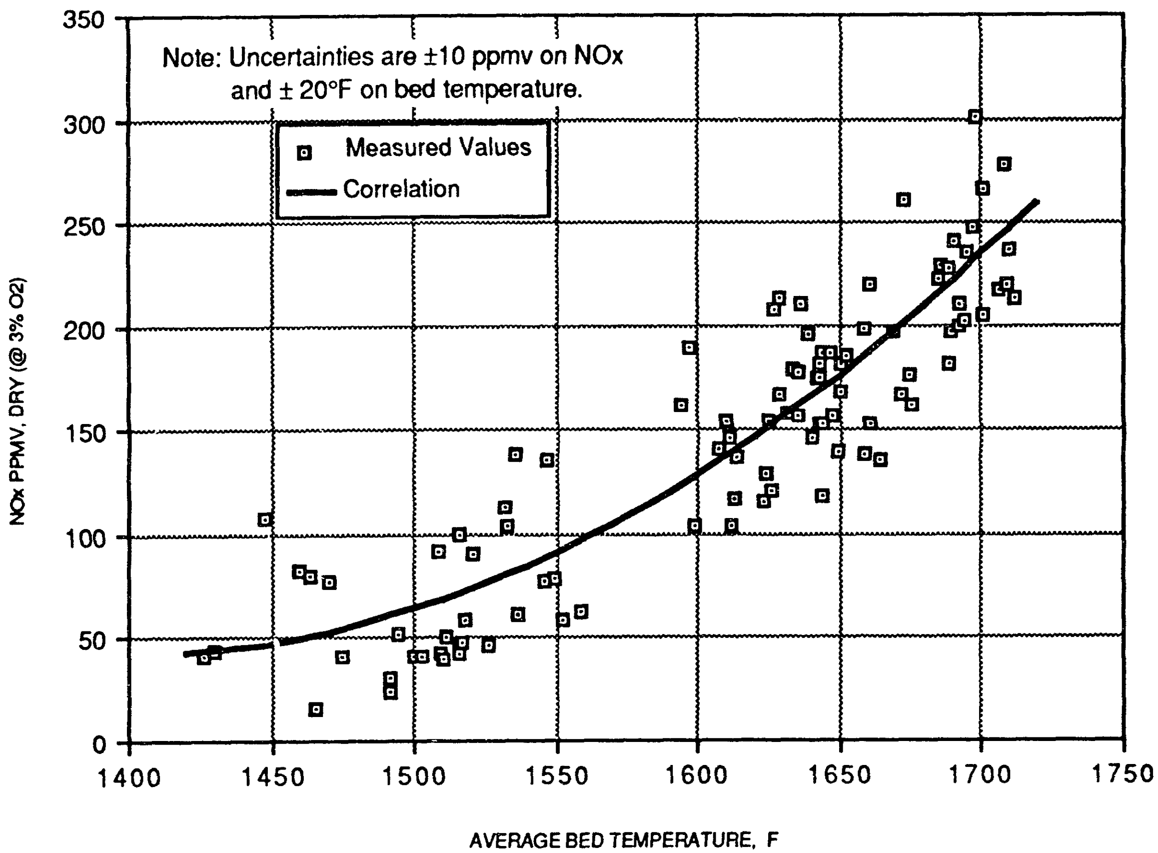


Table 6-5. EFFECT OF LIMESTONE FEED ON NOx EMISSIONS

(Page 1 of 2)

Test No.	NOx PPMV @3% O2	Mean Bed Temp. deg F	O2 % Vol.	Nitrogen content of coal	Coal feed rate Klb/hr	Limestone feed rate Klb/hr	Ca/N weight ratio	Volatile content of coal
P57	16	1467	6.4	0.43	61	0.0	0.0	31.3
P49	118	1642	3.5	1.29	95	1.5	0.4	33.5
SD1	62	1562	3.9	1.53	103	2.3	0.5	31.3
A06	103	1599	4.2	0.94	85	1.2	0.5	28.1
AO3	136	1614	3.5	1.06	107	1.7	0.5	29.0
PS29	120	1500	6.4	1.25	59	1.5	0.7	34.4
PS28	126	1502	6.3	1.32	60	1.7	0.8	34.6
P68A	115	1623	2.9	1.47	54	2.0	0.9	32.9
PS24R1	115	1518	6.4	1.22	60	1.8	0.9	32.6
PS13M1A	179	1633	2.9	1.91	53	2.6	0.9	33.9
PS18	124	1496	6.5	1.27	61	2.0	0.9	32.5
PS15	167	1628	3.8	1.56	110	4.7	1.0	32.1
PS27	103	1483	6.4	1.25	58	1.9	1.0	31.3
P36A	77	1546	3.0	1.31	55	2.0	1.0	32.3
P30	30	1493	5.7	1.03	58	1.7	1.0	31.7
PS25	107	1495	6.4	1.21	57	2.0	1.0	32.3
PS09M1	167	1672	3.2	1.93	105	5.9	1.0	33.4
P07A	128	1624	3.0	1.42	53	2.2	1.1	32.8
M01B	162	1675	3.0	1.23	57	2.1	1.1	32.1
P67A	117	1613	3.0	1.21	55	1.9	1.1	32.5
PS16	158	1632	3.8	1.44	105	4.4	1.1	32.9
P71A	103	1612	2.9	1.23	57	2.1	1.1	32.5
M01A	139	1649	3.0	1.31	56	2.3	1.1	32.6
P32A	154	1610	4.4	1.12	54	1.9	1.1	32.6
PS31	185	1652	3.2	1.63	109	5.9	1.2	32.8
P70A	78	1549	3.0	1.24	55	2.2	1.2	31.6
PS26	113	1465	6.4	1.23	61	2.4	1.2	32.3
P32B	177	1636	4.4	1.12	54	2.0	1.2	32.4
P08A	120	1626	3.0	1.28	55	2.4	1.2	32.2
P69B	135	1664	3.0	1.30	56	2.5	1.2	31.9
P52	46	1523	6.3	1.50	54	2.9	1.3	33.6
P64	44	1430	6.6	1.29	61	2.9	1.3	32.9
PS12R1	168	1650	3.1	1.34	110	5.6	1.3	31.9
P65B	176	1674	3.0	1.38	56	2.9	1.3	32.7
P31	58	1556	3.8	0.84	80	2.6	1.4	33.7
PS32	196	1639	3.8	1.30	108	5.5	1.4	32.0
P50	156	1638	3.5	1.64	94	6.2	1.4	30.8
P58	46	1430	6.6	1.16	63	2.9	1.4	30.8
P06A	152	1642	3.0	1.13	54	2.5	1.5	32.6
P63	76	1473	6.6	1.25	58	3.0	1.5	31.7
M02A	211	1636	3.0	1.32	56	3.1	1.5	30.4
A07	52	1495	5.9	0.93	59	2.3	1.5	28.8
M03A	146	1640	3.1	1.19	52	2.6	1.5	32.6
P39	61	1538	6.0	1.13	58	2.9	1.6	28.8
P20	24	1494	6.2	0.52	64	1.5	1.6	33.3
PS01	156	1647	3.1	1.18	109	5.6	1.6	33.4
PS11A	175	1642	3.1	1.38	52	3.3	1.6	32.0
P62	79	1463	6.3	1.30	58	3.5	1.6	31.9
PS14A	197	1669	2.1	1.52	55	3.9	1.7	32.7
P07B	200	1692	3.2	1.35	54	3.5	1.7	32.9
M05A	175	1643	3.0	1.24	55	3.3	1.7	33.8

Table 6-5. EFFECT OF LIMESTONE FEED ON NOx EMISSIONS

(Page 2 of 2)

Test No.	NOx PPMV @3% O2	Mean Bed Temp. deg F	O2 % Vol.	Nitrogen content of coal	Coal feed rate Klb/hr	Limestone feed rate Klb/hr	Ca/N weight ratio	Volatile content of coal
A04	141	1608	4.2	0.77	86	3.2	1.8	29.5
P66A	138	1658	2.0	1.13	55	3.1	1.8	32.3
C01A	181	1643	3.0	1.21	56	3.4	1.8	32.7
PS33A	187	1646	3.2	1.35	51	3.5	1.8	32.6
P21	58	1520	6.3	1.23	57	3.6	1.8	32.8
PS08	153	1661	3.2	0.99	110	5.7	1.9	32.5
C02A	182	1650	3.0	1.26	55	3.8	2.0	32.9
P55B	199	1659	3.6	1.33	110	8.0	2.0	30.3
M04A	187	1644	3.0	1.26	55	3.8	2.0	33.5
P68B	198	1689	3.1	1.50	54	4.6	2.1	32.9
A08	154	1625	3.4	0.81	100	4.6	2.1	30.6
P55A	138	1532	3.5	1.26	108	7.9	2.1	30.7
A01	146	1606	3.7	0.82	98	4.6	2.1	30.2
P60B	218	1712	2.5	1.24	114	8.4	2.1	32.4
P60A	162	1601	2.5	1.24	112	8.5	2.2	32.8
P61A	220	1670	2.5	1.21	112	8.3	2.2	30.7
P56A	135	1552	2.5	1.22	111	8.3	2.2	27.8
P56B	182	1688	2.5	1.17	112	8.1	2.2	30.1
P67B	220	1708	3.1	1.25	54	4.1	2.2	32.8
P06B	236	1695	3.0	1.15	55	4.0	2.3	31.9
P61B	237	1716	2.5	1.24	113	8.8	2.3	32.6
PS24	81	1498	6.4	0.52	60	2.0	2.3	32.5
P08B	211	1692	3.1	1.26	58	4.7	2.3	31.1
M02B	261	1672	3.0	1.29	56	4.8	2.4	31.0
PS14B	248	1697	2.1	1.71	56	6.4	2.5	32.5
C01B	266	1700	3.2	1.17	58	4.7	2.5	31.6
P71B	203	1694	3.1	1.23	57	4.8	2.5	32.2
PS33B	230	1686	3.0	1.35	52	5.2	2.6	32.1
P70B	228	1689	3.0	1.26	55	5.5	2.8	32.0
P36B	223	1685	3.0	1.31	55	5.8	2.9	32.3
PS11B	241	1690	3.0	1.38	52	6.1	3.0	32.3
AF09B	103	1533	4.2	1.28	51	5.5	3.0	29.7
PS02	153	1643	3.1	0.55	110	5.3	3.2	32.8
M03B	205	1701	3.0	1.17	52	5.4	3.2	32.8
C02B	278	1708	3.1	1.27	56	6.6	3.4	33.0
A05	189	1597	4.3	0.88	85	7.0	3.4	31.7
AF09A	90	1521	4.1	1.27	49	6.0	3.5	30.4
AF07B	100	1515	6.4	1.26	37	4.5	3.5	31.9
A02	208	1627	3.5	0.94	99	9.5	3.6	32.9
AF10	113	1531	4.2	1.15	100	12.0	3.7	29.7
AF08B	91	1508	6.3	1.19	36	4.4	3.7	30.6
M05B	301	1698	3.1	1.24	55	7.2	3.8	33.3
PS17	121	1506	6.3	0.35	63	2.4	4.0	31.6
AF08A	82	1460	6.2	1.18	37	5.1	4.0	30.1
AF07A	107	1448	6.5	1.24	38	5.5	4.2	30.5
P66B	213	1711	2.0	1.11	55	7.6	4.5	32.0
PS10	214	1629	3.1	0.55	115	7.9	4.6	32.4

Figure 6-10. Effect of Ca/N Ratio on NOx Emissions

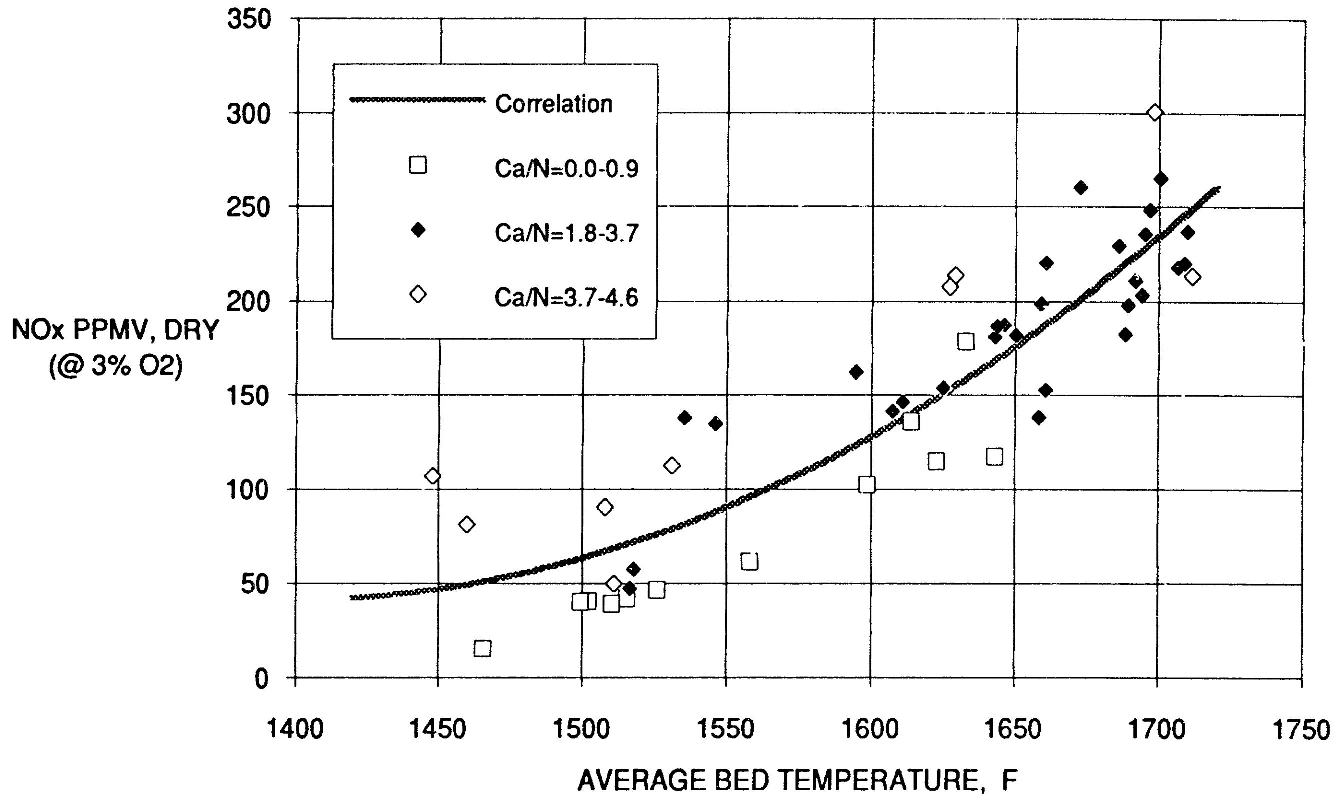


Figure 6-11. NOx Emissions by Fuel Type

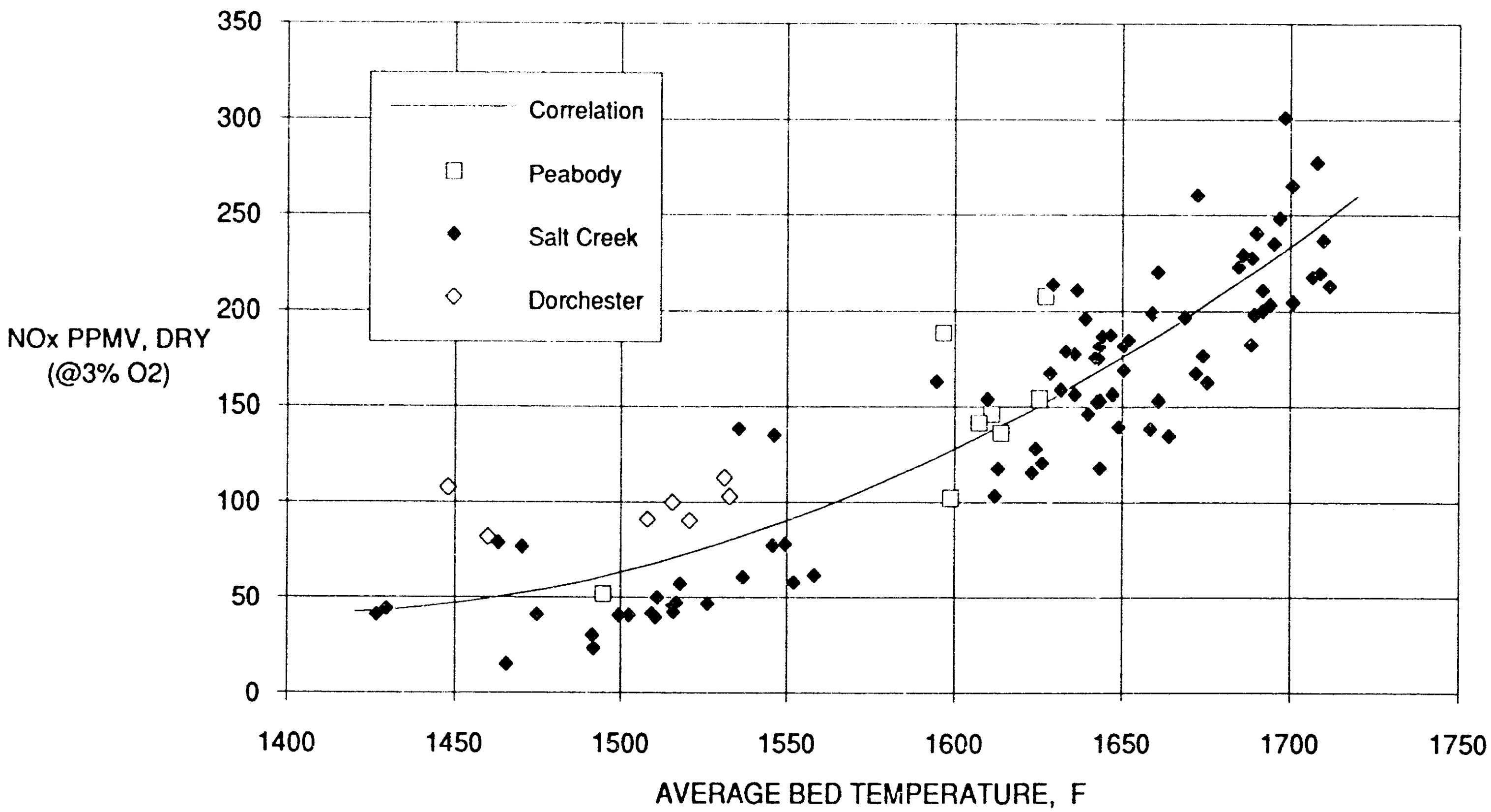


Figure 6-12. Effect of Coal Feed Configuration on NOx Emissions

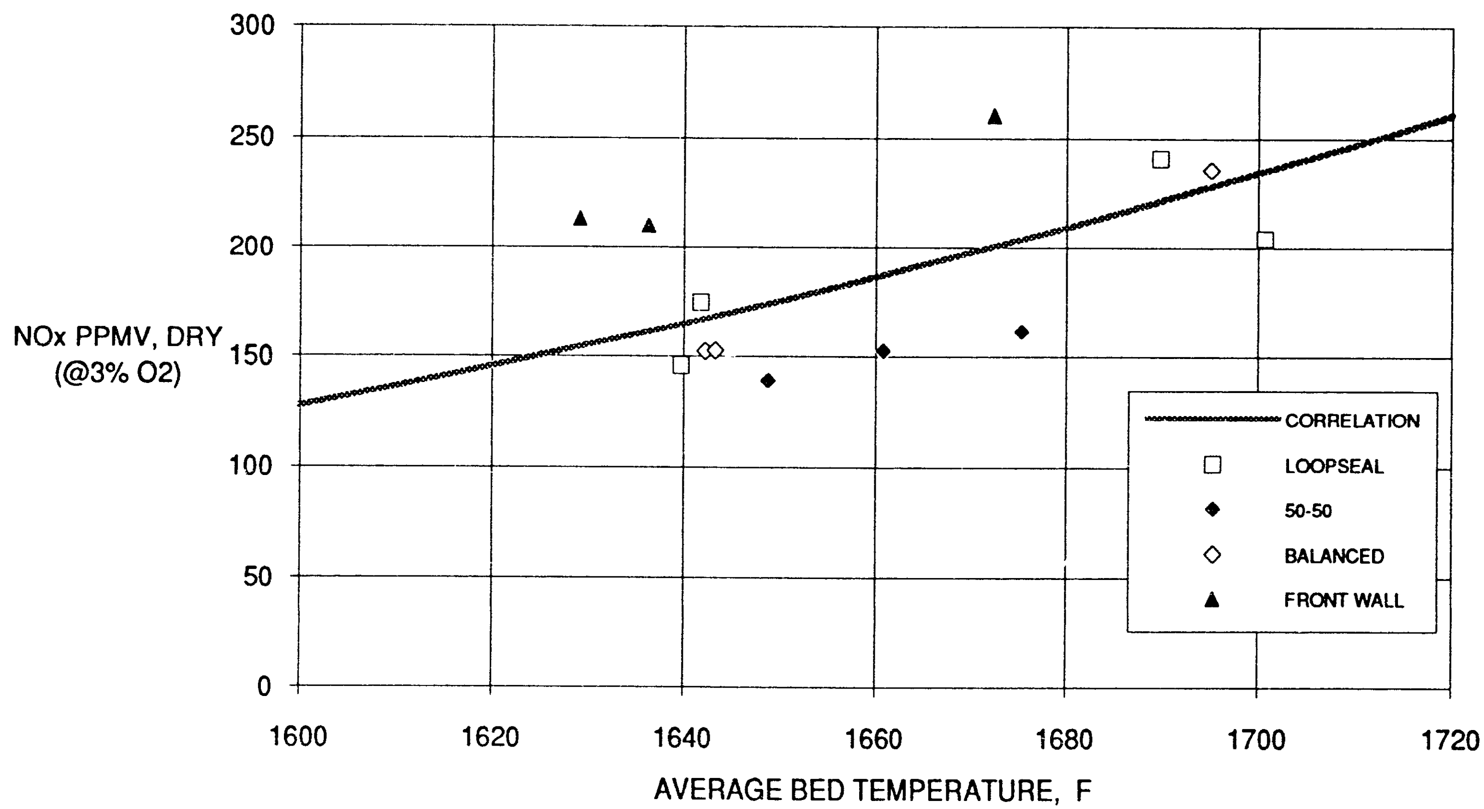
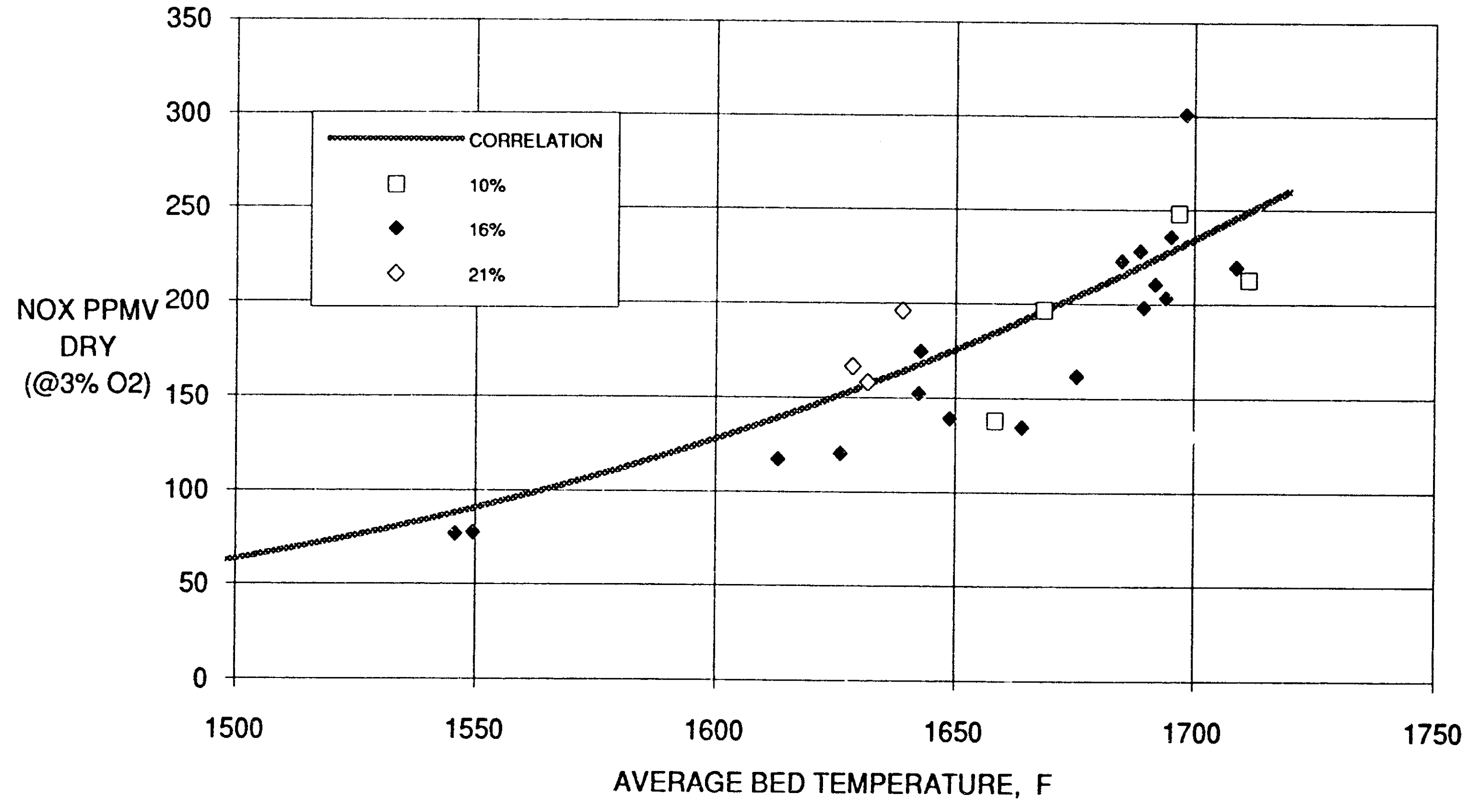


Figure 6-13. Effect of Excess Air on NOx Emissions



Limestone feed configuration, SA/PA ratio, and CO concentration were found to have no measurable effect on NO_x emissions over the range of testing that was conducted at Nucla. In addition, other than the effect due to increased temperature with increasing load, no effect of load on NO_x emissions was found.

6.1.3 Carbon Monoxide Emissions

Figure 6-14 is a plot of CO emissions, corrected to 3 percent O_2 in the dry flue gas, against mean bed temperature for all test runs completed during the Phase I and Phase II test programs. It can be seen that, in general, CO emissions decrease as mean bed temperature increases. A second order polynomial was used to curve-fit the data points. The equation for the correlation is:

$$[CO] = 2542 - 2.858 * T + 8.253E\text{-}4 * T^2$$

where

[CO] = CO concentration corrected to 3% O_2, ppmv
T = Mean bed temperature, °F

Figure 6-15 is a plot showing the CO emissions performance during operation of the boiler on the three different fuels used at Nucla. It can be seen that the use of Peabody coal leads to emissions of CO that are consistently at or below the correlated values, while nearly all CO emission values for tests run on Dorchester coal fell above the correlation curve.

The effect of coal feed configuration on CO emissions on Salt Creek coal at full load is shown in Figure 6-16. This figure shows that, as was the case with NO_x, emissions of CO drop when the front wall only coal feed configuration is used. No effect was seen at lower loads.

The effect of excess air on CO emissions was investigated at full load on Salt Creek coal. The results are shown in Figure 6-17. Excess air appears to have a slight impact on CO, however, the difference is within the uncertainty band of the measurements. It should be noted, however, that the highest CO emission shown in Figure 6-17 corresponds to the lowest value of excess air for any test run, 10.1%. This suggests that when excess air is reduced to low values, CO emissions begin to increase.

As with Ca/S requirements and emissions, SA/PA ratio had no influence on CO emissions over the range tested.

6.2 COMBUSTION EFFICIENCY

In this section, combustion efficiency is discussed from 68 performance tests for which this parameter was calculated. The values obtained for combustion efficiency range from 96.9% to

Figure 6-14. Effect of Bed Temperature on CO Emissions

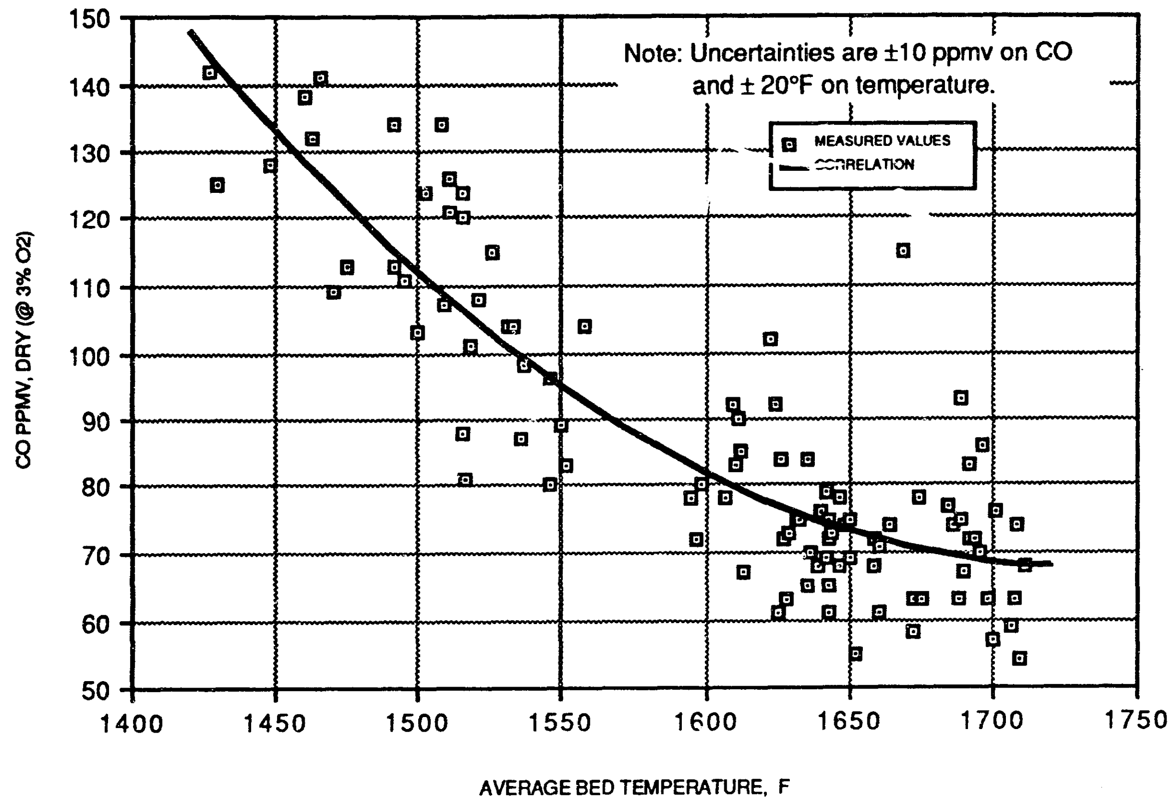


Figure 6-15. CO Emissions by Fuel Type

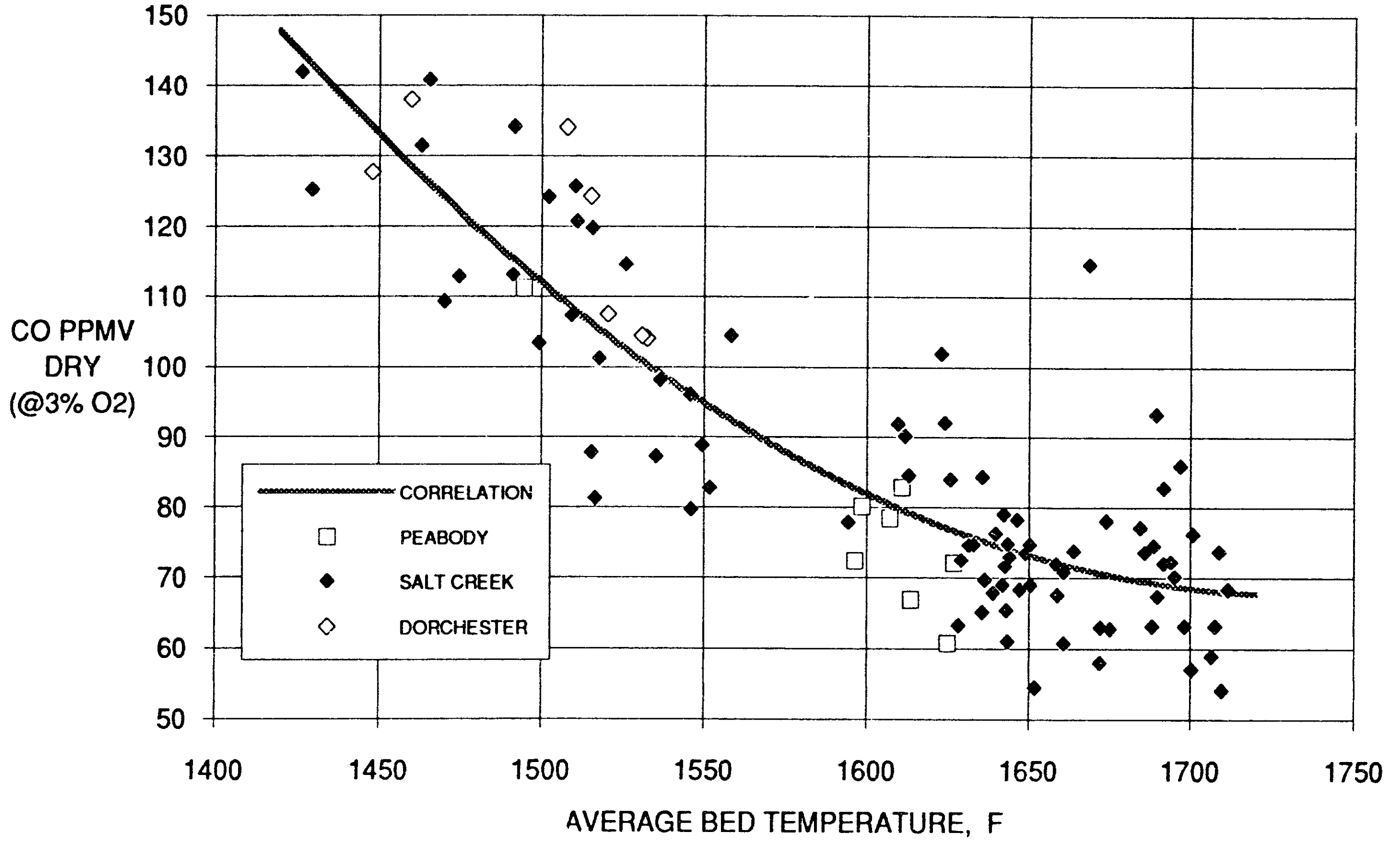


Figure 6-16. Effect of Coal Feed Configuration on CO Emissions

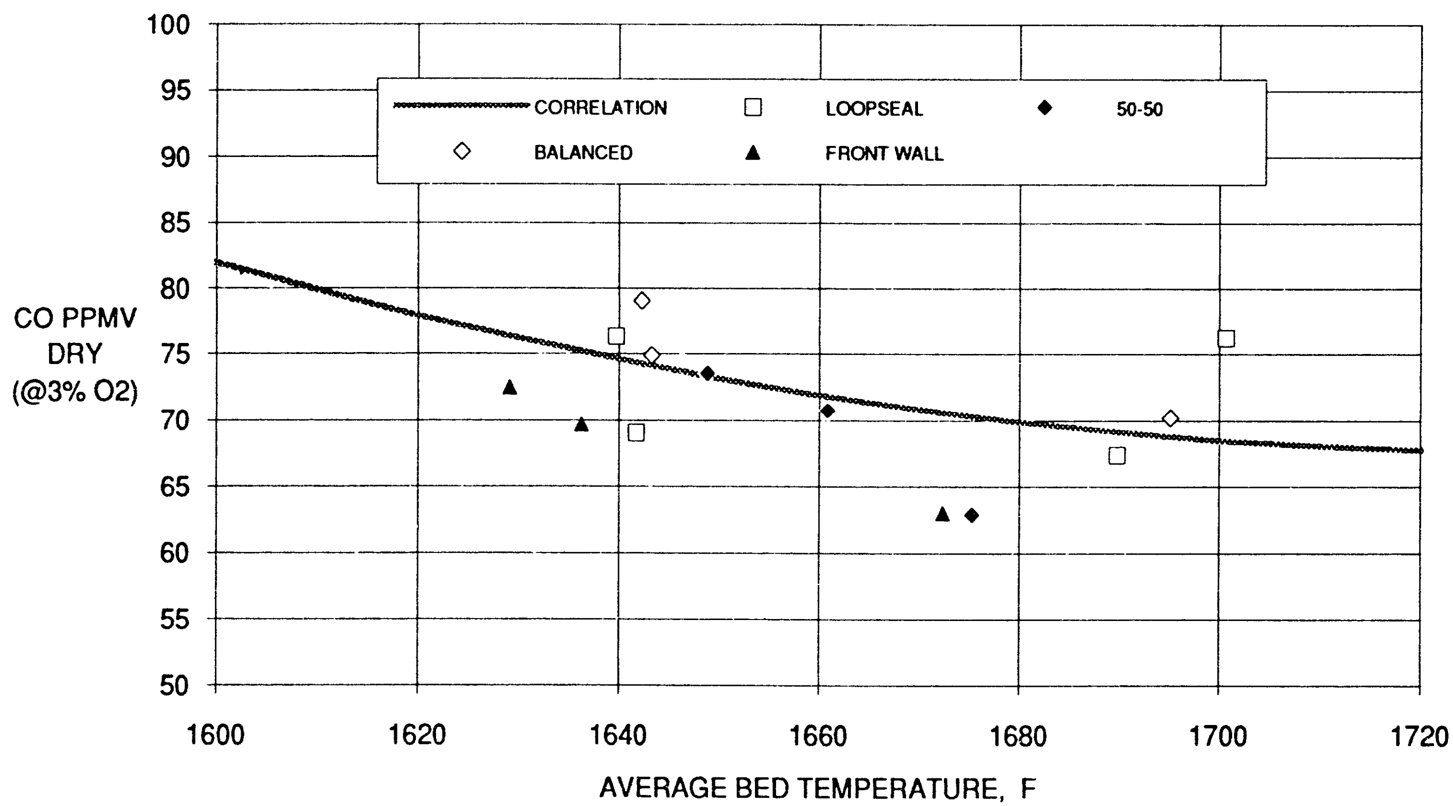
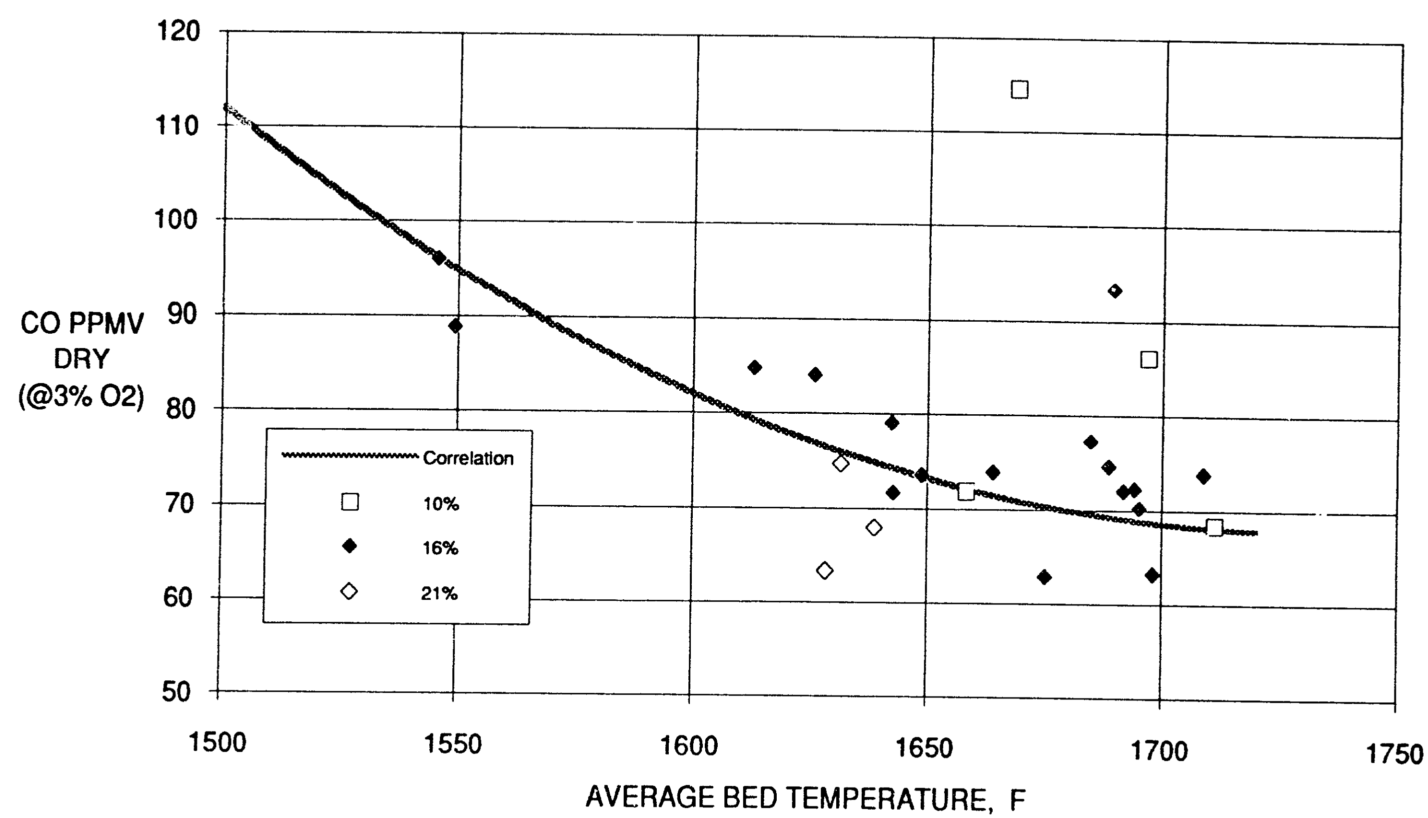


Figure 6-17. Effect of Excess Air on CO Emissions



98.9%. Combustion data are summarized in Table 6-6. No significant differences between the Salt Creek and Peabody coals were found, and no single process parameter (e.g., bed temperature, SA/PA ratio, coal feeder configuration, etc.) appeared to affect the results over the full range of operating conditions.

Combustion efficiency is a measure of the quantity of carbon that leaves the boiler before being fully oxidized to CO_2. There are four sources of incompletely burned carbon:

- Carbon in the fly ash
- Carbon in the bottom ash
- Carbon monoxide in the flue gas
- Hydrocarbons in the flue gas

Carbon in the fly ash is the largest source of heat loss from incomplete combustion of carbon at Nucla. For tests conducted to date, this stream averaged about 93% of the incompletely burned carbon leaving the boiler. Another 5% is contained in the bottom ash stream. In addition to having a lower carbon content, the flow rate of bottom ash averages only 15% of the fly ash flow rate. The contribution from carbon monoxide in the flue gas averages 2%. Hydrocarbons in the flue gas were measured during one full load baseline test and were found to be negligible.

Figure 6-18 shows that combustion efficiencies for Dorchester and Peabody coals are generally less than for Salt Creek coal when bed temperatures are below 1550 °F. Above 1550 °F, combustion efficiencies for tests run on Peabody coal fall in the middle of the range of the Salt Creek coal tests. It can also be seen that while bed temperatures do not seem to correlate well to combustion efficiency at higher temperatures, for tests run on Salt Creek coal, it does correlate rather well below 1550 °F. Further discussion of this behavior can be found in Section 6.3 of this report. Section 6.3 is devoted to boiler efficiency, and the behavior of unburned carbon loss (which is essentially the complement of combustion efficiency) is covered there in more detail.

6.3 BOILER EFFICIENCY

In this section, the results of the analysis of boiler gross efficiency by the losses method are presented for 68 performance tests for which this parameter was calculated. Efficiencies for these tests vary from 85.6% to 88.6%. This range (3.0%) is significant relative to the uncertainty band of ± 0.3% that has been calculated for these values because it represents 10% of the total.

Tables 6-7, 6-8 and 6-9 show the averages and ranges of values for the various contributions to heat loss calculated for the tests run on Peabody, Salt Creek, and Dorchester coals, respectively.

Table 6-6. COMBUSTION EFFICIENCY AND RELATED PARAMETERS FOR ALL TESTS

(Page 1 of 2)

TEST	COMBUSTION EFFICIENCY %	ABSOLUTE UNCERTAINTY (+/-)	UNIT LOAD MW	EXCESS AIR %	AVG BED TEMP DEG F	AVG WINDBOX PRESSURE IN WG	FLYASH/ BOTTOM ASH RATIO	FLYASH CARBON %	BOTTOM ASH CARBON %	FLUE GAS CO PPMV
SD1	98.1	0.2	105	23	1558	44	4.9	7.5	1.0	99
P30	98.7	0.2	55	36	1491	32	3.1	6.1	1.0	96
P31	98.6	0.1	82	22	1552	37	4.5	6.5	0.8	79
A01	97.6	0.2	105	21	1611	45	4.6	10.6	2.5	80
A07	97.6	0.2	55	39	1495	33	1.7	8.3	2.2	93
A04	98.3	0.3	82	25	1607	42	3.7	5.7	1.4	73
A05	97.9	0.2	82	25	1597	42	4.6	5.9	1.5	67
A06	97.9	0.1	83	24	1599	42	3.2	7.6	1.1	75
A02	98.0	0.1	104	19	1627	45	9.8	6.9	1.3	70
A03	97.8	0.1	104	20	1614	45	3.1	8.6	1.8	65
A08	97.7	0.2	104	19	1625	44	5.0	8.8	1.7	59
P49	98.6	0.1	98	20	1643	44	36.0	6.0	0.4	59
P50	98.7	0.1	98	20	1636	45	15.6	5.6	0.7	63
P39	98.8	0.1	55	39	1537	39	2.4	5.2	1.4	82
P21	98.7	0.1	55	42	1518	38	3.6	5.1	2.1	83
P52	98.9	0.1	55	42	1516	37	2.7	5.2	2.1	72
P55	98.2	0.2	108	20	1598	48	4.9	6.6	1.2	75
P56	97.9	0.2	108	13	1619	50	6.2	7.3	1.4	74
P20	98.5	0.1	55	40	1492	47	2.5	4.8	0.7	111
P57	98.3	0.2	55	42	1466	43	3.8	5.8	2.8	115
P58	98.1	0.1	55	46	1427	48	3.4	6.2	1.5	113
P60	97.9	0.2	109	13	1653	54	7.4	6.9	1.1	71
P61	98.0	0.2	109	13	1686	49	7.8	6.3	1.4	59
P62	98.5	0.1	56	45	1463	45	4.0	5.8	1.3	105
P63	98.5	0.2	56	45	1470	48	2.6	5.6	2.0	87
P64	97.9	0.2	56	45	1430	43	2.1	8.8	2.3	100
M01	97.7	0.1	111	16	1664	49	5.7	7.9	1.5	69
M02	97.8	0.3	111	16	1654	49	7.4	7.9	1.9	67
P06	97.4	0.3	110	16	1669	50	10.9	9.1	1.1	75
M03	97.3	1.0	110	17	1671	50	10.3	9.4	1.9	76
P66	97.5	0.1	111	10	1686	49	6.5	8.6	1.5	74
P32	97.5	0.3	111	26	1622	50	10.1	10.3	1.6	81
P67	97.9	0.2	111	16	1661	54	13.5	4.7	1.2	79
P68	97.1	0.4	111	16	1656	56	8.9	10.6	1.6	98

Table 6-6. COMBUSTION EFFICIENCY AND RELATED PARAMETERS FOR ALL TESTS

(Page 2 of 2)

TEST	COMBUSTION EFFICIENCY %	ABSOLUTE UNCERTAINTY (+/-)	UNIT LOAD MW	EXCESS AIR %	AVG BED TEMP DEGF	AVG WINDBOX PRESSURE IN WG	FLYASH/ BOTTOM ASH RATIO	FLYASH CARBON %	BOTTOM ASH CARBON %	FLUE GAS CO PPMV
P07	97.3	0.4	111	17	1657	55	11.4	9.8	1.2	87
P08	96.9	0.5	111	16	1660	54	5.1	10.1	1.4	78
P36	97.2	0.6	110	17	1615	57	10.0	8.6	1.1	87
P70	97.6	0.3	110	16	1622	52	6.5	7.4	1.7	83
P71	97.3	0.4	111	16	1654	52	10.4	7.9	1.1	81
C01	98.0	0.3	110	17	1672	50	13.8	5.7	0.9	61
C02	98.1	0.2	110	17	1679	50	13.5	6.1	0.9	68
M05	98.3	0.2	110	17	1670	50	14.3	5.4	0.6	68
PS17	98.5	0.1	56	42	1506	42	2.9	8.4	0.7	98
PS24	98.5	0.1	56	43	1498	41	3.9	5.5	1.0	66
PS18	98.4	0.3	56	44	1496	42	2.3	5.5	2.5	100
PS26	98.2	0.1	55	43	1465	42	4.1	6.0	1.3	91
PS25	98.8	0.2	55	43	1495	42	1.9	4.7	1.4	87
PS27	98.6	0.1	55	43	1483	41	2.4	4.8	1.6	84
PS24R1	98.5	0.1	56	42	1518	42	4.9	5.0	1.1	93
PS28	98.5	0.1	56	42	1502	41	3.3	5.5	1.1	102
PS29	98.6	0.1	56	43	1500	42	3.1	5.6	1.5	97
PS01	98.0	0.2	110	17	1647	50	13.6	7.1	1.4	68
PS08	97.9	0.2	110	17	1661	50	6.7	7.2	1.0	70
PS10	98.0	0.1	110	17	1629	51	6.6	6.2	1.1	72
PS12R1	98.1	0.1	111	17	1650	50	9.6	6.6	1.2	69
PS02	97.8	0.2	111	17	1643	51	8.8	7.5	1.1	75
PS09M1	98.2	0.1	110	17	1672	50	14.2	6.9	1.1	57
PS31	98.0	0.2	111	18	1652	50	8.8	6.9	1.1	54
PS14	98.1	0.1	109	11	1683	51	7.8	5.9	0.9	105
PS15	98.2	0.1	109	22	1628	51	11.6	5.7	1.0	60
PS16	98.1	0.2	109	22	1632	53	25.2	7.0	0.9	71
PS32	98.3	0.2	109	21	1639	46	9.4	6.1	1.1	65
PS11	98.0	0.2	110	17	1667	50	14.4	6.4	0.7	68
PS33	97.8	0.2	110	17	1666	51	11.5	7.3	1.1	75
AF07	98.2	0.1	58	43	1445	41	2.9	4.7	0.7	102
AF08	97.8	0.4	58	42	1461	42	2.2	4.2	2.7	111
AF09	97.9	0.1	83	24	1523	47	2.1	5.2	0.8	99
AF10	97.8	0.2	83	25	1519	48	2.0	5.0	0.6	97

Figure 6-18. Temperature vs. Combustion Efficiency

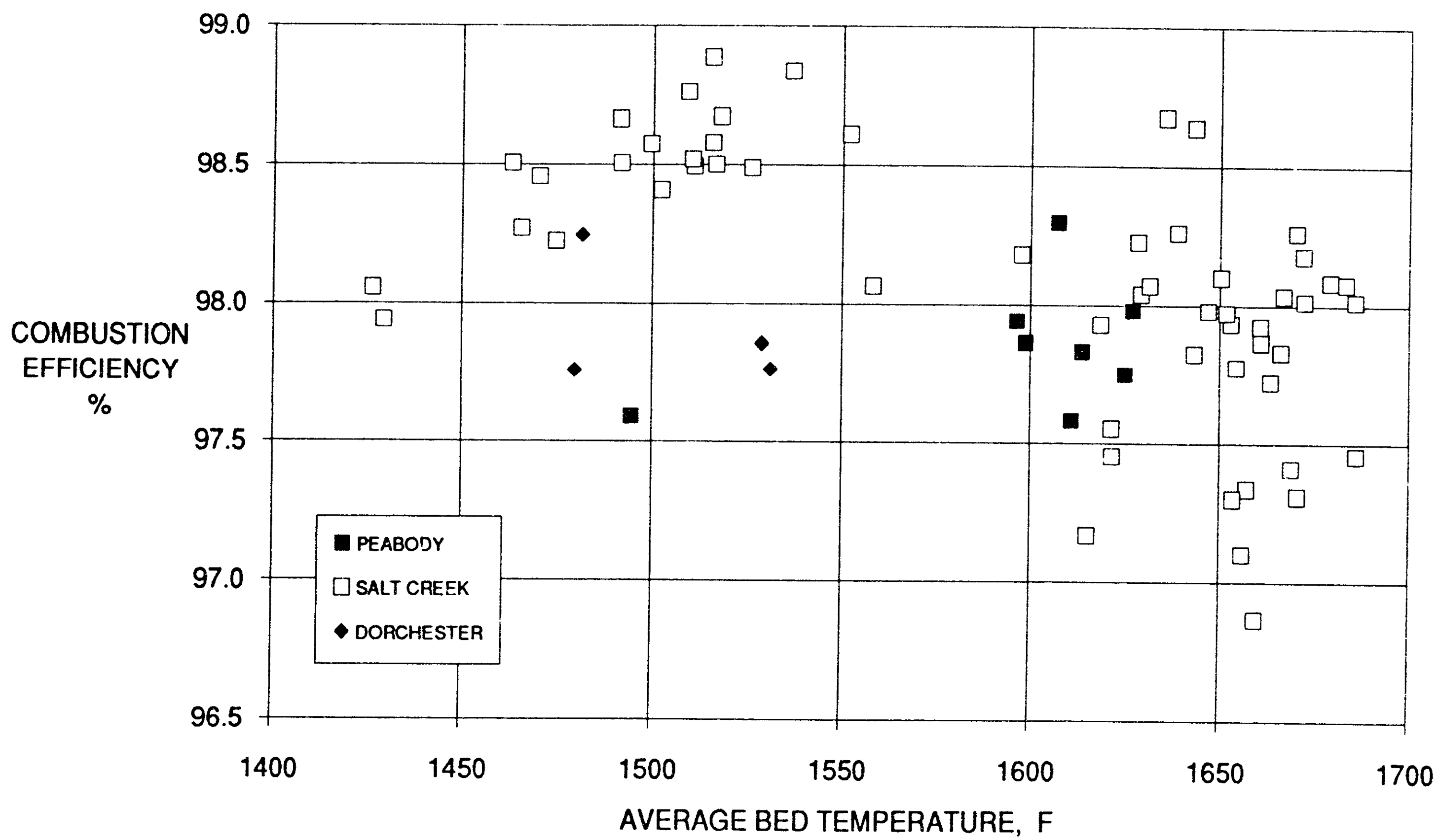


TABLE 6-7

CONTRIBUTIONS TO BOILER HEAT LOSS
PEABODY COAL TESTS
(% OF ENERGY IN)

DESCRIPTION	AVERAGE	MINIMUM	MAXIMUM	RANGE
• UNBURNED CARBON	2.1	1.6	2.3	0.7
• SENSIBLE HEAT IN DRY FLUE GAS	4.7	4.5	4.8	0.4
• FUEL & SORBENT MOISTURE	0.6	0.5	0.7	0.2
• LATENT HEAT IN BURNING HYDROGEN	3.2	2.9	3.3	0.4
• SORBENT CALCINATION	0.3	0.1	0.5	0.5
• RADIATION AND CONVECTION	0.5	0.4	0.8	0.4
• BOTTOM ASH COOLING WATER	0.6	0.5	0.8	0.2
• MISCELLANEOUS*	0.2	0.2	0.2	0.0
• TOTAL	12.2	11.7	12.6	0.9

* Includes heat loss due to CO formation and to sensible heat in the fly ash and bottom ash.

TABLE 6-8

CONTRIBUTIONS TO BOILER HEAT LOSS
SALT CREEK COAL TESTS
(% OF ENERGY IN)

DESCRIPTION	AVERAGE	MINIMUM	MAXIMUM	RANGE
• UNBURNED CARBON	1.9	1.1	3.1	2.0
• SENSIBLE HEAT IN DRY FLUE GAS	4.7	4.0	5.4	1.4
• FUEL & SORBENT MOISTURE	1.0	0.7	1.1	0.3
• LATENT HEAT IN BURNING HYDROGEN	3.4	3.2	3.6	0.4
• SORBENT CALCINATION	0.3	0.0	0.6	0.6
• RADIATION AND CONVECTION	0.6	0.4	0.8	0.4
• BOTTOM ASH COOLING WATER	0.6	0.4	1.2	0.8
• MISCELLANEOUS*	0.2	0.1	0.3	0.1
• TOTAL	12.6	11.4	13.5	2.1

* Includes heat loss due to CO formation and to sensible heat in the fly ash and bottom ash.

TABLE 6-9

CONTRIBUTIONS TO BOILER HEAT LOSS
DORCHESTER COAL TESTS
(% OF ENERGY IN)

DESCRIPTION	AVERAGE	MINIMUM	MAXIMUM	RANGE
• UNBURNED CARBON	2.0	1.6	2.1	0.5
• SENSIBLE HEAT IN DRY FLUE GAS	4.5	4.3	4.8	0.5
• FUEL & SORBENT MOISTURE	1.3	1.1	1.4	0.3
• LATENT HEAT IN BURNING HYDROGEN	3.4	3.3	3.4	0.1
• SORBENT CALCINATION	0.8	0.8	0.9	0.1
• RADIATION AND CONVECTION	0.6	0.5	0.7	0.2
• BOTTOM ASH COOLING WATER	0.8	0.7	0.9	0.2
• MISCELLANEOUS*	0.2	0.2	0.2	0.0
• TOTAL	13.7	13.4	14.4	1.0

* Includes heat loss due to CO formation and to sensible heat in the fly ash and bottom ash.

These tables show that tests run on Peabody coal had the highest average efficiency (87.8%), efficiencies for Salt Creek coal tests were slightly lower (average of 87.4%), and tests on Dorchester coal averaged significantly lower (86.3%). It can be seen that the primary reason for the higher efficiencies with Peabody coal was the lower losses due to fuel and sorbent moisture. There were two main contributors to the lower Dorchester efficiencies, which were fuel and sorbent moisture and sorbent calcination losses. The Dorchester coal had a higher level of moisture than either of the other two coals, and a much higher sulfur content, resulting in higher limestone feed rates and therefore higher calcination losses.

Sensible heat in the flue gas and burning hydrogen are the largest contributors to the total heat loss from the boiler. However, sensible heat of the dry flue gas and unburned carbon losses have the largest range of values. In addition, these are the only two losses that might be affected by controllable combustion process parameters (e.g., excess air, coal feed configuration, etc.). The other major contributors to boiler heat loss are dependent upon feed stock properties and plant design parameters. Moisture in the feed stocks and burning hydrogen in the coal are properties of the fuel and sorbent. The quantity of energy absorbed by the calcination reaction is dependent entirely upon the calcium flow rate, which is in turn determined by the quantity of sulfur in the coal and the calcium to sulfur ratio for the required SO_2 emission level. The bottom ash cooling water heat loss is controlled by the design of the bottom ash coolers and the temperature of the cooling water entering the control volume. The heat loss due to radiation and convection depends upon the design of the boiler, ambient temperature, and load.

The most useful correlations are therefore those that are tied to analyses of the flue gas and unburned carbon losses. It can be seen that flue gas exit losses (adjusted for air inlet temperature) increase as excess air increases (Figure 6-19).

Unburned carbon loss is shown plotted against freeboard gas velocity in Figure 6-20. In this figure, it appears that this loss stays at a fairly low level to about 16 ft/s, then increases. One possible explanation for this behavior is that the residence time of the burning coal particles is reduced at these higher velocities, such that there is insufficient residence time to completely burn before exiting the cyclone.

Figure 6-21 shows how temperature affects the unburned carbon loss. It can be seen that from about 1430 °F to 1500 °F, this loss goes down steadily with temperature. Above 1550 °F, however, it begins to increase with temperature. Below 1500 °F, increasing operating temperatures result in faster reaction times, leading to a lower loss.

Figure 6-19. Effect of Excess Air on Dry Flue Gas Exit Loss

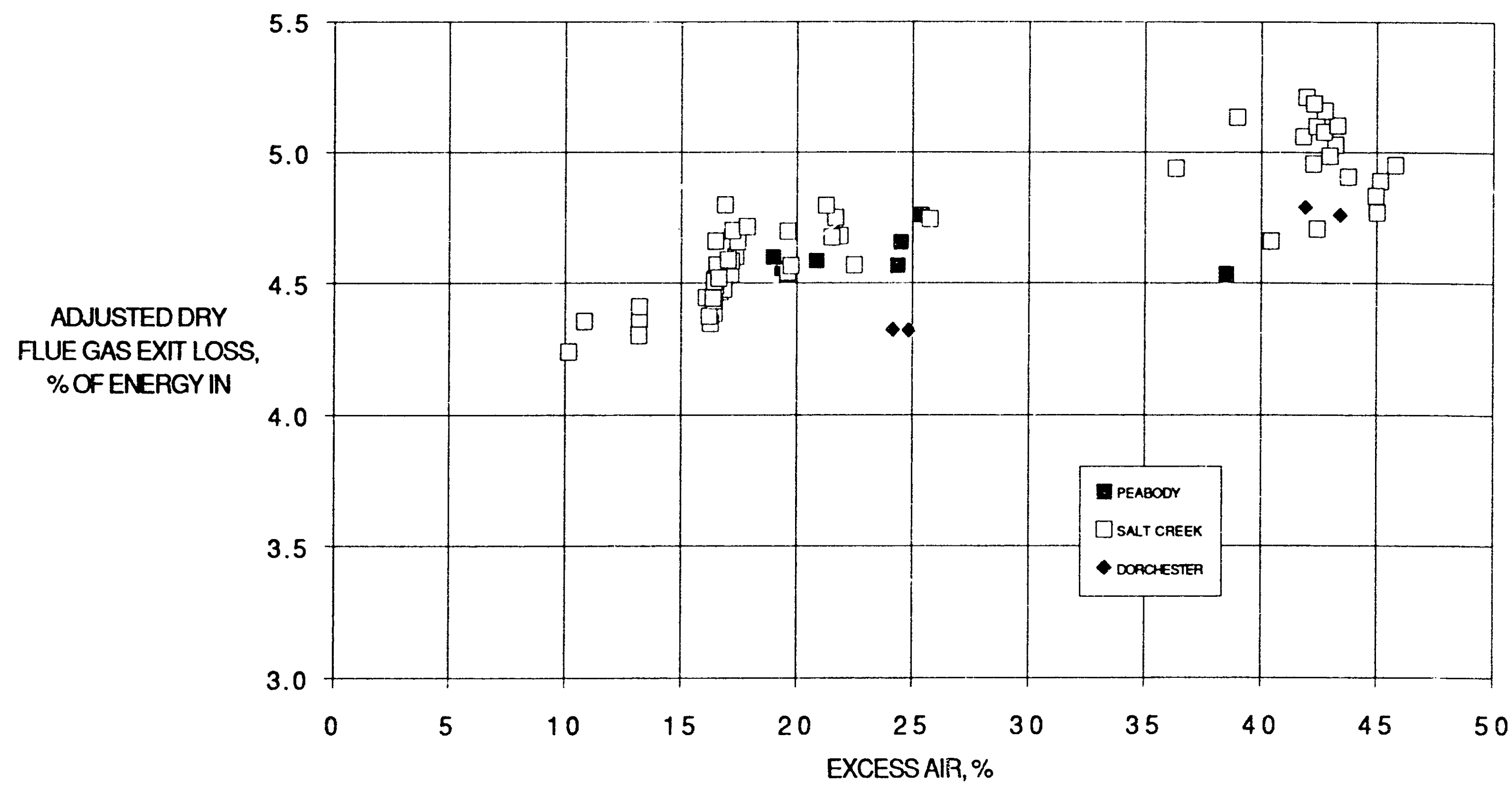


Figure 6-20. Effect of Combustor Gas Velocity on Unburned Carbon Loss

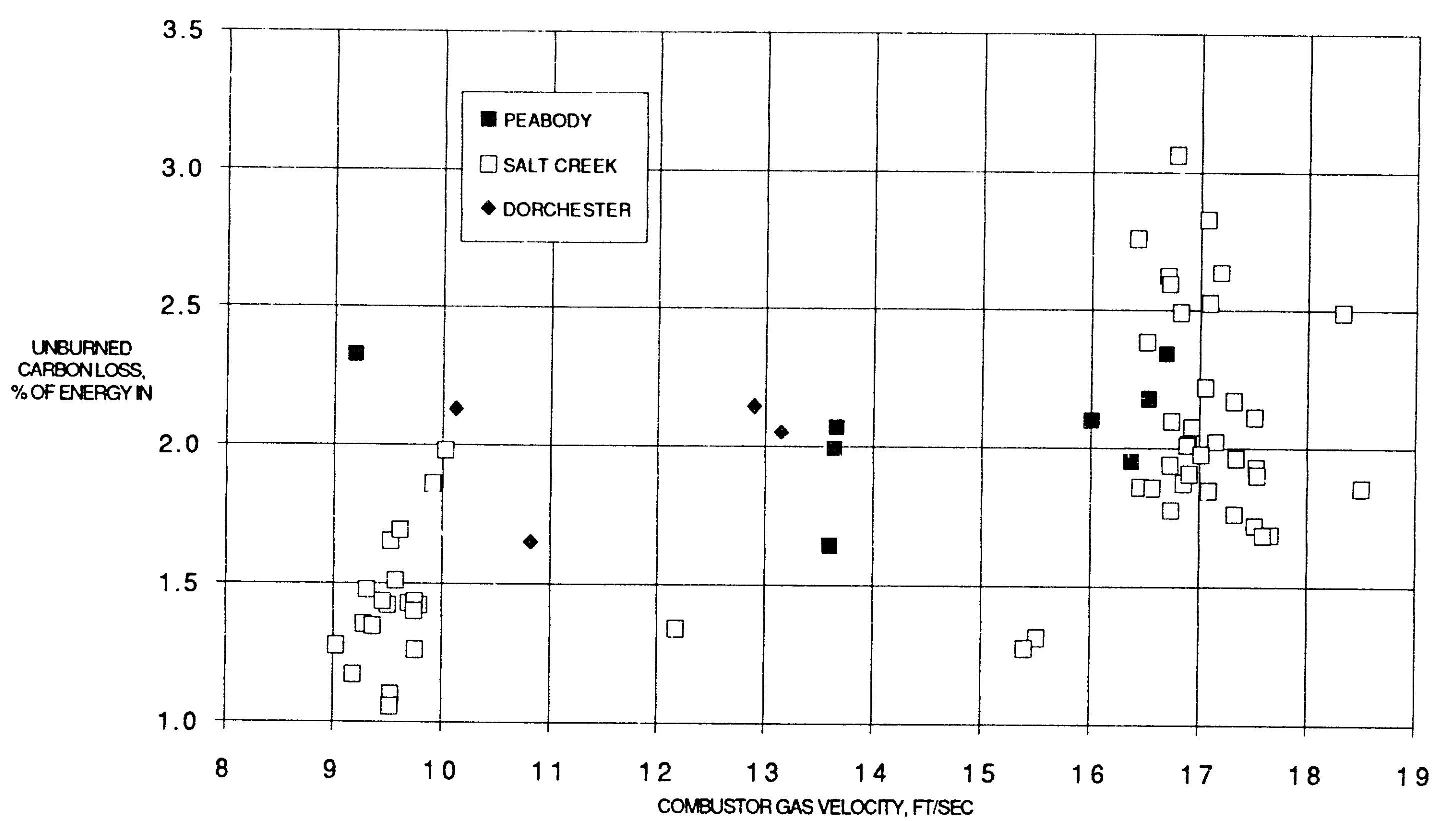
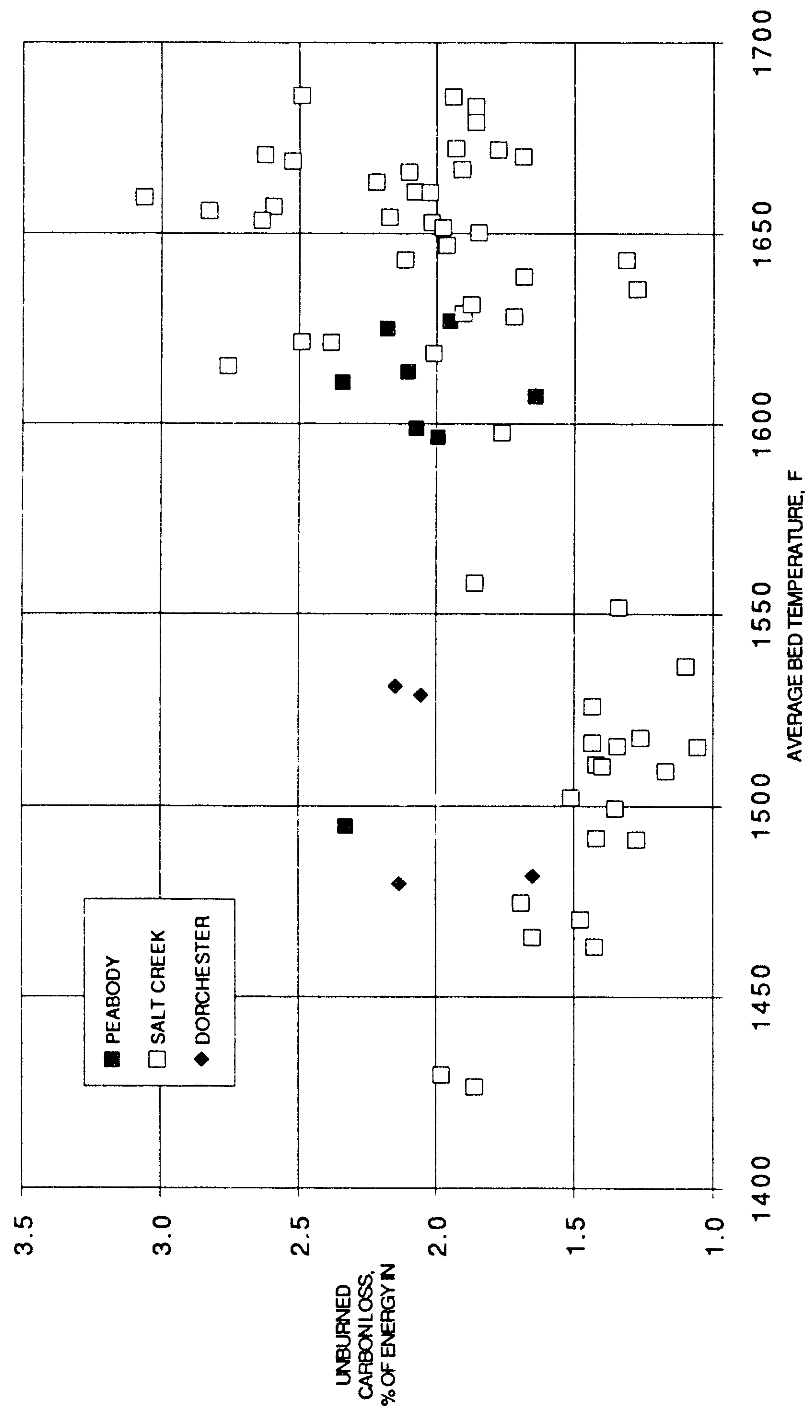


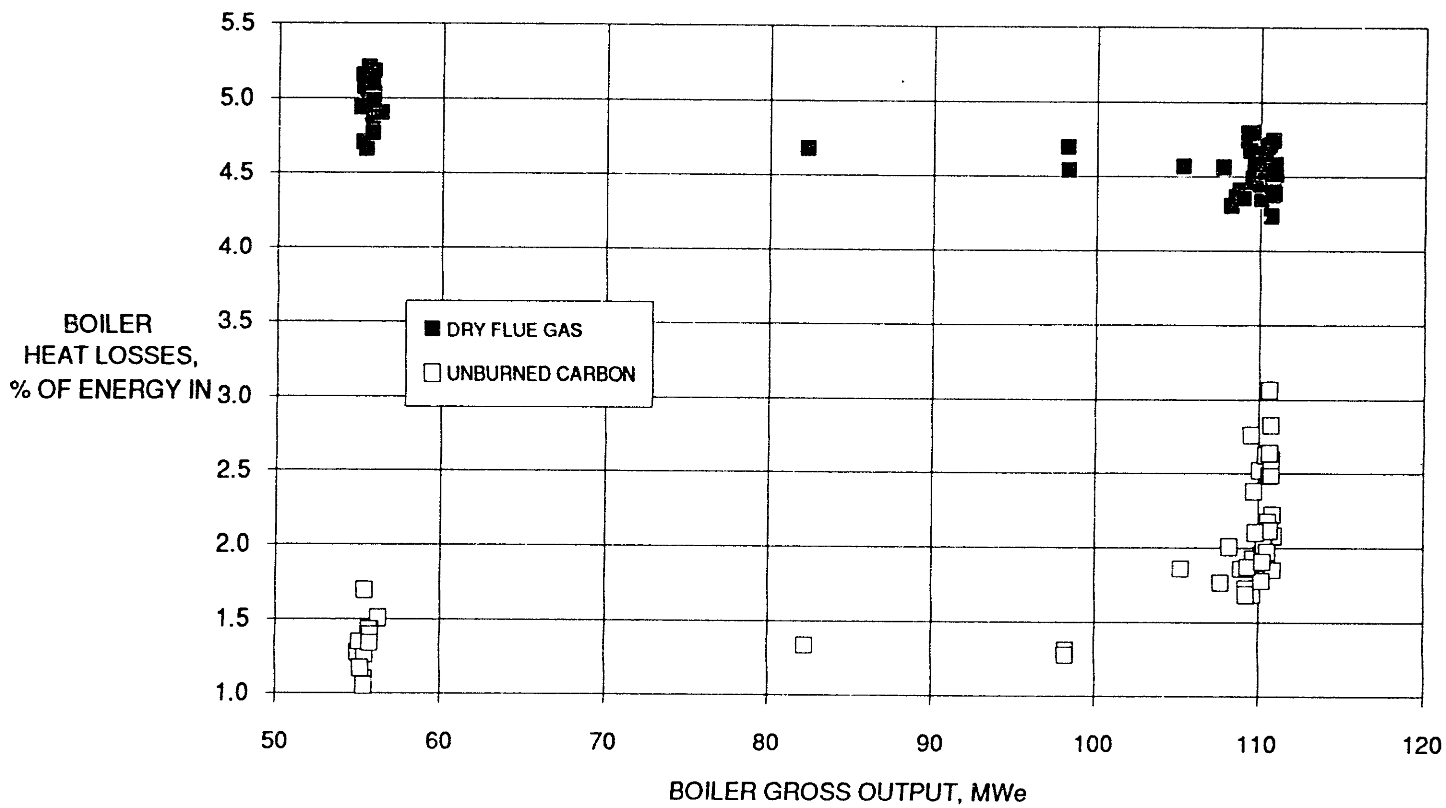
Figure 6-21. Effect of Bed Temperature on Unburned Carbon Loss



At Nucla, the freeboard velocity, temperature, and excess air are all strongly dependent on load. From half load to full load, excess air decreases, while temperature and freeboard velocity increase. It is not possible to vary these parameters independently over a wide range at Nucla. As a result, dry flue gas losses can be seen to go down as load increases, while unburned carbon losses go up. This phenomenon is shown for all Salt Creek coal tests in Figure 6-22. The net result is a cancelling effect such that boiler efficiency at Nucla is independent of load.

Neither coal feed configuration or SA/PA ratio were found to influence dry flue gas or unburned carbon losses. Heat balance summary reports showing the heat loss breakdowns for each of the tests analyzed during the test program can be found in the volume of performance summary reports.

Figure 6-22. Effect of Load on Boiler Heat Losses (All Salt Creek Coal Tests)



Section 7

START-UP, COLD AND HOT RESTART CHARACTERISTICS

This Test Plan investigated the response characteristics of the CFB boiler and its auxiliary systems during start-up and restart after various time periods of unit shutdown. Data from representative cold, hot, and warm restarts were analyzed and are presented below. The annual reports contain additional data for start-ups analyzed during the corresponding reporting period.

7.1 SUMMARY OF RESULTS

Ultimately, it is the plant owner's objective to raise steam conditions and put energy onto the grid as quickly as possible using start-up procedures that maximize safety and equipment life.

Cold start-up times at Nucla are governed by the time required to, 1) achieve 100 °F of superheat prior to turbine roll without exceeding the manufacturer's recommended drum metal temperature ramp rates of 100 °F/h, 2) heat soak the turbine prior to generator synchronization, and 3) synchronize the generator and raise unit load. The data suggests that drum metal temperature rates are more critical in the first five to six hours of start-up than bulk refractory temperatures, which also have a manufacturer's recommended limit of 100 °F/h. However, refractory components located near the surface of hot solids and gas streams, which have been prone to pinch spalling and failure near the surface, may have temperature rates which exceed the 100 °F/h criteria. The ability of refractory materials to perform in a cycling environment with an economical life expectancy is the best test of this CFB component.

Warm and hot restart times are governed by how quickly, 1) plant operators can isolate the turbine and maintain steam conditions during the shutdown and, 2) fans can be isolated to preserve bed temperature. Gas firing durations during restarts will be determined by the time required to reestablish 100 °F superheat temperatures or by the time to reestablish 950 °F bed temperatures necessary for the initiation of coal feed. Changes to boiler purge methodologies may reduce the impact of the latter on restart times.

7.2 OBJECTIVES AND APPROACH

The following objectives were defined in the Detailed Test Plan and are addressed in this section:

- Times to full power operation, starting from cold conditions and from various intervals of unit downtime.
- The component of the boiler system that limits the rate at which it can be restarted.
- Characteristics of the boiler or its auxiliary components that limit the capability to match the steam turbine conditions.
- Start-up fuel (propane) requirements.
- Potential improvements in the start-up procedures that may lead to operational and economic advantages.

Data were collected for start-ups and restarts after various outage durations during the normal course of unit operation (i.e., restart tests were not pre-planned). Table 7-1 summarizes the start-ups analyzed indicating the date, outage duration, test classification, and other pertinent information including start-up gas requirements. Based on the results of this test plan, a revised start-up procedure was developed and is included in Appendix B.

7.3 COLD START-UPS

Cold start-ups are defined here as those which occur following a shutdown interval during which all boiler components, particularly those made up of refractory, have essentially reached ambient temperature. Following a unit trip, this can be achieved in approximately 48 hours with fans in service to cool the bed and refractory components.

Data from a cold start-up on 10/09/89 are shown in Figures 7-1 through 7-10. This particular start-up is somewhat unique in that the economizer was deliberately emptied prior to gas firing in an effort to reduce drum level instability during the first six hours of gas firing. A detailed discussion of this test is included in the 1990 Annual Report. This did not affect start-up times or procedures and the trend plots shown in Figures 7-1 through 7-10 are representative of a normal cold start-up. The steps involved in a cold start are marked on the figures and are summarized as follows:

1. Fans are started and air flow is initiated through the windbox and air distribution grid. In Figure 7-3, only the air flow and bed temperatures are shown on combustor A since data are similar on combustor B. Following a five minute air purge, the duct burners

Table 7-1. Start-Up and Restart Data Summary

• Date	UNITS	Dec. 4 1989	Sept. 13 1989	Oct. 9 1989
		HOT	WARM	COLD
• Outage Duration	hours	1	8.8	384
• Time without Underbed Air Flow	hours	0.6	7	>300
• Time to Reach 600 psig Drum Pressure	hours	xxx	1	7
• Duration of Gas Firing	hours	3.6	4.5	14.8
• Maximum Rate of Gas Flow	Kscf/hr	145	150	165
• Average Total Gas Flow Rate	Kscf/hr	80	75	70
• Total Propane Consumed	MMscf [MBtu]	0.29 [740]	0.35 [870]	1 [2550]
• Maximum Rate of Change of Drum Metal Temperature **	°F/hr	+60,-85	+70,-185	+130,-30
• Maximum Rate of Change of Cyclone Refractory Temperature **	°F/hr	+15,-50	+35, -60	+65, 0
• Maximum Rate of Change of Turbine Metal Temperature **	°F/hr	+200,-300	+140,-300	+160, 0

** the maximum rate of temperature change is reported for increasing and decreasing temperature changes.

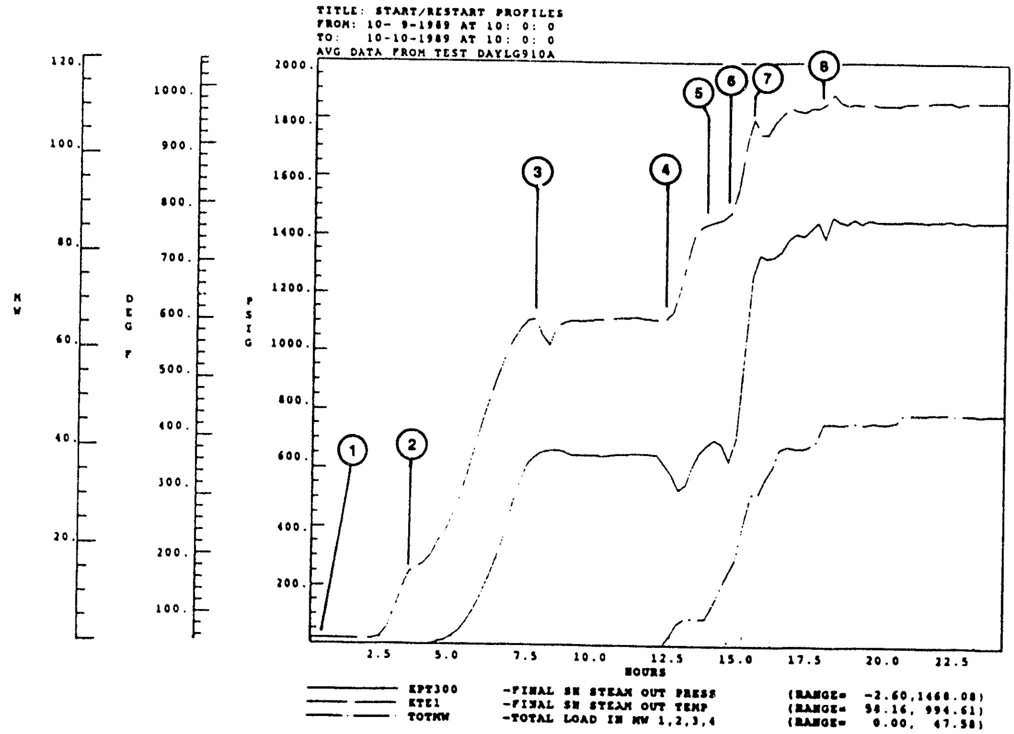


Figure 7-1. Load & Steam Conditions for Cold Start-up.

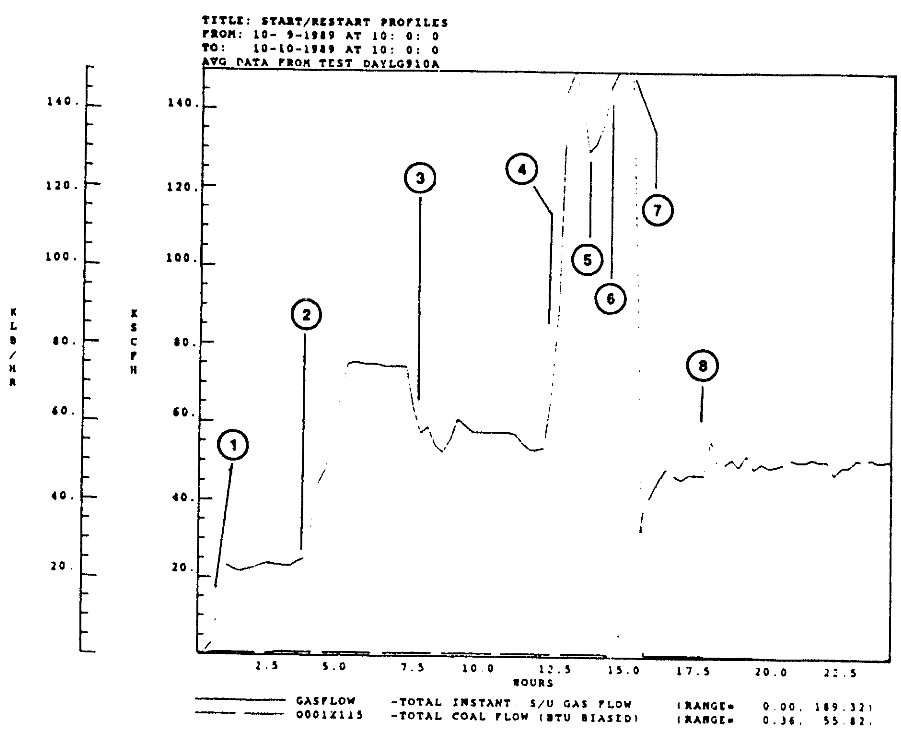


Figure 7-2. Coal and Gas Flow for Cold Start-up.

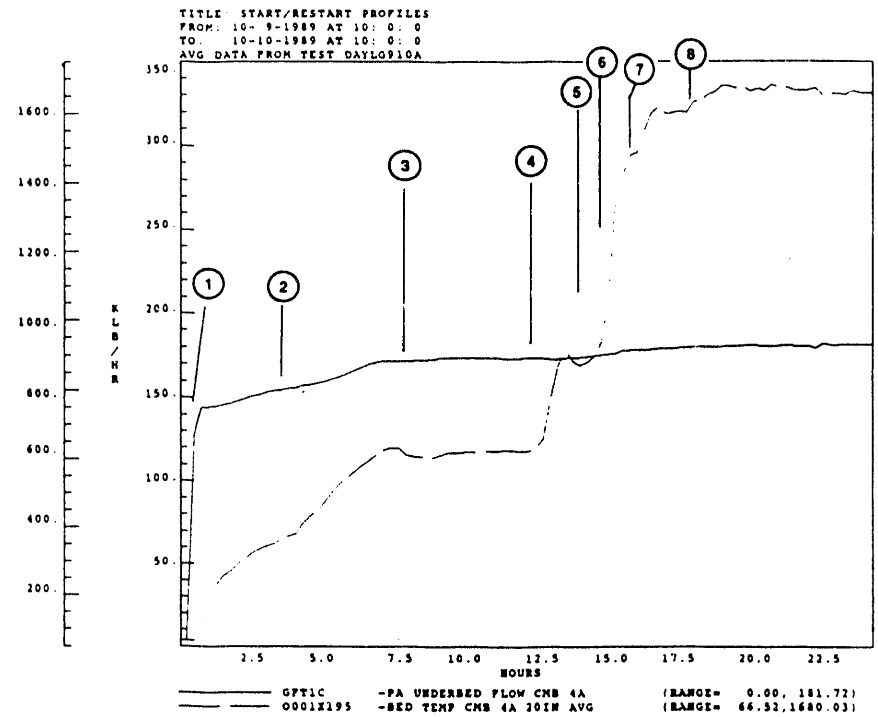


Figure 7-3. Air Flow & Bed Temps. for Cold Start-up.

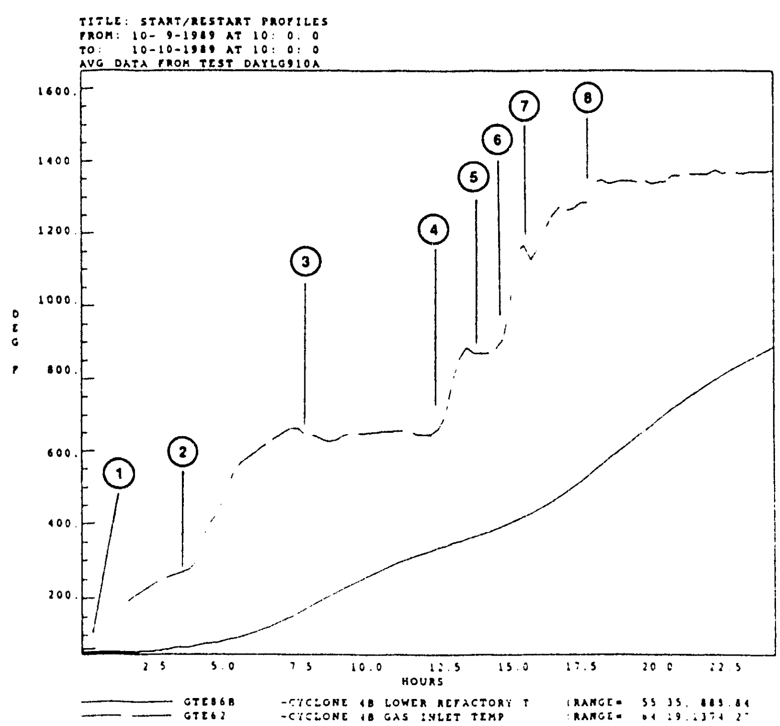


Figure 7-4. Cyclone Refractory Temps. for Cold Start-up.

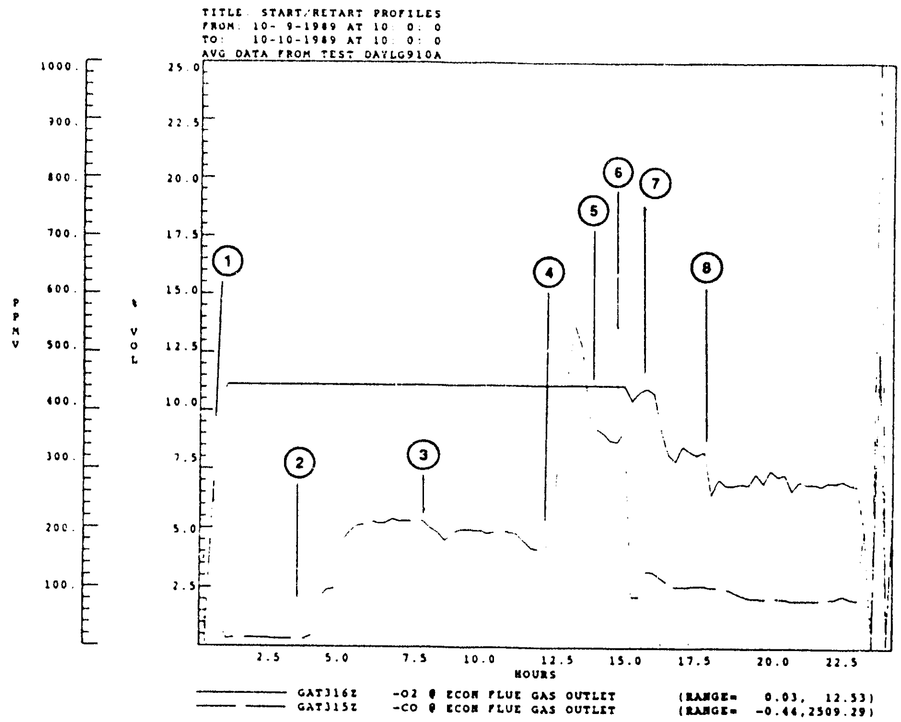


Figure 7-5. O_2 and CO Emissions During Cold Start-up.

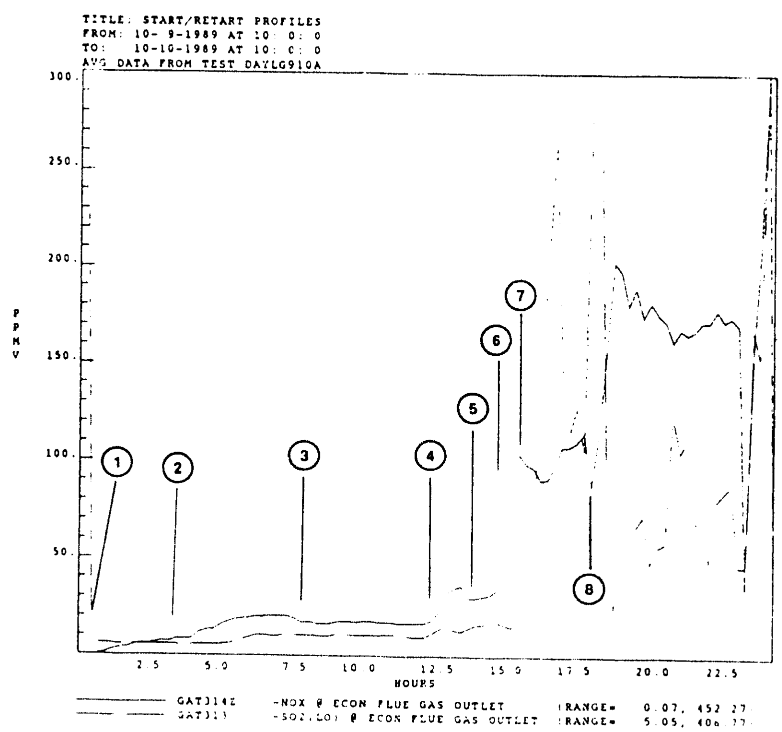


Figure 7-6. NO_X and SO_2 Emissions During Cold Start-up.

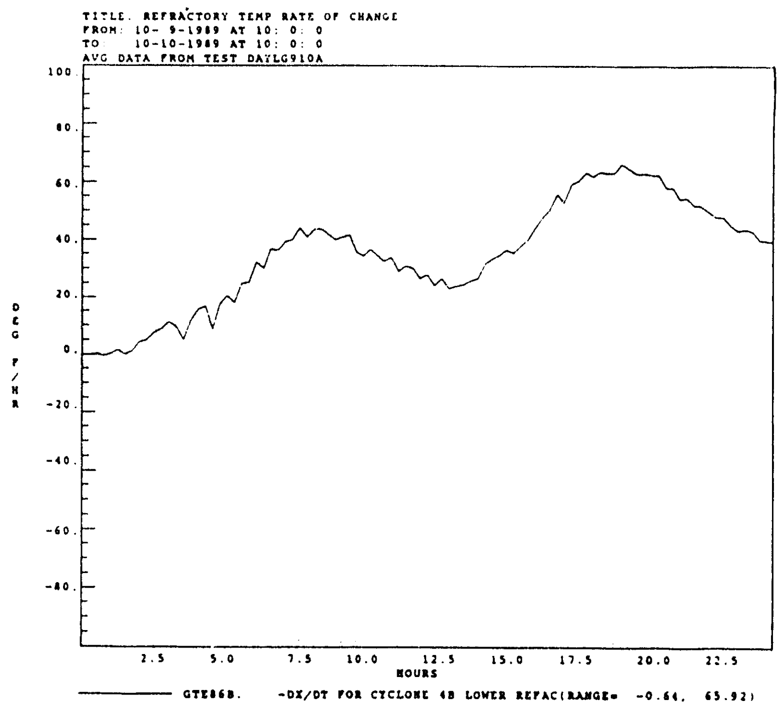


Figure 7-7. $\frac{dx}{dt}$ of Cyclone Refractory - Cold Start-up.

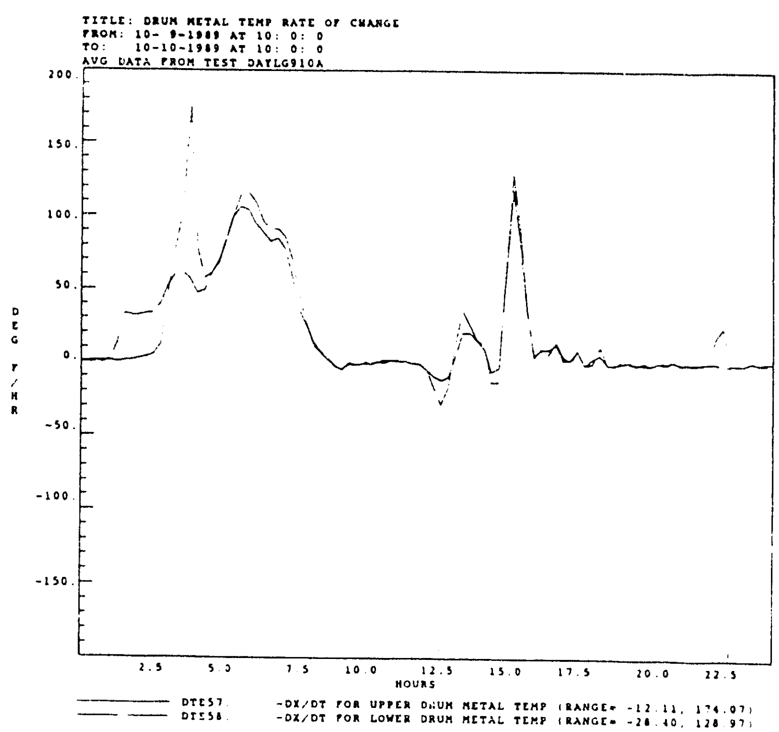


Figure 7-8. $\frac{dx}{dt}$ of Drum Metal Temp. - Cold Start-up.

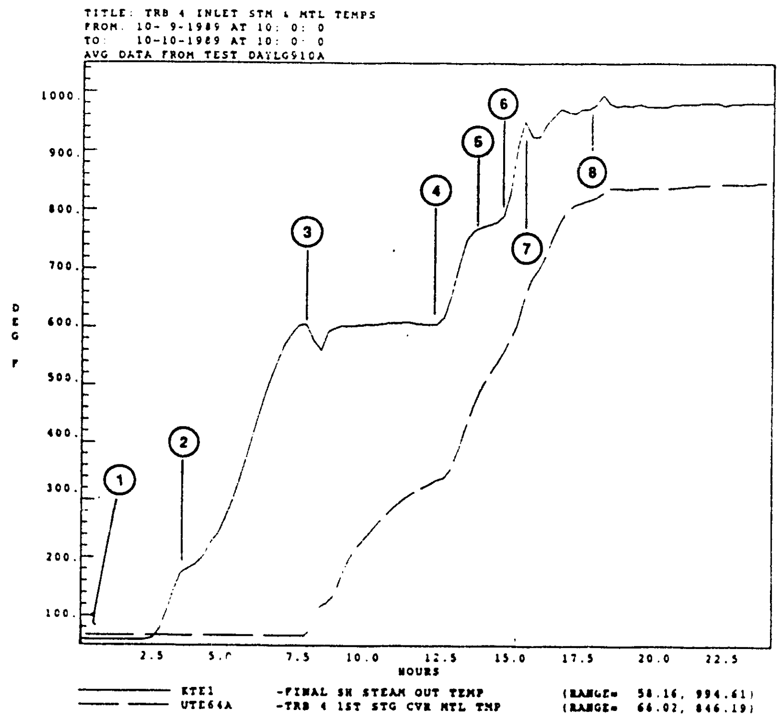


Figure 7-9. Steam & Turbine Metal Temps. - Cold Start-up.

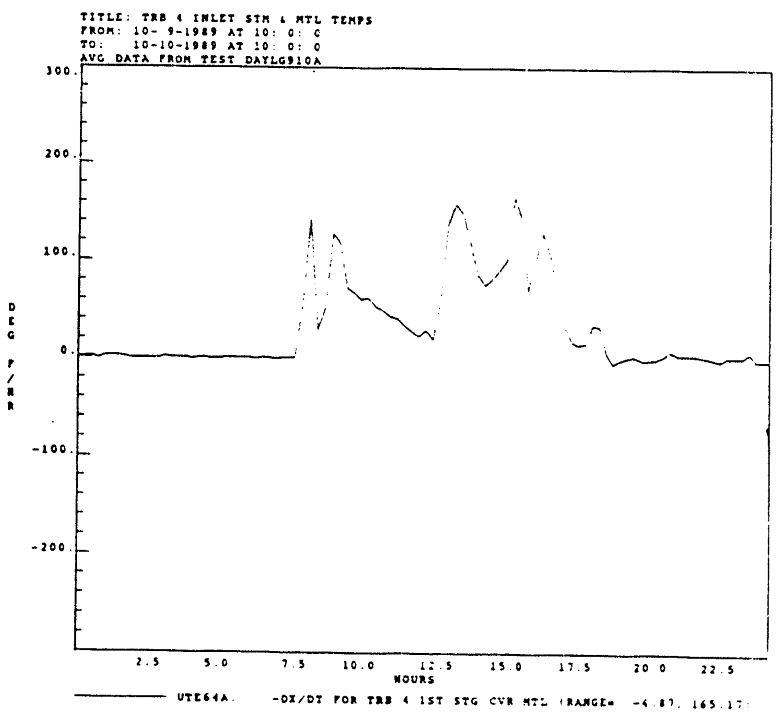


Figure 7-10. $\frac{dx}{dt}$ of Turbine Metal Temps. - Cold Start-up.

(located immediately upstream of the windbox) are started on both combustors. In this example, duct burners are operated for approximately 3 hours until a drum pressure of 25 psig is reached. At this time, all boiler vents and drains are closed except for the main steam lead drains.

2. One in-bed start-up burner is fired in each combustion chamber, raising the total gas flow from approximately 10 to 20 kscfh per combustor. Thirty minutes later, an additional start-up burner is fired in each combustor, bringing the total gas flow to approximately 38 kscfh (per combustor). The propane firing rate during this period is based on drum metal and refractory temperature restrictions of 100 °F/h and control of drum level. At this point, one duct burner and two of the three in-bed start-up burners are in service on each combustion chamber.

3. Turbine roll is initiated once 100 °F of superheat is reached. This occurs at approximately 600 psig and 600 °F steam conditions. Turbine roll lasts for approximately 5 hours in this example, although 3 hours is recommended by the turbine manufacturer as adequate. As seen in Figure 7-2, propane firing rate is reduced to approximately 30 kscfh per combustor during turbine roll.

4. Once the turbine heat soak period is complete, the generator is synchronized and load is increased to 5 MWe gross output and held at this level for one hour to stabilize. A third in-bed start-up burner is placed in service on each combustor and the total propane firing rate is increased.

5. Following stabilization at 5 MWe, propane firing rates are increased to 70 kscfh per combustor and bed temperatures are increased to 950 °F, required for the initiation of coal feed. Gross unit output has increased during this period to approximately 20-25 MWe on propane only.

6. Coal flow is initiated once bed temperatures increase to 950 °F, required for light-off. Load is increased as coal flow is established.

7. Start-up burners are shut off once bed temperatures have reached 1400 °F.

8. Gross unit output is increased to approximately 45 MWe on the new turbine/generator set. Although not shown on the figures, each of the three 12.5 MWe generator sets are then sequentially placed into service and overall load is increased to 110 MWe gross output.

In this example, the time required from initial light-off to turbine roll was 7 hours, turbine roll (heat soak) was approximately 5 hours, synchronization and a stabilization period at 5 MWe takes approximately 2 hours, and the time required to reach 45 MWe was 3 hours. The overall time required to place the generator on-line from cold conditions was 12 hours and the total time to reach 45 MWe was 17 hours.

Figure 7-1 indicates final steam conditions and shows that seven hours were required to reach 100 °F superheat temperatures (step 3) prior to turbine roll. Figure 7-2 shows the propane and coal feed rates during start-up. Figure 7-3 indicates underbed air flow and the increase in bed temperature in combustor A. Data are overlapping for combustor B and have been omitted for clarity. Coal flow is initiated at step 6 once bed temperatures have reached approximately 950 °F.

Figure 7-4 shows the increase in cyclone inlet gas temperature and the corresponding rise in refractory temperature. Refractory temperatures are measured at various locations in cyclone B. Thermocouples are inserted at various depths in the one foot thickness of refractory insulation. The value plotted in Figure 7-4 represents a point in the conical section of the cyclone. Figure 7-7 shows a maximum rate of change of refractory temperature for this measurement of 65 °F/h. The manufacturer's recommended limit is 100 °F/h. Although this thermocouple may not be representative of all temperatures within the cyclone refractory, particularly those facing the hot solids and gases near the refractory surface, it does indicate that bulk temperatures during a cold start-up are not exceeding recommended rate limitations and, therefore, are not imposing a restriction on start-up.

Gaseous emissions data are presented in Figures 7-5 and 7-6. CO emissions are in excess of 500 ppmv during the interval when propane firing rates are high following the completion of the turbine heat soak, and when coal flow is first initiated and bed temperatures have not reached 1250 °F. Above this temperature (minimum CO ignition temperature is 1128 °F), CO emissions drop to less than 150 ppmv. NO_x emissions increase to as high as 200 ppmv as coal is first introduced and load is increased to 45 MWe. SO_2 emissions showed two brief spikes to 250-300 ppmv as coal is first introduced and load in increased. As limestone feed is initiated, emissions are restored to compliance levels. It may be possible to remain in SO_2 compliance throughout a cold unit start-up by charging the bed with limestone prior to initiating coal flow.

Figure 7-8 shows the rate of change of drum metal temperatures throughout the start-up. Note that prior to turbine roll, a 100 °F/h rate of increase is reached, which is the manufacturer's recommended limit. Propane firing (energy input) cannot proceed at a faster rate or this criteria will be exceeded. At a minimum, the time required to raise 100 °F of superheat temperature (600 °F at 600 psig) is 5 hours, which corresponds to 100 °F/h increase in drum metal temperature. In this example, drum metal temperatures did not exceed 50 °F/h during the first three hours of start-up. This is because the propane firing rate (heat input) is restricted during this interval to prevent upsets in drum level. Once boiler vents and drains are closed and the drum pressure is in excess of 25 psig, drum level fluctuations diminish in magnitude but must be monitored until a drum pressure of 300 psig is reached. From this point, the restriction on the rate of increase in pressure part metal temperatures dictates the time to turbine roll.

Figure 7-9 shows the final steam temperature along with the turbine first stage cover metal temperature. The rate of change in the latter temperature is shown in Figure 7-10, which exceeds 150 °F/h for short intervals when 600 °F steam is first introduced to the turbine, and again as the generator is synchronized and steam flow is increased. It is not certain if this differs from a start-up of a pulverized coal fired unit or if these short intervals at 150 °F/h are hazardous to turbine life.

Under optimum conditions with a turbine rated at 110 MWe, full load from cold conditions could be reached in approximately ten hours. This includes five hours to raise 100 °F superheat temperatures, a three hour turbine soak, a one hour hold at 5 MWe to stabilize, and one hour to full load. Achieving full load from 45 MWe is complicated at Nucla because of the 74 MWe turbine with controlled extraction to three 12.5 MWe turbine, and the time required to bring each of these systems on-line.

7.4 WARM RESTART

Data are presented for a warm restart following a unit trip and a seven hour period with the turbine-generator off-line. The unit trip was initiated by a secondary air (SA) fan trip which caused a unit trip. All fans were out of service for a seven hour period immediately following the trip. This shutdown/restart sequence simulates a condition where the unit is taken off-line during a period of low load demand around 10:00 pm and is restarted the following morning during a period of high demand. The shutdown and restart sequence is numbered on Figures 7-11 through 7-20 according to the following sequence:

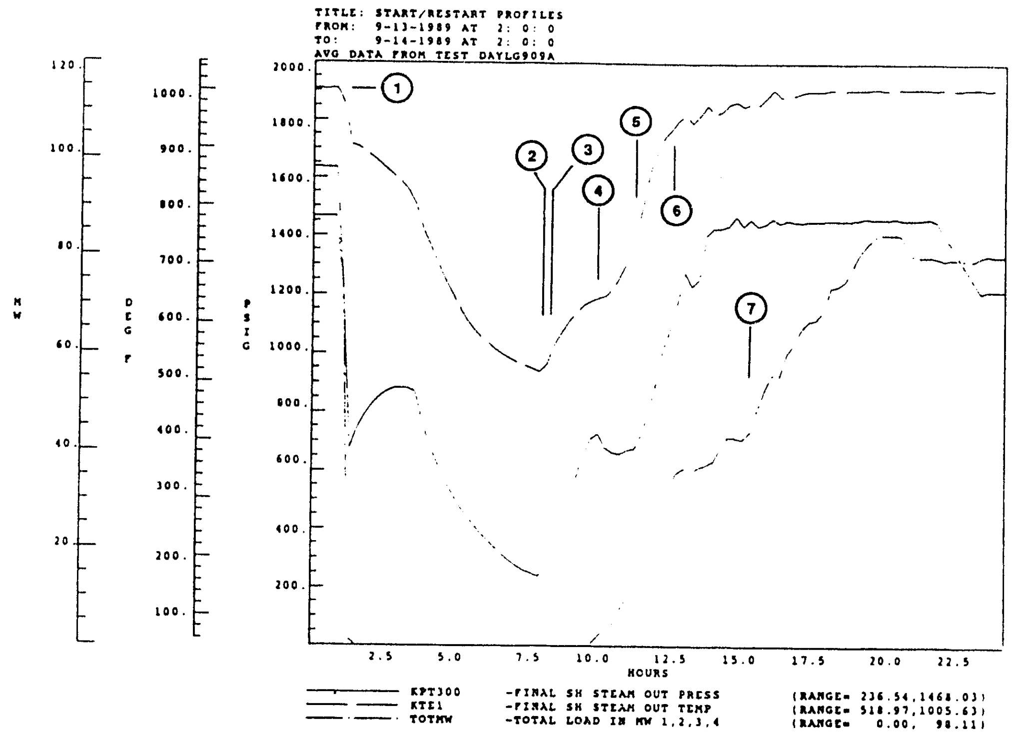


Figure 7-11. Load & Steam Conditions for Warm Restart.

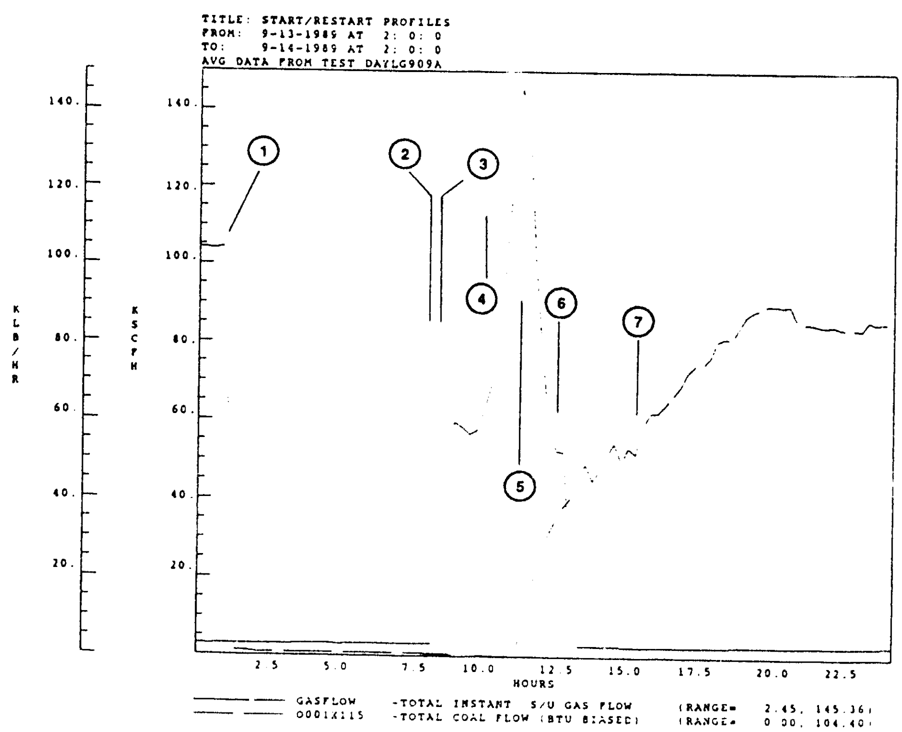


Figure 7-12. Coal and Gas Flow for Warm Restart.

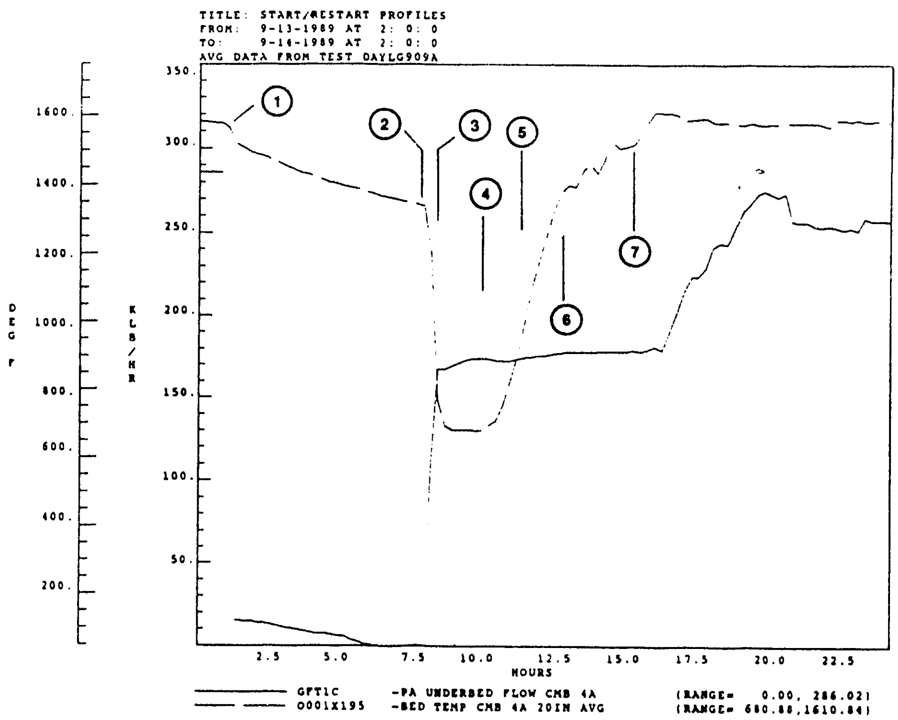


Figure 7-13. Air Flow & Bed Temps. for Warm Restart.

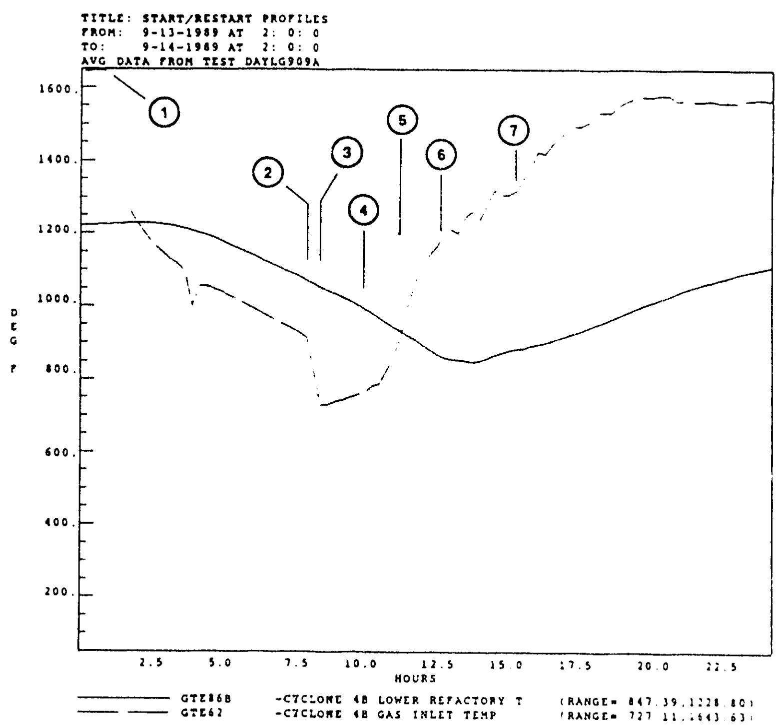


Figure 7-14. Cyclone Refractory Temps. for Warm Restart.

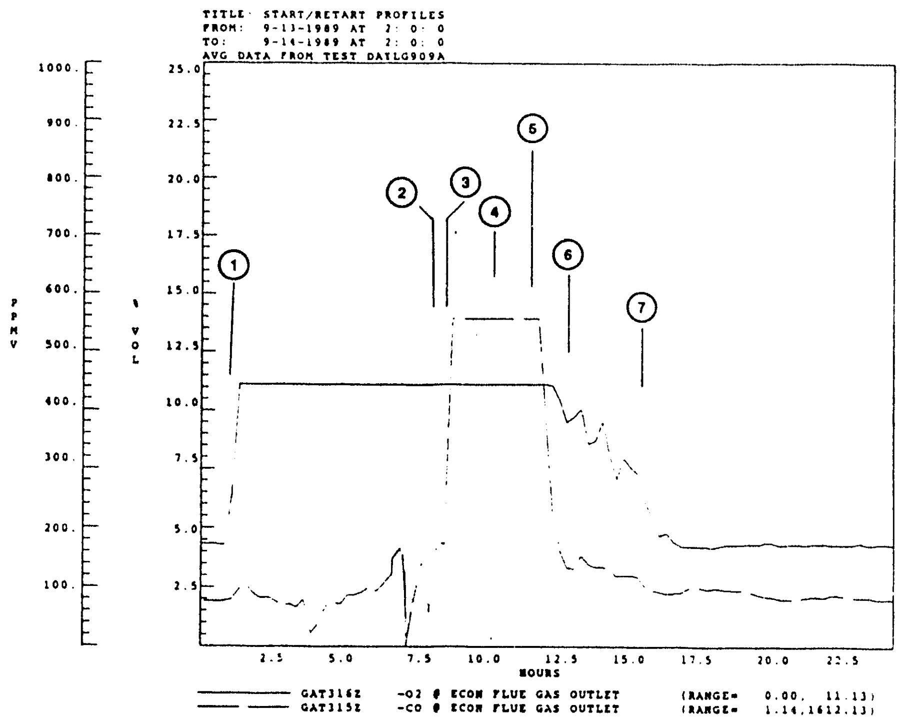


Figure 7-15. O_2 and CO Emissions During Warm Restart.

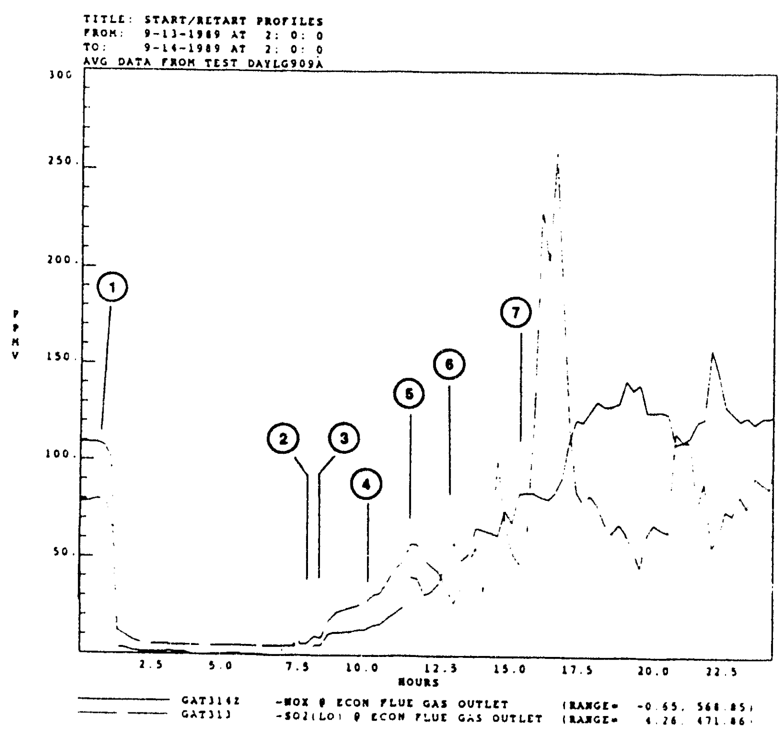


Figure 7-16. NO_X and SO_2 Emissions During Warm Restart.

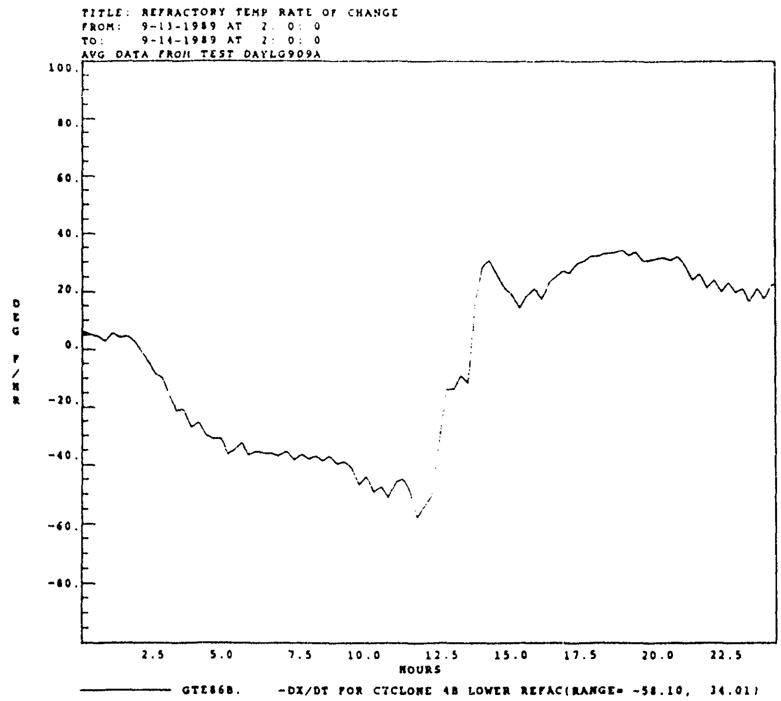


Figure 7-17. $\frac{dx}{dt}$ of Cyclone Refractory - Warm Restart.

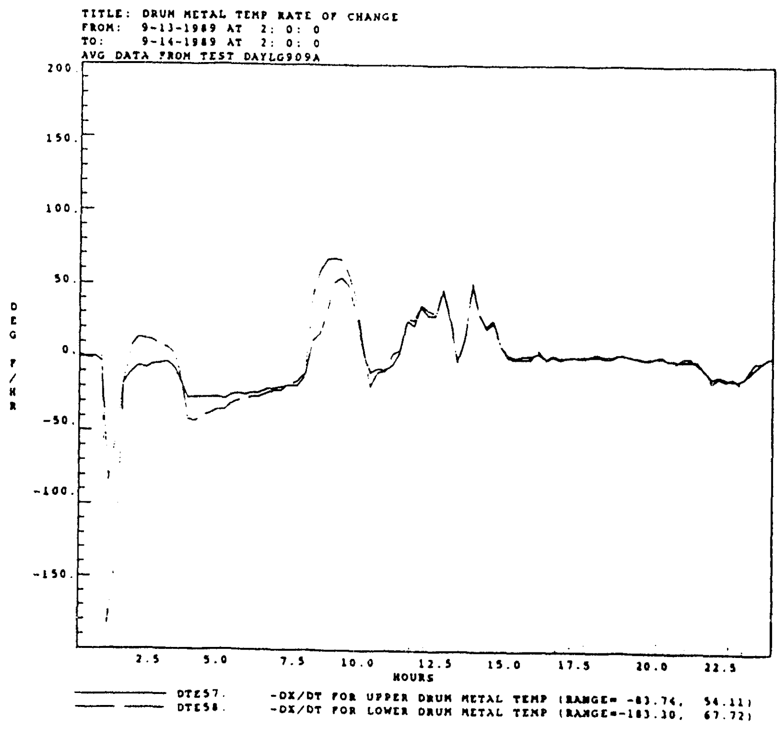


Figure 7-18. $\frac{dx}{dt}$ of Drum Metal Temp. - Warm Restart.

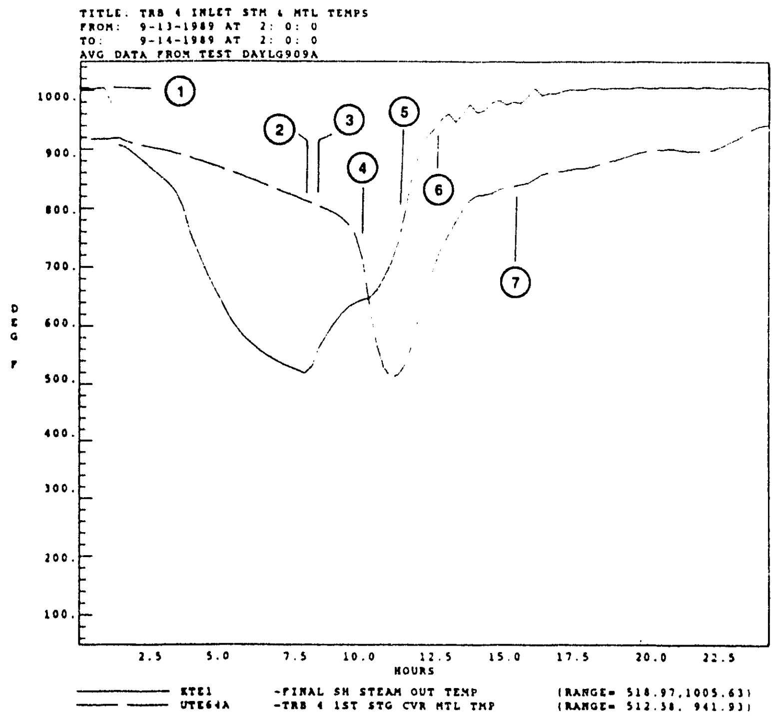


Figure 7-19. Steam & Turbine Metal Temps. - Warm Restart.

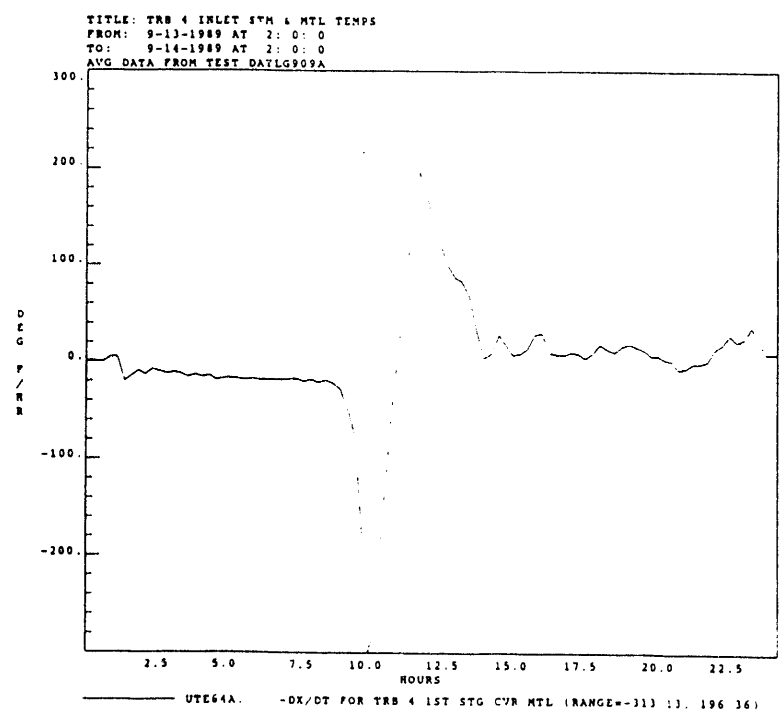


Figure 7-20. $\frac{dx}{dt}$ of Turbine Metal Temps. - Warm Restart.

1. Unit trip from 95 MWe gross output at approximately 03:00 as the result of a secondary air fan trip. Power to all fans is off and the fan rotors are in wind-down. Final steam pressure drops to 700 psig as load is reduced on the 74 MWe generator before it is taken off-line (the old 12.5 MWe turbines trip immediately).

2. Fans are restarted at approximately 09:50.

3. Once all fans and the high pressure blower have been started and powered up, a duct burner and two in-bed start-up burners are fired on each combustor following a five minute air purge.

4. With 100 °F of superheat established at 600 °F and 600 psig final steam conditions, the generator is synchronized and load is increased to 5 MWe gross. The third in-bed start-up burner is fired in each combustion chamber and propane firing is increased to both combustors.

5. Coal flow is introduced once bed temperatures increase to above 950 °F. Generator output is increased during this period. Propane flow is reduced as coal feed is increased.

6. Start-up burners are shut off once bed temperatures have increased above 1400 °F.

7. Load is increased to 45 MWe gross output on the new 74 MWe turbine. Overall load is slowly increased to approximately 80 MWe as the 12.5 MWe units are brought on-line.

The figures and formats for data presentation are identical to those presented for the cold start-up. Figure 7-11 shows the drop in steam pressure from 1450 to 700 psig and steam temperature from 1000 °F to 525 °F during the seven hour interval following the unit trip and prior to the start of fans and gas burners. The drop in steam pressure results from maintaining steam flow to the 74 MWe turbine for a 15 to 20 minute interval following the trip. This also results in a 100 °F drop in final steam temperature. The additional decrease in steam temperature from 900 °F to 525 °F over 6 hours represents unit cool-down without fans in service.

Figure 7-13 shows a decline in bed temperature of 175 °F over 6 hours without fans in service, or approximately 30 °F/h. With fans in service and air flow through the air distributor plate, bed temperatures decrease at a rate approaching 200 °F in 5 minutes, which is the time required for a unit purge. This is an important factor in establishing restart times, since a bed temperature of 950 °F is required prior to the initiation of coal feed. In this example, bed temperatures decreased only 175 °F over a 6 hour period. Although this demonstrates the ability of a CFB to effectively store energy for fast restarts without the use of start-up burners, the time required to restart fans and complete the boiler purge cycle reduces bed temperatures to just above 600 °F, well below that required for the initiation of coal feed. This could be circumvented by closing off dampers to the air distributor grid during fan start-up and completing the boiler purge cycle through ports located above the hot, slumped bed. Although the latter is not permitted by code, this modified procedure is currently under review by the National Fire Prevention Association (NFPA).

Figures 7-14 and 7-17 show the rate of change of refractory temperature during the warm restart. A maximum rate of change of 50 °F/h was reached for a two hour interval immediately following the re-establishment of coal flow to the boiler. This is well under the recommended limit of 100 °F/h.

Figures 7-15 and 7-16 indicate emissions during the restart. Again, CO emissions are in excess of 500 ppmv during the period when start-up burners are fired and coal flow is initiated to the point where bed temperatures increase above 1250 °F. SO_2 emissions remain in compliance except for a brief one hour period when coal flow is first introduced. This may be preventable by initiating limestone feed in advance of coal feed. NO_x emissions remain in compliance throughout the period.

Figures 7-18 and 7-20 show the rate of change for drum metal and turbine first stage metal cover temperatures during the restart. Both remain within recommended margins, except for a three hour period when steam flow is initiated to the turbine and first stage metal cover temperatures go through a -300 to +200 °F/h transient.

7.5 HOT RESTART

Data are presented for a hot restart following a unit trip and a one hour period with the turbine-generator off-line. the unit trip was initiated by a turbine control system trip which also tripped unit fans for approximately a 20 to 30 minute period. The shutdown and start-up sequence is similar to a warm restart. The numbering sequence on Figures 7-21 through 7-30 corresponds to the following numbered descriptions:

1. Unit trip at 110 MWe gross output at approximately 10:15 as the result of a turbine control trip. The combustion air fans and high pressure blower also trip and are in wind-down. Final steam pressure remains at

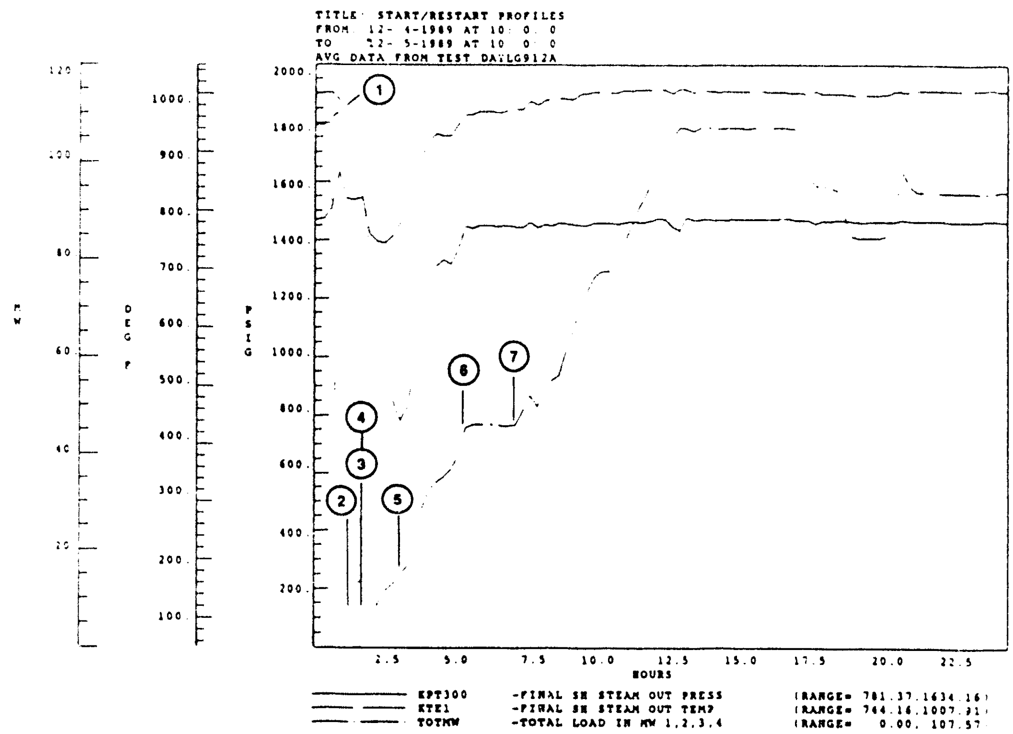


Figure 7-21. Load & Steam Conditions for Hot Restart.

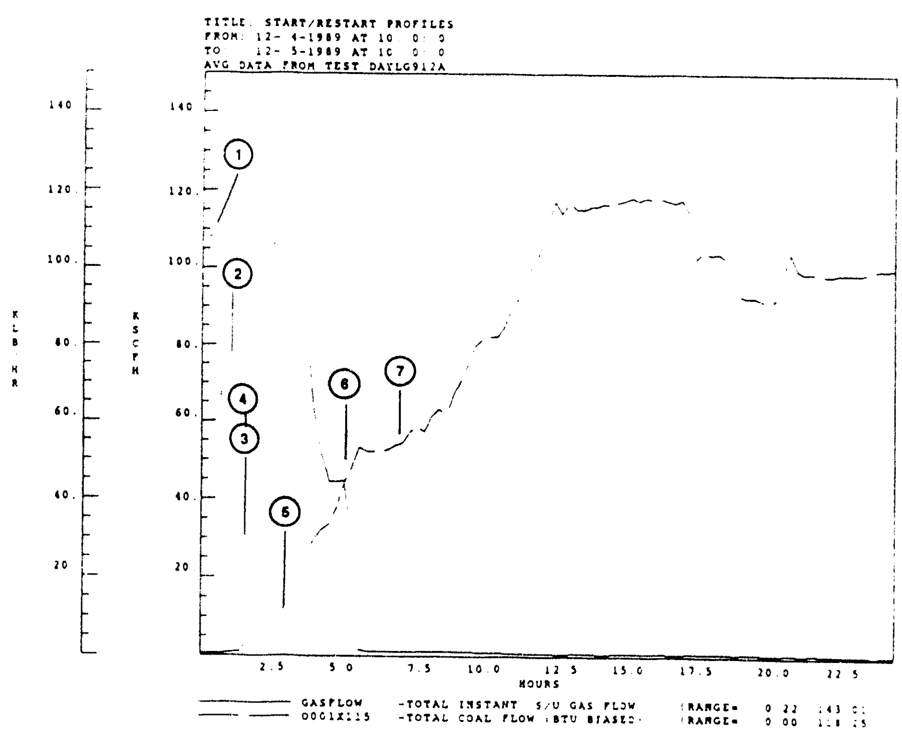


Figure 7-22. Coal and Gas Flow for Hot Restart.

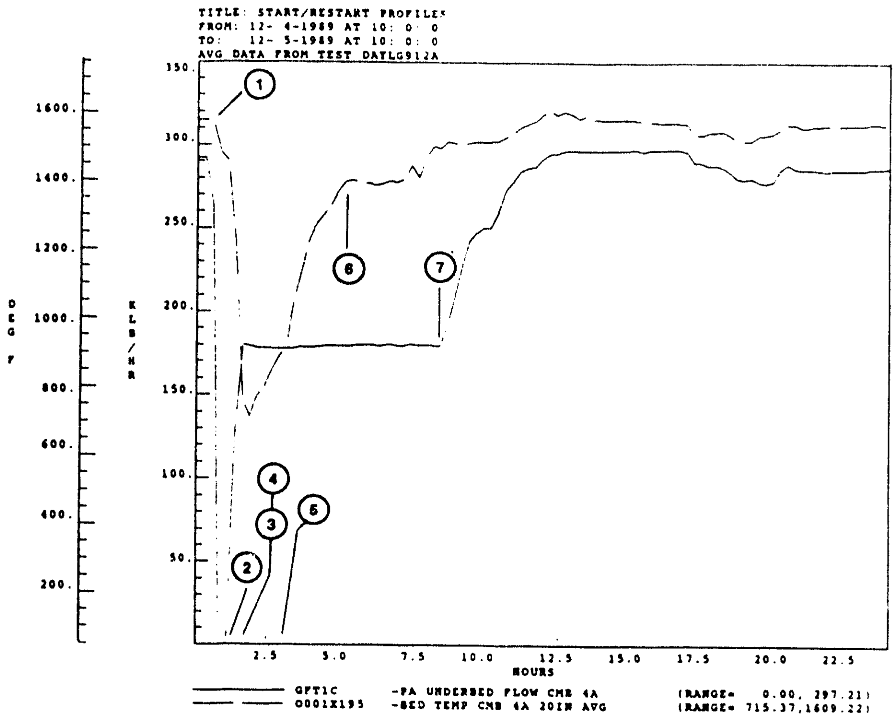


Figure 7-23. Air Flow & Bed Temps. for Hot Restart.

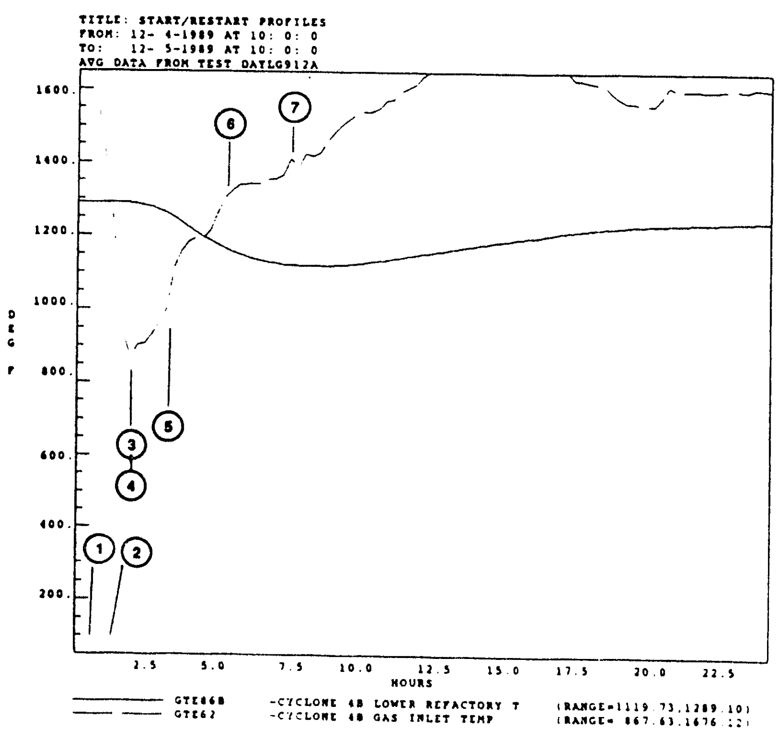


Figure 7-24. Cyclone Refractory Temps. for Hot Restart.

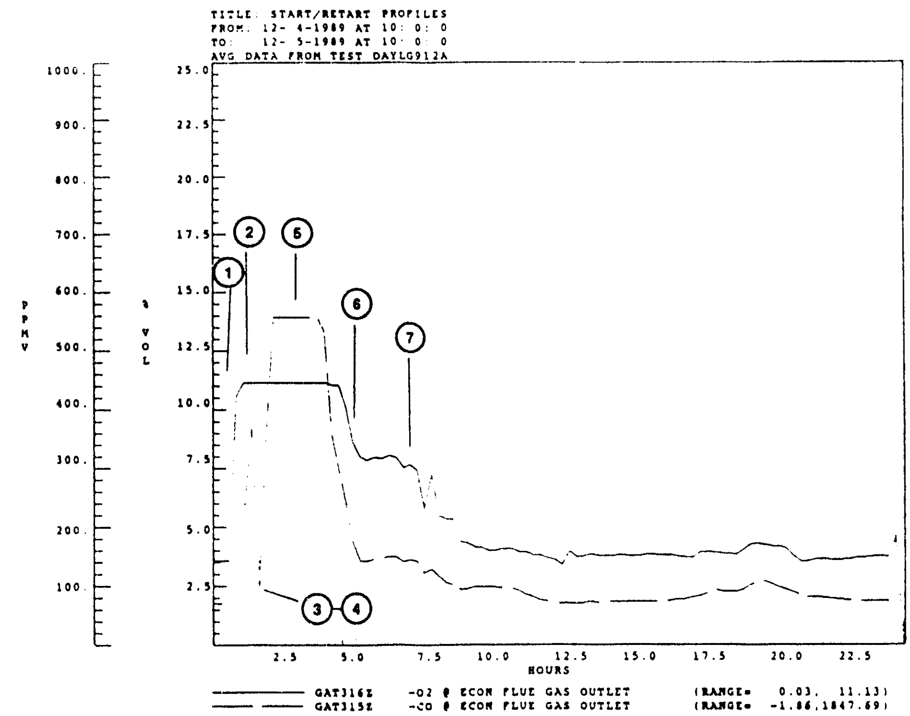


Figure 7-25. O_2 and CO Emissions During Hot Restart.

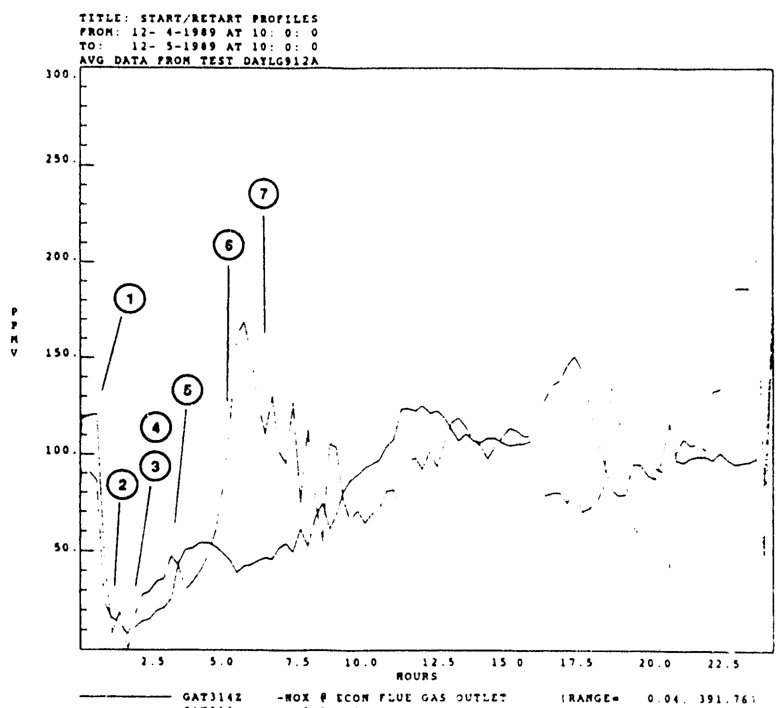


Figure 7-26. NO_X and SO_2 Emissions During Hot Restart.

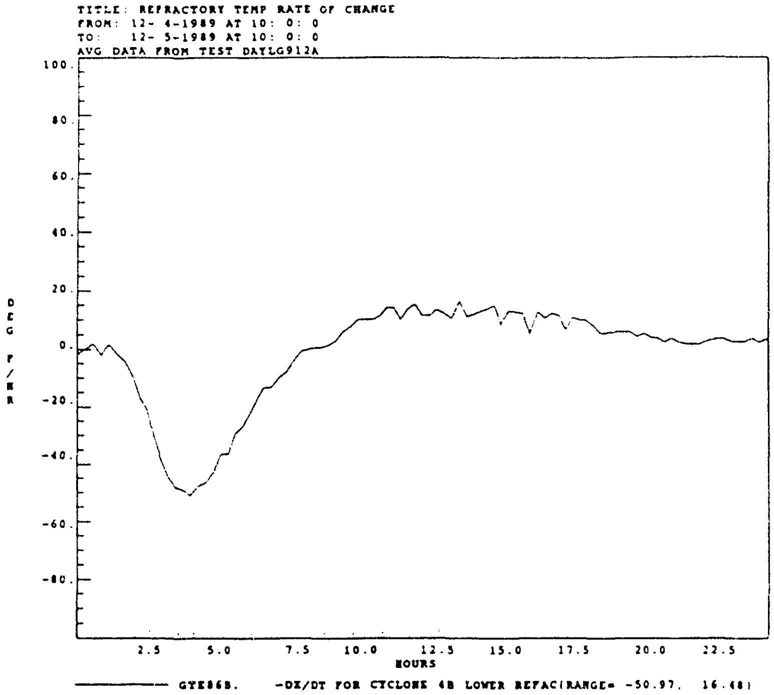


Figure 7-27. $\frac{dx}{dt}$ of Cyclone Refractory - Hot Restart.

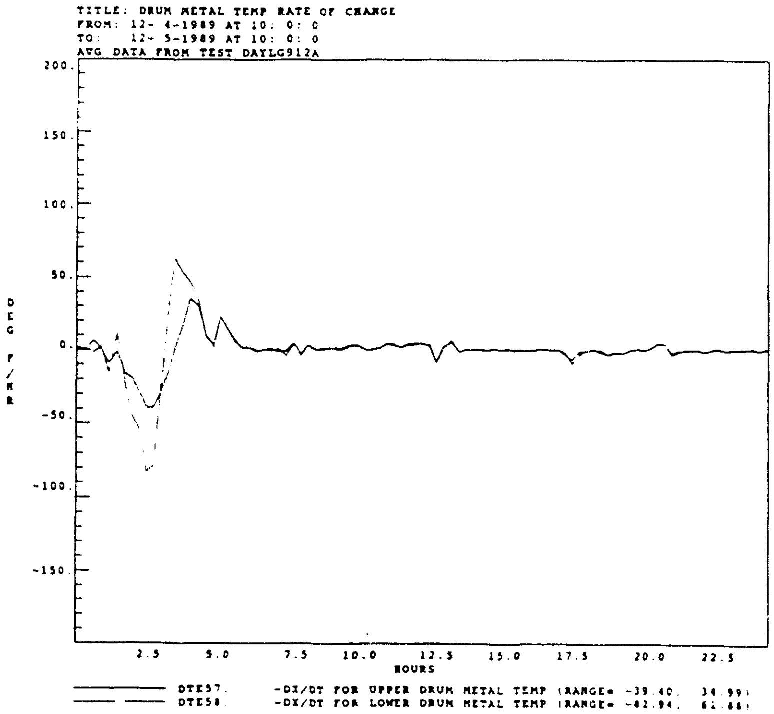


Figure 7-28. $\frac{dx}{dt}$ of Drum Metal Temp. - Hot Restart.

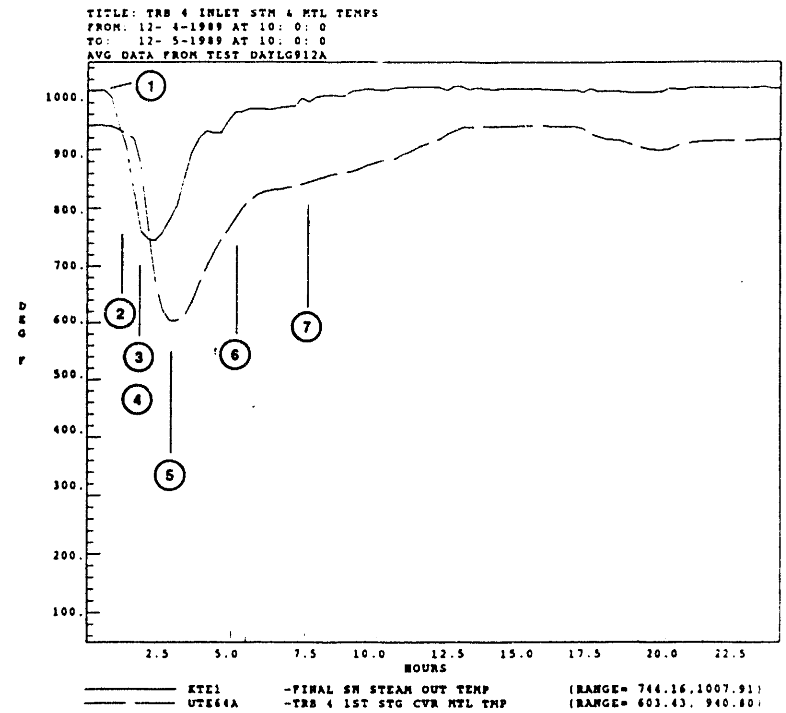


Figure 7-29. Steam & Turbine Metal Temps. - Hot Restart.

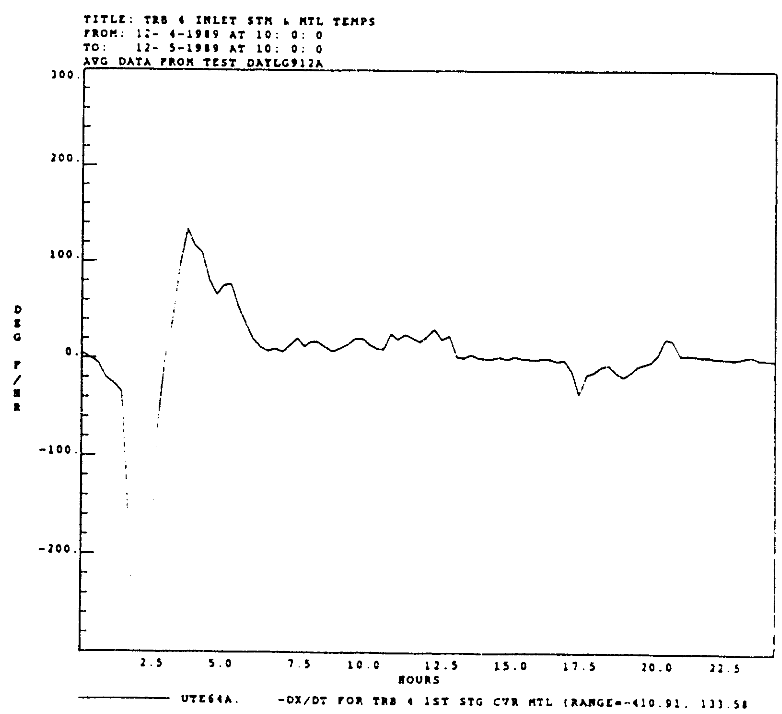


Figure 7-30. $\frac{dx}{dt}$ of Turbine Metal Temps. - Hot Restart.

1450 psig since the turbine is brought off-line immediately.

2. Fans are restarted at approximately 11:05.

3. Once all fans and the high pressure blower have been started and powered up, the duct burner and three start-up burners in each combustor are placed into service and total propane firing rate on both combustors is increased to 140 kscfh.

4. Since 100 °F of superheat is maintained following the unit trip, the 74 MWe generator is synchronized at approximately 11:35 and load is increased.

5. Coal flow is introduced at approximately 12:50 once bed temperatures reach approximately 950 °F. Generator output is increased during this period. Propane flow is reduced as coal feed is increased.

6. Start-up burners are shut off once bed temperatures have increased above 1400 °F.

7. Load is increased to 45 MWe gross output for a two hour period after which the three 12.5 MWe turbine-generators are sequentially placed into service as gross output is restored to 110 MWe.

Again, the figures and formats for data presentation are similar to those presented for cold and warm start-ups. Figure 7-21 shows a slight increase in steam pressure following the turbine trip because steam flow is immediately terminated while some energy is still being released in the boiler as the fans wind down. Steam temperature drops approximately 100 °F during the 20 to 30 minute interval when fans are out of service. Figure 7-22 shows the start times and flow rates for propane and coal feed as well the shutdown time for propane flow.

Figure 7-23 shows a minimal drop in bed temperature during the interval with fans out of service, but a large decline of 750 °F during the period when fans are restarted and the boiler purge cycle is completed. As mentioned, this temperature drop could be reduced if air flow were directed through overbed ports during fan start-up and boiler purge. This would reduce the time required on propane to raise bed temperatures back to 950 °F. Supplemental propane is required by current boiler operating logic when the unit is operating on coal and bed temperatures are less than 1400 °F.

Figures 7-24 and 7-27 show the rate of change of refractory temperature during the hot restart. A maximum rate of change of 50 °F/h was reached for a two hour interval following the restart of fans and the introduction of coal feed. This is similar to results for a warm restart.

Figures 7-25 and 7-26 show emissions performance during the hot restart. As was shown for the cold and warm starts, CO emissions are in excess of 500 ppmv during the period when start-up burners are fired and coal flow is initiated until 1250 °F bed temperatures are reached. SO_2 spiked to 175 ppmv during a one hour interval when coal feed is first introduced but remain in compliance thereafter. NO_x emissions are in compliance throughout the start-up.

Figures 7-28 and 7-30 show the rate of change for drum metal and turbine first stage metal cover temperatures during the hot restart. The former remains within recommended limits while turbine metal cover temperatures go through a transient similar to that reported during a warm restart when steam flow is first initiated to the turbine. It is not certain what effects this brief temperature transient has on turbine life.

Section 8

LOAD FOLLOWING AND RATE OF LOAD CHANGE

This section summarizes results from a series of 16 dynamic response tests. During these tests, the output of the new 74 MWe turbine-generator was ramped at various rates of load change. These changes were made in both directions (i.e., increasing and decreasing load) over two magnitudes of total load change. The intent of this testing was to identify rate limiting factors in CFB boiler response to turbine load changes. Results indicated limitations at 7 MWe/min for some tests due to drum level control. Part of this limitation is believed to be correctable with improved accuracy of the final steam flow measurement used in three-element drum level control. No CFB-related ramp rate limitations were evident at 7 MWe/min.

8.1 OBJECTIVES AND APPROACH

The objectives of this plan were to test the dynamic response characteristics of the Nucla CFB to determine its capability to respond to changes in steam flow requirements demanded by load following operating modes. In particular, the intent was to define any rate limiting factors to load response that may be CFB-related or unique to the Nucla CFB design. Of particular concern at the outset of testing was the large thermal mass of a CFB boiler in both the refractory and circulating bed material. During load changes, fluidizing velocities change in the boiler, which affect solids recirculation and density profiles. This, in turn, alters heat transfer to the water walls and superheaters in the combustion chamber, and to superheater and economizer surface in the convection pass.

To accomplish the objectives of the Dynamic Test Plan, 16 tests were conducted at ± 1, ± 3, ± 5, and ± 7 MWe/min ramp rates over 20 MWe and 40 MWe magnitude changes. Load changes were made on the new 74 MWe turbine only. Each of the three 12 MWe turbines were held at constant 36 MWe output for each of the tests. All downward ramps were initiated from 110 MWe and all upward ramps terminate at 110 MWe gross unit output.

Load ramps are accomplished by setting the final load setpoint and the desired rate of load change on the plant's distributed control system. Upon actuation of the control system to the new setpoints, the following occurs: 1) the MWe ramp generator begins to ramp toward the new load demand setting at a rate determined by the load ramp setpoint, 2) the turbine load controller drives the governor valves to a position where the unit load equals the output of the MWe ramp generator, and 3) the boiler master then adjusts fuel and air flows to maintain steam throttle pressure at 1450 psig. Air flow is then trimmed to maintain 2.3 vol.% O_2 at the economizer outlet.

The maximum rate of load change suggested by the turbine manufacturer on the new 74 MWe turbine is 10 % of rated capacity. This limits dynamic testing on the Nucla CFB to 7 MWe/min, which was the maximum rate tested.

8.2 TEST MATRIX

Table 8-1 summarizes the load response tests completed during the course of the Phase I and Phase II test programs. Data from tests at 1, 3, and 5 MWe/min ramp rates are presented in the Annual Reports. There were no rate limiting factors during these tests. Only data from tests conducted at 7 MWe/min are presented in this report.

Figure 8-1 shows a schematic of the turbine arrangement at the Nucla CFB. The new 74 MWe turbine is shown with controlled automatic extraction of 600 psig steam to the three existing 12.5 MWe turbines. The condensate from each of the 12.5 MWe turbines is forwarded through its own low pressure feed water heater and deaerator before being transferred to the new unit 4 deaerator storage tank. For a complete description of the unit design, see Report No. CA-C-6.3, Detailed Public Design Report of the Nucla CFB.

Table 8-1. Summary of Load Response Tests

Test #	Date	Ramp Rate	Magnitude	From	To
D01	01/02/90	1 MWe/min	-20	110	90
D02	01/02/90	1 MWe/min	+20	90	110
D03	01/03/90	1 MWe/min	-40	110	70
D04	01/03/90	1 MWe/min	+40	70	110
DO5	01/04/90	3 MWe/min	-20	110	90
D06	01/04/90	3 MWe/min	+20	90	110
D07	01/04/90	3 MWe/min	-40	110	70
D08	01/04/90	3 MWe/min	+40	70	110
D09	01/05/90	5 MWe/min	-20	110	90
D10	01/05/90	5 MWe/min	+20	90	110
D11	01/05/90	5 MWe/min	-40	110	70
D12	01/05/90	5 MWe/min	+40	70	110
LF1	12/20/90	7 MWe/min	-20	110	90
LF2	12/20/90	7 MWe/min	+20	90	110
LF3*	12/20/90	7 MWe/min	-40	110	70
LF4	12/20/90	7 MWe/min	+40	70	110

* Unit trip on low drum level.

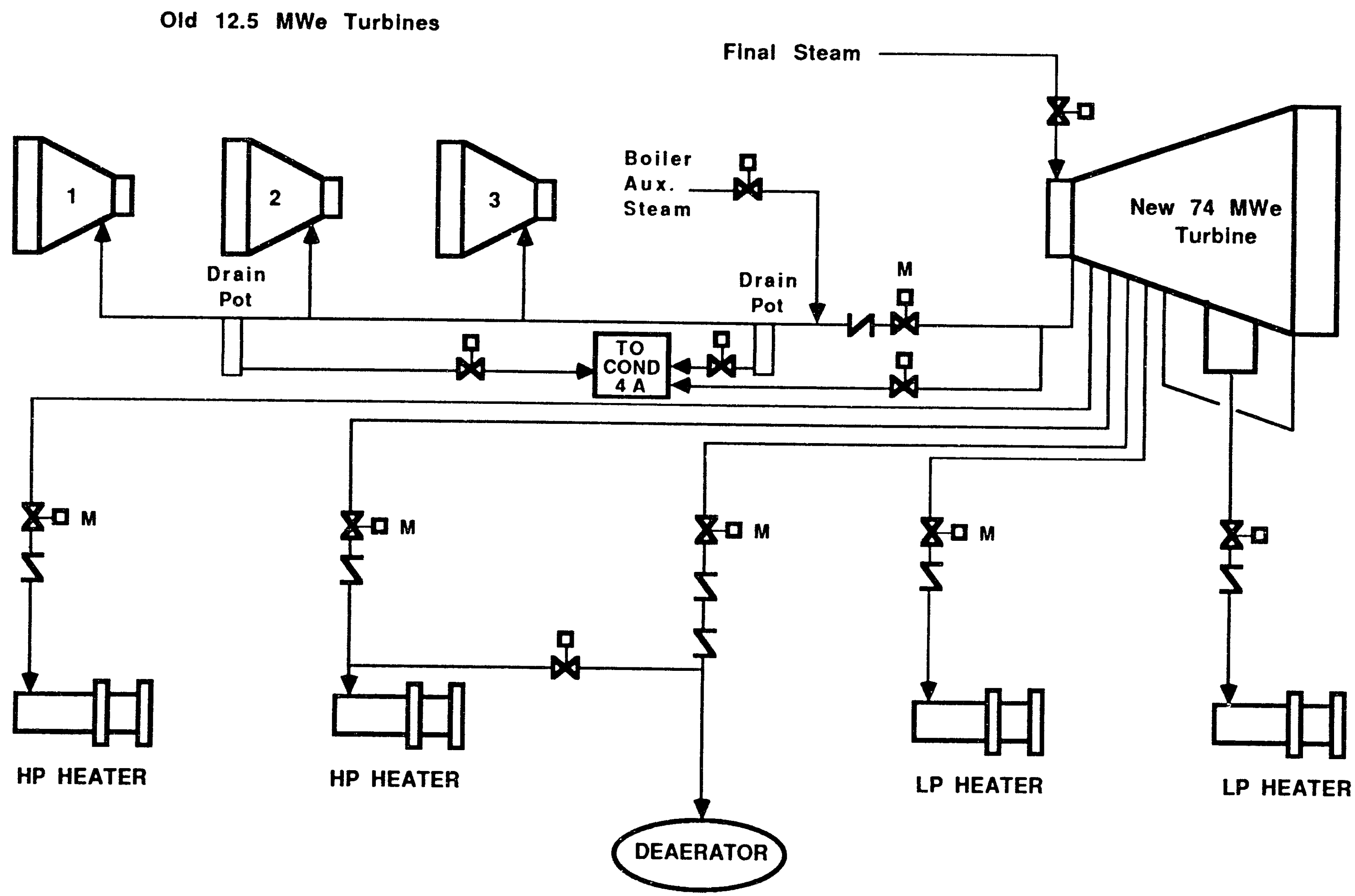


Figure 8-1. Schematic of New 74 MWe Turbines and Three Existing 12.5 MWe Turbines.

Note that it is not the intent of this section to provide a detailed analysis of the plant's control system. Rather, the intent is to identify rate limiting factors that may be CFB-related.

8.3 TEST RESULTS

Figures 8-2 through 8-13 summarize real-time data for key operating variables during tests LF1, LF2, LF3, and LF4. Each of these four tests can be seen in these figures from data on 12/20/90. The curves represent raw data collected at 30 second intervals. The following is a summary of data presented in the figures:

Figure 8-2.	74 MWe Generator Output and Demand.
Figure 8-3.	74 MWe Generator Output, Boiler Master Output, and 74 MWe Turbine Throttle Pressure.
Figure 8-4.	Total Plant Load, Main Steam Flow, and Feed Water Flow.
Figure 8-5.	74 MWe Generator Output and Drum Level.
Figure 8-6.	Final Superheater Steam Outlet Temperature, Total Attemperator Flow, and Total Plant Load.
Figure 8-7.	74 MWe Generator Output, 74 MWe Turbine First Stage Pressure, Extraction Pressure to Old Turbines.
Figure 8-8.	74 MWe Generator Output, Governor Valve Position, Main Steam Flow.
Figure 8-9.	Total Plant Load, Boiler Master Output, and Combustor A Coal Flow.
Figure 8-10.	Combustor B SO_2, Combustor B Limestone Feed Rate, Total Plant Load.
Figure 8-11.	Stack SO_2, Total Plant Load.
Figure 8-12.	Total Plant Load, A-side O_2, B-side O_2.
Figure 8-13.	Total Plant Load, CO Emissions, Stack NO_x.

Note that in Figures 8-9 and 8-10, the coal feed rate or the limestone rate is shown for only one combustion chamber in order to clarify the figure. Several observations are apparent in these plots. These include:

1. During ramp increases, throttle pressure initially goes down by 20 to 30 psig, depending on the magnitude of the load change as shown in Figure 8-3 during test LF4 and LF2. This occurs as the governor valves open in response to the demand increase in unit output. As shown in Figure 8-5, drum level increases with the decrease in throttle pressure and the corresponding decrease in drum pressure. The increase in drum level is caused by the increase in void fraction in the water walls and drum at the lower pressures. To compensate for the decrease in throttle pressure, the boiler master increases and along with it, the total coal and air flow. The reverse happens during downward ramps, such as shown for tests LF1 and LF3. For all tests, throttle pressure

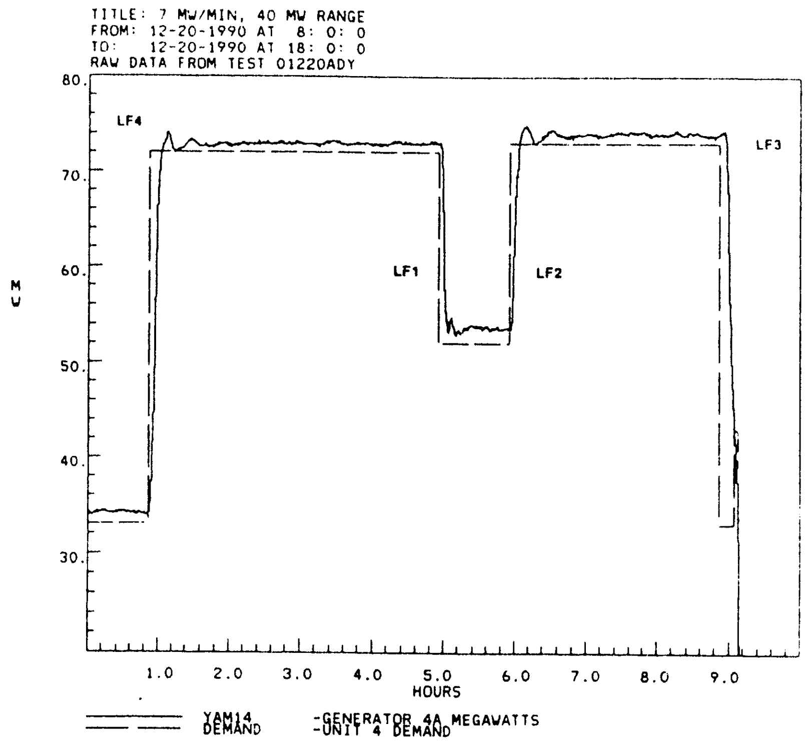


Figure 8-2. 74 MWe Generator Output and Demand.

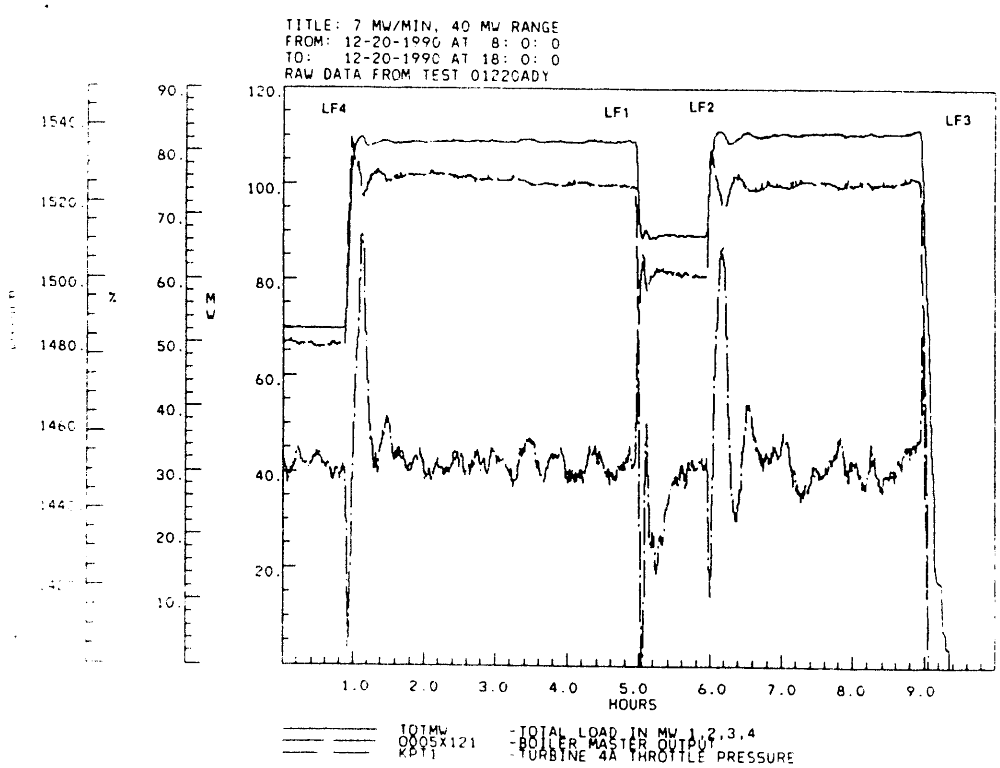


Figure 8-3. 74 MWe Generator Output, Boiler Master Output, and Turbine Throttle Pressure.

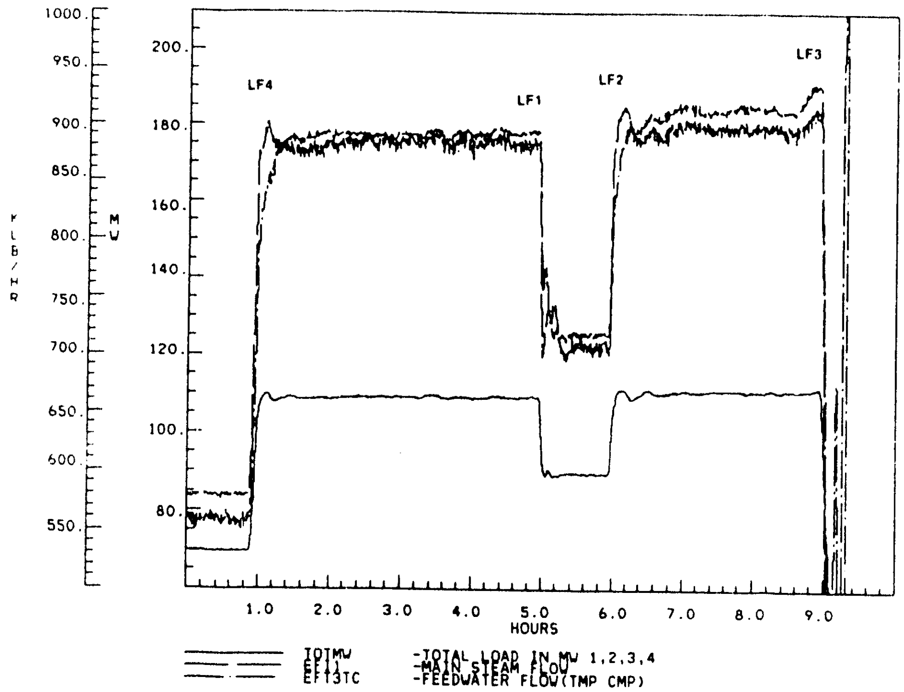


Figure 8-4. Total Plant Load, Main Steam Flow, and Feedwater Flow.

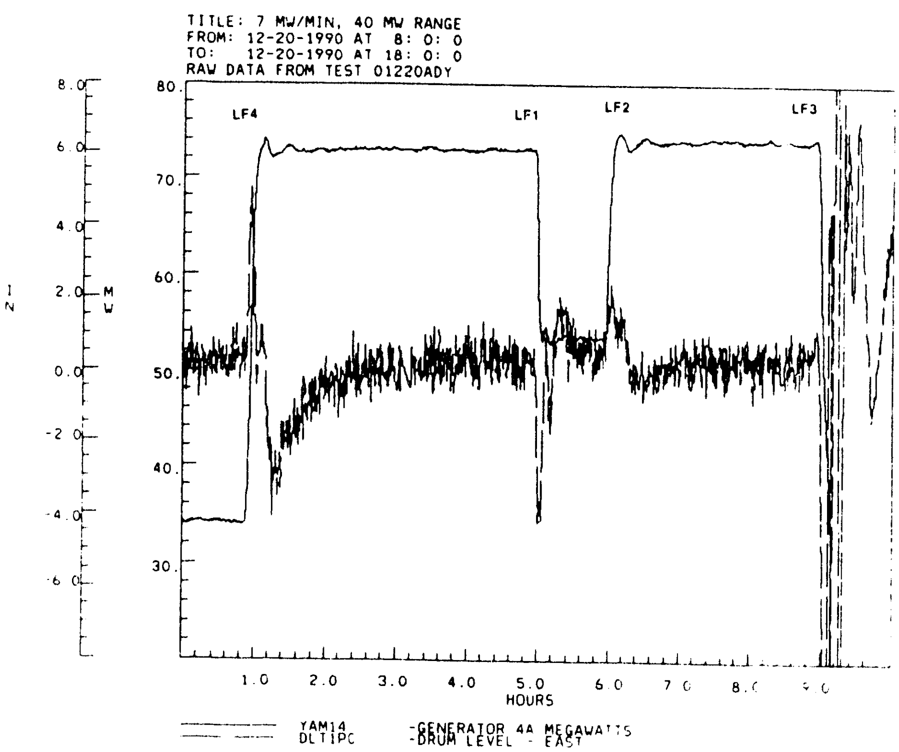


Figure 8-5. 74 MWe Generator Output and Drum Level.

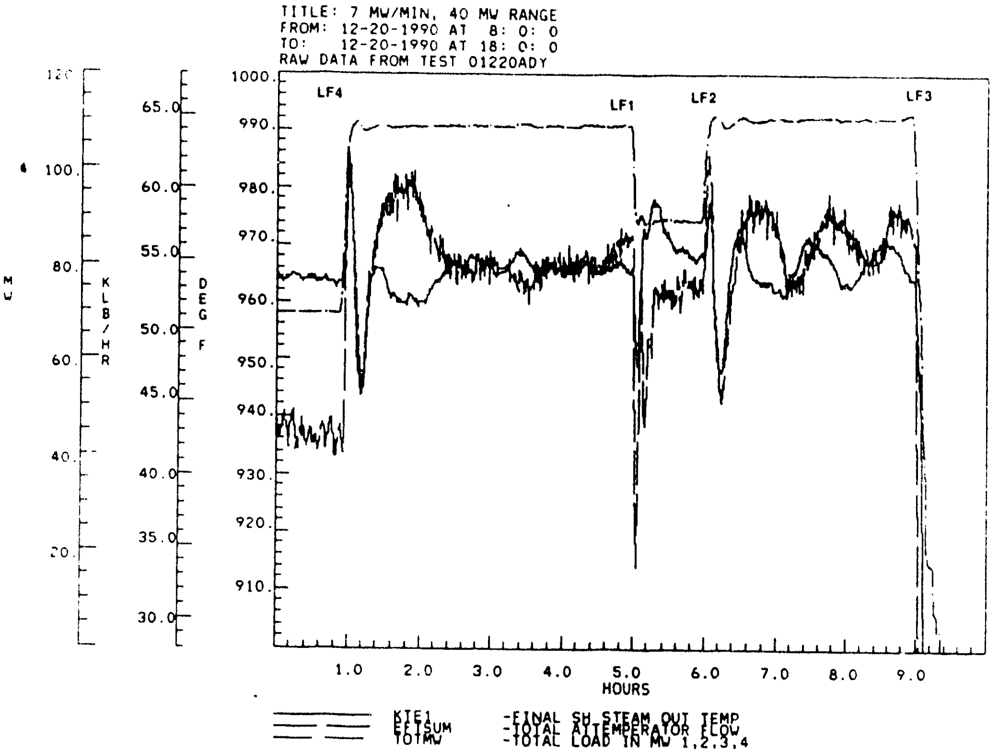


Figure 8-6. Final Superheater Steam Outlet Temp., Attemporator Flow, and Total Load.

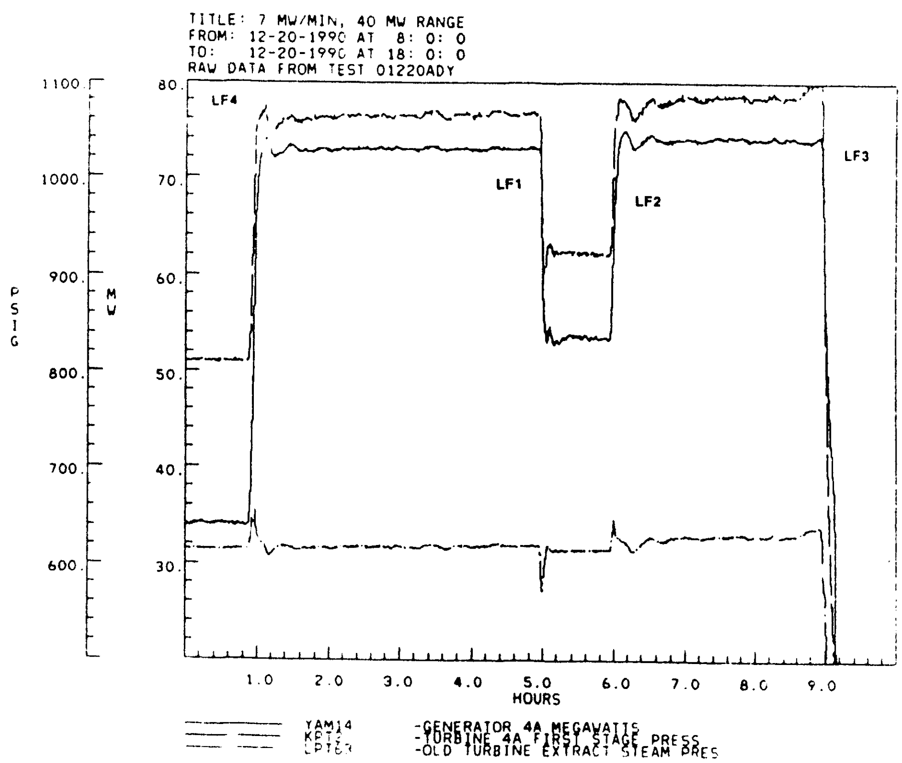


Figure 8-7. 74 MWe Generator Output, First Stage Pressu
Extraction Pressure to Old Turbines.

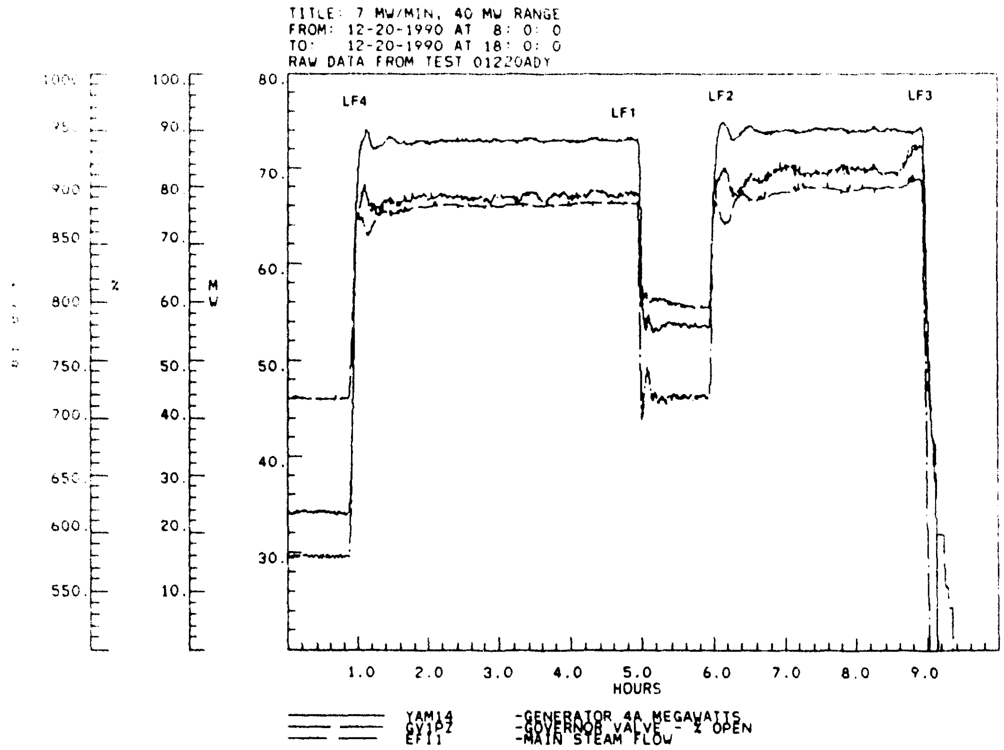


Figure 8-8. 74 MWe Generator Output, Governor Valve Position, Main Steam Flow.

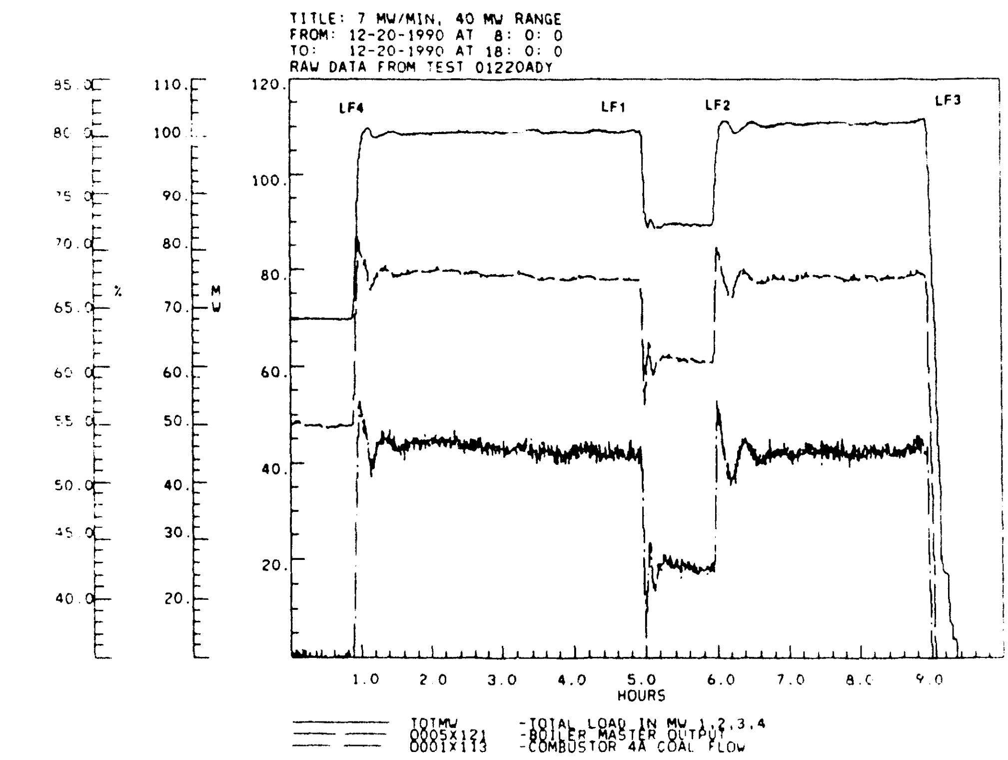


Figure 8-9. Total Plant Load, Boiler Master Output, and Combustor A Coal Flow.

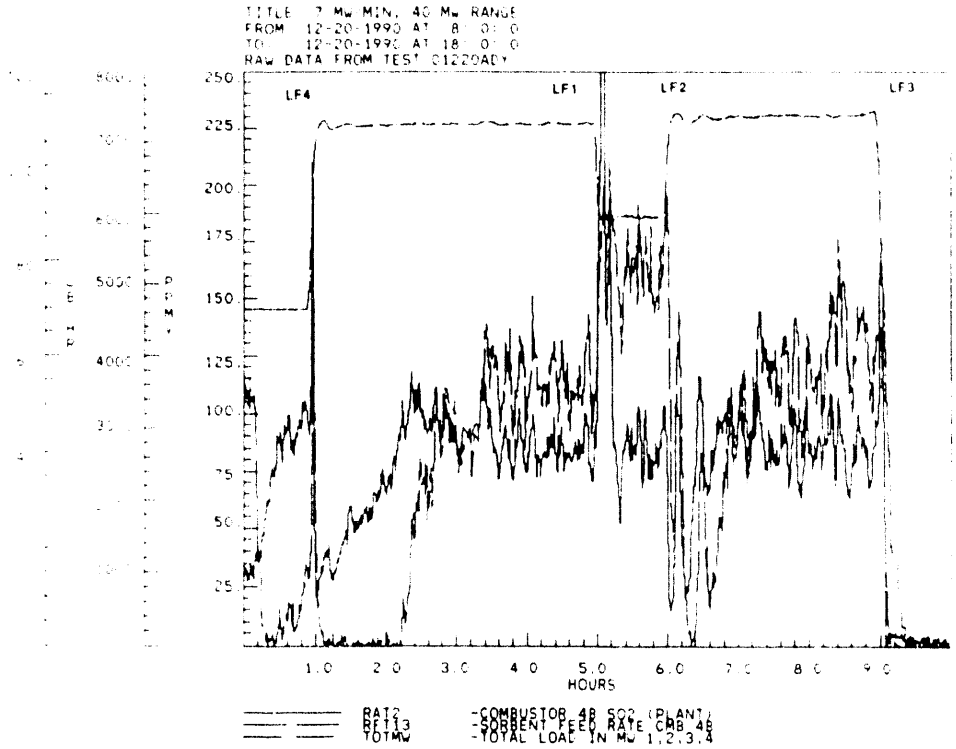


Figure 8-10. Combustor B SO_2, Combustor B Limestone Feed Rate, Total Plant Load.

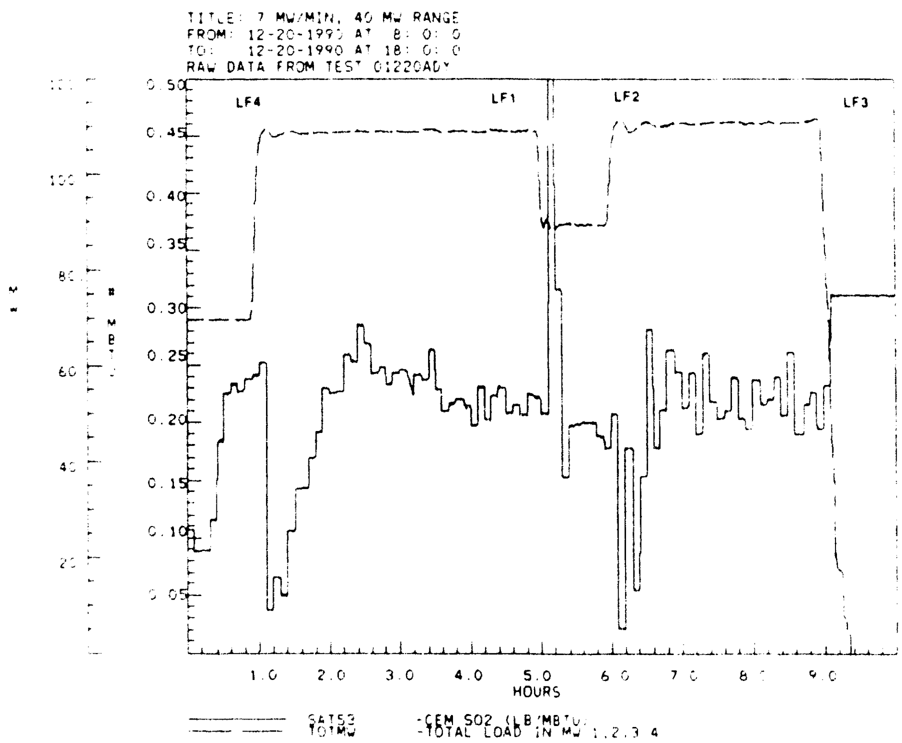


Figure 8-11. Stack SO_2, Total Plant Load.

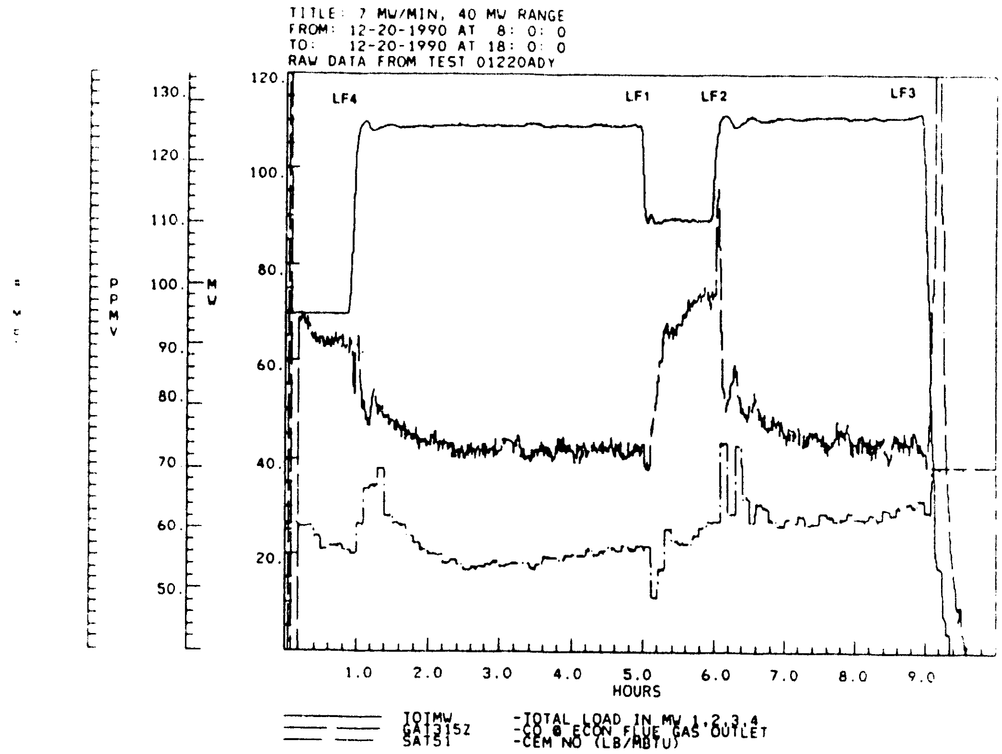


Figure 8-12. Total Plant Load, A-side O_2, B-side O_2.

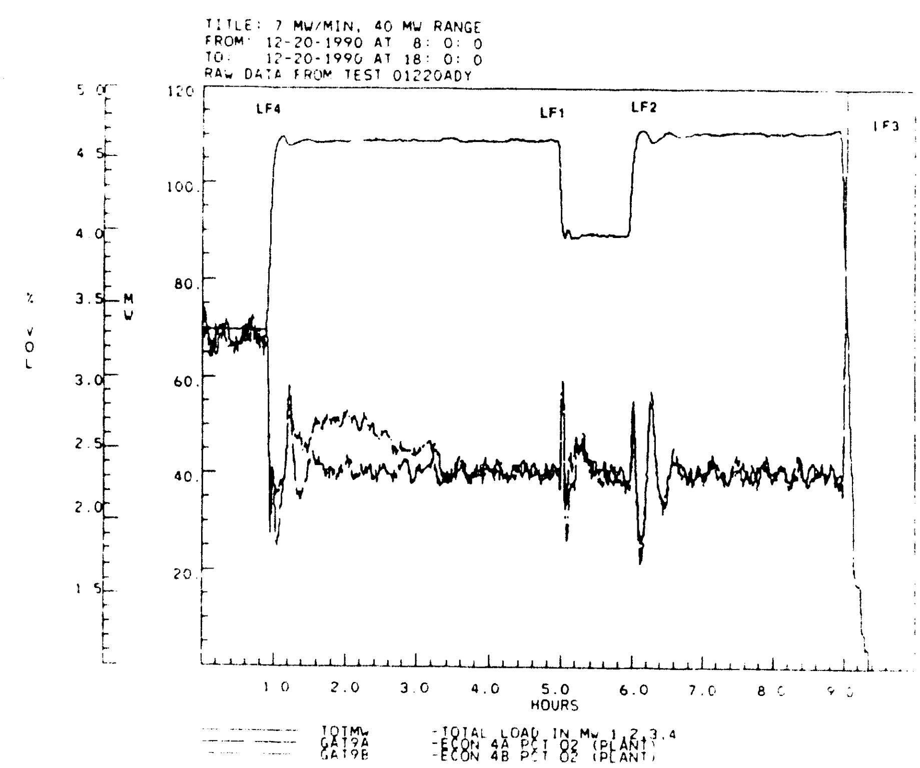


Figure 8-13. Total Plant Load, CO Emissions, Stack NOx.

initially overshoots its target as the boiler master works towards returning it to 1450 psig. Typically, within 30 minutes of the initial load change, oscillations in throttle pressure are dampened by the boiler master.

2. For these tests, the final steam temperature is approximately 960 °F. This is 40 °F lower than the other load following tests as the result of increased attemperator spray flows. The change in attemperator spray flow logic was incorporated into the control system in October 1990 in order to lower secondary superheater metal temperatures and prevent tube failures associated with overheating, as discussed in Section 16. During load ramps upward, the final steam temperature increases as the boiler master increases firing rates to the combustors. As can be seen in Figure 8-6, attemperator spray flows also increase and then modulate to maintain secondary superheater outlet temperatures below 925 °F.

3. In Figure 8-6, the first stage pressure on the 74 MWe turbine and the extraction pressure to the three existing 12.5 MWe turbines is shown for the four load response tests. During increases in load, the extraction pressure spikes upward approximately 30 psig for a 5 to 10 minute period before the auto-extraction valve dampens the oscillation back to the controlled setpoint of 600 psig. The reverse occurs during decreases in load. This fluctuation temporarily produces an erroneous steam flow indication, as will be discussed in Section 8.4.

4. Figures 8-10 and 8-11 show the limestone feed rate to combustor B, the in-plant SO_2 measurement to combustor B, and the SO_2 measurement at the stack by the continuous emissions monitors. Note that following increases in load, SO_2 emissions decrease significantly. Limestone feed rates also decrease since the SO_2 measurement "trims" the feeder output to maintain emissions compliance. This functions in much the same way that the oxygen measurement trims the air flow dampers to maintain a pre-set excess air level.

This decrease in SO_2 emissions is believed to result from the increased availability of stored calcium in the bed. At the higher fluidizing velocities accompanying the increase in load, this stored material becomes suspended higher in the combustion chambers and is carried over to the cyclones, where the coarser material is captured and recirculated and the finer material escapes. During reductions in load, SO_2 emissions temporarily increase as the availability of suspended calcium-enriched bed material in the size range supported by the lower fluidizing velocities is now diminished. These temporary excursions in SO_2 emissions could be eliminated by leading reductions in load with increased limestone feed.

5. CO emissions, shown in Figure 8-13, increase during load reductions due to the decrease in combustor operating temperatures. NO_x emissions, shown in the same figure, increase temporarily during load increases and exhibit the opposite behavior during reductions in load. However, compliance is maintained during all load response tests.

Figure 8-14 represents the results from 40 MWe increases in load for 1 MWe/min, 3 MWe/min, 5 MWe/min, and 7 MWe/min ramp tests. Note that from the initiation of the demand change in load to the first point of achieving the new setpoint, these tests averaged approximately 1.8, 2.3, 3.3, and 3.9 MWe/min, respectively. This is less than the ramp rate set point due to dampening effects of the control system on both ends of the overall load change. Taking the average slope in the middle portion of these curves, the ramp rates were approximately 2.2, 3.2, 5.6, and 6.2 MWe/min, respectively.

8.4 7 MWe/MIN RAMP DECREASE OVER 40 MWe

Figures 8-15 through 8-22 illustrate more detailed data from test LF3 compared to that presented above. Test LF3 was a downward ramp over 40 MWe from 110 MWe to 70 MWe at 7 MWe/min. During this test, the unit tripped on low drum level. Values in these figures represent data collected at 30 second intervals.

Figure 8-15.	Test LF3 showing the 74 MWe Generator Output and Demand.
Figure 8-16.	Test LF3 showing the Total Plant Output, Boiler Master Output, and 74 MWe Turbine Throttle Pressure.
Figure 8-17.	Test LF3 showing the Total Plant Output, Main Steam Flow, and Feed Water Flow.
Figure 8-18.	Test LF3 showing the 74 MWe Generator Output and Drum Level.
Figure 8-19.	Test LF3 showing the 74 MWe Generator Output, Governor Valve Position, and the Main Steam Flow.
Figure 8-20.	Test LF3 showing the 74 MWe Generator Output, 74 MWe Turbine 1st Stage Pressure, and Extraction Line Pressure.
Figure 8-21.	Test LF3 showing the Combustor A SO_2 and Limestone Feed Rate, and Total Plant Load.
Figure 8-22.	Test LF3 showing the Total Plant Load, and Final Steam Pressure and Temperature.

Following the change in load demand to 70 MWe gross unit output and the initiation of the ramp rate at 7 MWe/min shown in Figure 8-15, the governor valves begin to close as shown in Figure 8-19. As for other load reduction tests, this

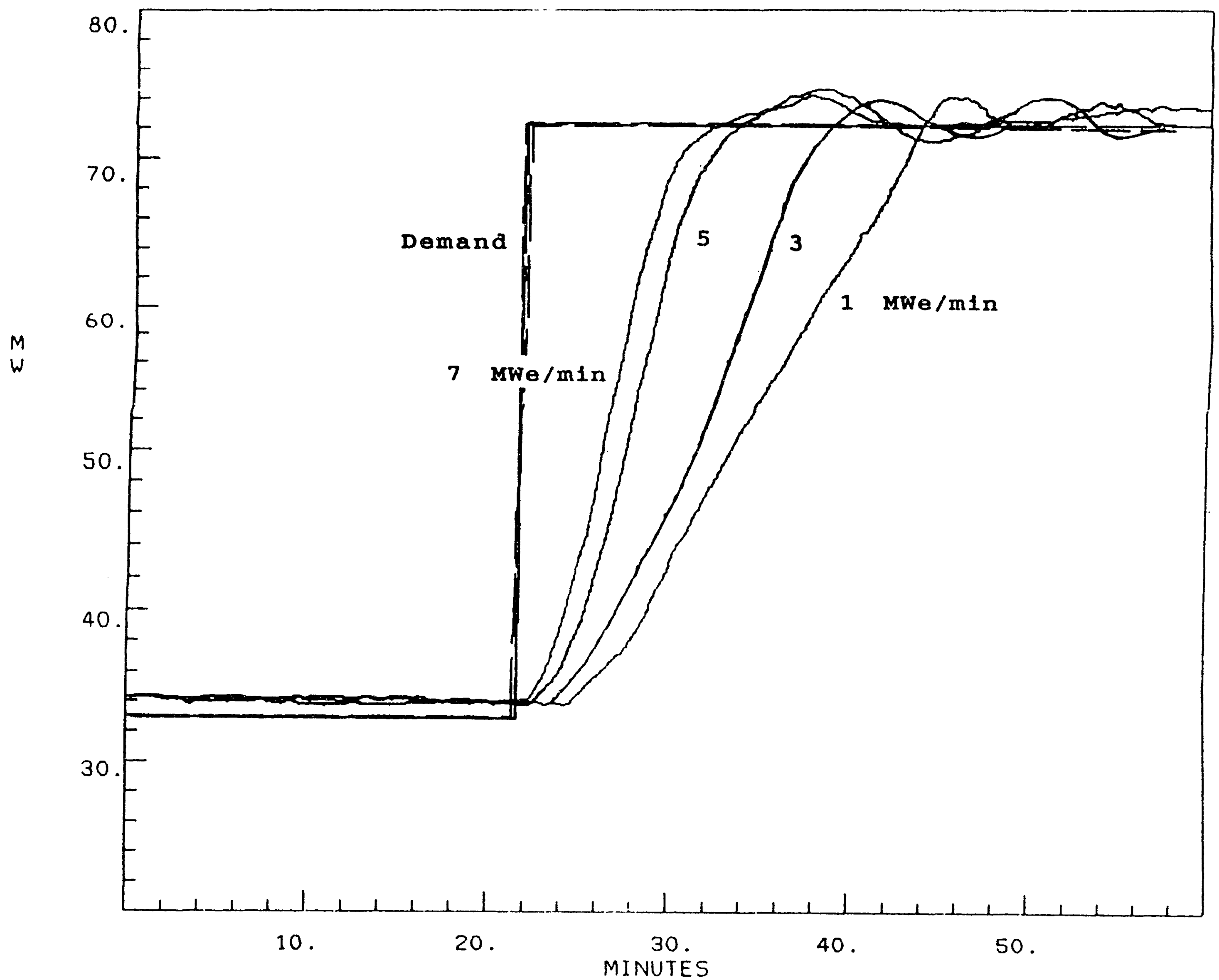


Figure 8-14. Summary of Load Response Tests for 40 MWe Increase in Load.

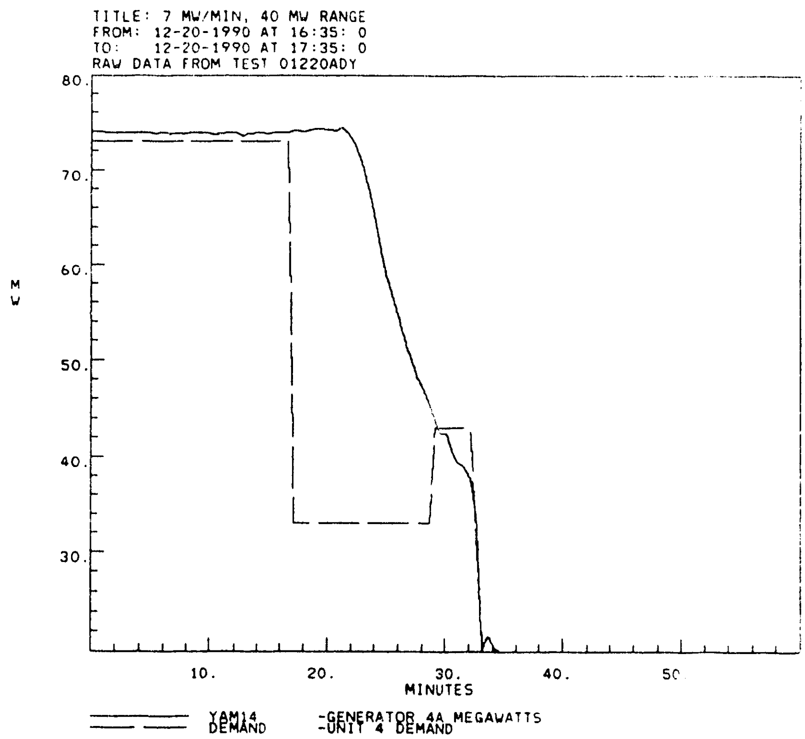


Figure 8-15. Test LF3: 74 MWe Generator Output and Demand.

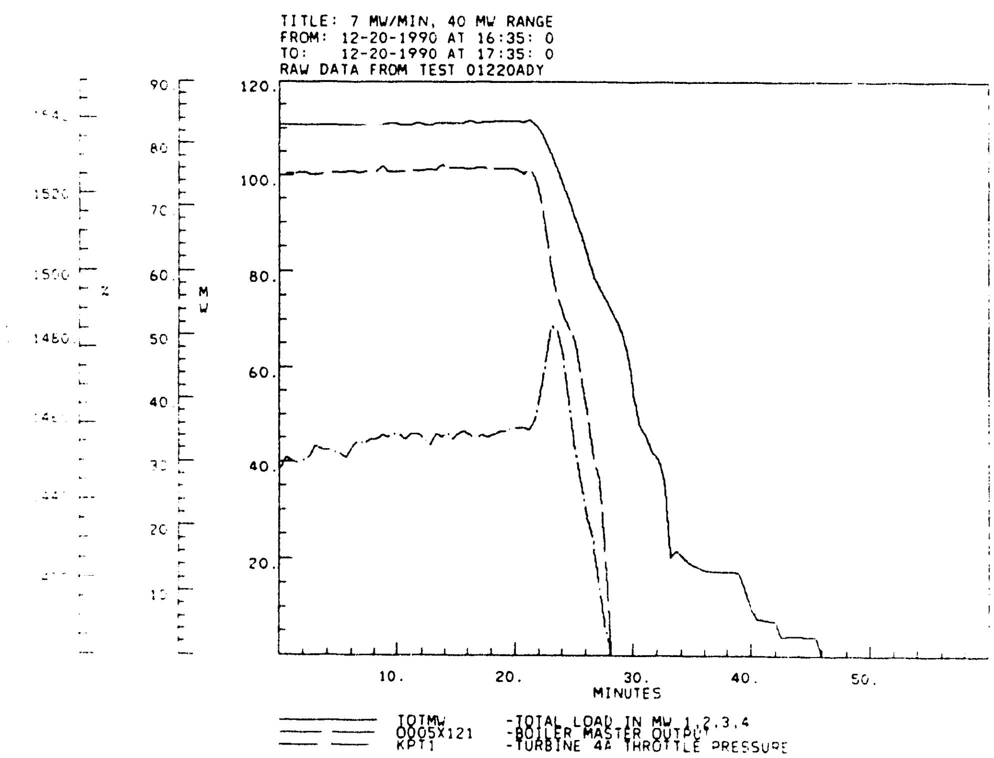


Figure 8-16. Test LF3: Total Plant Output, Boiler Master Output, and 74 MWe Turbine Throttle Pressure.

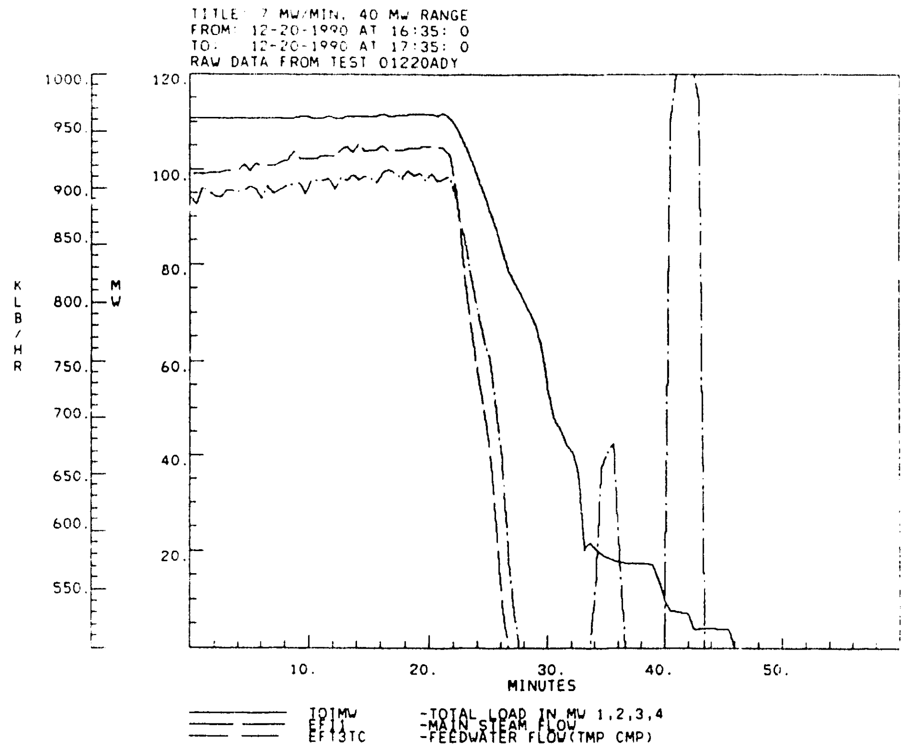


Figure 8-17. Test LF3: Total Plant Output, Main Steam Flow, and Feedwater Flow.

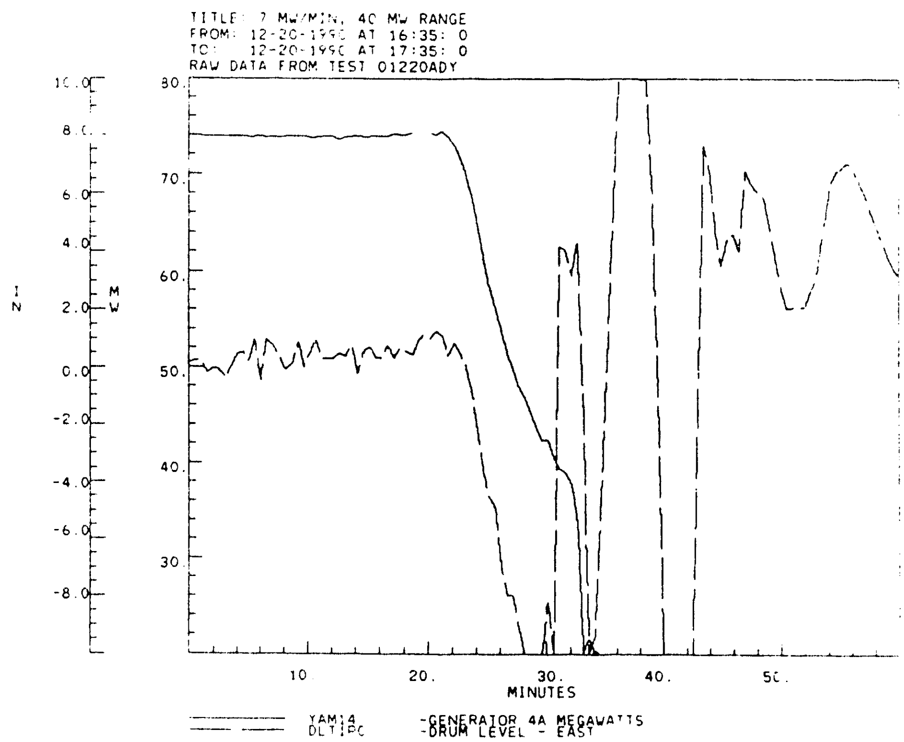


Figure 8-18. Test LF3: 74 MWe Generator Output and Drum Level.

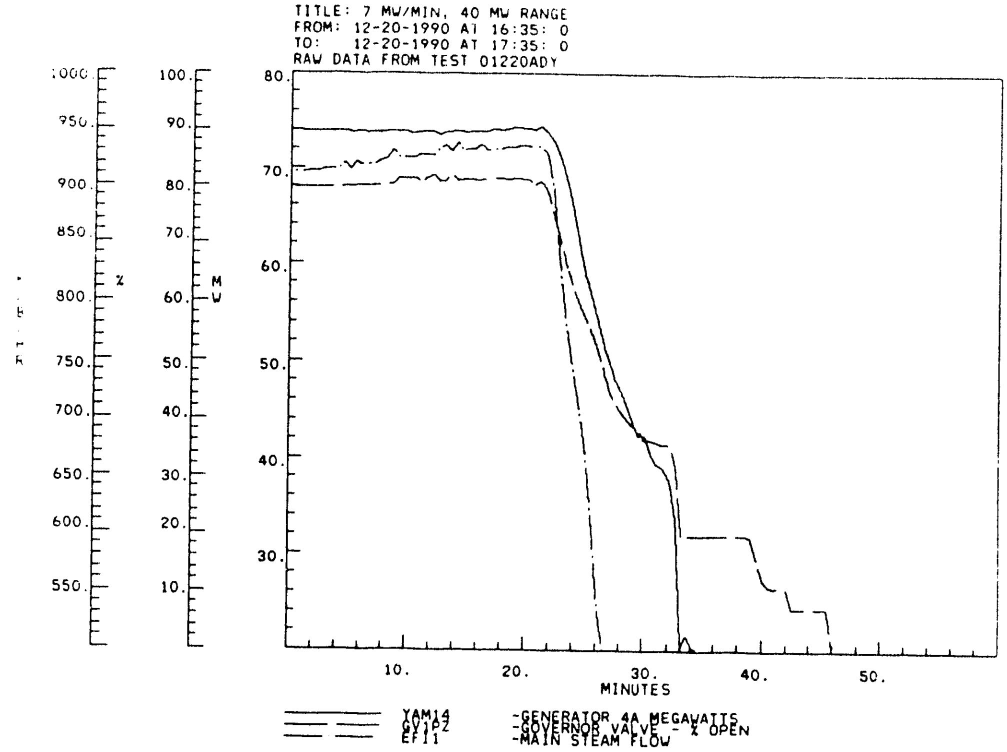


Figure 8-19. Test LF3: 74 MWe Generator Output, Governor Valve Position, and Main Steam Flow.

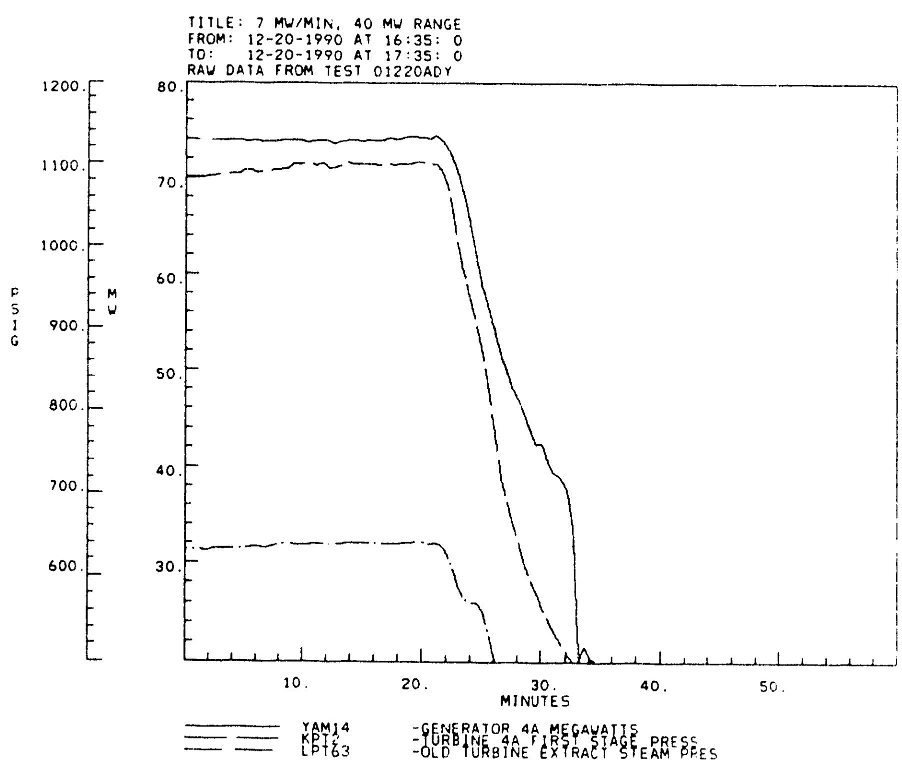


Figure 8-20. Test LF3: 74 MWe Generator Output, 1st Stage Pressure, and Extraction Line Pressure.

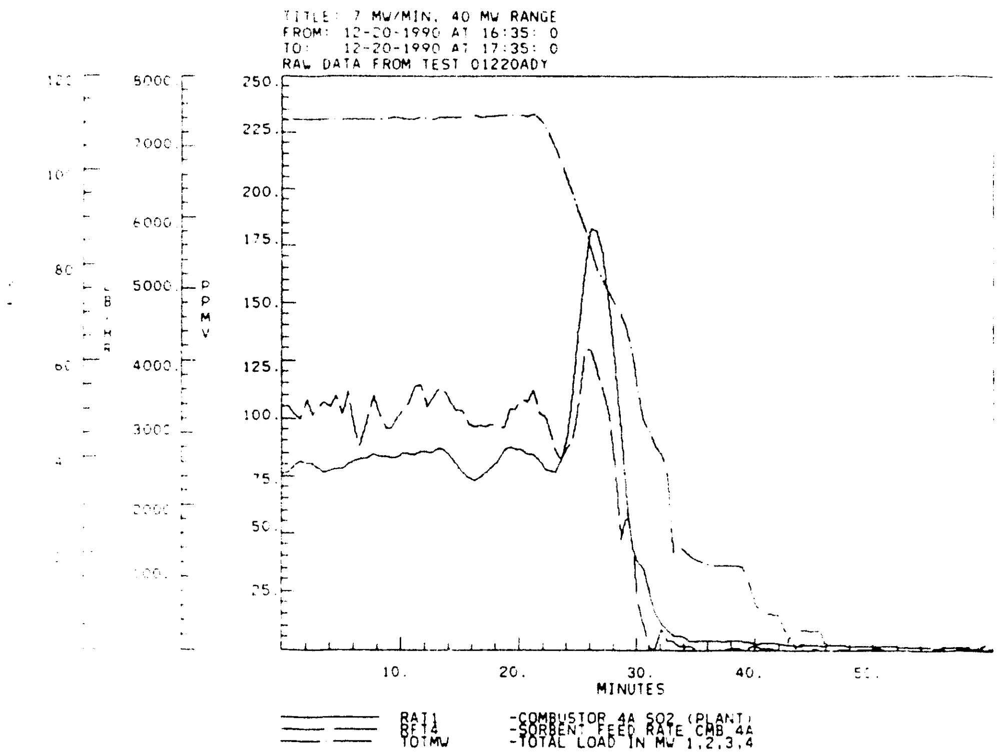


Figure 8-21. Test LF3: Combustor A SO_2 and Limestone Feed Rate, and Total Plant Load.

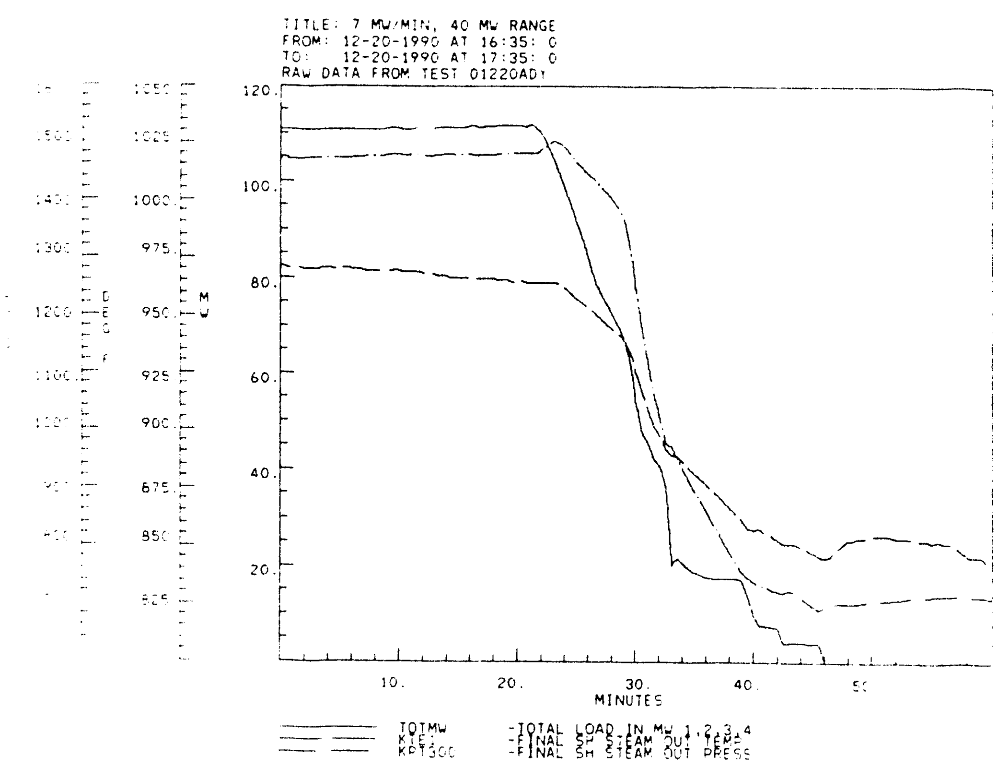


Figure 8-22. Test LF3: Total Plant Load, and Final Steam Pressure and Temperature.

results in an increase in throttle pressure shown in Figure 8-16 and a decrease in drum level shown in Figure 8-18. Again, the corresponding increase in drum pressure results in collapsing steam voids in the drum and water walls. This void reduction causes an unavoidable drop in drum level.

Since the load to the three existing 12 MWe turbines remains constant at 36 MWe gross output, the same quantity of steam flow is taken at the controlled extraction point on the 74 MWe turbine. However, during a load reduction, the steam flow through the 74 MWe turbine downstream of the extraction valve decreases along with the corresponding pressure drop. During test LF3, the pressure drop through the back end of the 74 MWe turbine decreased to the point that the controlled extraction pressure could no longer be maintained and dropped below 600 psig (see Figure 8-20). This drop in extraction pressure affects the main steam flow calculation.

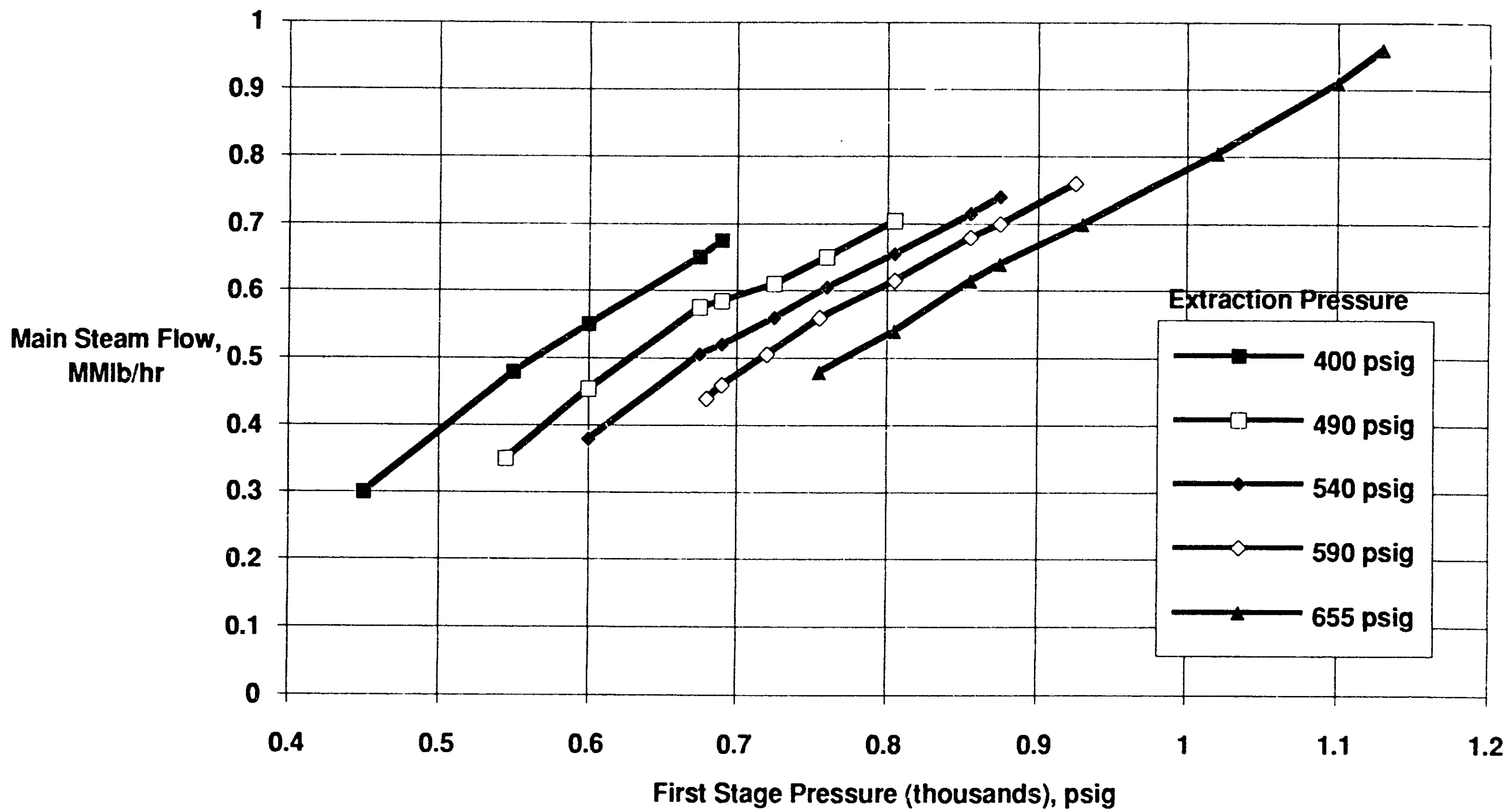
Final steam flow is calculated on the Nucla CFB using first stage pressure on the 74 MWe turbine. The calculation assumes a main steam pressure of 1464.7 psig, main steam temperature of 1005 °F, and an automatic extraction pressure of 640 psig. Any deviation in these values results in an error in final steam flow measurement based on first stage pressure, particularly with the extraction pressure. This is shown in Figure 8-23, which indicates that a sudden decrease in extraction pressure from 640 psig to 560 psig, as is the case in Figure 8-20, results in an error in the steam flow calculation by approximately 6 percent.

The importance of this is the use of the calculated steam flow rate in 3-element drum level control. This common control technique uses the steam flow rate as an anticipatory parameter to increase the feed water flow prior to any indicated change in drum level. The drum level indication is then used to "trim" the feed water flow. During drum level fluctuations with no indicated change in steam flow, the drum level takes over as the primary controller for feed water flow.

In test LF3, as the governor valves close in response to the change in load demand, the actual steam flow decreases by less than that calculated based on 1st stage pressure alone. However, the 3-element controller sees a larger reduction in steam flow by 6 percent, and reduces the feed water flow in excess of that required. This, coupled with the decrease in drum level due to the natural decrease in void fraction with increased drum pressure, results in a master fuel trip from low drum level.

Drum level control could be improved during load ramps by applying correction curves to the calculated steam flow for extraction pressure. Using the primary superheater

Figure 8-23. Effect of Extraction Pressure on Main Steam Flow Calculation



differential pressure as a measurement of the steam flow rate may provide another solution.

Section 9

SOLIDS AND GAS MIXING

9.1 OBJECTIVES AND APPROACH

In an effort to study mixing in the upper combustor area of the CFB, the freeboard gas analysis system (FGAS) was used to conduct flue gas traverses at two elevations in combustor B at Nucla during several performance tests. Tests were conducted at three loads with Peabody coal and at two loads with Salt Creek coal. In addition, traverses were also conducted with different coal feed and limestone feed configurations using Salt Creek coal to study the impact of the feeder configurations on the gas profiles.

Table 9-1 lists the conditions of the tests along with the fuels tested and the feeder configurations.

9.2 DESCRIPTION OF EQUIPMENT

A description of the FGAS traversing probe is given in Section 4.2.1 of this report. Two retractable probes were used to extract gas samples. One was located at elevation 44'6" and the other was located at 86'6". For convenience these two traverse points are referred to as the 40 ft. and 80 ft. traverse points. The 40 ft. elevation is approximately 25 ft. above the air distributor plate and the 80 ft. elevation is approximately 65 ft. above the air distributor.

Gas samples are collected at 1 ft. intervals throughout the 10 ft. range of the probes. Figure 9-1 shows a plan view of the Nucla combustor B and shows the relative locations of the coal feeders, limestone feeders, loop seal, secondary air ports, and traverse points. The loop seal enters the combustor approximately 2 ft. above the air distributor. One coal and one limestone feeder supply fuel and sorbent directly into the loop seal. The limestone feeders on the front wall and the outside wall are located about 5 ft. above the air distributor. The coal feeders on the front wall are approximately 7 ft. above the air distributor, as are the front and rear wall secondary air nozzles and the start-up burners. The secondary air nozzles along the outside and center walls are located about 8 ft. above the air distributor. On the outside wall, two ash cooler air return lines are located approximately where the secondary air nozzles would normally be located.

Table 9-1. Test Conditions For Gas Traverse Tests

Reference Test Number*	Traverse Test Date	Coal Type	Traverse Location	Load (MWe)	B-Bed Temperature °F	B-Bed Ca/S Ratio	Sulfur Retention B-Bed %	Coal Feed Configuration	Limestone Feeders Out Of Service	Gas Composition at Air Heater Inlet			
										O_2 Dry Vol %	CO Dry PPMV	NOx Dry PPMV	SO_2 Dry PPMV
A07	5/25/89	Peabody	40 & 80ft	55	1535	1.5	78	Balanced	None	5.9	93	44	150
A04	6/9/89	Peabody	40 ft	82.5	1650	1.7	75	Balanced	None	4.2	73	132	162
A04	6/22/89	Peabody	80 ft	82.5	1650	1.7	75	Balanced	None	4.2	73	132	162
A08	6/20/89	Peabody	40 ft	105	1650	1.8	73	Balanced	None	3.4	59	150	188
A08	6/21/89	Peabody	80 ft	105	1650	1.8	73	Balanced	None	3.4	59	150	188
P39	8/8/89	Salt Creek	40 & 80 ft	55	1569	2.6	80	Balanced	None	6.0	82	51	94
None	8/10/89	Salt Creek	40 & 80 ft	55	N/A	N/A	N/A	Front only	None	N/A	N/A	N/A	N/A
P52	8/14/89	Salt Creek	40 & 80 ft	55	1525	2.8	81	Loopseal only	None	6.3	72	38	85
None	12/27/90	Salt Creek	40 & 80 ft	108	N/A	N/A	N/A	Balanced	None	35.0	50	191	100
M01B	3/28/90	Salt Creek	40 & 80 ft	111	1700	2.6	69	50-50	None	3.0	63	162	145
M02B	3/19/90	Salt Creek	40 & 80 ft	110	1700	5.5	66	Front only	None	3.0	63	261	159
M03B	3/27/90	Salt Creek	40 & 80 ft	110	1726	6.8	69	Loopseal only	None	3.0	76	205	138
C02B	6/12/90	Salt Creek	40 & 80 ft	109	1715	5.1	79	Balanced	None	3.1	63	276	132
M05B	6/14/90	Salt Creek	40 & 80 ft	110	1702	5.8	75	Balanced	Side Wall	3.1	63	300	163

* Reference test number refers to a performance test of similar conditions and are not necessairly the same test.

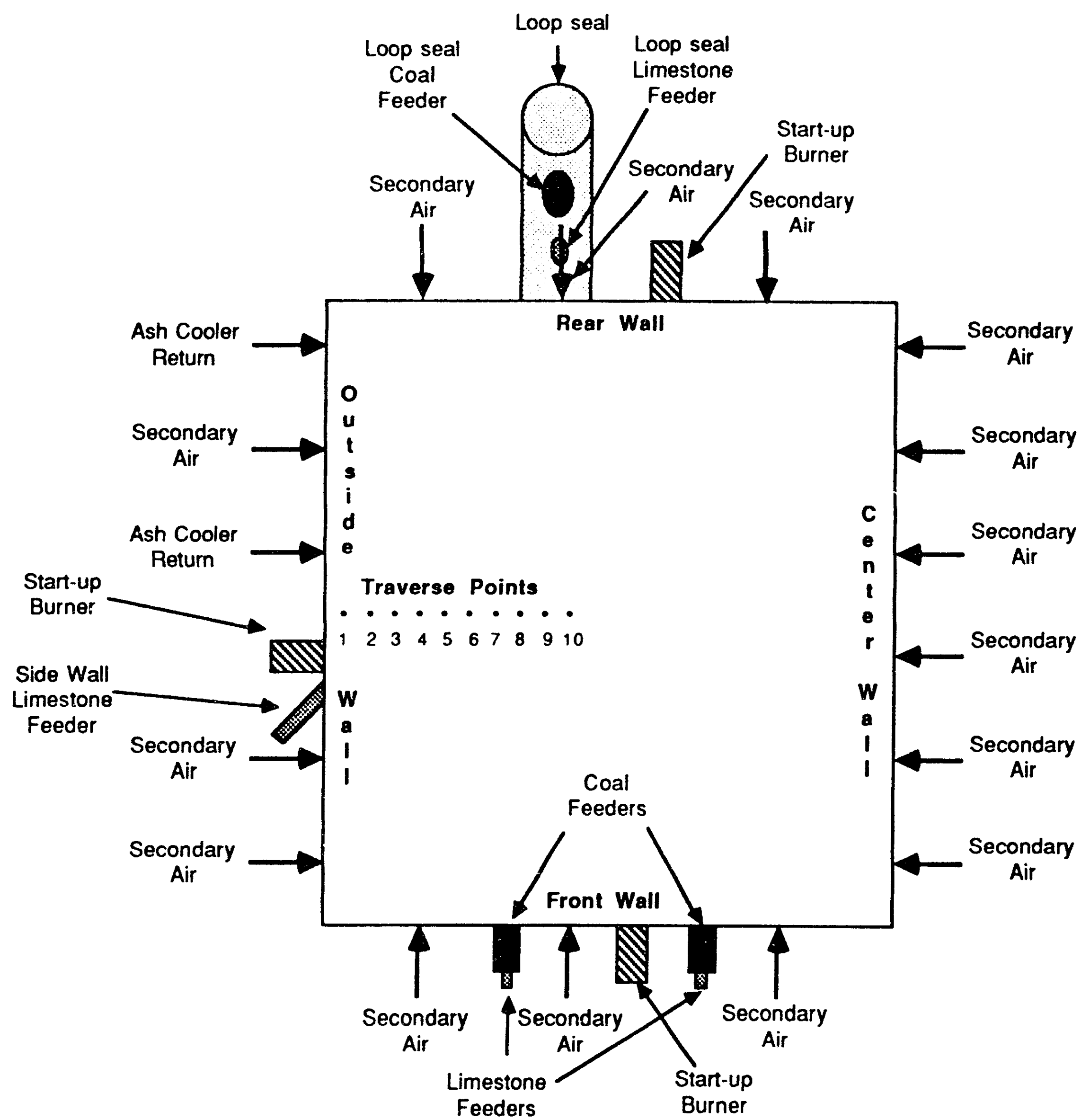


Figure 9-1. Plan view of Nucla B combustor showing location of fuel, limestone, loop seal and secondary air feeders.

Ten points are sampled as the probe is moved into the furnace. Each point is sampled for 6 minutes. The gas concentrations are recorded on the VAX computer every 4 seconds throughout the duration of the traverse. Data collected during the periodic line purges are deleted from the traverse results. Once a traverse is complete, the data are reviewed carefully, and the purge periods are identified and eliminated. The remaining data are broken down into the 6-minute periods representing the ten traverse points, averaged, and then plotted against depth into the boiler. The resulting graphs illustrate the gas concentration profiles along a single axis at two elevations within the combustor.

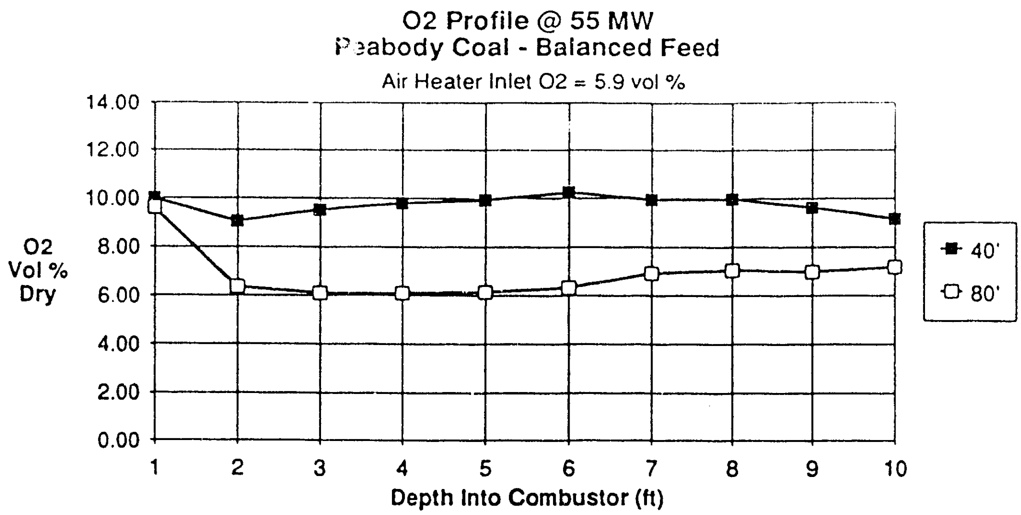
There are two limitations to the gas traverse data that must be considered when analyzing the results. First, the data are taken along a single axis at each elevation. The traversing points are located directly above each other. However, the traverse location only represents the gas concentrations within a narrow band at each elevation. There is no information provided across the entire cross-section of the boiler. Second, aspirating air is required at the insertion point to prevent combustion gasses from escaping the boiler. This air may contaminate the gas sample taken at the 1-foot depth. However, there is no indication that this contamination is occurring.

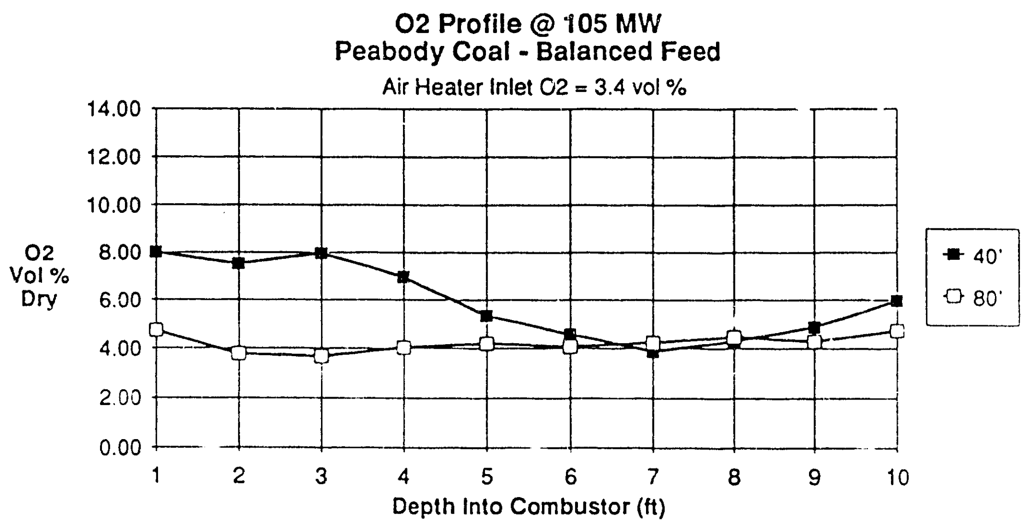
9.3 GAS TRAVERSE RESULTS

9.3.1 Effect of Load

Fourteen gas traverse tests were conducted. Table 9-1 contains a list of the tests and the dates completed. The first five traverses listed in Table 9-1 were performed using Peabody coal. These tests were conducted at three loads with balanced feed to all three coal and four limestone feeders to study the effect of load on gas mixing. Furthermore, two sets of traverses were conducted using Salt Creek coal at two loads with balanced feed (55 MW on 8/8/89 and 108 MWe on 12/27/89). Figures 9-2 through 9-5 show the effect of load for Peabody coal on O_2, CO, NO_x, and SO_2 traverses, respectively. Also shown on each figure is the concentration that was obtained at the air heater inlet. In order to allow comparisons of different graphs, all graphs for a gaseous component are drawn with the same Y-axis.

The O_2 profiles shown in Figure 9-2 are relatively flat. The 55 MWe traverses indicate that there is a considerable amount of combustion occurring between the 40 and 80 ft. traverse planes, as evidenced by the decrease in O_2 between these readings. The 82 and 105 MWe traverses seem to indicate that there is little, if any, combustion occurring between the two traverse planes near the center of the boiler, as evidenced





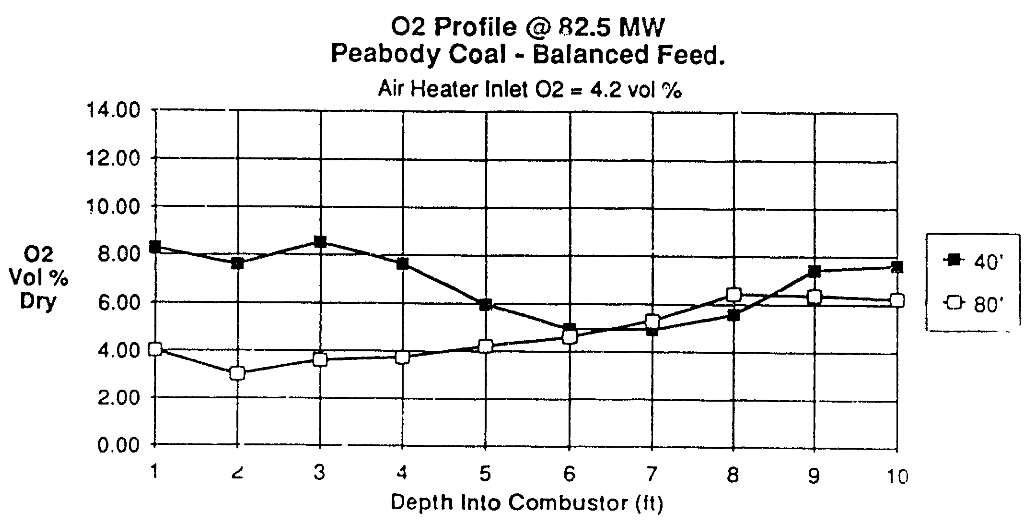


Figure 9-2. O_2 traverses for Peabody coal at three loads.

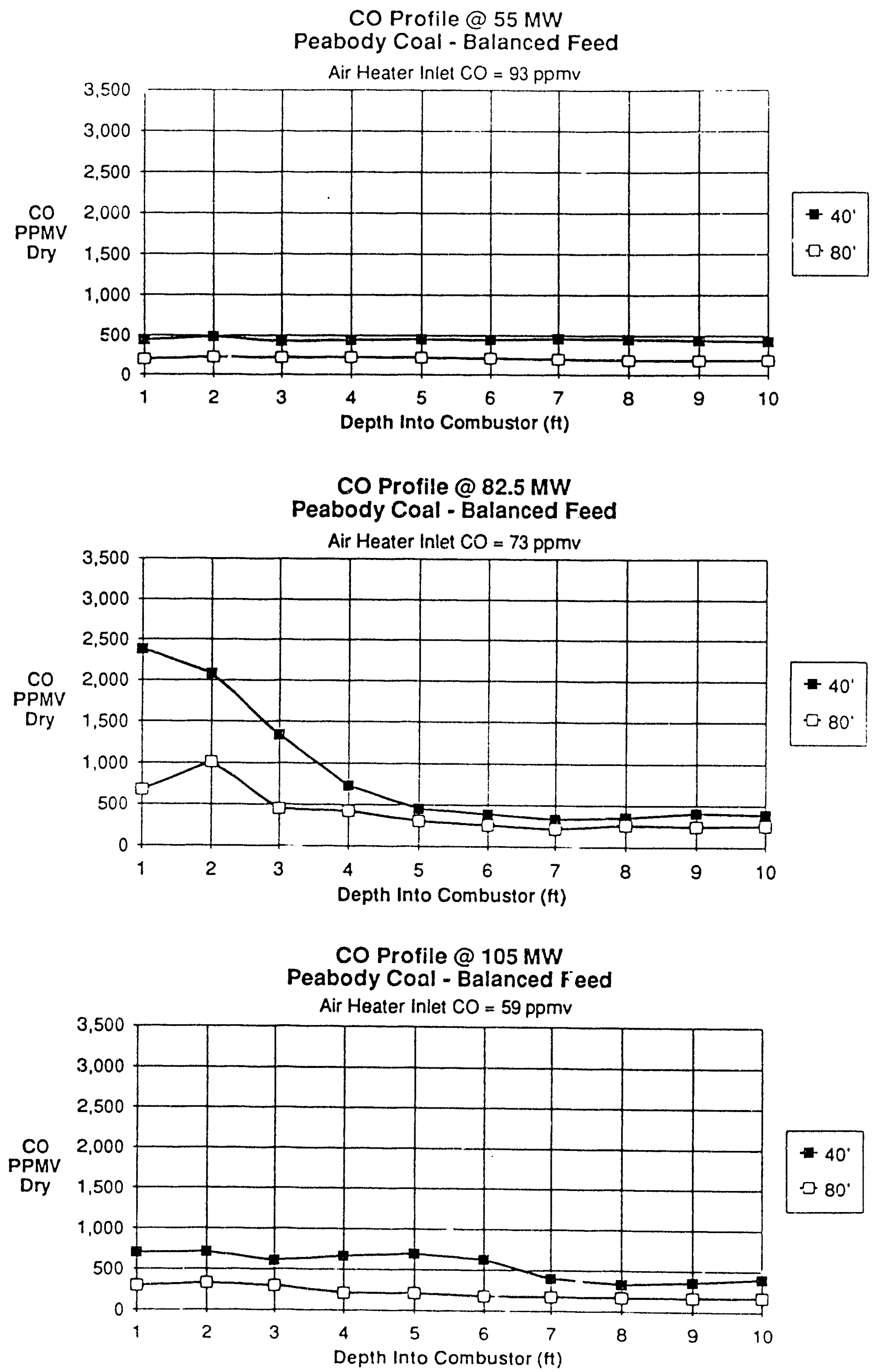
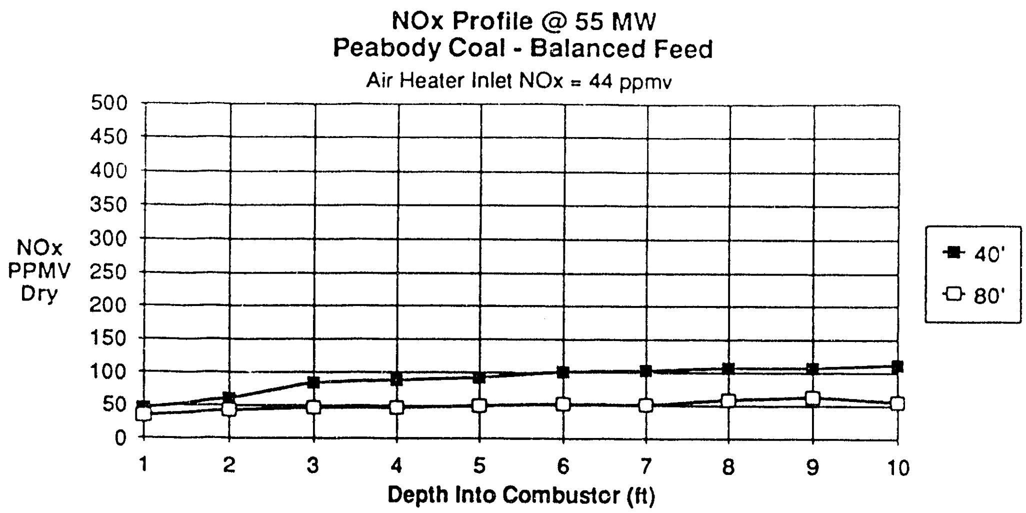
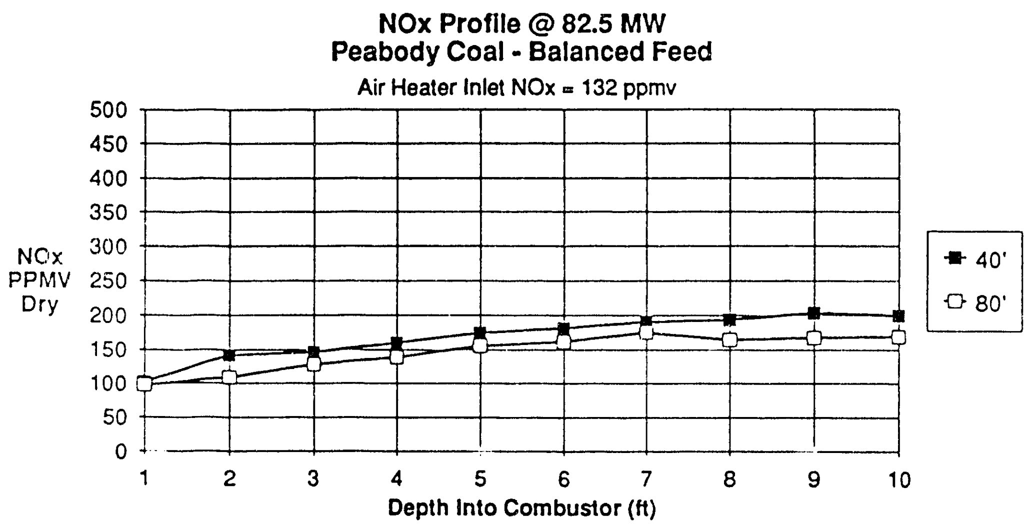


Figure 9-3. CO traverses for Peabody coal at three loads.





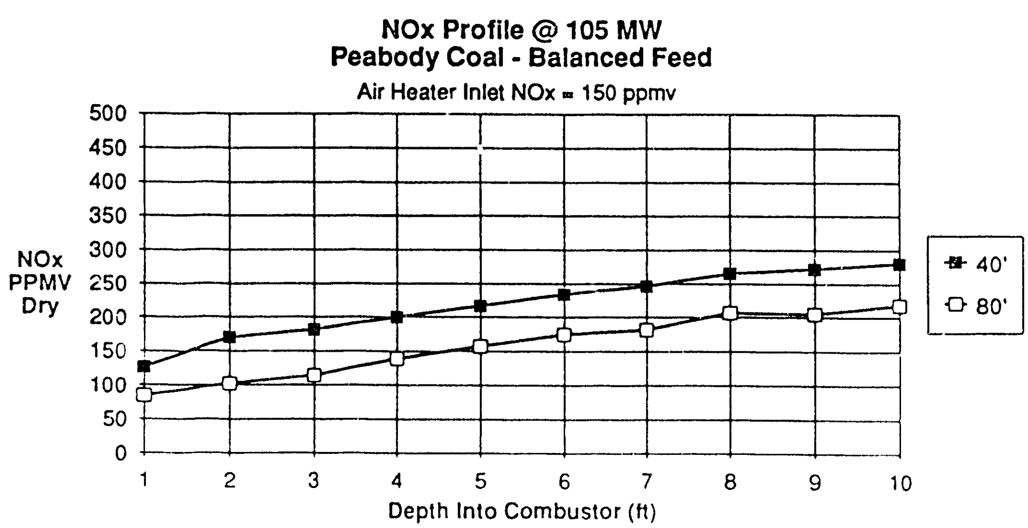
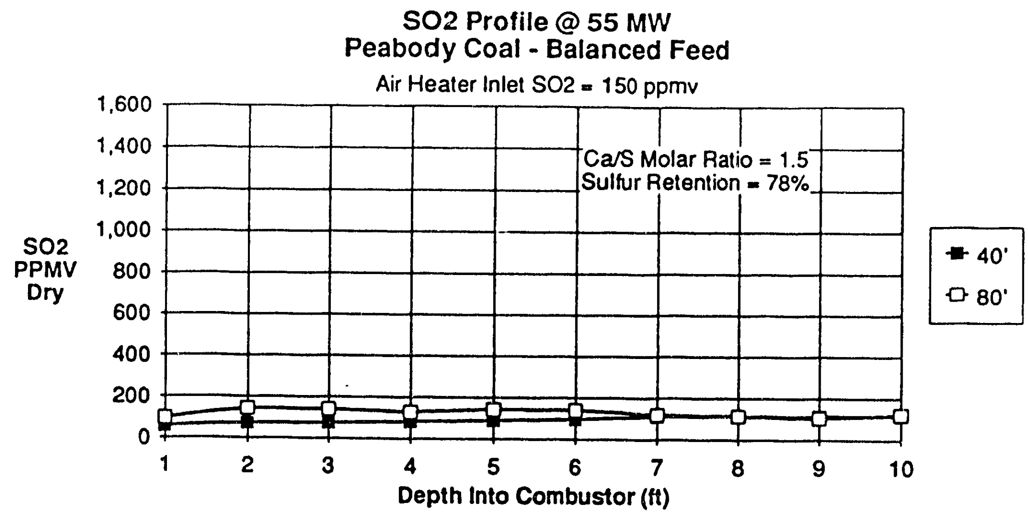
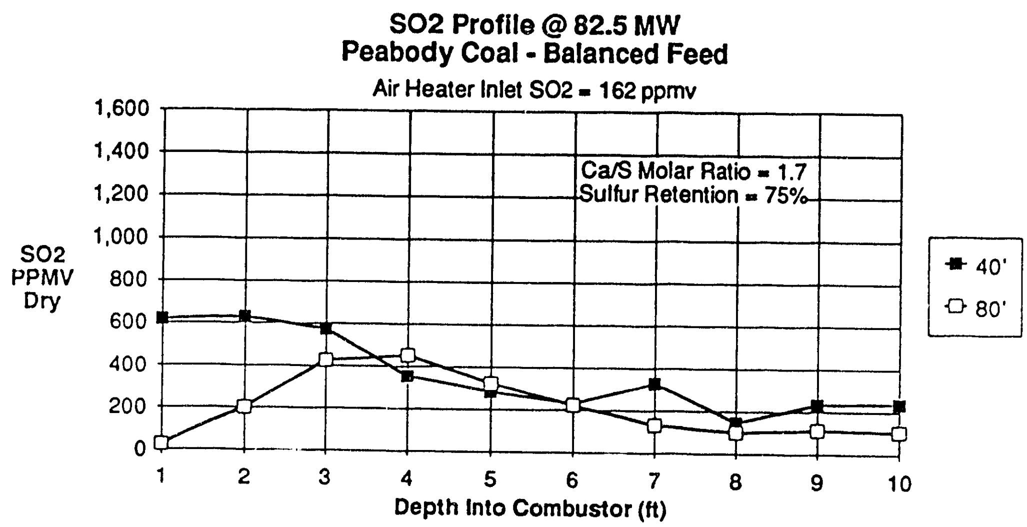


Figure 9-4. NO_x traverses for Peabody coal at three loads.





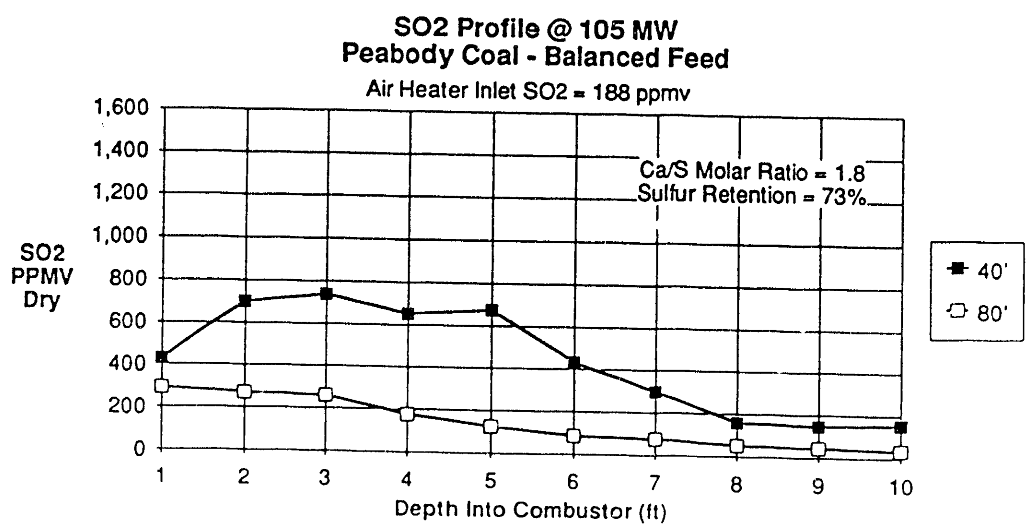


Figure 9-5. SO_2 traverses for Peabody coal at three loads.

by the fact that the oxygen is not changing. At the walls, however, oxygen is still being consumed.

The CO profiles, shown in Figure 9-3, show little difference for the 55 and 105 MWe traverses. However the 82.5 MWe traverse shows rather large concentrations of CO near the walls at the 40 ft. location. By the 80 ft. traverse, the CO levels have been reduced considerably. Note that the air heater inlet values show a trend of increasing CO with decreasing load. This trend is believed to be due to the higher furnace temperatures at the higher loads.

The NO_x profiles, shown in Figure 9-4, show a general trend of increasing values towards the center of the furnace. There is clear evidence of decreasing NO_x with height in the combustor. Note also that there is little difference between the 80 ft. values and the air heater inlet value.

The SO_2 profiles, shown in Figure 9-5, are relatively flat at 55 MWe with little change between the traverse planes and the air heater inlet. At 82.5 and 105 MWe the trend is for increased SO_2 near the wall. These traverses indicate that, for 82.5 and 105 MWe, SO_2 is being released high up in the combustor and near the wall. This observation is corroborated by the O_2 profiles that indicate combustion occurring between the two traverse planes. Also note that the Ca/S ratio increased with increasing load. This may have been due to the higher bed temperatures, or it may have been due to the release of SO_2 higher in the combustor. Note also that some sulfur capture must be occurring between the 80 ft. elevation and the air heater inlet.

9.3.2 Effect of Coal Type

Figures 9-6 through 9-9 show a comparison of traverses for Peabody and Salt Creek coals at half load and full load for O_2, CO, NO_x, and SO_2, respectively. Also shown on the plots are the values obtained at the air heater inlet during the traverses. These plots are shown to allow comparison of the gas traverses for the two fuels. The Peabody profiles are the same as those shown in Figures 9-2 through 9-5.

Table 9-2 shows the composition and size distribution for the coals used during these tests. The Salt Creek coal appears to have about 10% more fines (<600 microns). Furthermore, the ratio of oxygen to fixed carbon is slightly higher for Salt Creek coal. The ratio of oxygen to fixed carbon (O/FC) has been found to be indicative of the reactivity of the char. Based on the O/FC ratios, the Salt Creek is about 14% more reactive than Peabody. The Salt Creek coal also has slightly higher volatiles and nitrogen contents than the Peabody coal.

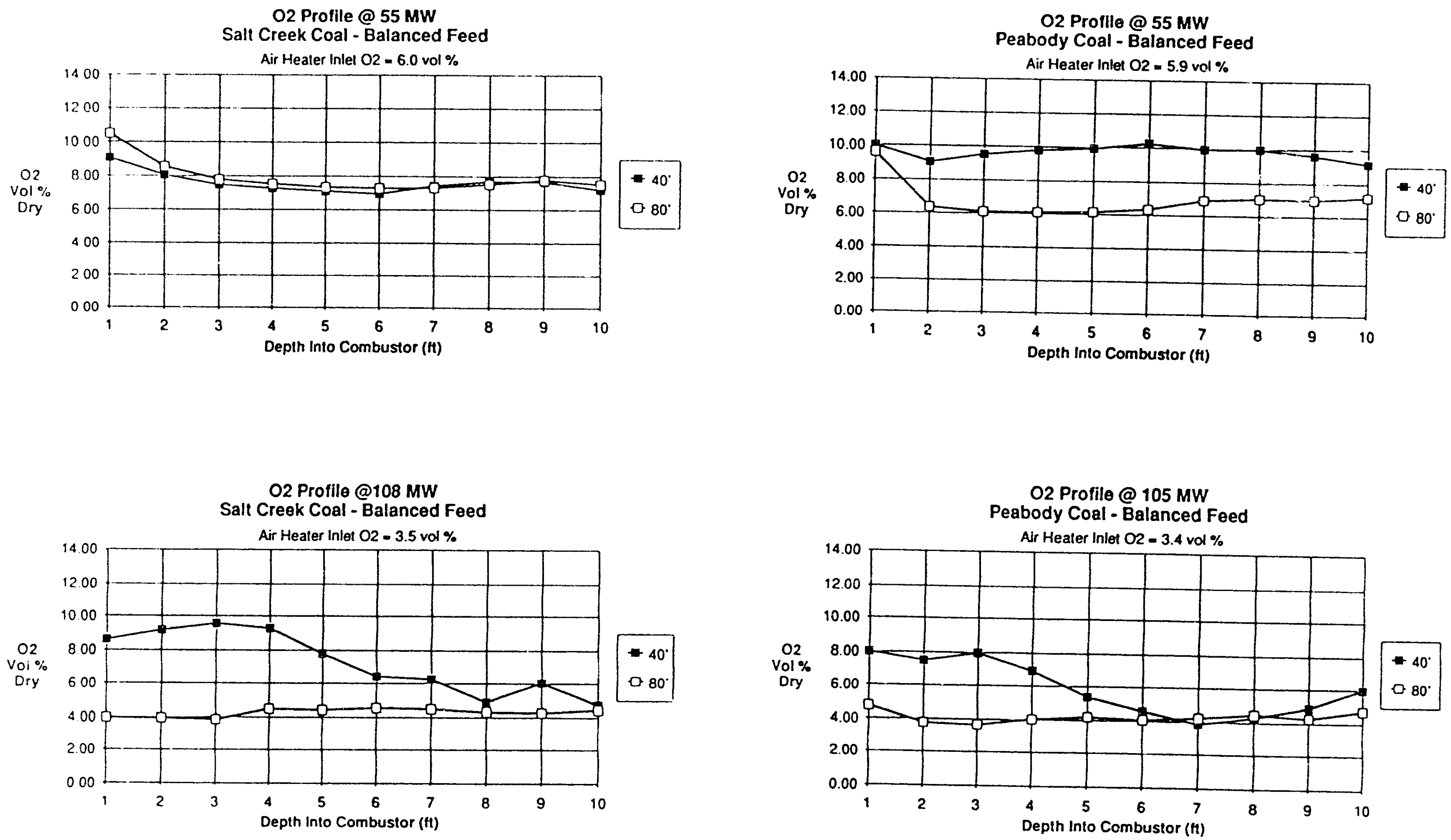


Figure 9-6. O2 traverses for Salt Creek and Peabody coal at two loads.

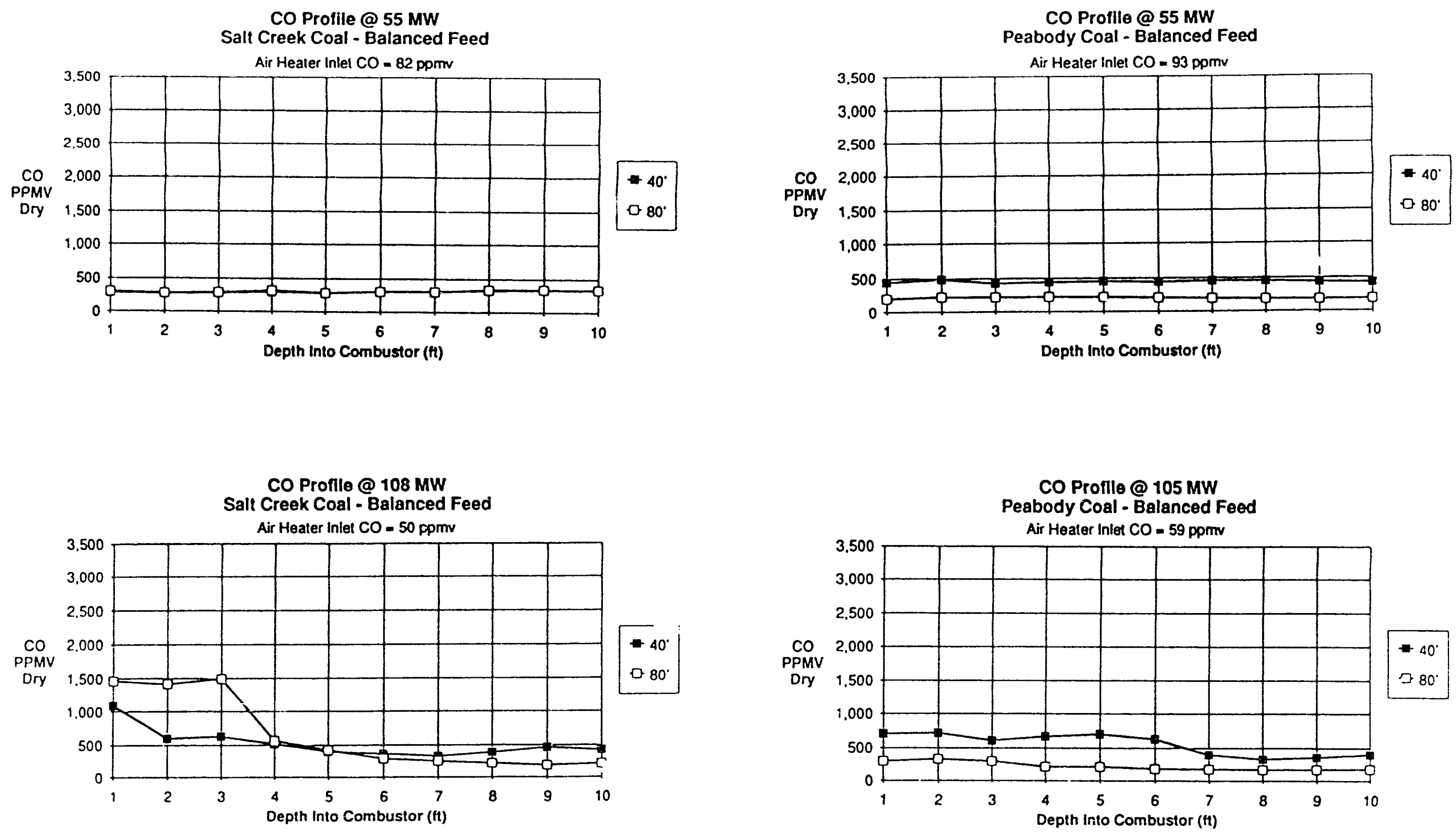


Figure 9-7. CO traverses for Salt Creek and Peabody coal at two loads.

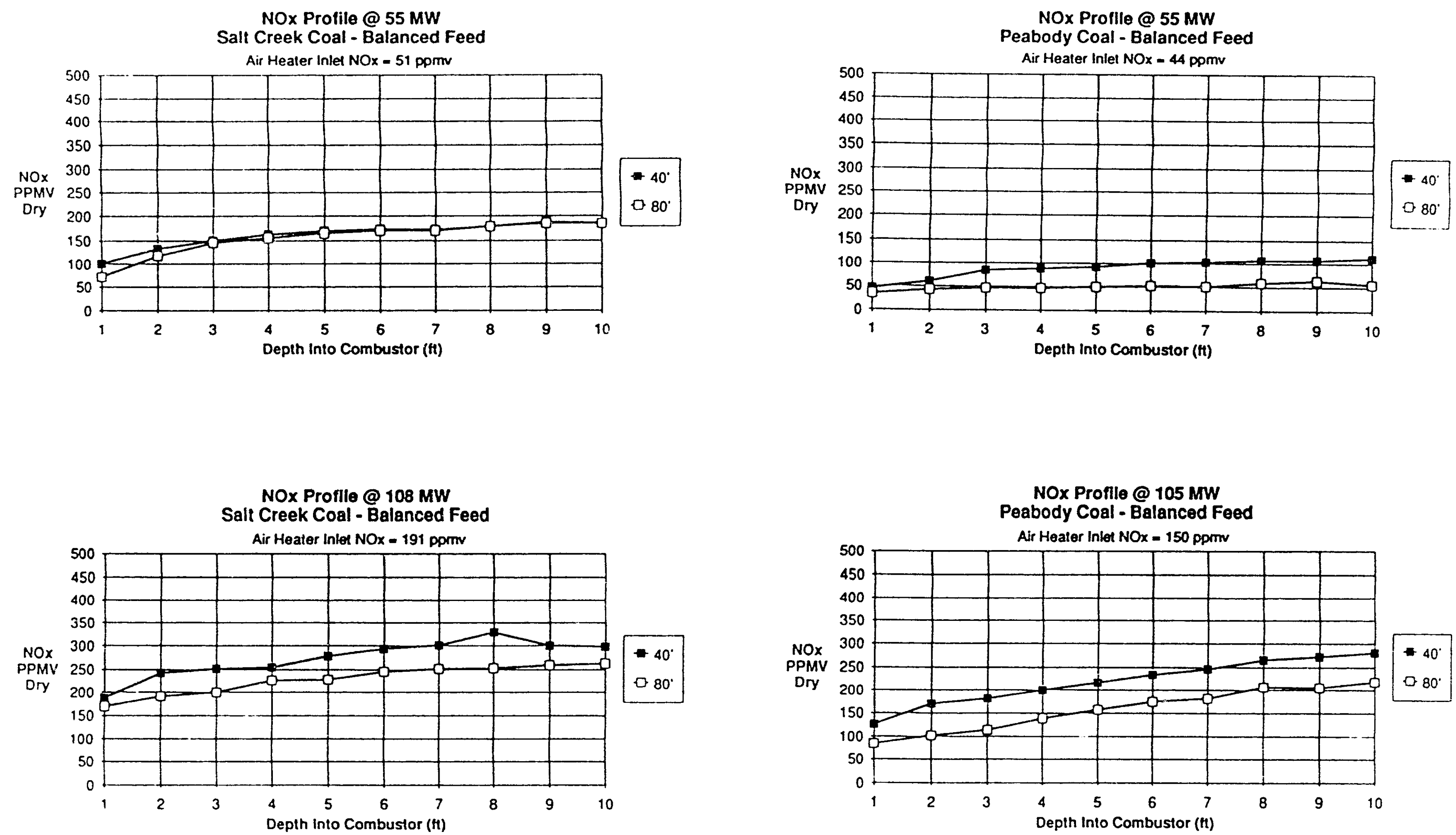


Figure 9-8. NO_X traverses for Salt Creek and Peabody coal at two loads.

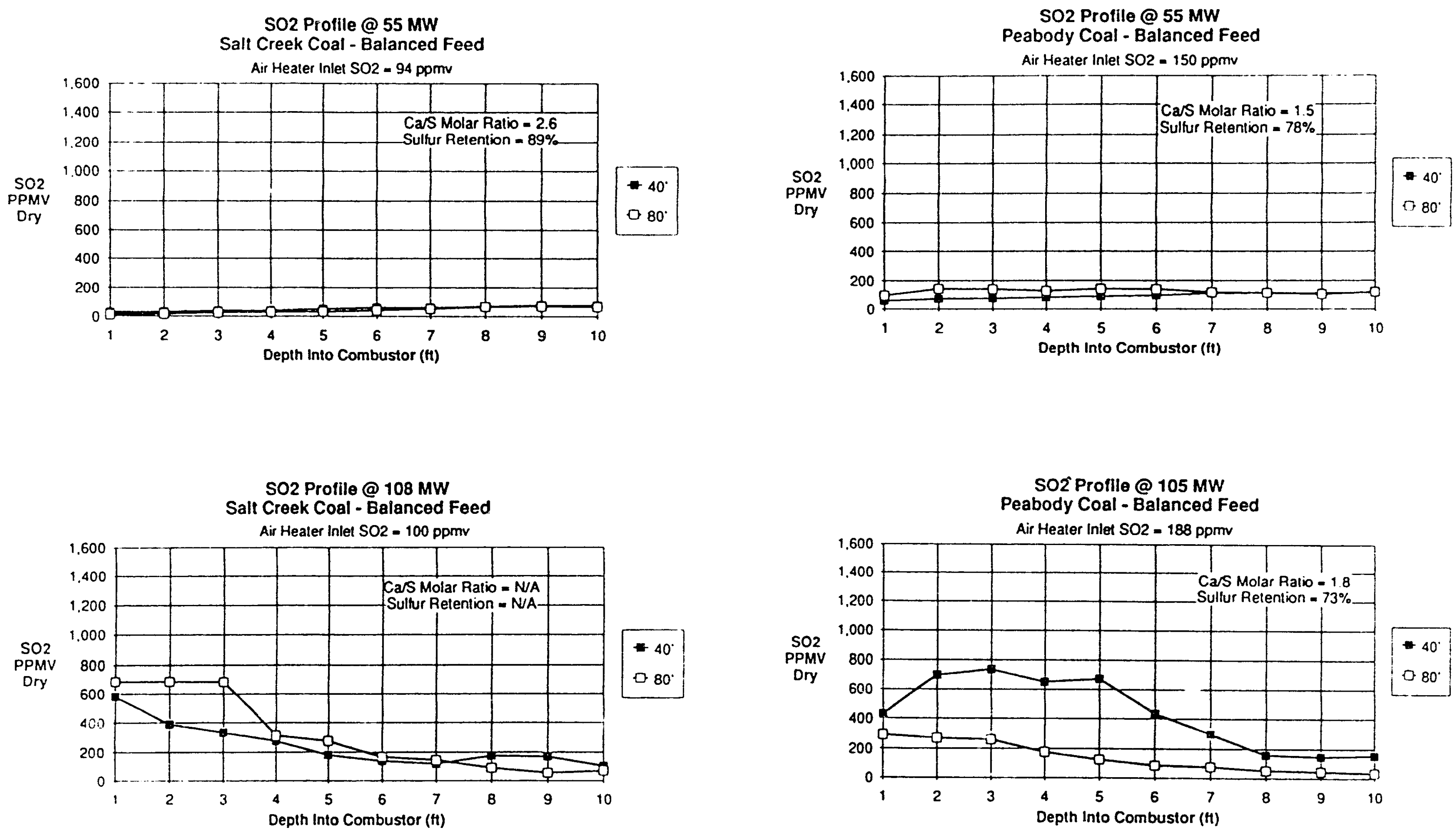


Figure 9-9. SO_2 traverses for Salt Creek and Peabody coal at two loads.

Table 9-2. Fuels Analyses for Traverse Tests

Test No Coal Gross Load MW	A07 Peabody 55	A08 Peabody 105	P39 Salt Creek 55	 Salt Creek 105
HHV (Btu/lb)	10,520	10,936	10,691	10,597
Proximate Analysis				
Total Moisture (%)	5.20	5.88	9.82	8.92
Voaltiles (%)	28.87	29.47	32.62	32.35
Fixed Carbon (%)	43.71	48.12	43.17	43.49
Ash (%)	22.22	16.53	14.38	15.24
Ultimate Analysis				
Carbon	59.28	63.77	61.41	61.23
Hydrogen	3.46	3.45	3.47	3.75
Oxygen	8.13	8.84	9.24	9.08
Nitrogen	0.93	0.81	1.13	1.35
Sulfur	0.79	0.72	0.54	0.44
Ash	22.22	16.53	14.38	15.24
Size Distribution % less Than				
19,000	100.00	100.00	100.00	100.00
12,500	92.40	93.15	100.00	100.00
6,300	79.15	82.25	93.05	89.69
4,750	71.75	75.65	86.85	84.22
3,350	62.85	64.60	77.65	74.30
2,360	54.30	53.90	68.10	63.98
1,700	45.50	43.35	57.65	52.90
1,180	36.95	34.55	47.60	42.64
850	29.95	27.55	38.90	33.98
600	24.60	22.55	31.80	27.34
300	15.30	14.10	18.95	16.00
150	8.00	8.05	10.35	8.59
106	3.30	4.85	4.21	5.86

The O_2 profiles are shown in Figure 9-6. For the 55 MWe traverses, the shape of the two profiles are similar. However, the Salt Creek coal shows little evidence of combustion between the 40 and 80 ft. traverse planes. This indicates that Salt Creek coal burns lower in the furnace. This characteristic could be explained by the higher reactivity and higher volatile content of Salt Creek coal.

CO profiles are shown in Figure 9-7. With the exception of the 108 MWe Salt Creek coal traverse, all of the traverses are relatively flat. The 108 MWe Salt Creek traverse shows increasing CO near the wall. This trend was also observed in Figure 9-3 for the 82.5 MWe test on Peabody coal. Despite the high CO readings (over 1400 ppmv near the wall for the 108 MWe Salt Creek traverse), the air heater readings remained low, indicating that CO is burned above the 80 ft. elevation. This probably occurs in the cyclone where turbulence mixes the oxygen with the CO.

Figure 9-8 shows the NO_x profiles for Peabody and Salt Creek coals at the two loads. The NO_x readings for Salt Creek coal are consistently higher than the Peabody coal readings. This may reflect the higher fuel nitrogen in the Salt Creek coal. In all cases, the NO_x levels increase towards the center of the furnace.

Figure 9-9 shows the SO_2 profiles for both coals at the two loads. The traverse profiles for the 55 MWe tests are quite similar, being relatively flat and near the air heater value. The full load tests show an interesting phenomenon. Near the wall, the Peabody coal 40 ft. traverse shows SO_2 values above the 80 ft. traverse, while the Salt Creek coal 40 ft. traverse has SO_2 values less than the 80 ft. traverse.

9.3.3 Effect of Fuel Feed Location

Another series of tests were performed to study the effect of fuel feed location on the gas traverses. These tests were conducted at 55 and 110 MW with Salt Creek coal. Three fuel feed configurations are examined in this report. The three configurations are: 1) balanced coal, with 33% coal feed to all three feeders; 2) front wall feed, with 50% of the coal feed to each of the front wall feeders; and 3) loop seal feed, with 100% coal feed to the loop seal coal feeder. An additional configuration of 25% coal to each of the front wall feeders and 50% to the loop seal, termed the 50/50 feed configuration, was tested at 110 MWe only. This feed configuration will be discussed separately.

Figure 9-10 shows the O_2 profiles for the two loads and the three feeder configurations. While the profile for the balanced feed is relatively flat, the two extreme feed conditions show opposite trends. The front wall feed

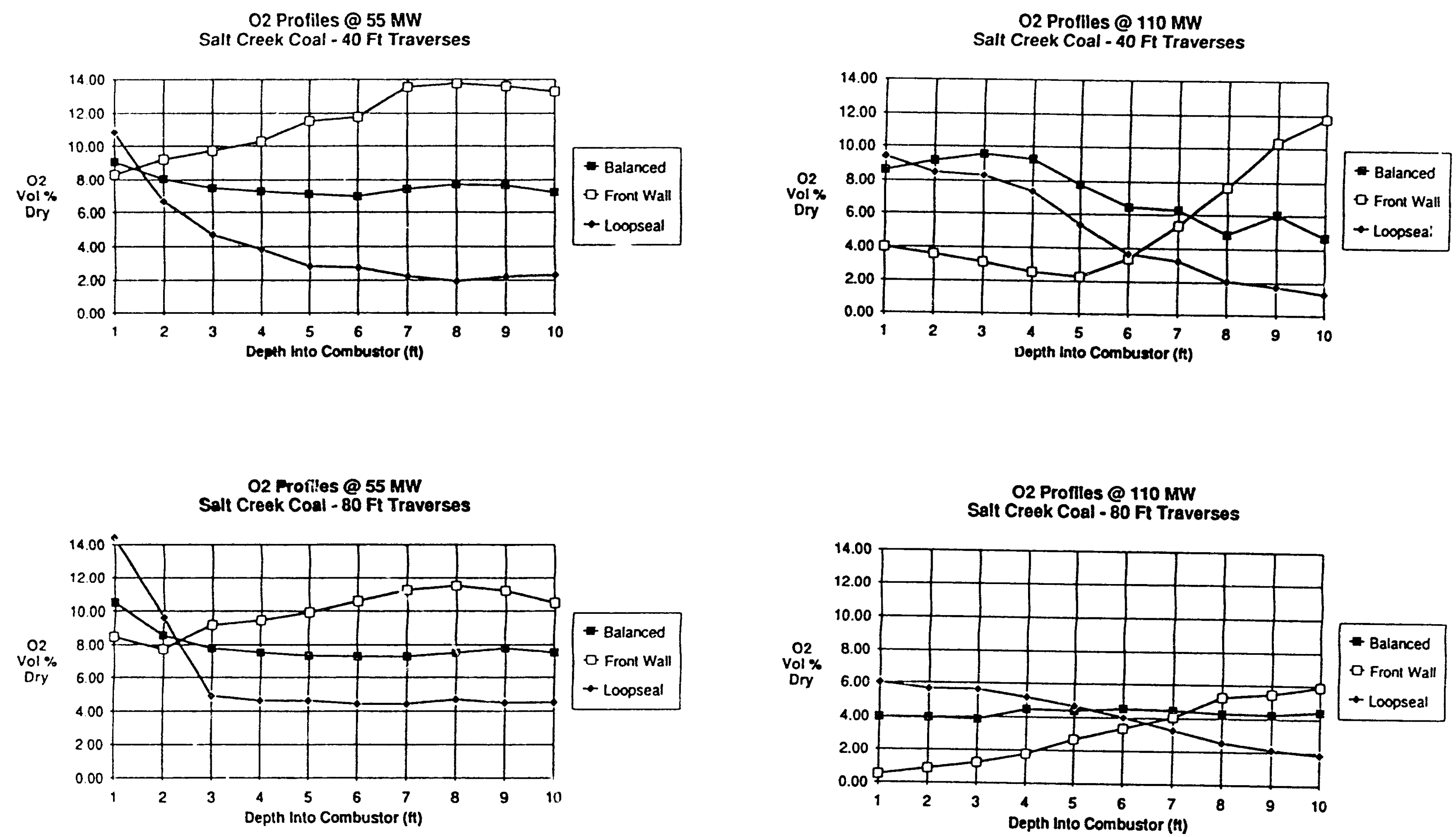


Figure 9-10. Effect of coal feed configuration on O_2 traverses for Salt Creek Coal.

configuration shows the oxygen concentration increasing towards the center of the furnace. The loop seal feeder configuration shows oxygen concentrations increasing towards the wall. The trend is most visible at the 110 MWe loads. These curves indicate that coal fed through the loop seal is forced towards the center of the furnace while coal fed at the front wall feeders apparently burns more towards the wall.

Figure 9-11 shows the CO traverses for the three feed configurations at both loads. As with the oxygen, the CO profiles indicate that the loop seal coal feed is burning towards the center of the furnace while the front wall feed burns towards the wall. Note also that, despite the extremely high CO levels at the 80 ft. traverse plane, the CO at the air heater was 63 ppmv for the front wall test and 76 ppmv for the loop seal test. This again indicates that CO is being burned downstream of the 80 ft. plane, probably in the cyclones.

Figure 9-12 shows the NO_x traverses for the three feed configurations and the two loads. At 55 MWe, the balanced feed traverses showed the highest NO_x readings, however this trend reverses at full load. Furthermore, while the front wall feeder at full load did not show any traverse points higher than the loop seal configuration, the front wall feeder gave the highest NO_x readings at the air heater inlet (261 ppmv NO_x for the front wall, 205 ppmv for the loop seal, and 191 ppmv for the balanced). The loop seal feed configuration did not appear to have any impact on NO_x at the air heater inlet, but did show increased values inside the furnace.

Figure 9-13 shows the SO_2 traverses for the three feed configurations and the two loads. The 55 MWe traverses indicate that the loop seal feed configuration had higher SO_2 readings towards the center of the furnace than the other two configurations. This can be explained by the lower O_2 readings in this region (see figure 9-10). However, the differences are small. At full load, the trend is for increased SO_2 readings towards the center of the furnace for the loop seal feed configuration, and towards the walls for the front wall feeders. It should also be pointed out that both the front wall tests and the loop seal tests showed poorer sulfur capture efficiency than the balanced feed configuration, with the loop seal configuration being slightly worse than the front wall configuration.

Figures 9-14 through 9-17 compare the 50/50 feed distribution (25% coal to each wall feeder and 50% to the loop seal) to the balanced feed configuration (33% coal feed to all three feeders). The graphs for the 50/50 feed show similar trends to the balanced feed configuration. However, combustion

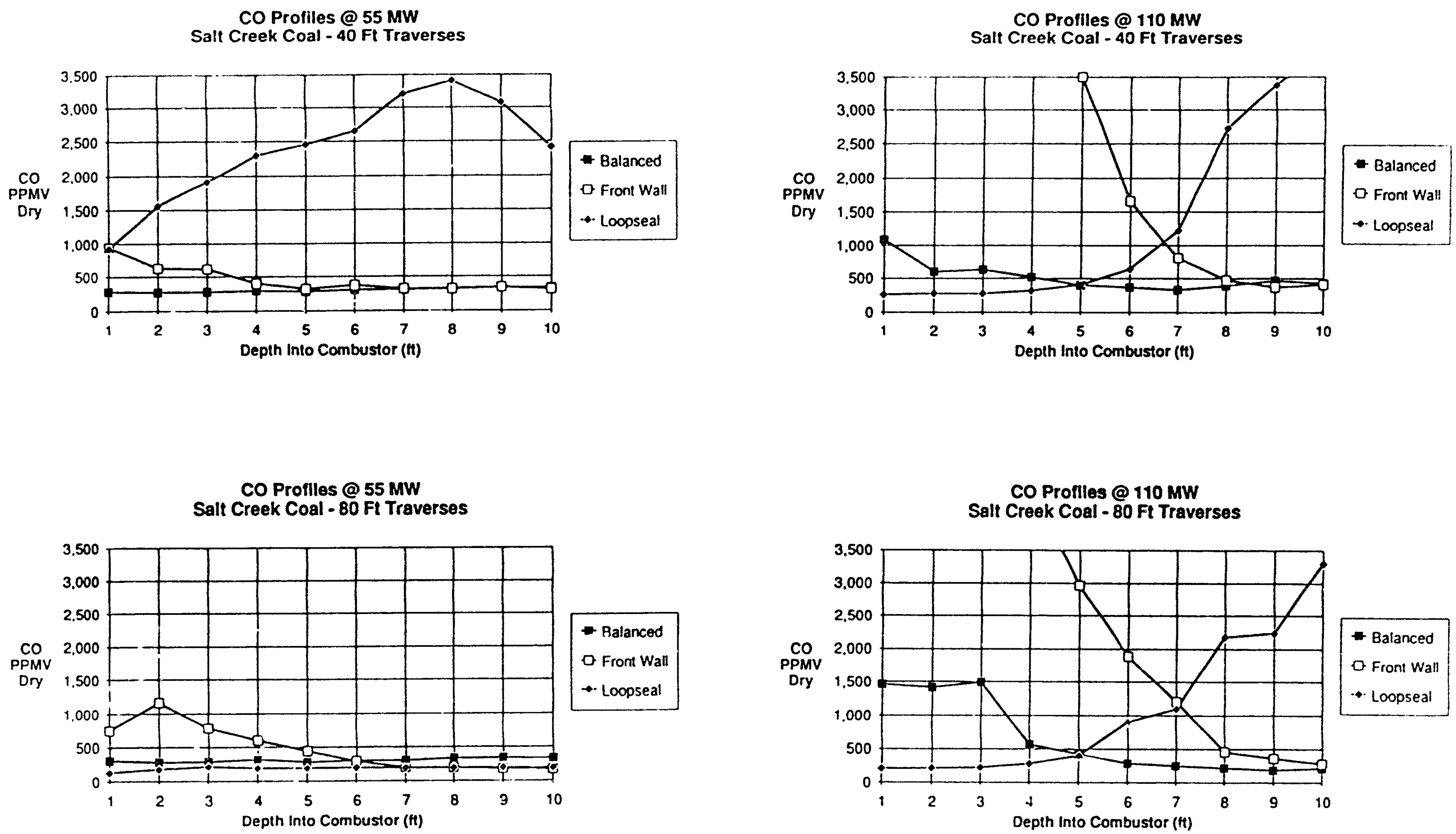


Figure 9-11. Effect of coal feed configuration on CO traverses for Salt Creek Coal.

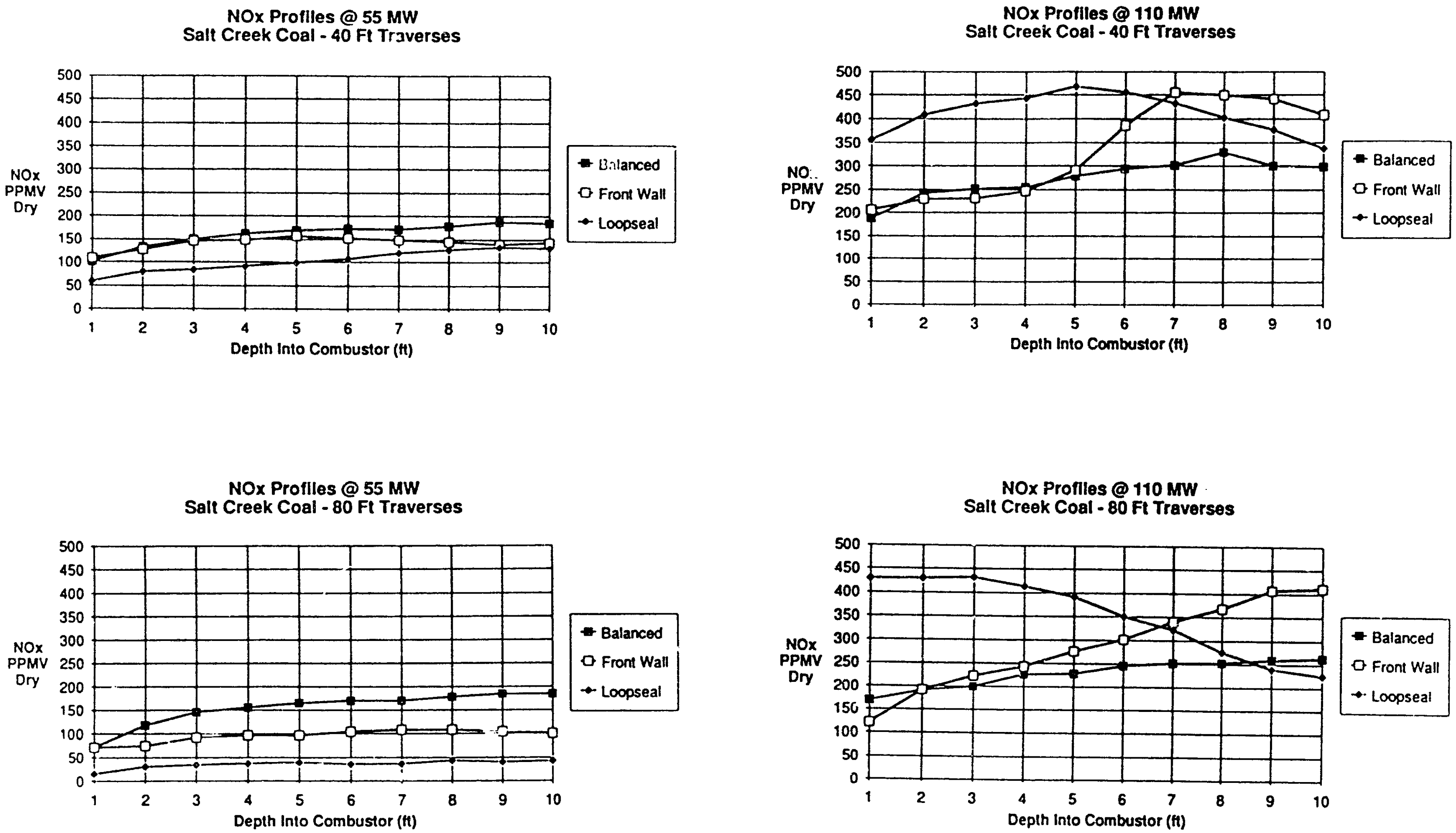


Figure 9-12. Effect of coal feed configuration on NO_x traverses for Salt Creek Coal.

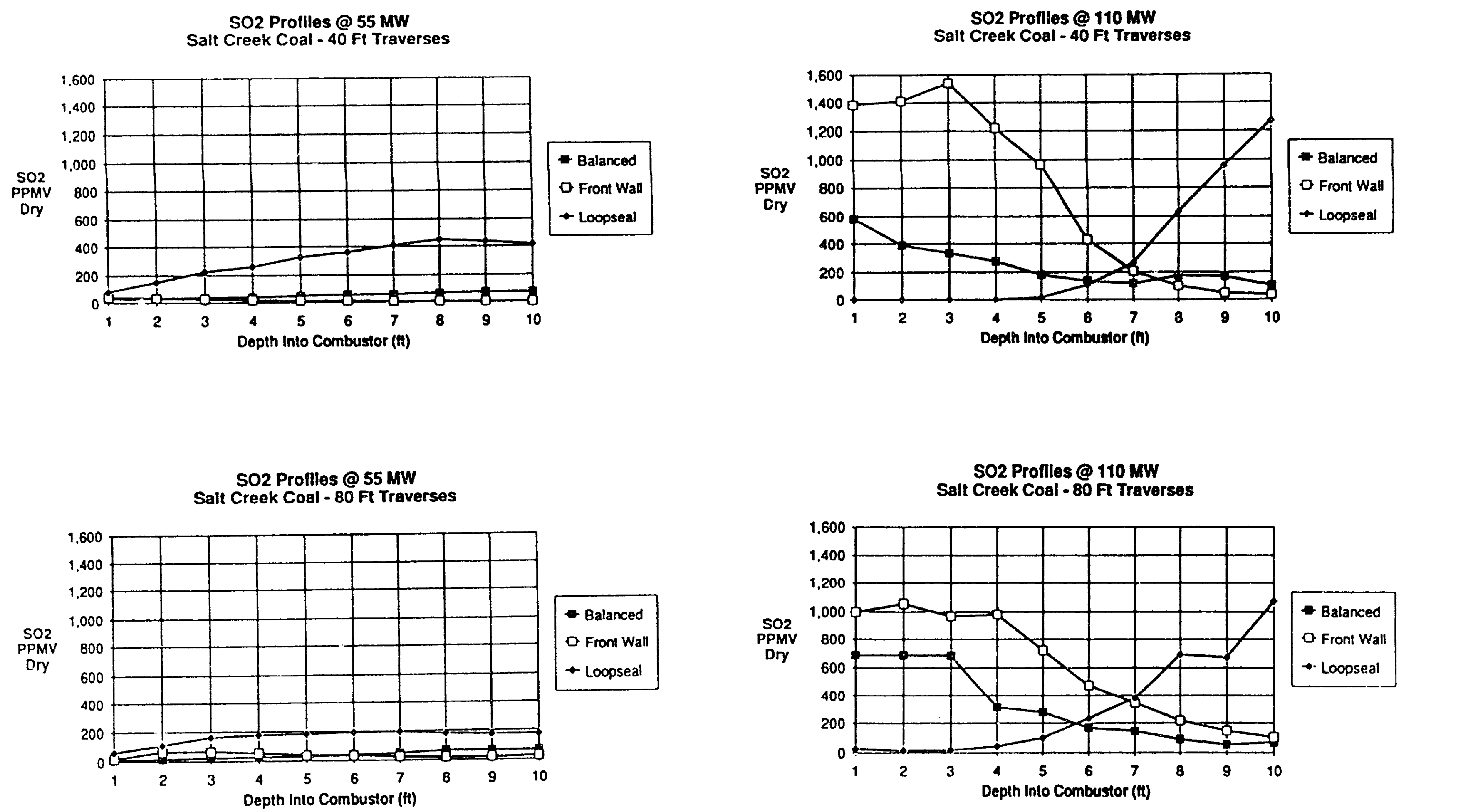
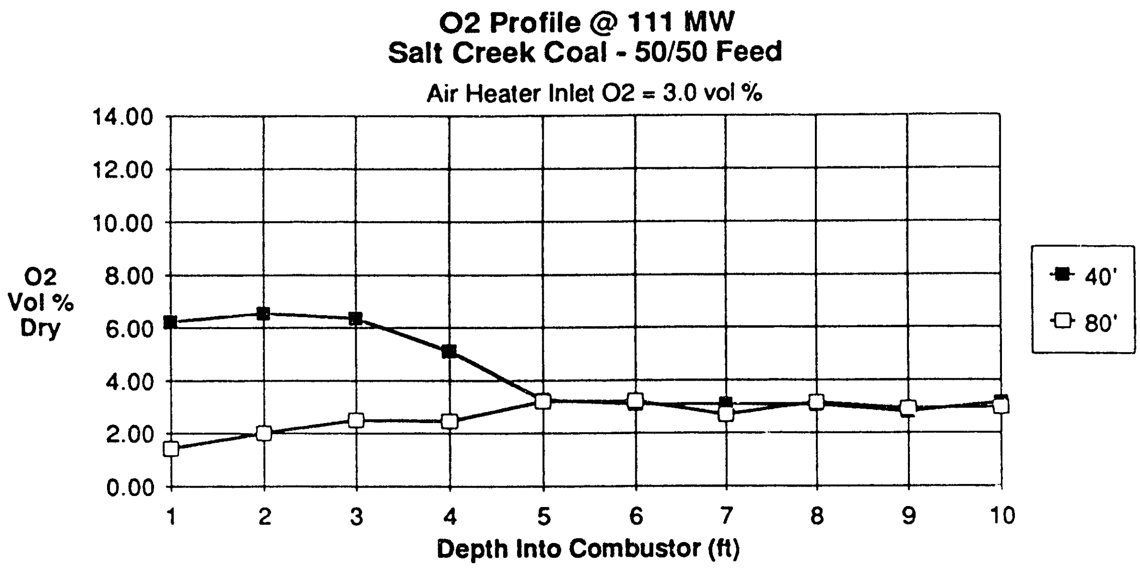


Figure 9-13. Effect of coal feed configuration on SO_2 traverses for Salt Creek Coal.



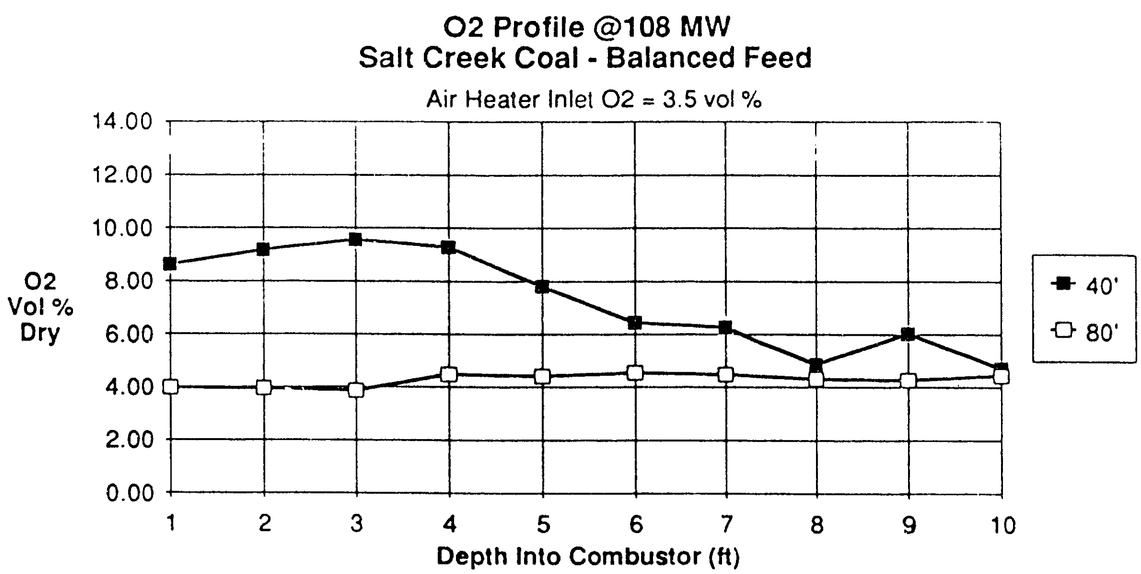
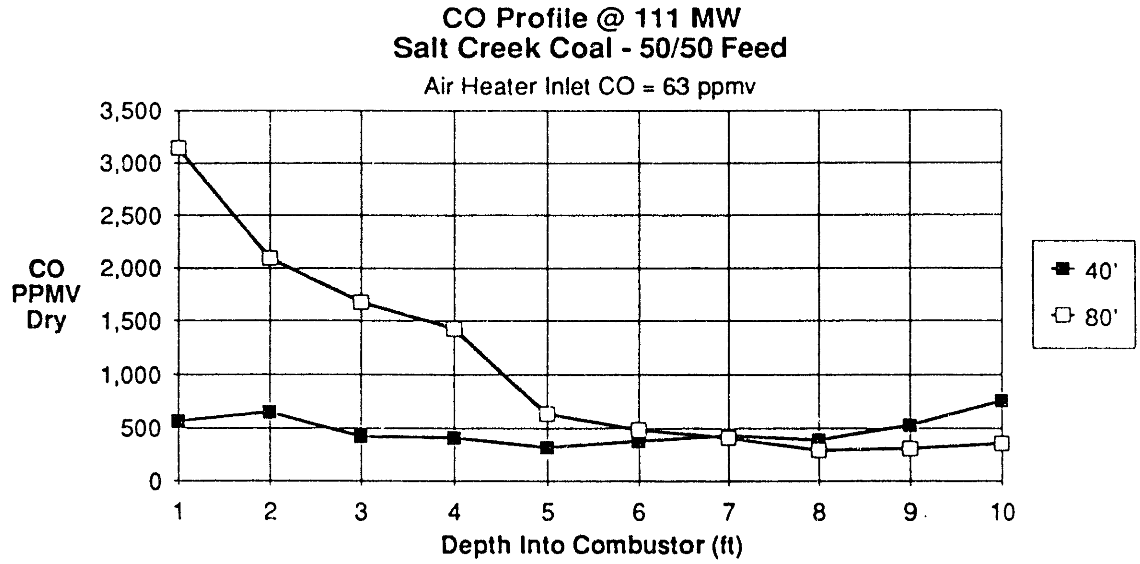


Figure 9-14. Comparison of O_2 traverses for 50/50 coal feed and balanced coal feed.



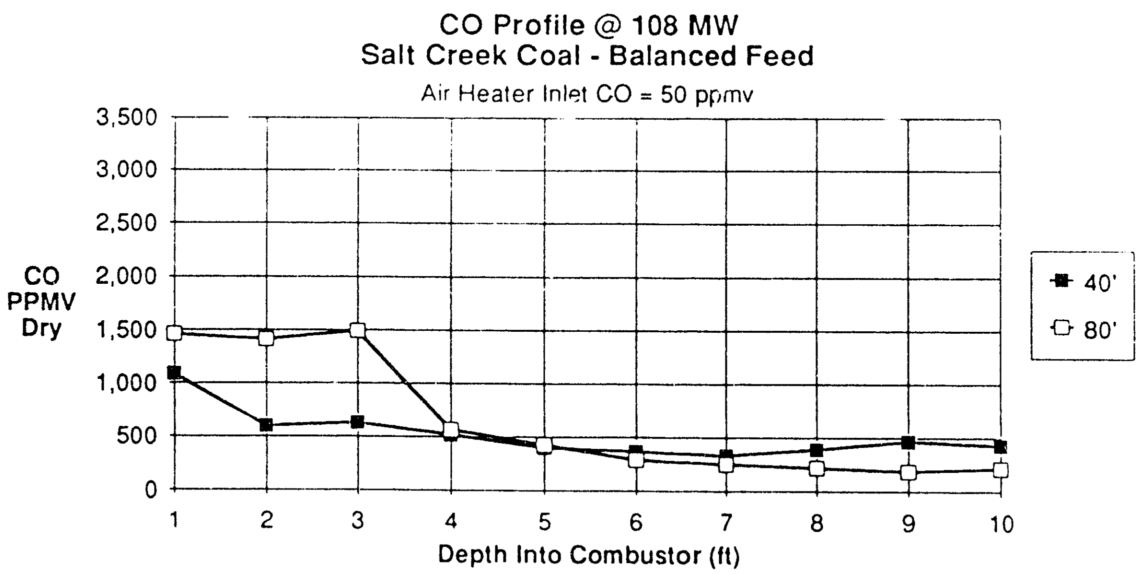
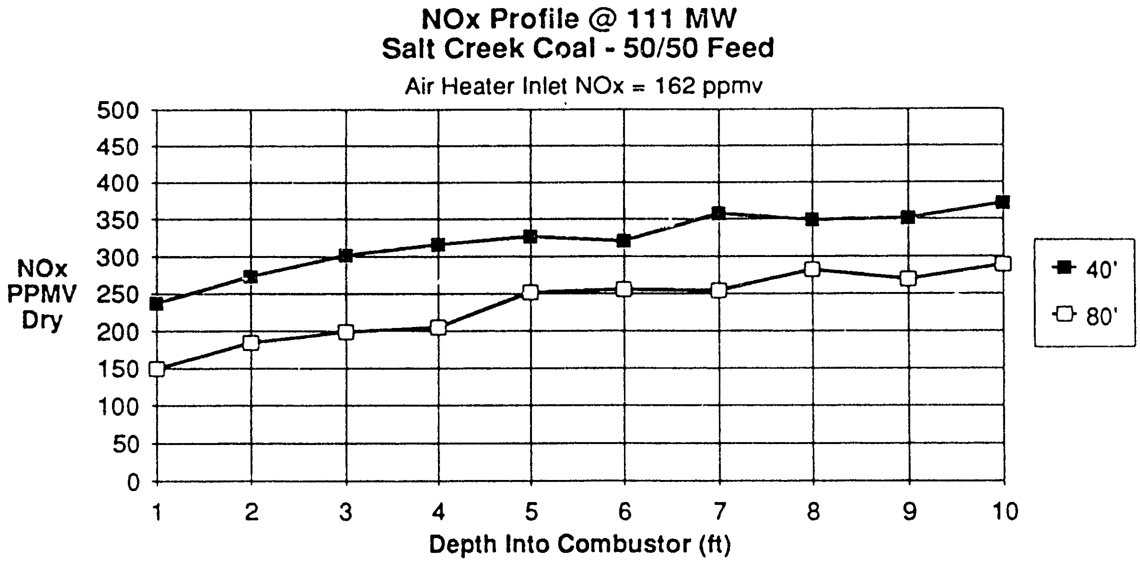


Figure 9-15. Comparison of CO traverses for 50/50 coal feed and balanced coal feed.



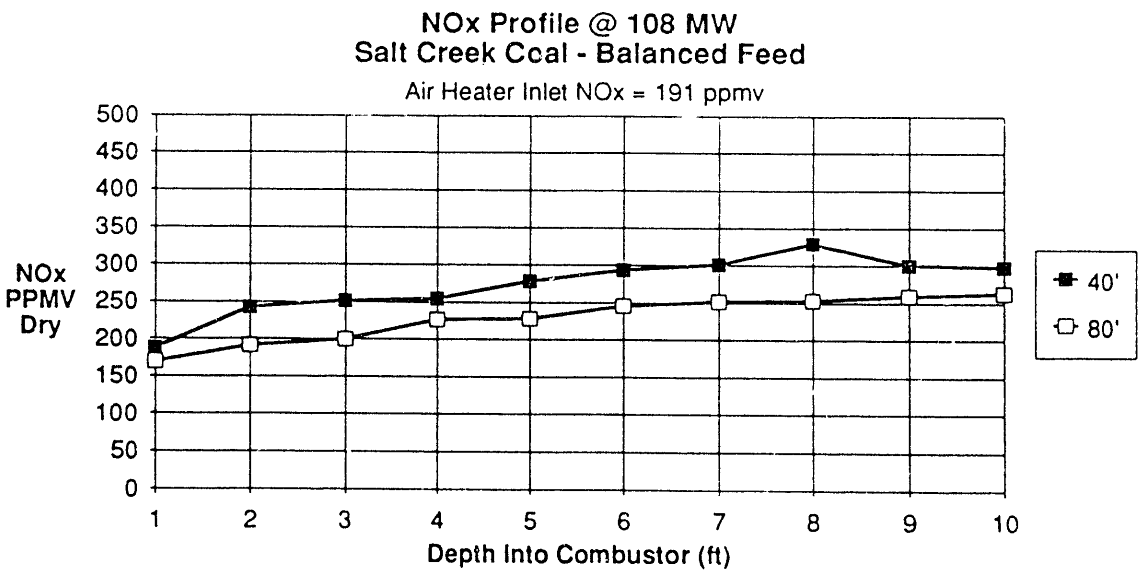
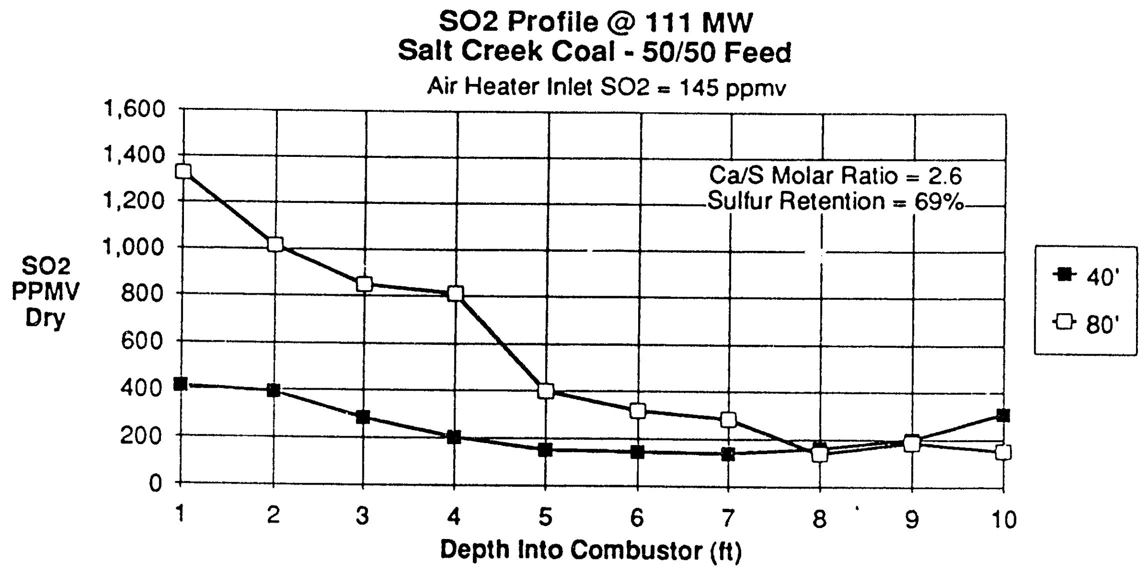


Figure 9-16. Comparison of NO_x traverses for 50/50 coal feed and balanced coal feed.



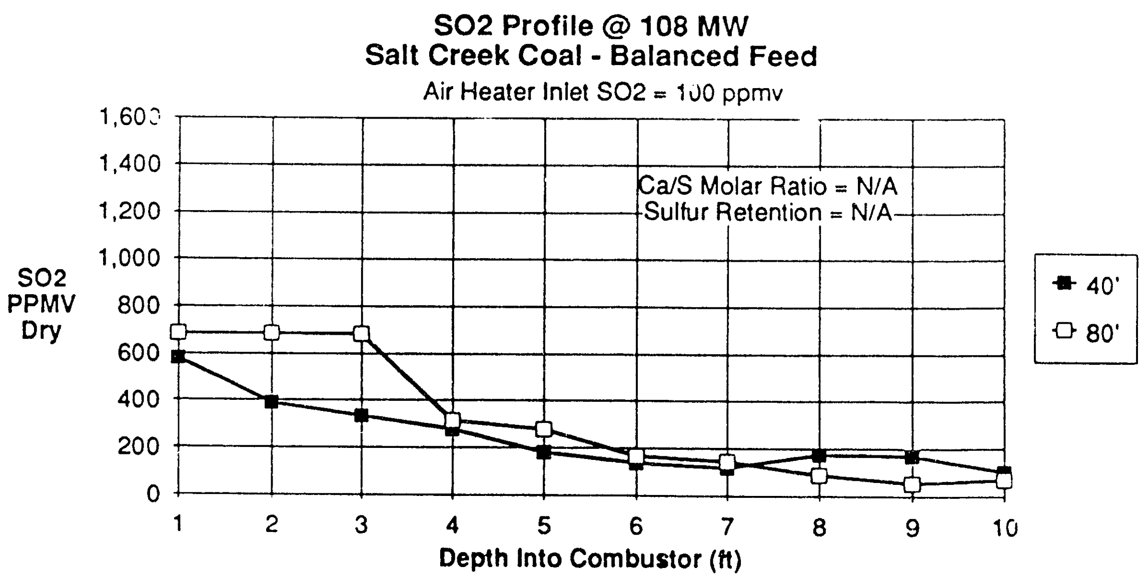


Figure 9-17. Comparison of SO_2 traverses for 50/50 coal feed and balanced coal feed.

appears to be shifted slightly towards the walls for the 50/50 feed distribution. These profiles are quite similar to the Peabody coal traverses at 105 MWe.

9.4 DISCUSSION OF RESULTS

The gas traverses tend to confirm the same conclusions regarding emissions that were reached in Section 6. Namely, better distribution of the fuel inside the combustor results in improved emissions. The traverses also indicate that there is poor lateral mixing of gaseous products between the two traverse planes. This is evidenced by the fact that peaks in a gaseous component at the 40 ft. elevation also appear in approximately the same place in the 80 ft. elevation traverse.

The traverses also indicate that fuel distribution has an impact on the gaseous products all the way through the combustor. This observation is based on the loop seal and front wall feed configurations where 100% and 50% of the total fuel was fed at a single feed point. These traverses suggest that improved fuel distribution, in the form of more feed points, may improve the emissions from a CFB. However, the relatively flat profiles obtained for the balanced feed configuration indicate that sufficient distribution may already be achieved.

The most intriguing result of these traverses is the apparent differences seen for the front wall feed and the loop seal feed configurations. These traverses indicate that coal fed to the loop seal tends to burn in the center of the furnace, while coal fed to the front wall feeder appears to burn near the walls. This result is surprising since the loop seal feeder is located about 9'6" ft. from the outside wall and the nearest front wall feeder is about 7'6" from the outside wall. While situated on opposite walls at the axis of the traverse, these two feed points are located almost the same distance from the traverse plane. Thus, even though the two feeders are relatively close to the center of the furnace, their impact on the gas traverses is dramatic.

One possible explanation for this observation could be due to the location of the feeders relative to the air distributor. The loop seal feeds the recycle and coal just above the air distributor, while the front wall feeders are located about 7 ft. above the air distributor. If there is a dense bed that is only a few feet deep on the air distributor, then the loop seal will be feeding into the dense bed while the front wall feeder will be feeding over top of this bed. The outside and center walls of the combustors are sloped slightly, with the area of the air distributor being smaller than the area of the upper furnace. Bed material falling down these walls will cause the dense bed to move towards the center of the furnace, since material is being added at the walls. Such motion would tend to force fuel fed in at the loop seal towards the center of the furnace. This hypothesis is also corroborated by the erosion pattern on the air distributor, shown in Figure 16-7, which indicates that the recycle material remains in a narrow channel along the center of the bed.

Fuel fed above the dense bed will be forced by the gas flow path, which follows the contours of the furnace walls, and will be forced toward the walls. Any material that reaches the dense bed will be carried by the bed movement toward the center of the furnace. However, the fuel fines and a good portion of the fuel volatiles will probably be carried with the gas toward the walls.

It was widely believed that the secondary air ports would completely mix the gaseous products and solid material as it leaves the primary combustion zone. Apparently this does not happen at Nucla to a great degree. It is possible that a better secondary air design involving more air nozzles and higher velocity jets could provide better mixing and, therefore, better emissions control.

The traverses taken at Nucla are only performed at two elevations and along a single traverse line into the center of the combustor. However, the furnaces are not symmetrical and it would be unwise to assume that the traverses shown represent the profiles across the entire boiler. Traverses along a line over a front wall coal feeder and a loop seal feeder would probably be quite different from the ones obtained in this study. Another problem with these traverses is that there is no measurement of the gas flow rate at each traverse point. Thus, in a region of low O_2, there is no way of knowing the volume of gas that is rising at that point. This makes comparison of the traverse readings to the air heater inlet averages difficult. Nevertheless, despite these limitations, the gas traverses provided some new insight into the operations of the CFB furnace.

Section 10

HEAT TRANSFER

10.1 APPROACH AND METHODOLOGY

In the Nucla CFB, heat transfer takes place between the water walls in the combustors and the recirculating solids that make up the bed material. Some additional heat transfer takes place between the circulating bed and the superheaters. The amount of heat transferred to the walls of the combustor ultimately determines the operating temperature of the combustor.

In this section, data from the Phase I and Phase II test programs will be used to develop correlations for the combustor temperature. The effects of load, excess air, superficial velocity, bed pressure drop, and suspension density on heat transfer and bed temperature will be studied. Correlations for bed temperature will be developed for Peabody and Salt Creek coals. Correlations will also be developed to relate the heat flux to the walls with the superficial velocity and the suspension density. Finally, these correlations will be used to discuss control options for the Nucla boiler.

10.2 DESCRIPTION OF INSTRUMENTATION

During testing at Nucla, data were taken to help provide a better understanding of the parameters that affect heat transfer. The data included pressure and temperature measurements. In addition to these measurements, chordal thermocouples were installed on the rear wall of combustor B by EPRI during the Phase I testing to measure the heat flux at different elevations in the combustor. EPRI also installed pressure taps up the rear wall on combustor B. Table 10-1 shows the elevation above the air distributor for the chordal thermocouples and the pressure taps.

Actual details of the chordal thermocouples can be found in the Annual Reports. The data taken from these pressure taps and chordal thermocouples is proprietary to Pyropower and cannot be reported here. However, averages over three zones in the combustor, the lower zone, the middle zone, and the upper zone, were available to be used to develop correlations. These zones are defined as follows:

Lower furnace: 20-40 ft. above air distributor
Middle furnace: 40-70 ft. above air distributor
Upper furnace: 70-113 ft. above air distributor

Table 10-1

Location of Pressure Taps
and Chordal Thermocouples

Pressure Transmitter	Feet Above Air Distributor
GPT300	12
GPT301	15
GPT302	18
GPT303	22
GPT304	28
GPT305	37
GPR306	49
GPT307	62
GPT308	75
GPT309	89

Chordal Tc.	
GTE300A & B	15
GTE301A & B	18
GTE302A & B	23
GTE303A & B	28
GTE304A & B	37
GTE305A & B	49
GTE306A & B	62
GTE307A & B	75
GTE308A & B	89
GTE309A & B	101

The heat flux data averaged over these three zones are reported in this section, the suspension densities cannot be reported. Both are used to develop correlations for the heat transfer.

In addition to the pressure taps in combustor B, ΔP transmitters were installed on both combustors to measure the upper combustor pressure drop. These taps are located 12 ft. and 88 ft. above the air distributor and measure the pressure drop of the suspended bed material. The pressure drop data will be used to correlate bed temperatures.

10.3 BED TEMPERATURE ANALYSIS

At a given set of firing conditions (i.e. load, excess air, etc.) the bed temperature in a combustor is an indication of the amount of heat transfer taking place between the bed and the walls of the combustor. A heat balance taken around the Nucla boiler shows that approximately 65% of the heat released in the furnace is absorbed by the water walls and superheater II. The remainder of the heat is removed from the furnace by the hot flue gas and is transferred to the convection pass surfaces. Tables 10-2 and 10-3 show the actual distribution of heat absorption for Salt Creek and Peabody coals, respectively, at various loads. Also shown on these tables are the load, excess air, and average bed temperatures for sides A and B of the boiler. The percentage of heat absorption values are based on the following measurements:

- Steam/water flow rate through the boiler component
- Boiler component inlet and outlet steam/water temperatures
- Boiler component inlet and outlet steam/water pressures

Table 10-2.

Boiler Heat Absorption for Salt Creek Coal

Test No.	SD1	P30	P31	P49	P50	P21	P52	P39
Load MWe	105	55	82	98	98	55	55	55
Excess Air %	22.5	36.4	21.9	19.6	19.6	42.0	41.8	39.0
A Bed Temp °F	1579	1500	1562	1660	1641	1552	1551	1559
B Bed Temp °F	1550	1556	1587	1671	1677	1540	1525	1569
	Furnace % of Heat Absorbed							
Combustor	56.5	58.7	58.1	55.5	56.2	56.8	56.7	57.1
SH2	11.5	10.0	11.0	11.0	11.1	9.8	9.4	9.9
Total	68.0	68.7	69.1	66.5	67.3	66.6	66.1	67.0
	Backpass % of Heat Absorbed							
SH1	13.9	12.1	12.9	14.1	14.0	13.8	14.1	13.5
SH3	4.6	3.3	3.6	4.9	4.8	3.7	3.8	3.9
Eco & Hanger	10.6	12.4	11.1	11.0	10.7	12.4	12.5	12.2
Conv Cage	2.9	3.5	3.3	3.5	3.2	3.5	3.5	3.4
Total	32.0	31.3	30.9	33.5	32.7	33.4	33.9	33.0

Flow rates were directly measured except for main steam flow which was calculated based on feed water, total attemperator, and blowdown flows. Fluid temperatures at the inlet and outlet of each section were also directly measured. Steam pressures were only available at the steam drum inlet, the drum, and the outlet of superheater III. All other pressures were estimated based on design pressure drops.

Data show that the percentage of heat absorption in the furnace is relatively constant with load. There also appears to be little difference in the heat absorption of the furnace when firing the different fuels. In general, the heat absorption in the furnace increases slightly (0.5 to 1%) with load. This is most likely due to the fact that as the load is increased, the excess air is decreased.

Table 10-3

Boiler Heat Absorption for Peabody Coal

Test No.	A01	A02	A03	A04	A05	A06	A07	A08
Load MWe	100	104	104	82	82	82	55	104
Excess Air %	20.9	19.4	19.6	24.5	25.4	24.4	38.5	19.0
A Bed Temp °F	1593	1629	1593	1632	1613	1617	1533	1649
B Bed Temp °F	1671	1675	1675	1650	1650	1648	1535	1650
Furnace % of Heat Absorbed								
Combustor	55.2	55.6	55.9	55.5	55.3	55.8	57.0	55.7
SH2	11.4	11.4	11.3	10.8	10.8	10.9	9.9	11.5
Total	66.6	67.0	67.2	66.3	66.1	66.7	66.9	67.2
Backpass % of Heat Absorbed								
SH1	14.2	14.2	14.3	14.2	14.4	14.3	13.1	14.3
SH3	4.9	4.8	4.7	4.6	4.5	4.5	3.7	4.7
Eco & Hanger	11.0	11.0	10.6	11.2	11.5	10.9	12.3	10.6
Conv Cage	3.3	3.0	3.2	3.7	3.5	3.6	4.0	3.2
Total	33.4	33.0	32.8	33.7	33.9	33.3	33.1	32.8

Tables 10-2 and 10-3 also show a recurring problem experienced at Nucla, namely that the bed temperature in combustor B is typically higher than the temperature in combustor A, except at low loads. Attempts to discover the cause of this difference revealed that the upper combustor flue gas pressure drop in combustor B was generally operating at a lower level than in combustor A.

To further understand the effects of various operating parameters on the bed temperatures, data from combustor B was analyzed when firing Peabody coal. It was found that the parameters that most affect bed temperature are load, flue gas oxygen, and upper combustor ΔP measured between the 24 and the 100 ft. pressure taps. These parameters are not entirely independent of each other, but were found to be effective in estimating operating temperatures. A correlation was developed for the bed temperature in combustor B of the form:

$$T = T_{Ref} \left(\frac{Load}{Load_{Ref}}\right)^{\alpha} \left(\frac{O2}{O2_{Ref}}\right)^{\beta} \left(\frac{\Delta P}{\Delta P_{Ref}}\right)^{\gamma} \qquad (1)$$

Where: Load = Gross load in MWe
O_2 = Flue gas oxygen at economizer outlet, Vol%
ΔP = Upper combustor pressure drop, in wg.

Test A08 was chosen as the reference test. For this test T_{Ref} = 1620°F, $Load_{Ref}$ = 104 MWe, $O2_{Ref}$ = 3.32 vol %, and ΔP_{Ref} = 6 in wg. The correlation yielded the following exponents:

α = 0.1697

β = -0.0823

γ = -0.1153

Figure 10-1 shows the results of the correlation for the Peabody coal tests. These measurements and this correlation were developed during the Phase I testing. The standard deviation of the fit was 12 °F, which indicates that 68% of the bed temperature measurements fell within ±12 °F of the calculated value.

During Phase II testing, the data from Salt Creek coal was correlated for bed temperature. This time, data from both beds were used to develop the correlation. Furthermore, it was recognized that superficial velocity and load are somewhat analogous, although excess air has some impact on the differences between the two. Superficial velocity was used because the correlation was developed for both combustors, and velocity in each combustor is a better indication of the firing rate. The final form of the correlation chosen was:

$$T = T_{Ref} \left(\frac{V_S}{V_{S\,Ref}}\right)^{\alpha} \left(\frac{O2}{O2_{Ref}}\right)^{\beta} \left(\frac{\Delta P}{\Delta P_{Ref}}\right)^{\gamma} \qquad (2)$$

Where: Vs = superficial velocity in each combustor.

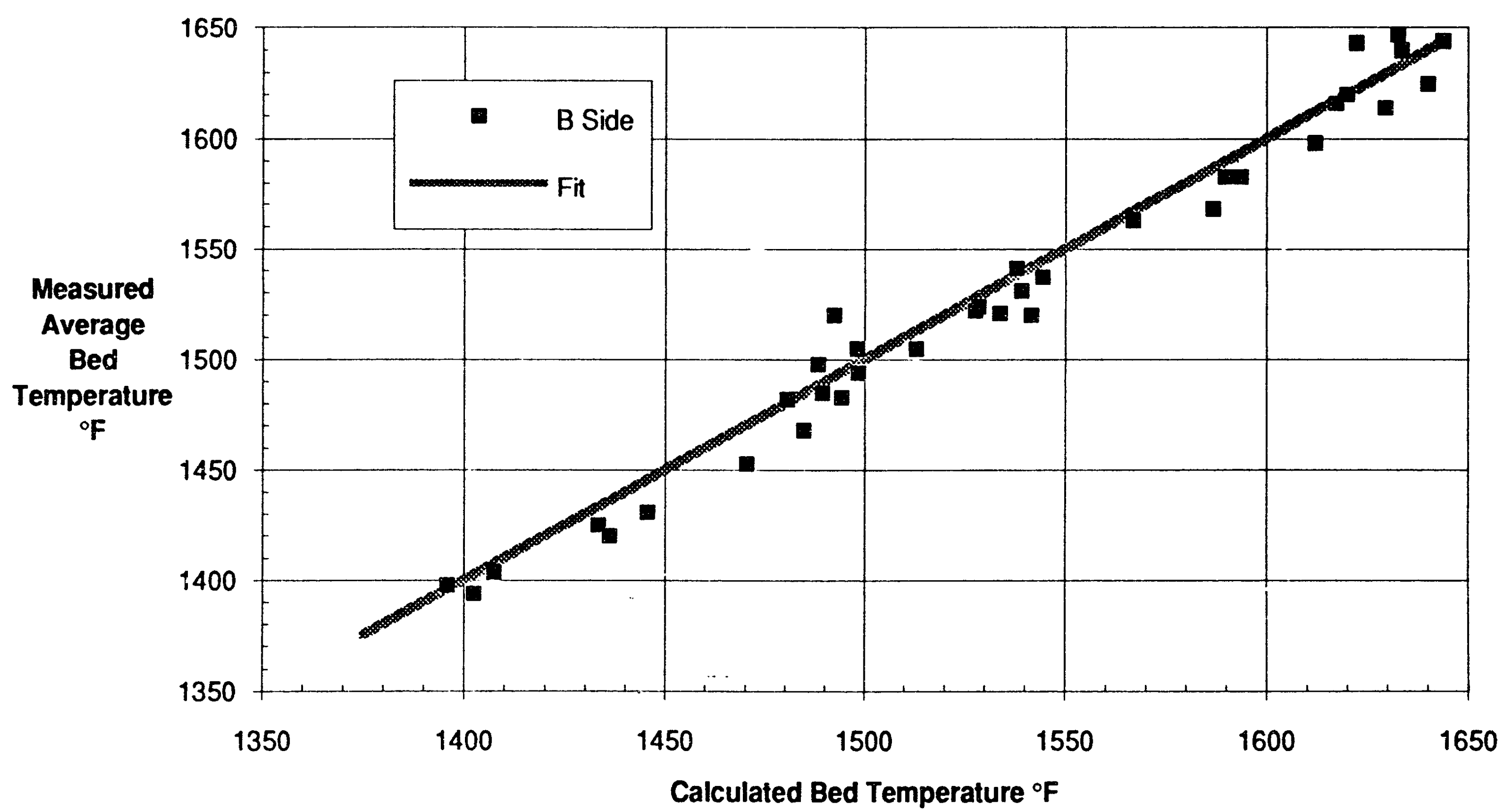
For this correlation, it was desired to find one function that would fit both combustors. The following reference values were chosen: T_{Ref} = 1653 °F, Vs_{Ref} = 17.681 ft/sec, $O2_{Ref}$ = 3.132 vol %, and ΔP_{Ref} = 6.145 in wg. The correlation yielded the following exponents:

α = 0.184

β = -0.085

γ = -0.100

Figure 10-1. Measured Versus Predicted Bed Temperatures For Phase I Testing on Peabody Coal



These values are similar to the ones obtained for the correlation for Peabody coal. Figure 10-2 shows the results of this correlation for the Phase II tests on Salt Creek coal. The standard deviation for this correlation was 15° F. Note that this correlation fits both combustors. This indicates that there are no significant differences between the combustors to account for the temperature differences. Had there been differences, a single correlation would not have fit the data as well as this correlation.

Equation 2 shows that a 1.5 inch differential in pressure between the two combustors accounts for about a 40° F differential in temperature. This is about the order of magnitude for both the differential pressure and operating temperature. This indicates that the different operating temperatures in the two combustors may be due to differences in the recirculation rates between the two combustors.

10.4 HEAT FLUX CORRELATION

The heat flux probes installed in the freeboard area were used to develop a correlation for the heat transfer in combustor B. Data used in the analysis were taken early during the Phase I test campaign. Shortly after the data were collected, some of the pressure taps were disconnected and the transmitters were used elsewhere in the plant. Table 10-4 shows the results of these heat flux measurements averaged over the three zones of the combustor.

The suspension density is the weight per unit volume of the bed. The bed is comprised of solid particles and void spaces. The suspension density is given by:

$$\rho_s = (1 - \varepsilon)\ \rho_p \tag{3}$$

Where: ε = bed voidage

ρ_s = suspension density, lb/ft^3

ρ_p = particle density, lb/ft^3

The suspension density is calculated from the pressure profile in the combustor. The equation defining the suspension density is:

$$\rho_s = -\frac{1}{g}\left(\frac{\Delta P}{\Delta h}\right) \tag{4}$$

Where: g = the gravitational constant

h = height in ft.

Combustor B at Nucla was equipped with 10 pressure taps and transmitters at various elevations up the rear wall of the

Figure 10-2. Measured Versus Predicted Bed Temperatures For Phase II Testing on Salt Creek Coal

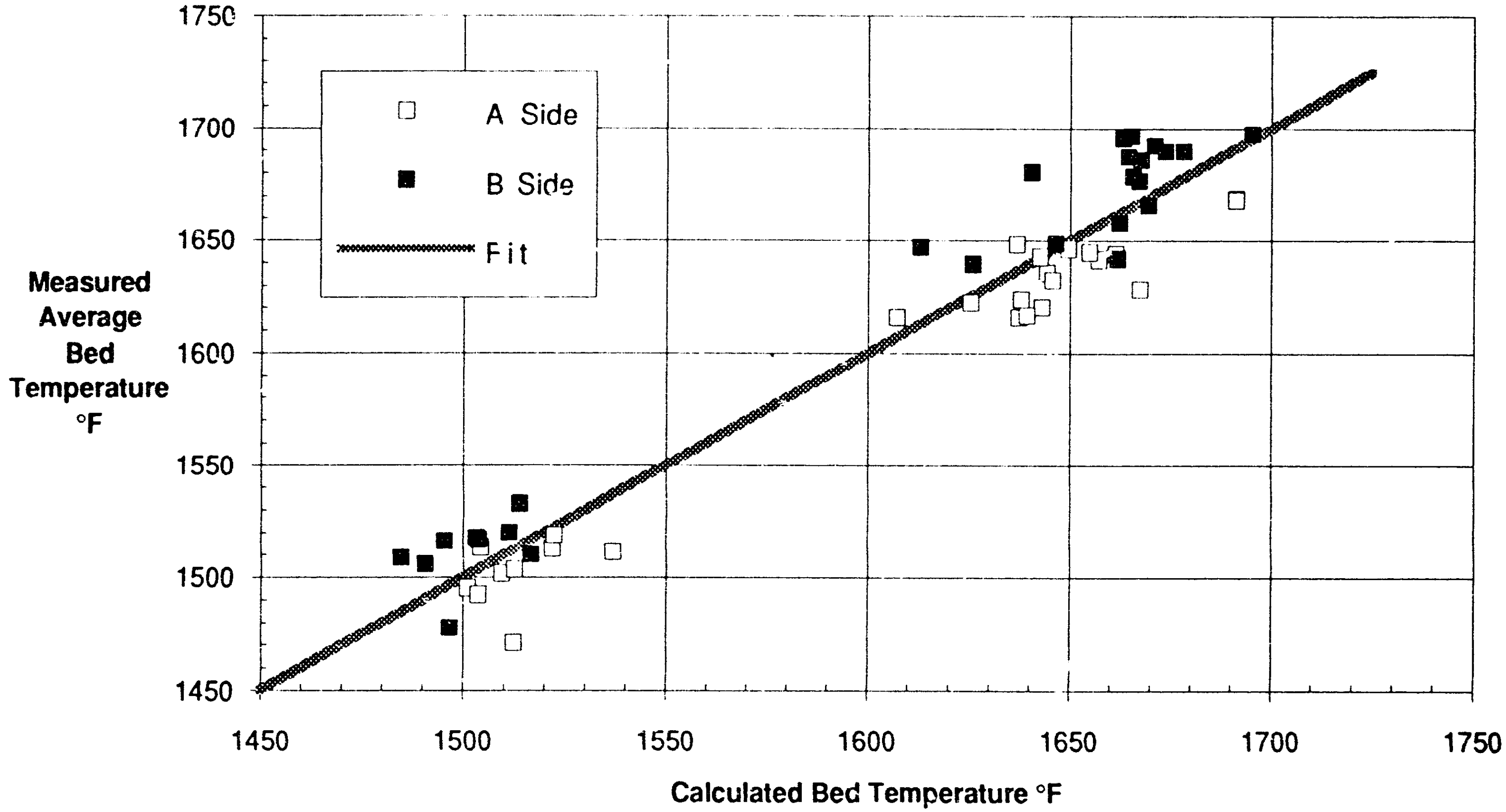


Table 10-4. Heat Flux Data from Combustor B

Test	Unit Load MWe	Furnace Section	Height Above Grid (ft)	Heat Flux From Chordal TC's Btu/ft^2	Combustor B Bed Temp (°F)	Superficial Velocity ft/sec	Flue Gas O2 vol %	B-Bed ΔP in. wc.	Calculated Heat Flux Btu/ft^2
A03	104	LOWER	20-40	32094	1644	15.44	3.48	5.52	32094
		MIDDLE	40-70	30802	1651				31116
		UPPER	70-113	31735	1658				30588
A04	82	LOWER	20-40	28013	1589	12.96	4.20	4.09	28556
		MIDDLE	40-70	27286	1584				27568
		UPPER	70-113	28176	1579				27064
A05	82	LOWER	20-40	27559	1585	13.04	4.14	3.94	28566
		MIDDLE	40-70	27360	1584				27674
		UPPER	70-113	27826	1583				27189
A06	82	LOWER	20-40	27906	1587	13.11	4.19	4.22	28780
		MIDDLE	40-70	27409	1582				27825
		UPPER	70-113	27654	1578				27330
A07	55	LOWER	20-40	24116	1433	8.65	5.93	3.64	22500
		MIDDLE	40-70	22659	1401				21684
		UPPER	70-113	22027	1371				21272
A08	104	LOWER	20-40	31481	1614	15.10	3.41	6.04	31836
		MIDDLE	40-70	29955	1619				30875
		UPPER	70-113	30244	1624				30353
AO1	100	LOWER	20-40	34515	1644	16.82	3.69	6.16	33841
		MIDDLE	40-70	33171	1649				32785
		UPPER	70-113	33429	1653				32219
AO2	104	LOWER	20-40	32171	1639	15.97	3.46	5.81	32791
		MIDDLE	40-70	31226	1648				31837
		UPPER	70-113	31705	1657				31307
P21	55	LOWER	20-40	22757	1450	9.81	6.30	3.02	23719
		MIDDLE	40-70	21757	1418				23165
		UPPER	70-113	20990	1389				22825
P30	55	LOWER	20-40	22150	1456	9.18	5.66	2.71	22761
		MIDDLE	40-70	21609	1428				21732
		UPPER	70-113	19910	1402				21236
P31	82	LOWER	20-40	28314	1551	12.17	3.84	4.85	27743
		MIDDLE	40-70	26955	1544				26680
		UPPER	70-113	26359	1537				26150
P39	55	LOWER	20-40	23751	1475	9.39	5.98	2.95	23126
		MIDDLE	40-70	22640	1437				22506
		UPPER	70-113	21965	1403				22143
P49	98	LOWER	20-40	31103	1650	14.82	3.50	5.76	31462
		MIDDLE	40-70	29415	1644				30477
		UPPER	70-113	29931	1639				29945
P50	98	LOWER	20-40	31425	1645	14.88	3.50	5.80	31431
		MIDDLE	40-70	29704	1643				30550
		UPPER	70-113	29655	1641				30034
P52	55	LOWER	20-40	25040	1443	9.64	6.28	2.90	23416
		MIDDLE	40-70	23450	1420				22862
		UPPER	70-113	21886	1400				22507
SD1	105	LOWER	20-40	33935	1562	16.17	3.93	8.37	33753
		MIDDLE	40-70	31727	1567				32667
		UPPER	70-113	32518	1573				32091

combustor. Taking the value of $\frac{\Delta P}{\Delta h}$ directly from the pressure tap readings proved difficult since the data were not always smooth. To improve the calculation of the suspension density, a second order polynomial curve was fit to the absolute pressure readings versus the logarithmic height above the grid. This function was found to give a good fit of the pressure profile. Differentiating the curve fit with respect to height yielded the pressure gradient, which was then substituted into equation 4 above to give the suspension density as a function of height. The suspension densities were then averaged for the three zones.

Figure 10-3 shows the trend observed for the suspension density as a function of superficial velocity. Actual values for the suspension density cannot be shown. This curve shows that the suspension density is a relatively smooth function of velocity. Furthermore, the suspension density decreases with height in the combustor. Figure 10-4 shows the overall bed pressure drop versus superficial velocity. Note the similarity between this figure and the suspension density. Figure 10-5 shows the trend for the suspension density divided by the overall upper-bed ΔP versus superficial velocity. This normalized suspension density was found to be constant over the range of velocities tested. This figure suggests that the pressure profile is similar at all loads and that the magnitude of the effect is determined by the overall pressure drop through the combustor.

Figure 10-6 shows the effect of superficial velocity on the heat flux measurements. Note that the heat flux is a strong function of velocity, particularly as velocity increases. Furthermore, there is only a slight difference in the heat fluxes between the lower furnace and the upper furnace. The difference between the upper and lower heat fluxes averaged 1200 Btu/ft^2 and did not appear to be a function of velocity. Figure 10-7 shows the effect of suspension density on the heat flux. This figure shows that the suspension density does not strongly affect the heat flux, since the same heat flux can be obtained at densities that vary by as much as a factor of 2.

To further examine the effect of velocity and suspension density on the heat flux, a correlation of the form:

$$HF = HF_{Ref}\,(V_S)^{\alpha}\,(\rho_S)^{\beta} \qquad (5)$$

was developed. The value of HF_{Ref} was 6948 Btu/ft^2. The correlation yielded the following values for the exponents:

Figure 10-3. Suspension Density Versus Superficial Velocity

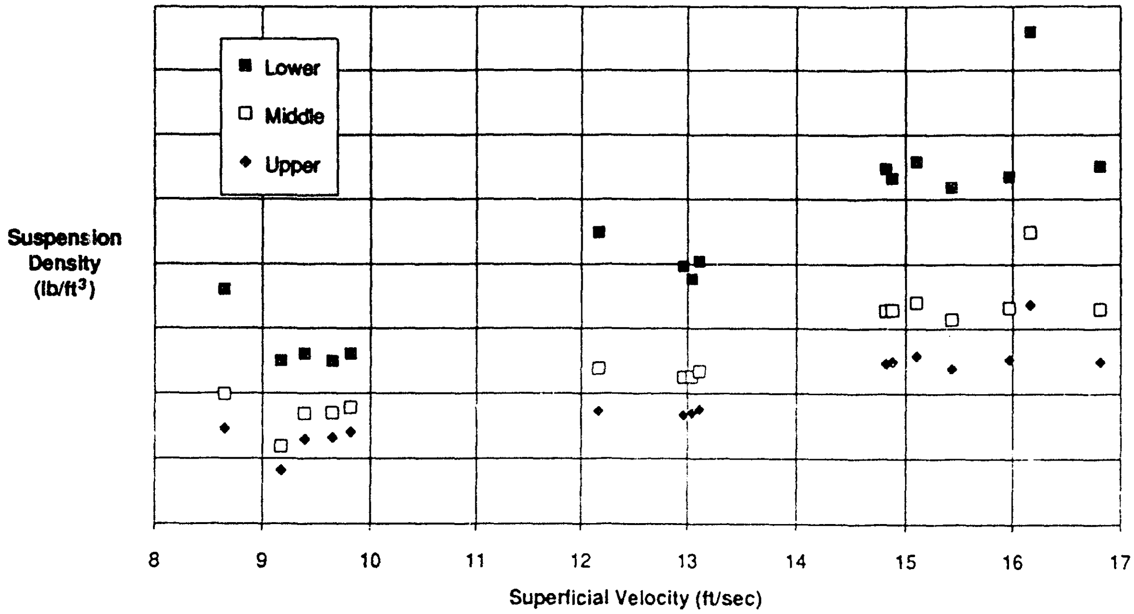


Figure 10-4. Bed ΔP Versus Superficial Velocity For Combustor B

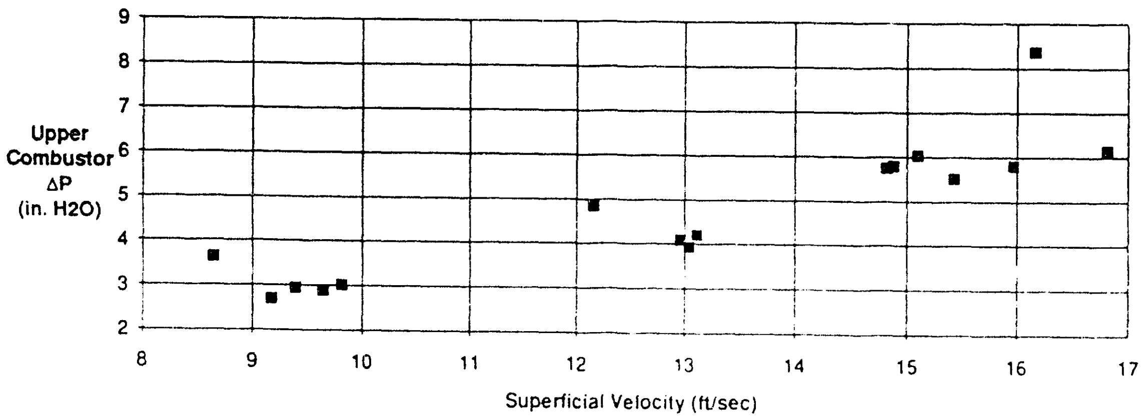


Figure 10-5. Normalized Suspension Density Versus Superficial Velocity

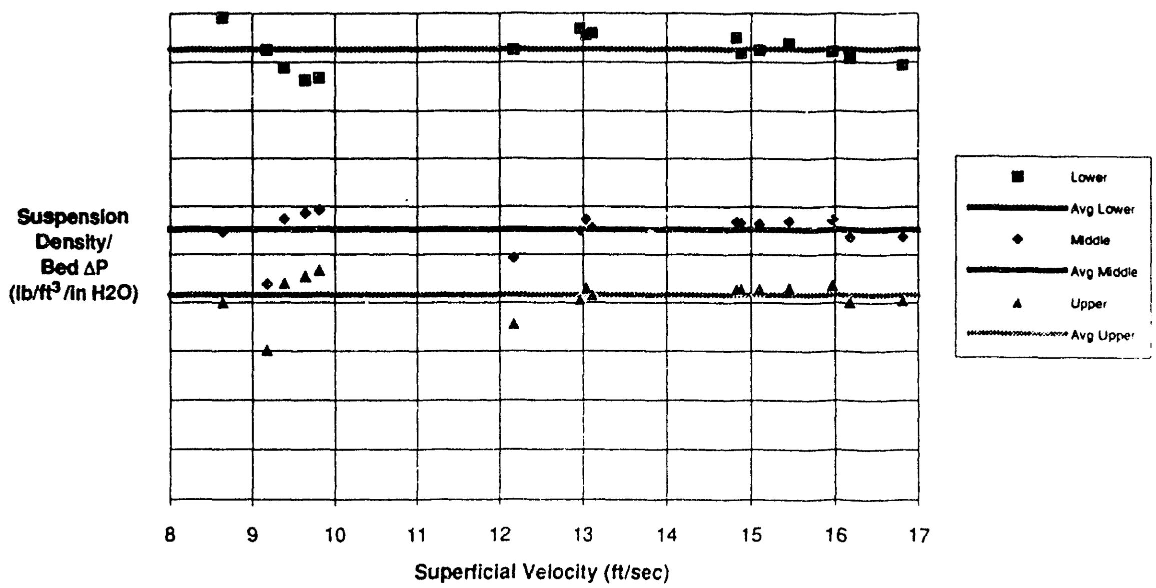


Figure 10-6. Heat Flux Versus Superficial Velocity

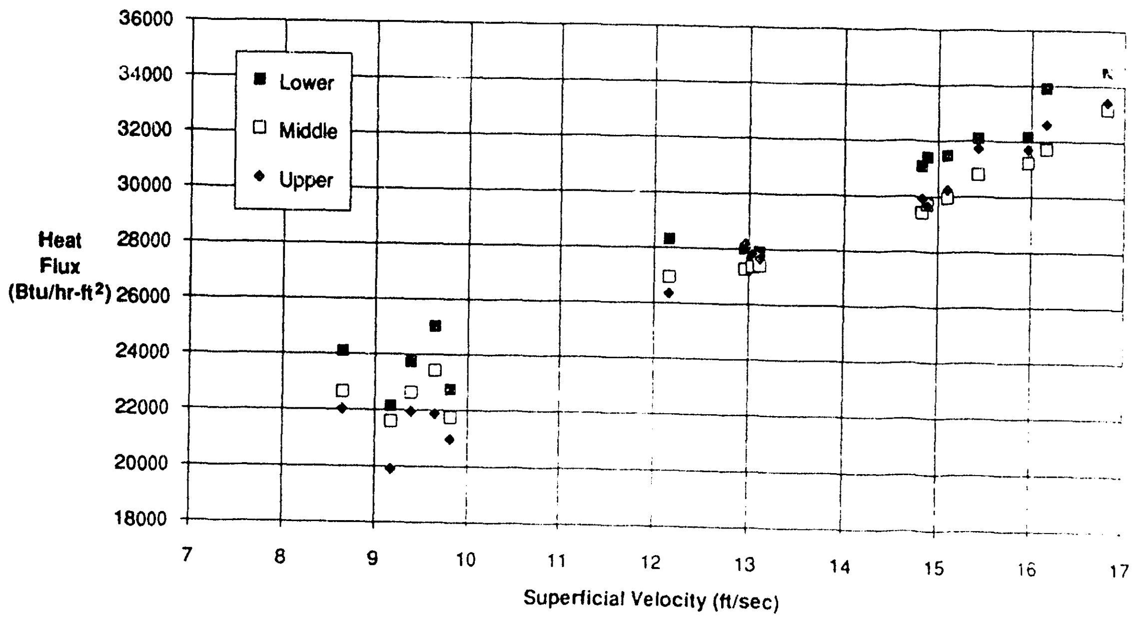


Figure 10-7. Heat Flux Versus Suspension Density

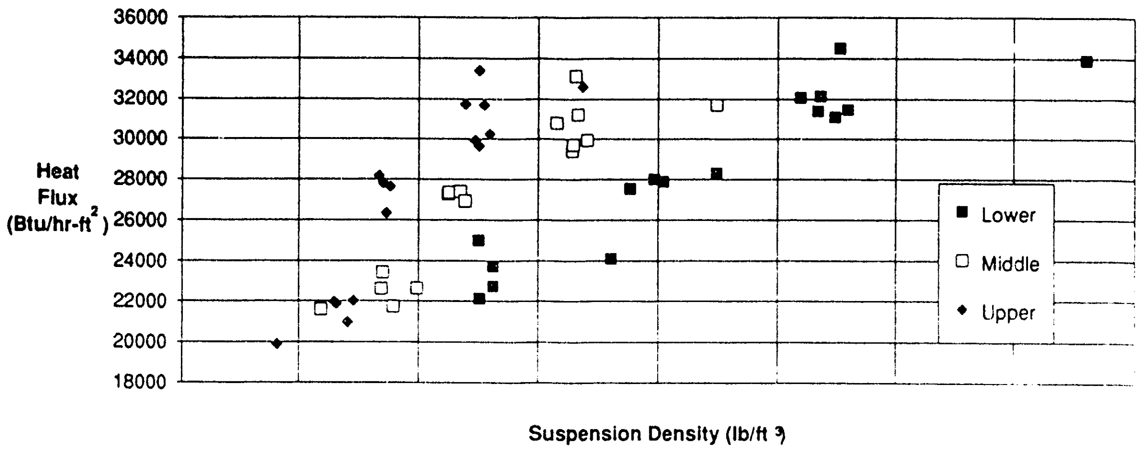
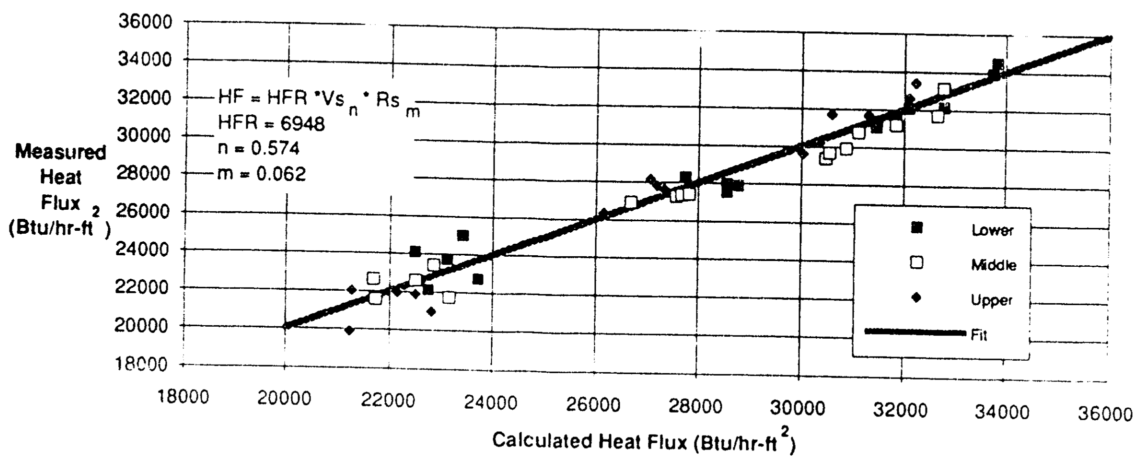


Figure 10-8. Heat Flux Correlation



$\alpha = 0.574$

$\beta = 0.062$

Note that the low value for the exponent on the suspension density indicates a very weak influence on the heat transfer. Figure 10-8 shows the results of this correlation. The standard deviation on the calculated heat flux was 795 Btu/ft^2.

The magnitude of the coefficients found in equation 5 indicates that the effect of suspension density is very minor relative to the effect of superficial velocity. The coefficient of 0.574 for the velocity term suggests a mechanism for heat transfer similar to gas convection, which has a velocity coefficient of 0.5. However the overall magnitude of the heat transfer rate is approximately two to three times the value for simple gas convection with radiation.

10.5 DISCUSSION OF RESULTS

In the 1990 Annual Report, a number of observations were made regarding the temperature differential between the two combustors. Those observations are repeated here as a start of the discussion on heat transfer and boiler operations.

Observation 1. Combustor B generally has the higher operating bed temperature and cyclone inlet temperature.

Observation 2. Furnace water-wall differential pressure is lowest in the combustor with the higher temperature. The differential pressure is a direct indication of solids loading and is generally lower in combustor B compared to combustor A.

Observation 3. Circulating material is consistently coarser in combustor B as indicated by samples taken from each loop seal. At full load operation, this material generally gets coarser after three or four days following a start-up until an equilibrium is achieved.

Observation 4. Loop seal pressure measured at the bottom of the loop seal is lowest in the combustor with the higher temperature. In addition, loop seal differential pressure is lowest in the combustor with the higher temperature. These pressure measurements may indicate lower recycle rates in cyclone B.

Observation 5. Cyclone differential pressure (between the inlet and outlet) is lowest in the combustor with the highest temperature. Typically, this value is 2.8 in. wg. in cyclone A and 2.3 in.wg. in cyclone B at full load.

Observation 6. The temperature in combustor B was only moderately affected by bed inventory changes, SA/PA split, loop seal air flow changes or classification in the bottom ash cooler at any classification velocity. Combustor A showed a better response to bed inventory and SA/PA split, but the temperature change effected was still only 30 °F.

Observation 7. Changes in coal ash content have affected combustor temperature. An increase in ash content resulted in a lower combustor temperature as seen on June 1990 when the delivered Salt Creek coal ash content increased from 14% to 20%.

Observation 8. Although the temperature differential has existed since initial start-up of the boiler, it appears to have become more prevalent since switching from Peabody coal to Salt Creek coal in July 1989. Unfortunately, periods of continuous full load operation with Peabody coal were infrequent. Therefore, the impact of coal type on the temperature differential is inconclusive. Peabody coal generally was several percent higher in ash content than Salt Creek coal.

Observation 9. Several upsets in furnace draft initiated by coal feeder trips have resulted in increased water-wall differential pressure and lower temperatures in combustor B. In every case, the improvement was short term and temperatures returned to their previous levels within hours of the event.

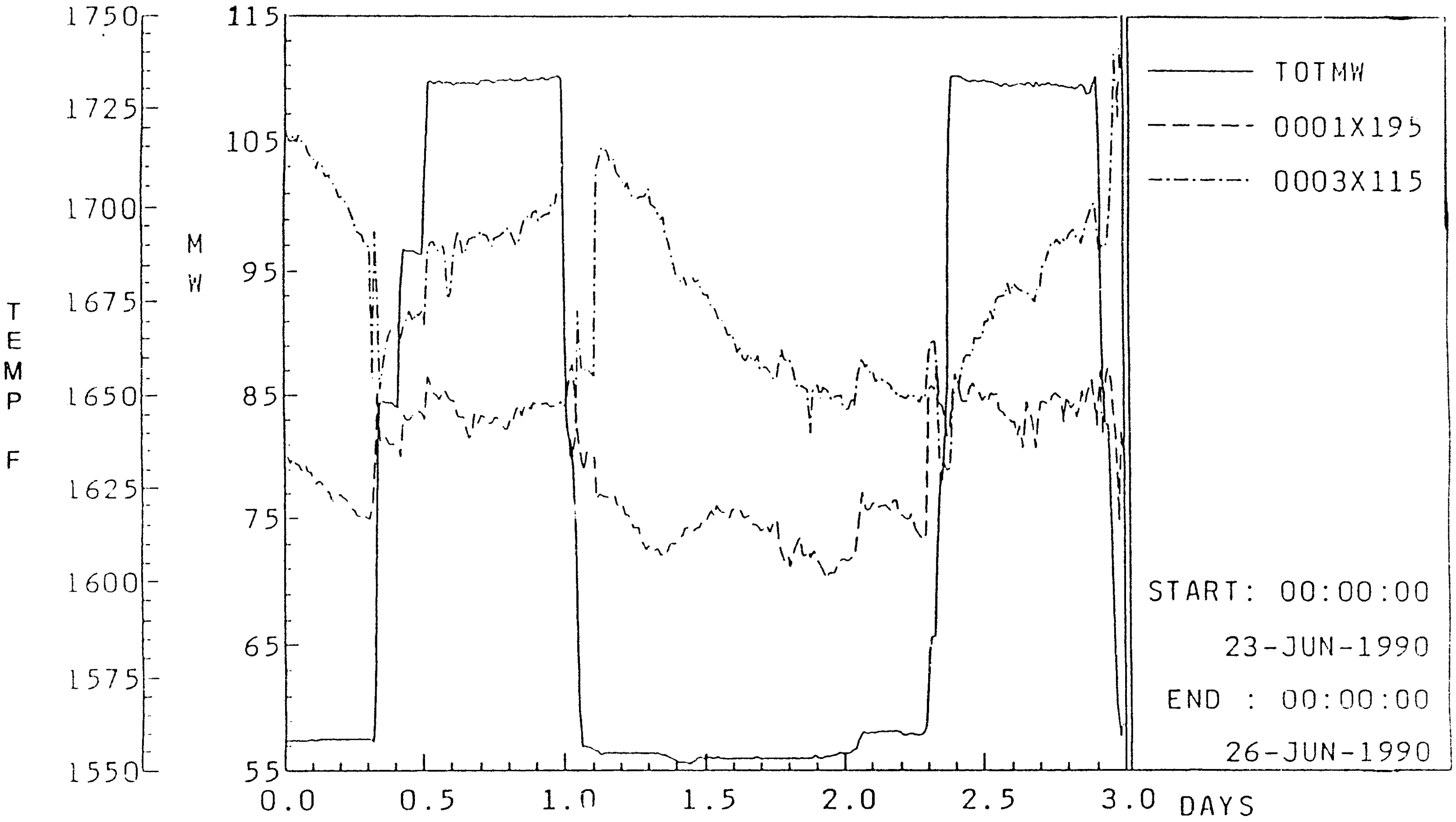
Observation 10. Load cycling of the boiler has demonstrated an interesting effect on the combustor B water-wall differential pressure, and therefore, on combustor B temperature. Figures 10-9 and 10-10 illustrate a typical cycling behavior. During full load, steady-state operation, Combustor B water-wall differential pressure is lower than the corresponding pressure in combustor A. When load was decreased to 50% MCR, both water wall differential pressures dropped and then started to increase to reach final equilibrium values. However, the rate of increase was faster in combustor B and within 36 hours, both water-wall differential pressures attained the same value. Consequently, the combustor temperatures became balanced. Upon return to full load, both water-wall differential pressures increased together to the previous full load value in combustor A, which was higher than the combustor B water-wall differential pressure. The Combustor A water-wall differential pressure remained constant but the water-wall differential pressure in combustor B started to decrease immediately, causing the bed temperatures to diverge.

The temperature differential prior to the load change in Figures 10-9 and 10-10 can be explained solely in terms of the water-wall pressure differential in the two combustors. Prior to the load change, the pressure differential in combustor A was 7.3 in.wg. and the pressure differential in combustor B was 5.5 in.wg. The correlations for bed temperature indicate that this pressure differential should result in approximately a 50 °F temperature differential between the two beds, while the actual differential was 55 °F.

Unfortunately, Observation 6 indicates that there is no way of controlling the water-wall pressure drop in either of the combustors. The bed classifier is not apparently capable of classifying the right size material in sufficient quantities to control the bed pressure differential. Therefore, the operation of the boiler at a given load is uncontrolled with respect to heat transfer, and the unit is dependent on the fuel ash content for temperature control.

The problem with the difference in water-wall pressure differentials between the two combustors appears to be due to a slight difference in the collection efficiency curves of the two cyclones. This is indicated by Observation 3 and Observation 10. Observation 3 states that the recirculating material in the seal leg of combustor B is coarser than the material from cyclone A. This indicates that A cyclone is more efficient at collecting smaller particles than combustor B.

Only a small difference in the collection efficiencies is required to force large differences in size the distributions between the two cyclones. Because all material that is



TOTMW-TOTAL LOAD IN MW 1,2,3,4
0001X195-BED TEMP CMB A 20IN AVG
0003X115-BED TEMP CMB B 20IN AVG

Figure 10-9. Temperature Response to Load Changes

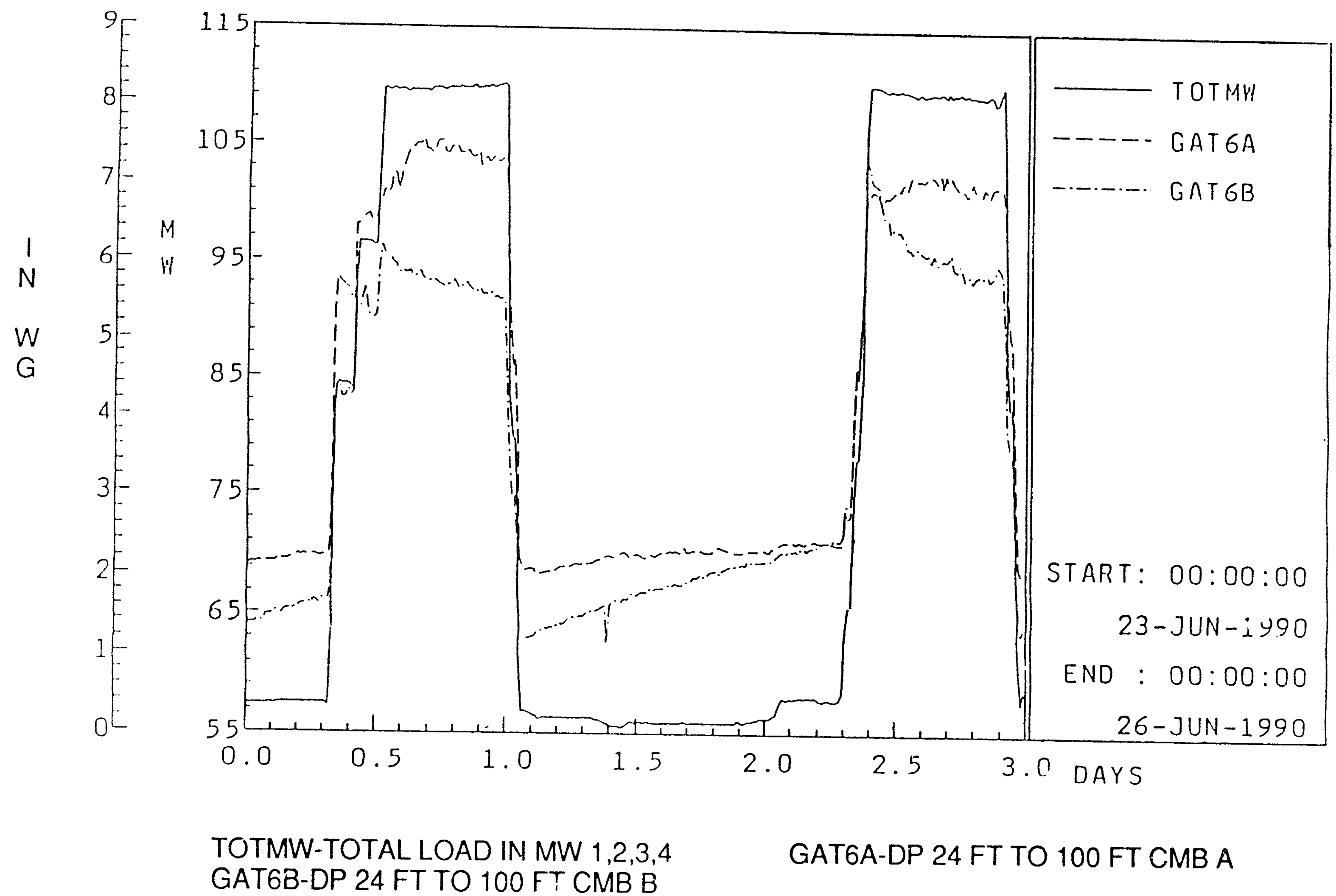


Figure 10-10. Waterwall ΔP Response to Load Changes

collected is reinjected, the weight of material in size cut D_i is given by:

$$W_{Di} = \frac{F_{Di}}{(1 - \eta_i)} \tag{6}$$

Where: F_{Di} = the amount of feed material in the size range D_i less the amount removed by the bed drain and attrition plus the amount added by attrition.

η_i = the cyclone collection efficiency for particles of size D_i

At a fixed load, F_{Di} is a constant value between both combustors. If, for example, the cyclone collection efficiency of a 180 micron particle is 98% in cyclone A and only 96% in cyclone B, equation 6 predicts that the amount of 180 micron material circulating in combustor A will be twice the amount of material in combustor B. Therefore, what amounts to an almost unmeasurable difference in cyclone collection efficiency can be magnified by the total recirculation system to become a very significant difference in the total recirculation rates between the two combustors.

Both the correlations for bed temperature and the correlation for heat flux show similar exponents for the ΔP term (0.116 and 0.1 for the temperature correlations and 0.062 for the heat flux correlation). All of the correlations predict only a weak influence due to the water-wall ΔP. The pressure drops listed above (7.3 in.wg for A and 5.5 in. wg. for B) should make the heat flux in combustor B be 1.7% less than the heat flux in combustor A. However, in order to operate either of the combustors at full load and 1550 °F, the water-wall ΔP will have to be raised to over 13 in.wg., which is very difficult with the present cyclones.

Based on the heat transfer tests conducted at Nucla, it is apparent that the combustor temperatures are essentially uncontrollable. On a given day, there is no control element available to the operator to modify the temperature in either combustor except by excess air. In order for the combustor B temperature to approximately equal that of combustor A, combustor B would have to be operated at about 4.5 vol % O_2, while combustor A was operated at the normal amount of about 3 vol % O_2. This type of operation would require about 5% more air than the present operations. Since SO_2 emissions have been found to increase dramatically above 1620 °F, it is recommended that the unit operate with enough excess air in each side of the combustor to maintain combustor temperatures below the 1620 °F limit.

Section 11

HOT CYCLONE PERFORMANCE

11.1 APPROACH AND METHODOLOGY

Proper performance of the hot cyclones of a CFB is vital to the proper operation of the unit. Data from Nucla have shown that maintenance of solids inventory in the furnace is essential for control of furnace temperatures. Therefore, it is important that the cyclones have a high collection efficiency in order to maintain the high solids loadings that are necessary.

The high solids loadings and the harsh environment in which these cyclones operate make direct measurement of the cyclone collection efficiency practically impossible. A plan had been developed to use samples of the seal leg and the fly ash to determine the cut point of the cyclones at Nucla and compare the measurements to model predictions. However, these tests were postponed indefinitely, at DOE's request, to concentrate CUEA's efforts on delivery of outstanding and final reports.

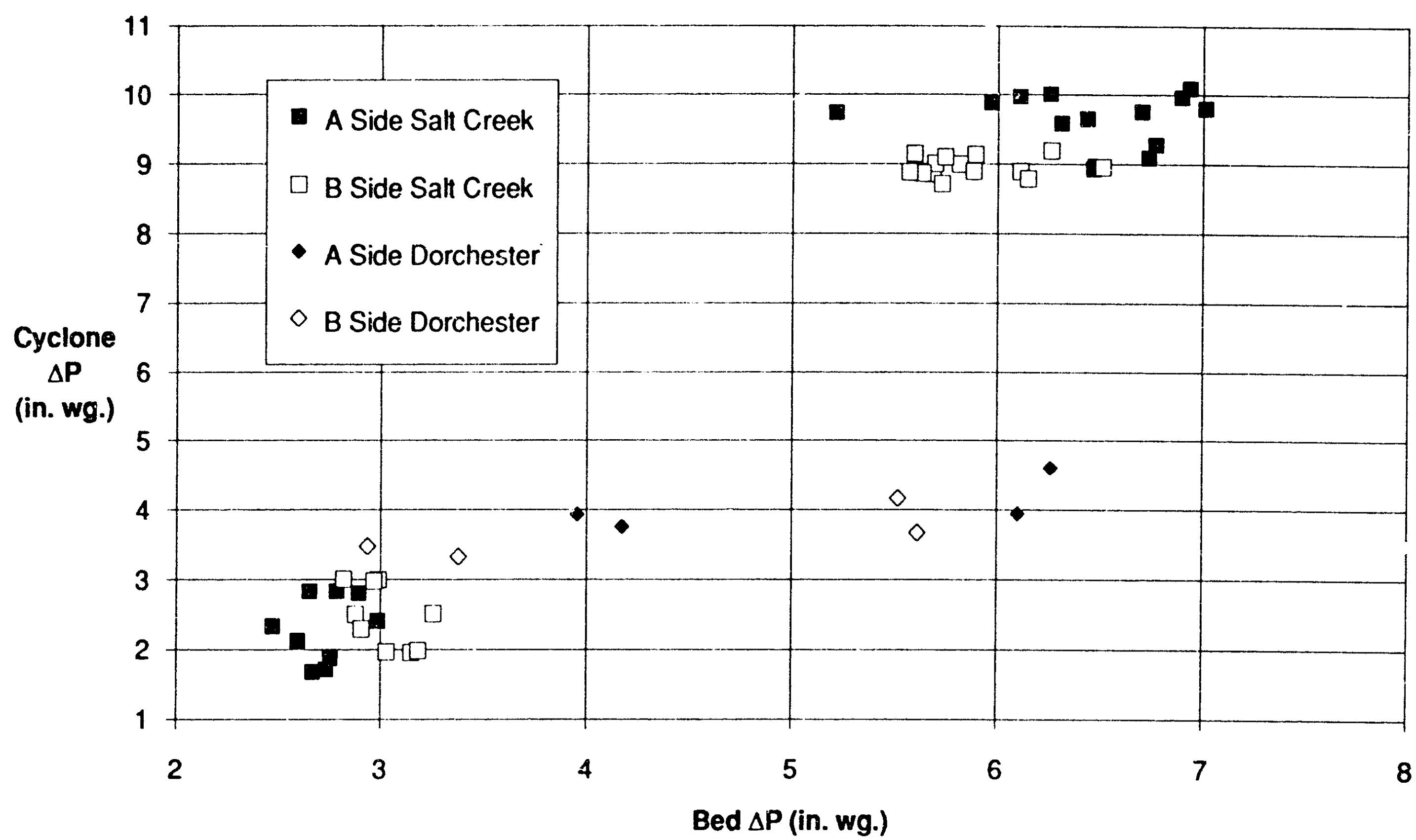
Temperature differences between the two combustors have indicated that there may be differences in the collection efficiency of the two cyclones at Nucla. In this report, data are presented from two direct measurements that were taken at the cyclone during the steady state performance tests. These measurements are cyclone pressure drop and temperature rise across the cyclone. The upper combustor pressure drop will also be used to evaluate the cyclone performance. These measurements will be examined to provide estimates of the different cyclone collection efficiencies.

11.2 PRESSURE DROP

The pressure drop across the cyclone is an important parameter both from a design and operational points of view. From a design standpoint, the cyclone pressure drop represents an energy loss that must be accounted for in the fan design. During operations, differences in the pressure drop readings under identical operating conditions may indicate a fuel change or a cyclone problem.

Figure 11-1 shows the cyclone pressure drop for both cyclones A and B, as a function of the upper bed pressure drop, for both the Salt Creek and Dorchester coal tests conducted during the Phase II test program. This graph shows that Dorchester coal, with the higher ash content, has a

Figure 11-1. Cyclone ΔP Versus Bed ΔP



different pattern than the Salt Creek coal. The bed pressure drop shown on the X-axis of Figure 11-1 is the pressure drop between the 24 and 100 ft elevations. This value is believed to be proportional to the solids loading in the furnace, and therefore, to the inlet loading of the cyclone.

The pressure drop through a cyclone is essentially the sum of two components. The first is the pressure drop associated with the gas velocity. This term is proportional to the velocity squared. The second component of the pressure drop is that associated with the acceleration of solid particles in the cyclone. This term is proportional to the solids loading times the velocity squared. Mathematically, the pressure drop can be expressed as:

$$\Delta P_{cyc} = K_1 \, V_s^2 + K_2 \, \rho_s \, V_s^2 \qquad (1)$$

Where: K_1 & K_2 = proportionality constants
V_s = superficial velocity in the combustor
ρ_s = solids density at the cyclone inlet.

The solids density at the combustor inlet can be approximated by the upper combustor ΔP (ΔP_{bed}). Rearranging equation 1 and replacing ρ_s with ΔP_{bed} gives:

$$\frac{\Delta P_{cyc}}{V_s^2} = K_1 + K_2 \, \Delta P_{bed} \qquad (2)$$

Equation 2 shows that a plot of $\frac{\Delta P_{cyc}}{V_s^2}$ versus ΔP_{bed} should yield a straight line of slope K_2 and intercept K_1. Figure 11-2 shows this plot for the Salt Creek coal and Dorchester coal tests. The lines represent the least squares fit of the combustor A and combustor B data for Salt Creek coal. While there is a good amount of scatter in the data, the least squares fit did give slightly different values for K_1 and K_2 for the two cyclones.

Figure 11-3 shows a plot of the measured versus calculated cyclone ΔP using the values of K_1 and K_2 for the two cyclones. The correlation does a fair job of predicting the cyclone pressure drop, with all but one of the Dorchester coal tests falling within ±1 inch wg.

11.3 COLLECTION EFFICIENCY ESTIMATE

As was stated above, the upper bed pressure drop is an indication of the solids loading in the combustor. Figure 10-5, in the Heat Transfer section, showed that the average suspension density divided by the bed ΔP was a constant that

Figure 11-2. Cyclone $\Delta P/Vs^2$ Versus Bed ΔP

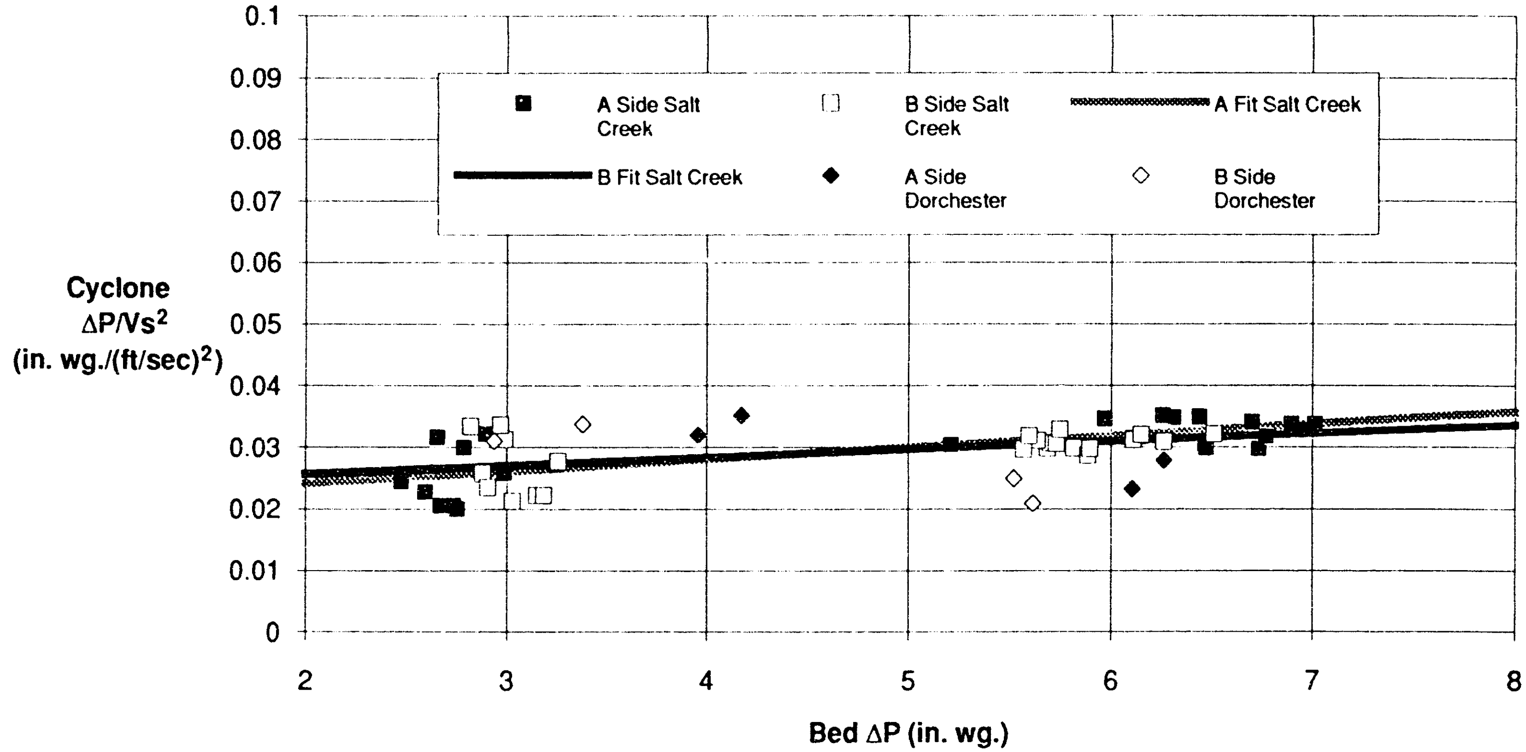
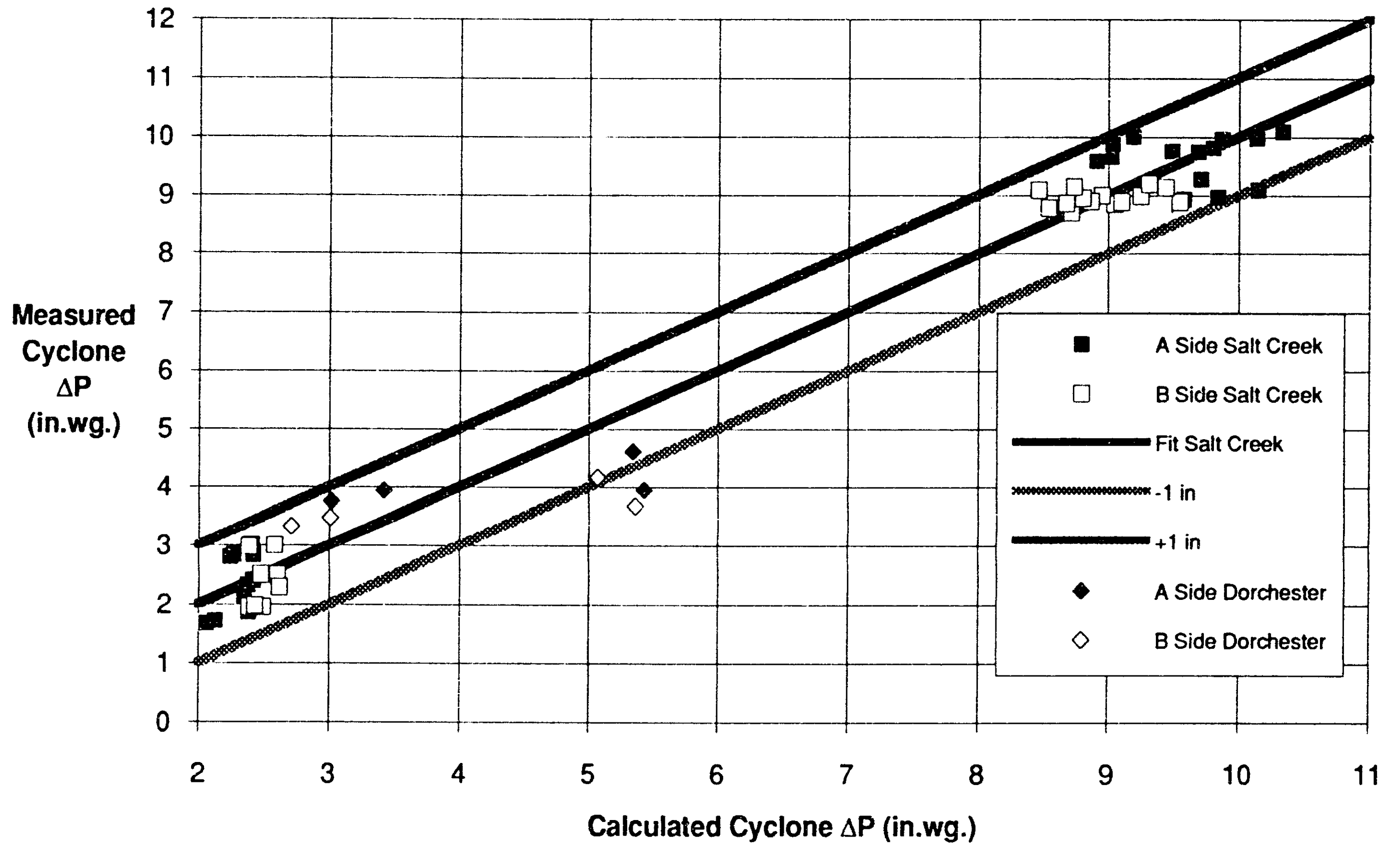


Figure 11-3. Measured Versus Calculated Cyclone ΔP



decreased exponentially with height up the combustor. Projecting this ratio of suspension density over bed ΔP to the top of the combustor yields a value of 0.0333 $lb/ft^3/in.wg$. Studies done with small scale CFB columns indicate that 80% of this pressure drop is due to the solids that are carried out of the furnace, while 20% of this pressure drop is caused by the forces needed to maintain the high solids loadings near the wall of the combustor. Therefore, the flow rate of solids out of the combustor and into the cyclone, W_{Cin}, is given by:

$$W_{Cin} = 0.0333 \bullet 0.8 \bullet \Delta P_{bed} \bullet V_s \bullet A_{bed} \bullet 3600 \quad lb/hr \qquad (3)$$

Where: A_{bed} = bed cross sectional area ft^2

The amount of fly ash leaving the combustor, W_{Cout}, can be found by performing an inerts balance around each combustor. The inerts balance is similar to the one used to calculate the fly ash flow rate leaving the boiler, and is described in Section 4.1.5. The cyclone collection efficiency is then given by:

$$\eta_{cyc} = 100 \left(1 - \frac{W_{Cout}}{W_{Cin}}\right) \qquad (4)$$

Figure 11-4 shows the cyclone efficiencies for both cyclones calculated for Salt Creek and Dorchester coal tests as a function of the combustor superficial velocity. Note that for the full load tests, between 16 and 18 ft/sec, the cyclone efficiency for cyclone B is slightly less than the efficiency for cyclone A. Also note that at the half load tests, between 9 and 10 ft/sec, this trend appears to reverse itself.

Figure 11-4 shows that the collection efficiency for the cyclones is quite high, ranging from 99.5% at half load to about 99.8% at full load. At these cyclone efficiencies, the recycle rate of solids in the combustor is quite high. Figure 11-5 shows the estimated recycle ratio, in lb fly ash/lb coal, versus the cyclone collection efficiency. For the full load tests, the recycle ratio ranged from 72 to 115 times the coal feed rate. Note that the combustor B recycle rate ranged from 72 to 105 times the coal feed rate while the recycle rate on combustor A ranged from 80 to 115 times the coal feed rate. This clearly demonstrates how even a slight difference in the cyclone collection efficiencies can be magnified by the total recycle system.

Figure 11-6 shows the estimated recycle rate versus the superficial velocity in the bed. The most surprising result of this graph is the apparently linear relationship between the recycle rate and the superficial velocity. However, there is not sufficient data to confirm this conclusion,

Figure 11-4. Estimated Cyclone Efficiency Versus Combustor Superficial Velocity

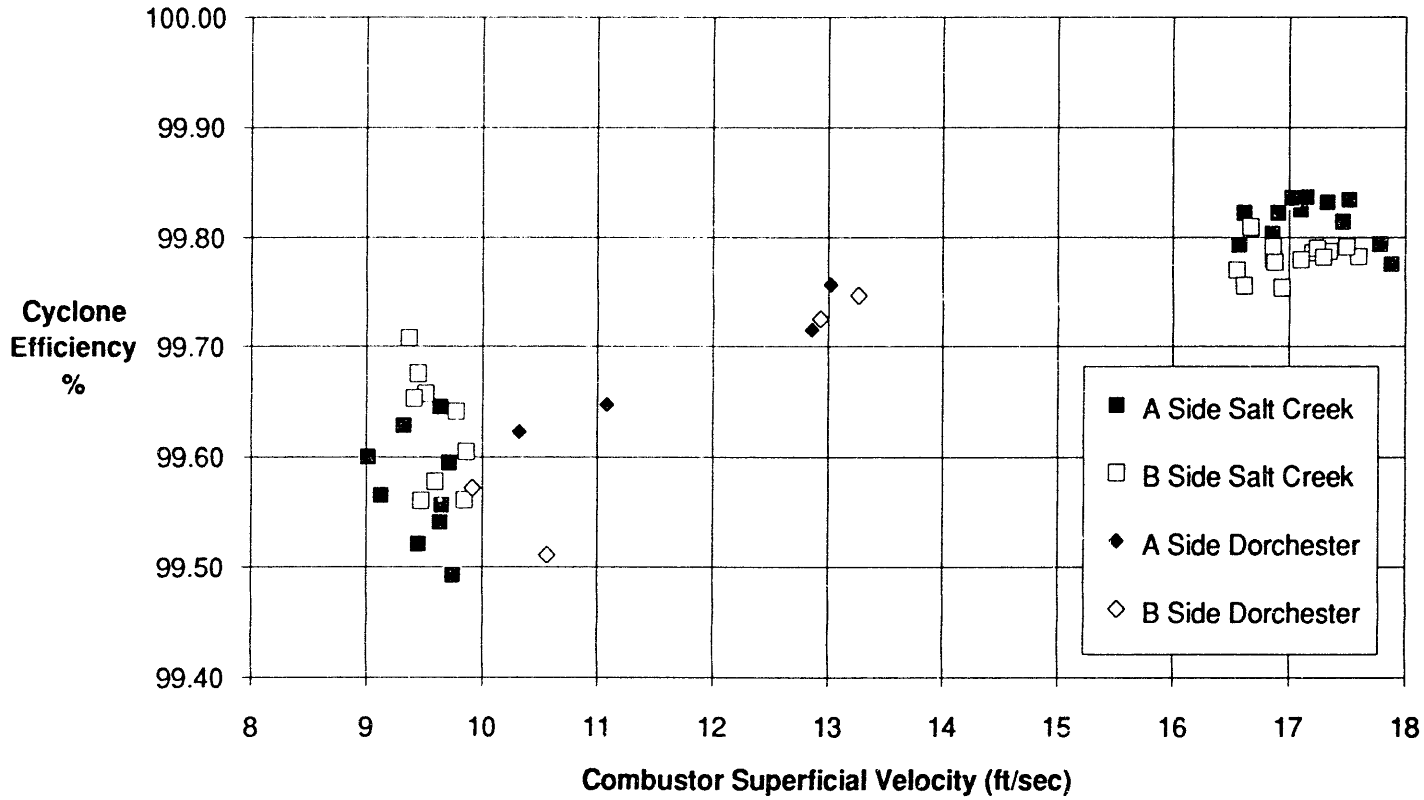


Figure 11-5. Estimated Recycle Ratio Versus Cyclone Efficiency

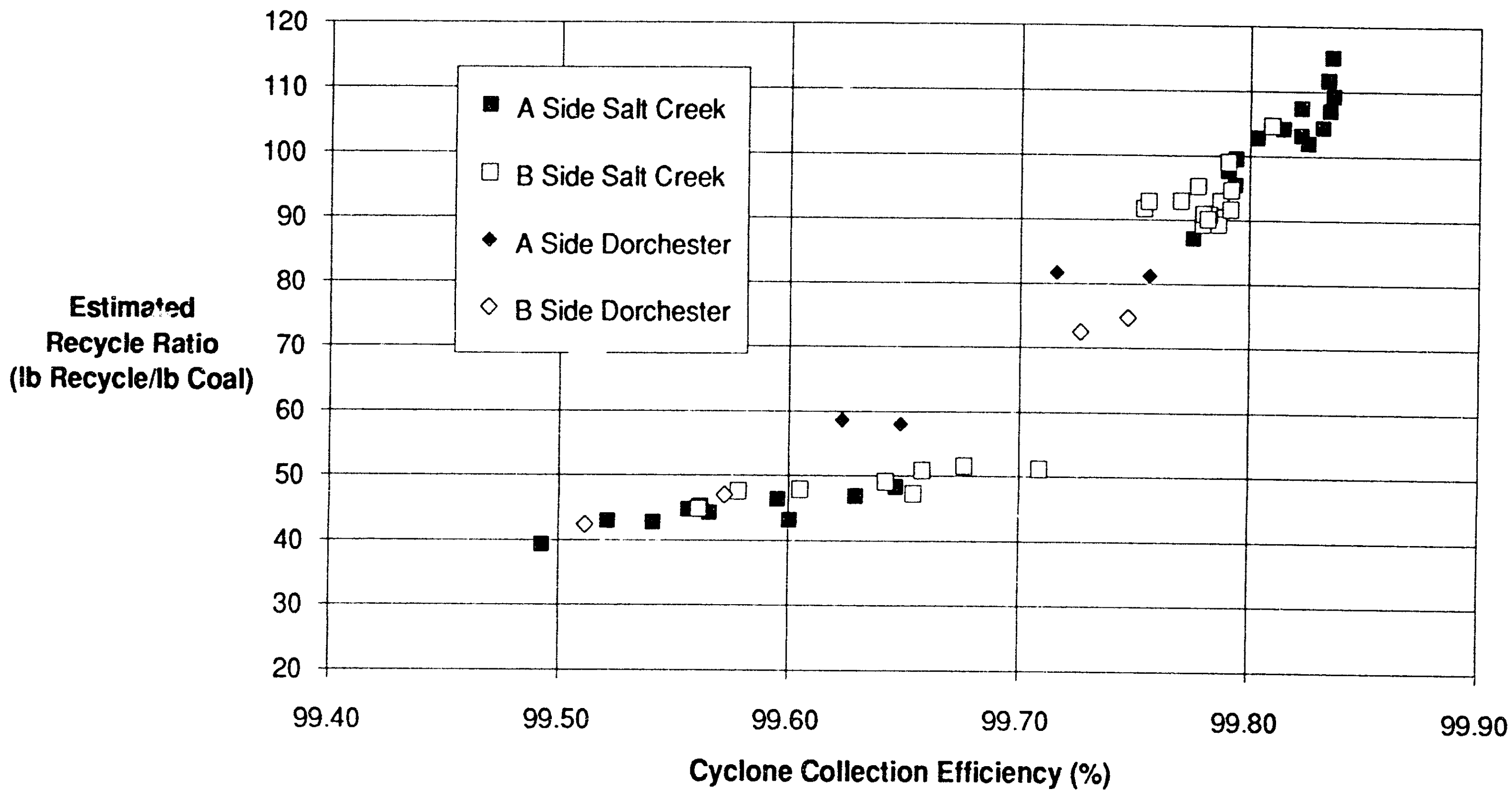
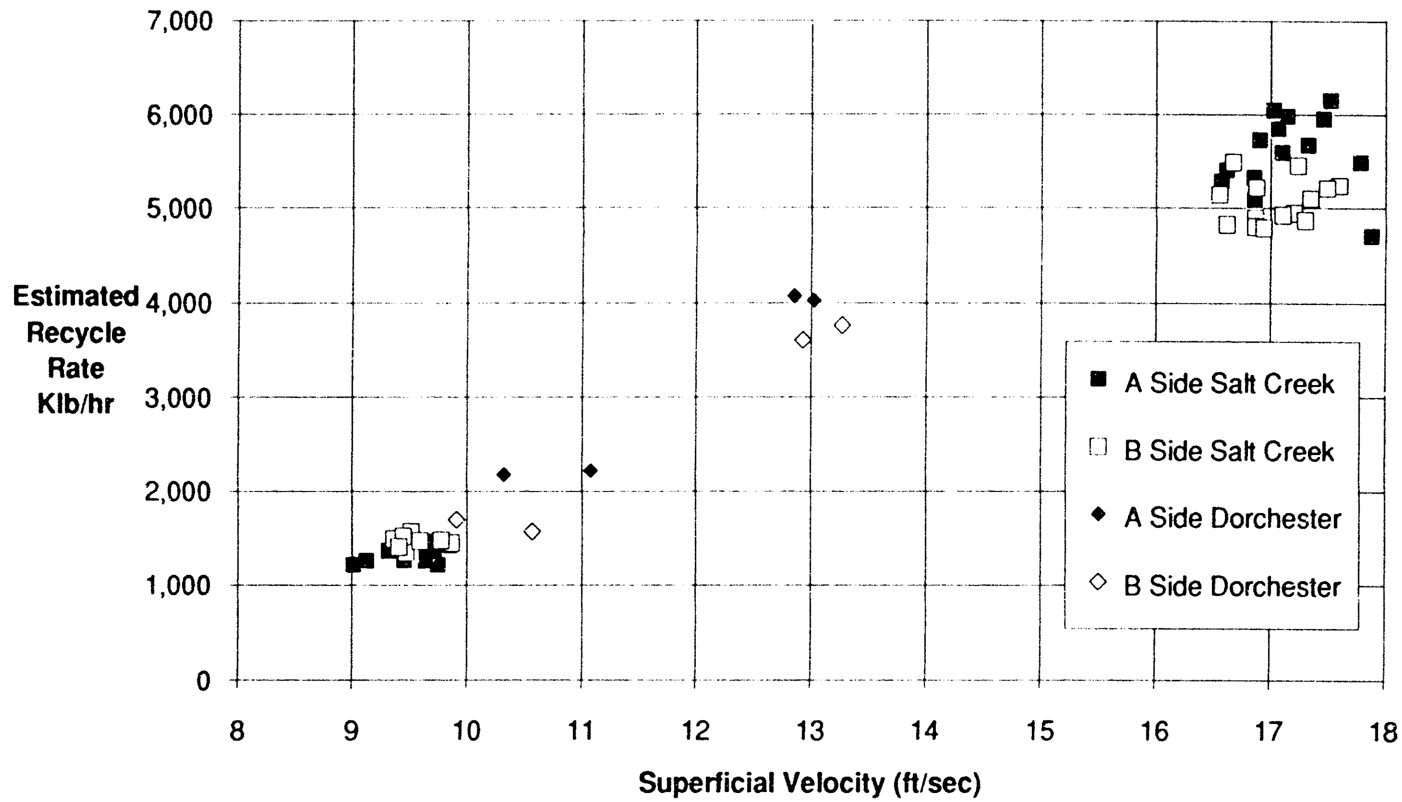


Figure 11-6. Estimated Recycle Rate Versus Superficial Velocity



since the Salt Creek tests were conducted at essentially two velocities as were the Dorchester coal tests. The data in this graph were taken during the Phase II test program, when the pressure taps measuring the upper combustor pressure drop were in place. There were a few tests on Salt Creek coal conducted during Phase I in the velocity range between 13 and 15 ft/sec. Unfortunately, the pressure taps were not installed at that time. Therefore, it is not possible to draw any conclusions regarding the linear nature of this relationship.

11.4 TEMPERATURE PROFILE

The temperature rise across the cyclones at Nucla is shown versus the superficial velocity in Figure 11-7. This figure contains data from all of the performance tests conducted during both the Phase I and Phase II campaigns. All of the data show a linear relationship with the temperature rise across the cyclone being positive (the gas heats up) at low velocities and decreases with velocity becoming negative (the gas is cooled down) at velocities above 12 ft/sec. This data is counter-intuitive, since the amount of combustion taking place in the cyclone is expected to increase with velocity in the bed.

Figure 6-22 showed that the carbon loss from the combustor increased with velocity, which would imply that more carbon, and therefore more combustion, is reaching the cyclones. However, the amount of carbon loss increased only slightly, while the amount of solids circulating increases dramatically. Nevertheless, this does not account for the gas cooling.

Figure 11-8 shows the seal leg solids temperature minus the cyclone inlet temperature. This data shows that, for most tests, there is a temperature increase for the solids. Thus, at full load the gas appears to be cooling at the same time the solids are heating. This suggests that something is cooling the flue gas after the solids are separated in the cyclone.

Figure 11-9 shows the gas temperature rise across the cyclone versus the A/B cyclone outlet pressure. Note that as the pressure is lowered, the amount of cooling increases. This suggests that air in-leakage may be responsible for the observed flue gas temperature drop across the cyclone. One possible source of this air in-leakage is the vortex cooler, which draws ambient air into the cyclone to cool the vortex finder. However the measurements taken on this air is not sufficient to account for all of the cooling at full load. The measurements showed that the total air flow into the vortex cooler was about 7,100 lb/hr, while the temperature drop at full load would require about 24,000 lb/hr of leakage. Furthermore, the measured air flow to the

Figure 11-7. Temperature Rise Across Cyclone Versus Bed Superficial Velocity

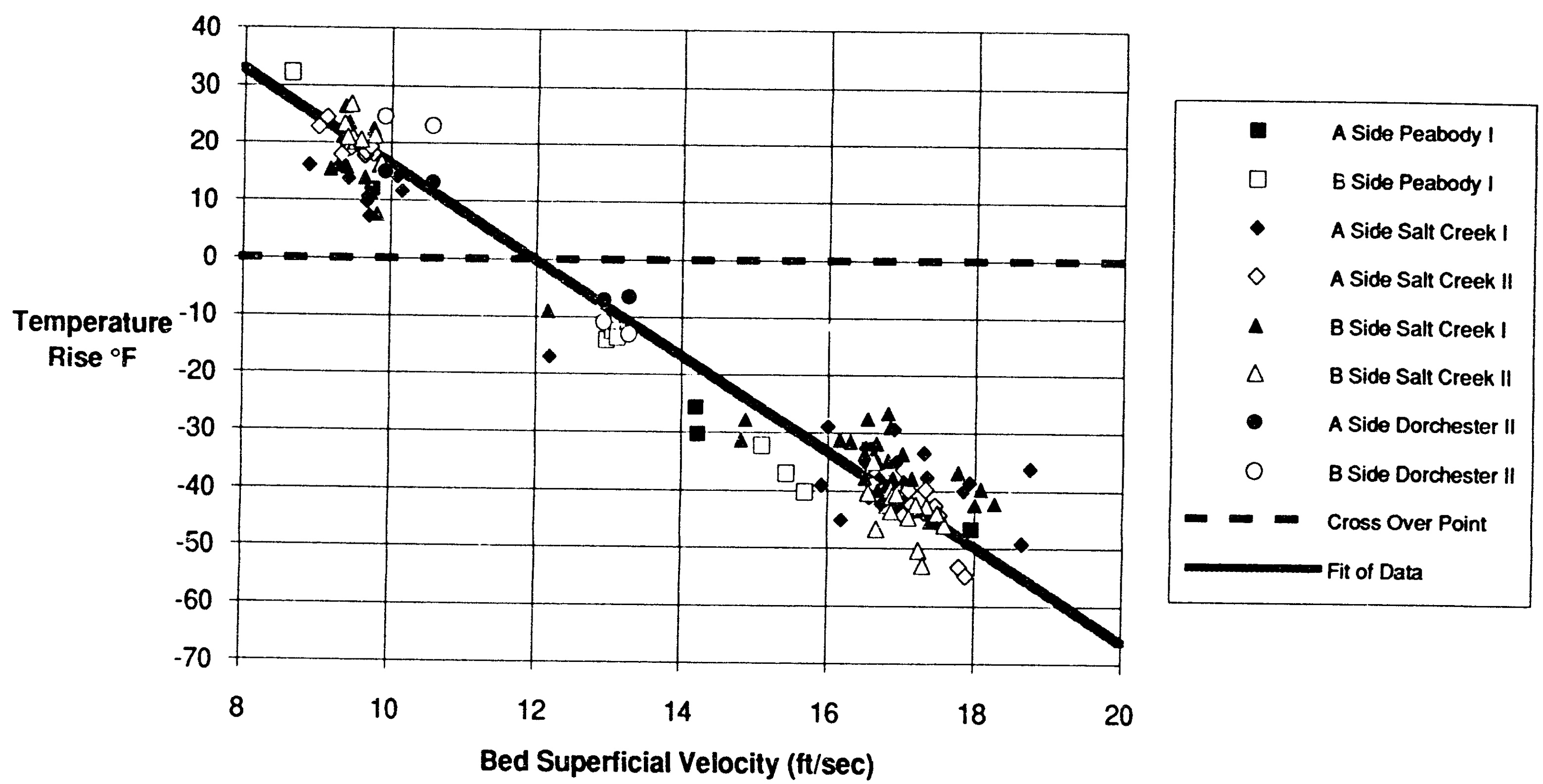


Figure 11-8. Seal Leg Temperature Minus Cyclone Inlet Temperature Versus Superficial Velocity

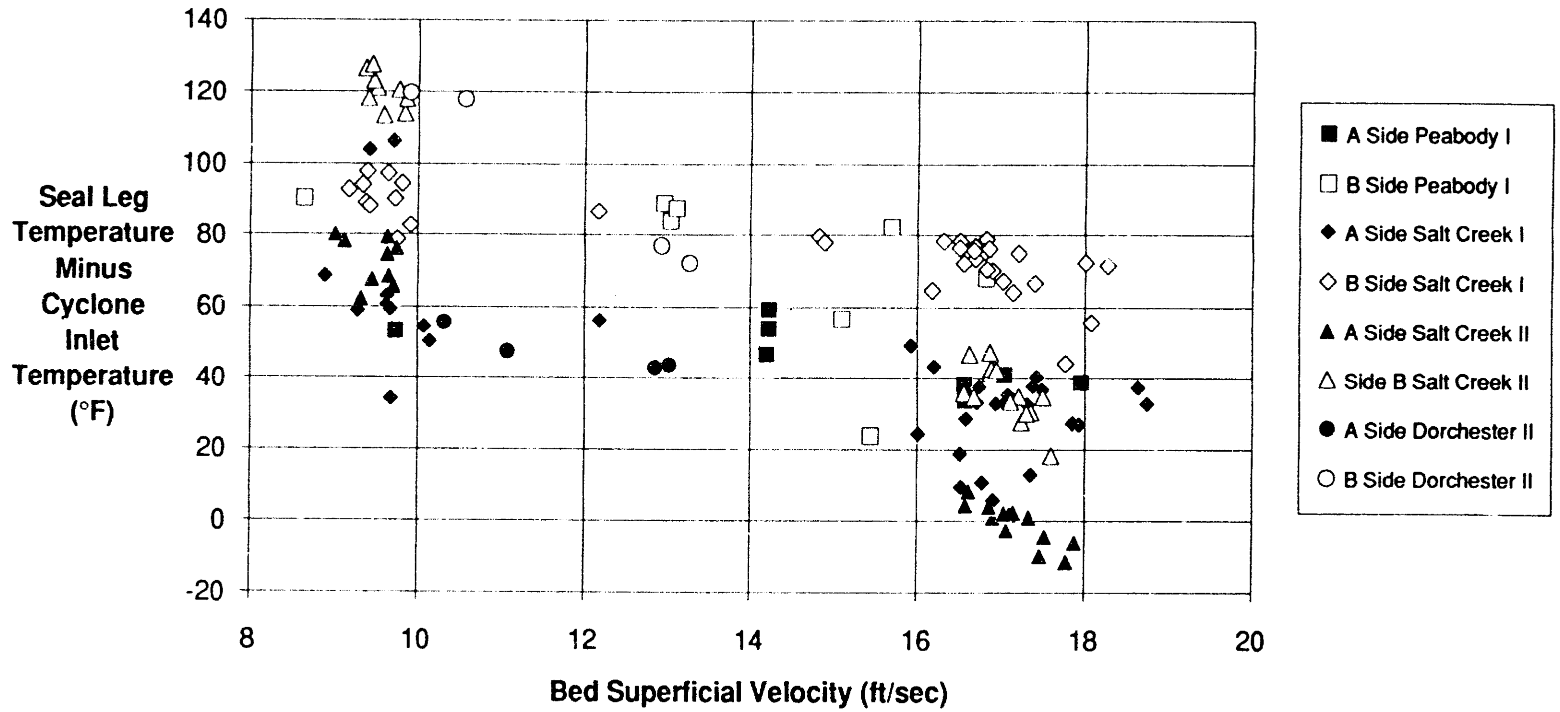
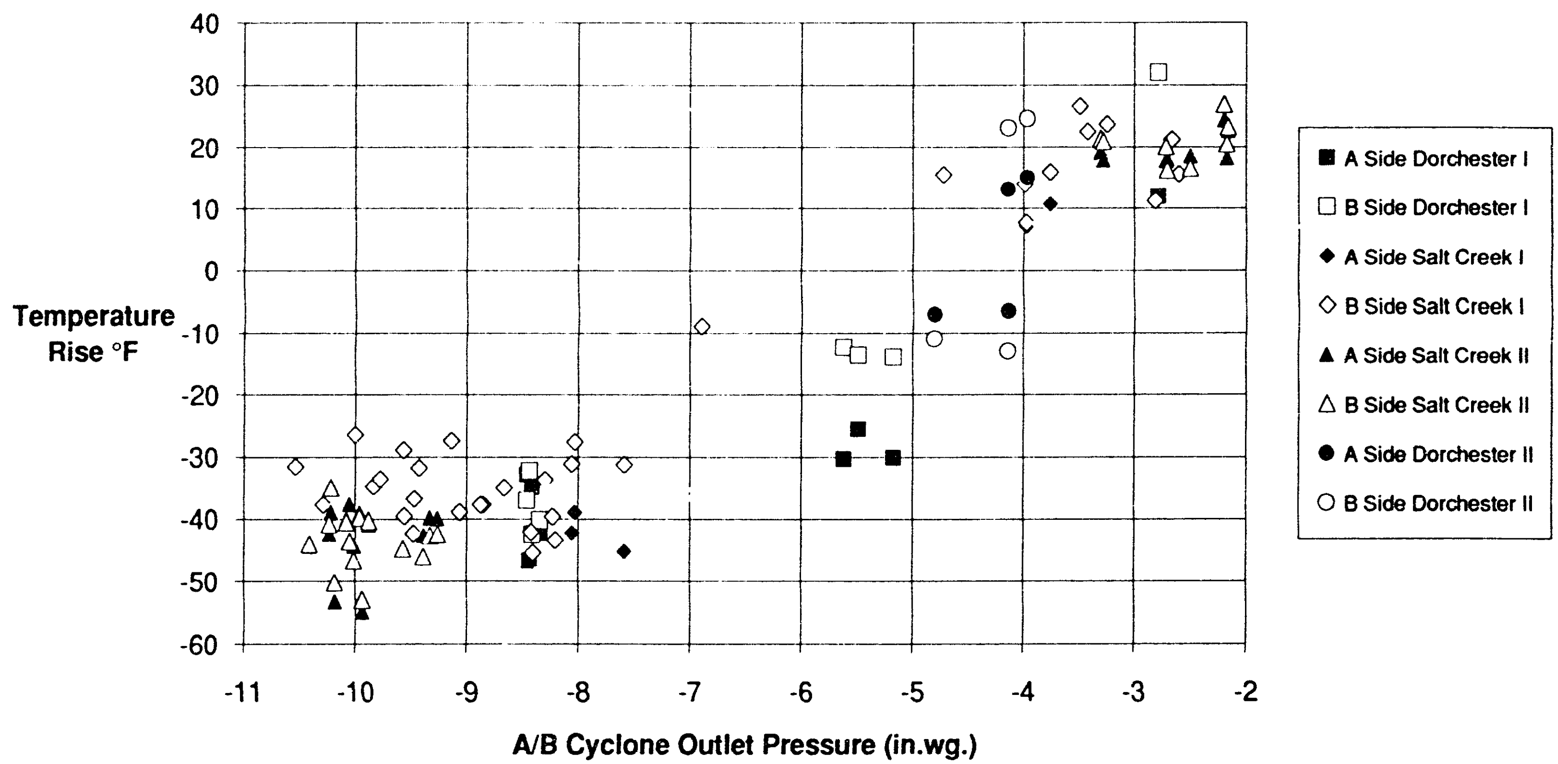


Figure 11-9. Temperature Rise Across Cyclone Versus Cyclone Outlet Pressure



combustor, including the estimated 7,100 lb/hr of the vortex cooling air, is consistently greater than the calculated air flow based on the flue gas oxygen for the full load tests. If additional air in-leakage were happening, then the calculated air flow would be higher than the total of the measurements. Therefore, while the trend shown in Figure 11-7 is consistent for all coals and loads, the source of this cooling has not been identified. One possibility for this apparent cooling may be due to a measurement error at the outlet of the cyclone. Radiation between the unshielded thermocouple and the water-cooled convection pass screen tubes may be causing the thermocouple to read low values for the gas temperature.

Section 12

COAL AND LIMESTONE PREPARATION AND HANDLING

12.1 COAL PREPARATION AND HANDLING

12.1.1 System Description

The existing, refurbished Nucla station coal system provides for coal receiving, two stages of crushing, weighing, sampling (as received), live storage/reclaim, and transfer into the plant building. The system is shown schematically in Figure 12-1 and is designed from existing and new equipment.

Raw run-of-mine coal is delivered from local coal mines to the plant by truck and is weighed and then dumped into an unloading hopper. Two half-capacity vibrating feeders deliver coal from the unloading hopper to the primary crusher where the coal is reduced in size to approximately 7" x 0. The primary crusher discharges onto a belt conveyor to a secondary "granulator-type" crusher where it is reduced in size to approximately 3/4" x 0. A single vibratory feeder delivers coal to the secondary crusher. From the secondary crusher, coal is delivered by a belt conveyor to a transfer house via an integral belt weigh scale.

In the transfer house, coal from conveyor A drops through a diversion gate that directs the coal flow to either storage via stack-out conveyor B, or into the power plant via conveyor C. A reclaiming hopper and vibratory feeder located beneath the "rocket" on the storage pile reclaims coal and feeds it onto plant conveyor C, which delivers coal to the main plant enclosure.

The discharge from conveyor C flows into a two-way diverter/splitter that directs coal onto either or both new en-masse inclined conveyors A and B. Each of these drag chain type conveyors are rated at 127 tons/h. A new "as-fired" coal sample system is located at the discharge of conveyor C at the base of these inclined conveyors. In the event of equipment problems, an 18 ton surge hopper has been installed just above the final crushers (at the discharge of the inclined conveyors) with capacity to store all coal on conveyor C (see Figure 12-2).

At the outlet of the surge hopper, a two-way splitter/diverter gate transfers coal onto either of two vibratory feeders prior to the final crushers. Both crushers operate simultaneously to accept the full output of plant

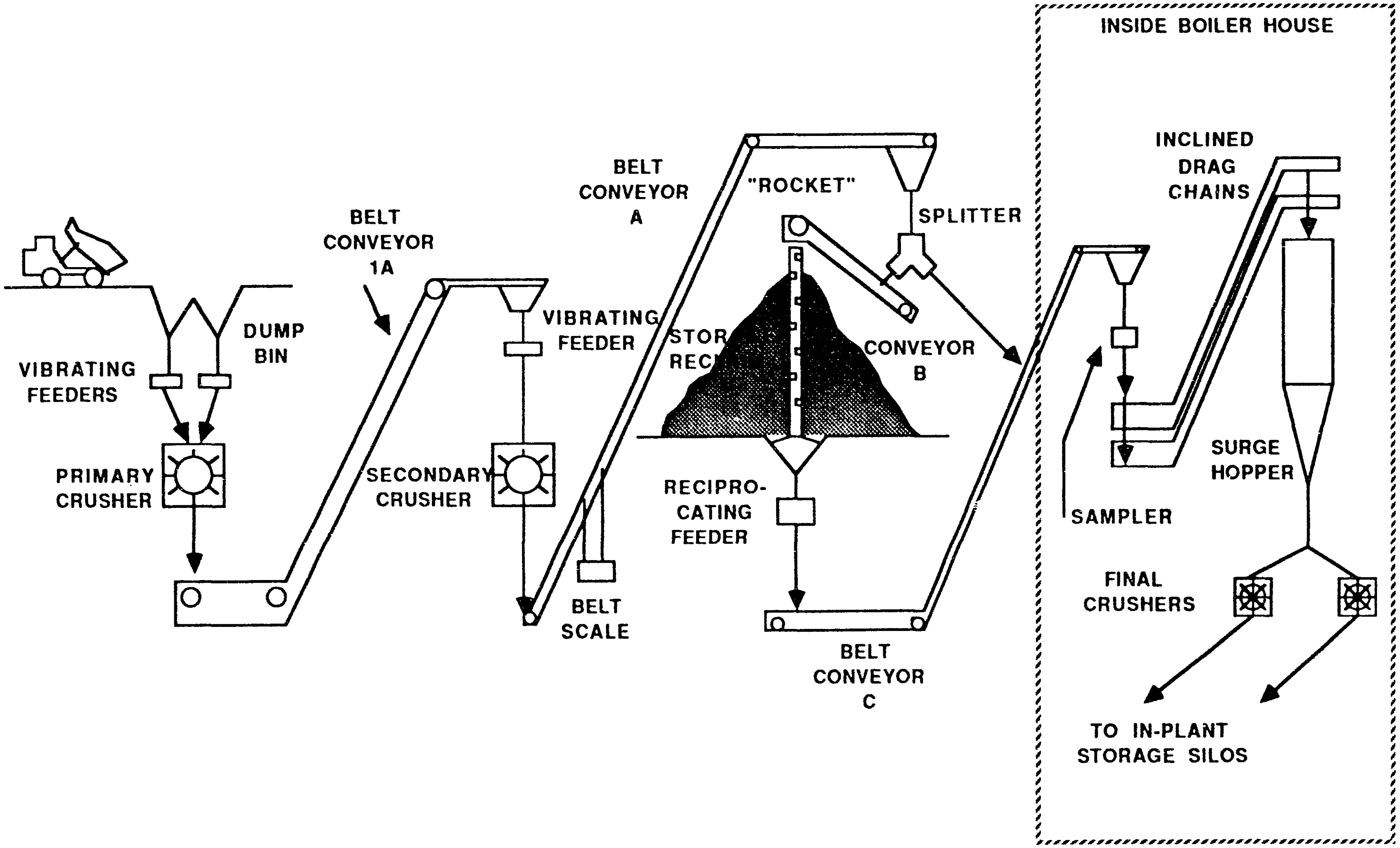


Figure 12-1. Schematic of Coal Preparation System.

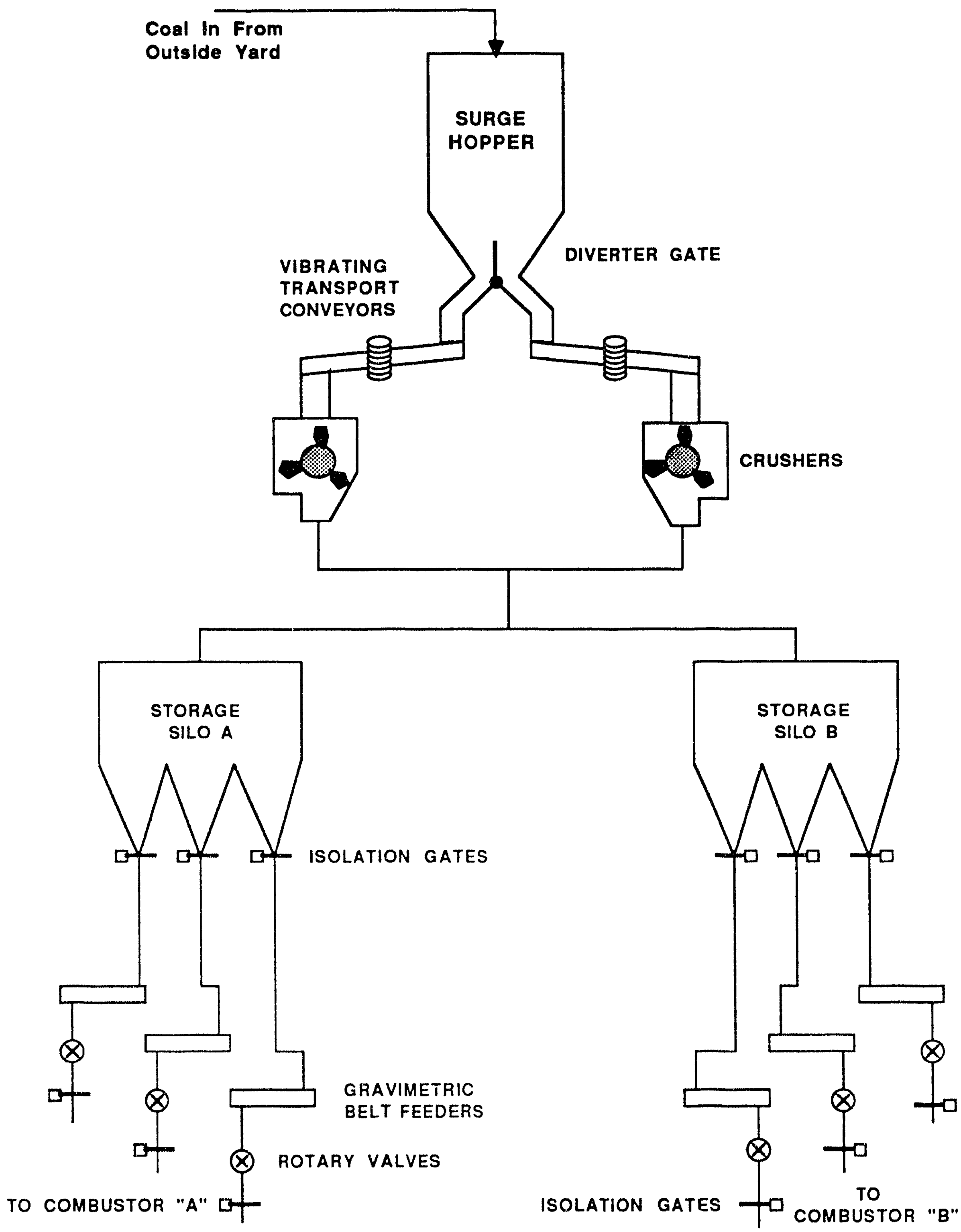


Figure 12-2. Schematic of Coal Feed System.

conveyor C. Both are reversible impact crushers which operate at a rate of 65 tons/h and reduce the coal size from 3/4" x 0 to 1/4" x 0, required for the CFB process. Since coal is normally delivered into the plant on conveyor C on a two-shift per day basis, both coal crushers are usually in service when the plant is operating at full load.

At the outlet of the final crushers, two 54' long horizontal drag chains transfer the full output from each crusher to either or both of the in-plant coal storage silos. Three feed points are provided from each conveyor at the top of each silo to obtain a high percentage fill. The inlet openings to silo A are equipped with remotely operated slide-gates so that this silo can be bypassed (when full) to fill silo B. Silo B is equipped with manually operated slide-gates.

Each coal silo has a capacity of 215 tons and is located in front of the front wall of the CFB boiler. This sizing provides an 8 hour storage capacity with the boiler operating at full load. Each silo has three discharge openings, designed to maintain mass flow movement to each of six boiler gravimetric feeders. Each silo discharge is equipped with a manual slide gate for isolation during maintenance on the gravimetric feeders (see Figure 12-3).

The gravimetric feeders discharge coal into the boiler via gravity and booster air flow. A motor actuated slide gate and rotary valve isolate the gravimetric feeders from the hot combustion products in the lower combustion chambers. One inclined and one horizontal drag chain-type conveyor is used to transfer coal from each of two gravimetric feeders situated along the front walls, around the side walls of each combustor, to the loop seal coal feed points.

12.1.2 Summary of Coal System Operating Problems

There have been no significant coal system equipment problems at the Nucla station. Most of the problems encountered have been maintenance related. These include rotary valve trips due to foreign matter entangled in the rotor, worn front wall coal chutes, and broken chain links and shear pins in the horizontal drag chain conveyor to the coal silos. For the most part, operation of this system has been trouble free and very reliable. Addressing these relatively minor problems more specifically:

- During operation on high moisture Dorchester coal, pluggage occurred in the outside preparation system at the inlets to the primary and secondary crushers and at the outside storage rocket (reclaim).

- Pluggage has occurred on occasion at the diverter gate on the in-plant surge hopper.

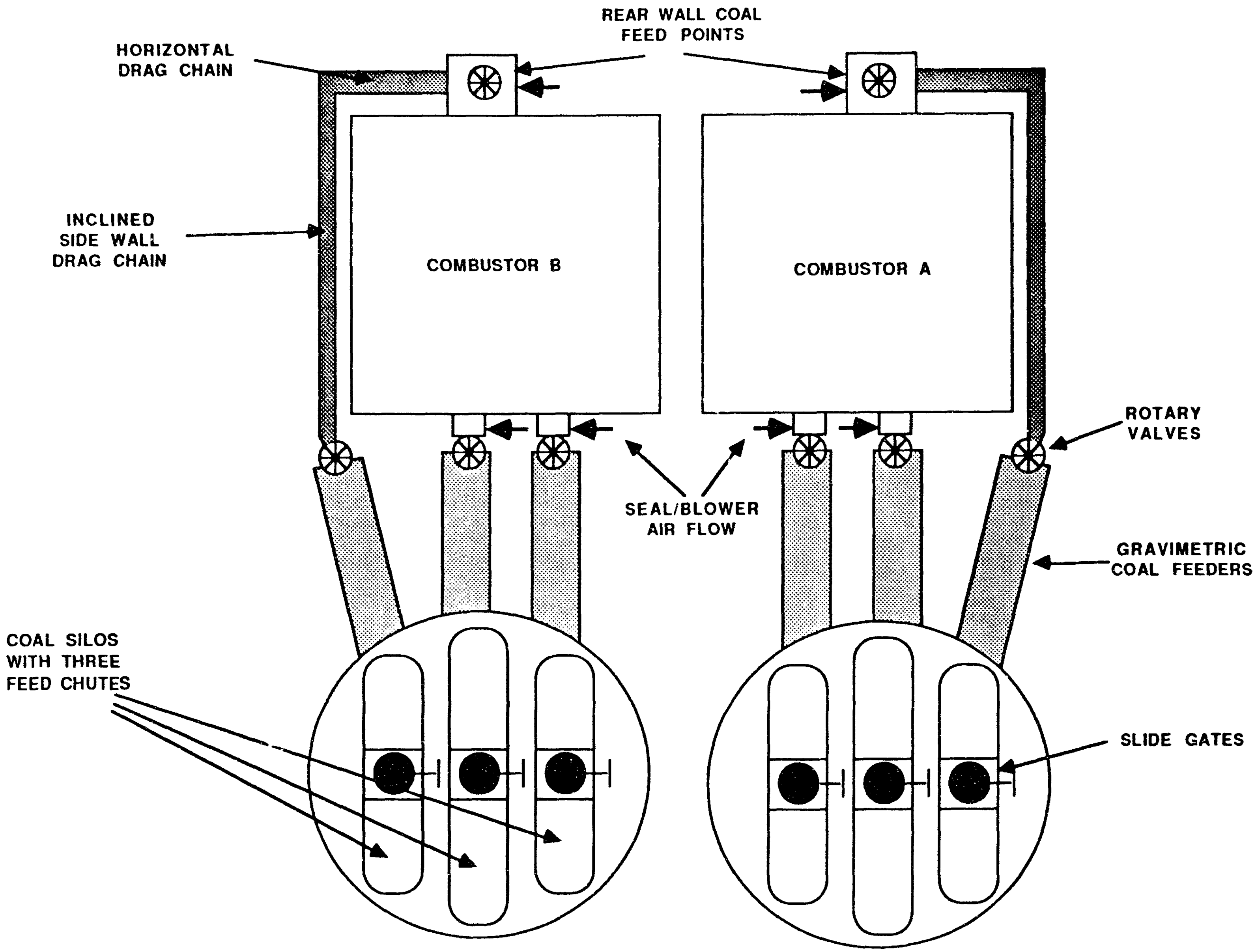


Figure 12-3. Plan View of Combustor Coal Feed Configuration.

- Drag chains are loud and the vendor added teflon sheets to the base of the drag chain during acceptance testing. This reduced noise but did not fully resolve the problem. Fortunately, the chains are located on the tripper deck, which is isolated from the rest of the plant.

- Periodic blockage of the rotary valves under the coal feeders occurs from tramp material.

- The biggest problem with the coal feeders comes from belt misalignment. To correct this problem, operators adjust the belt tension which throws the feeder out of calibration. This is a problem with a twin combustion chamber design where it is desirable to balance temperatures on each side.

- Vibrating conveyors downstream of surge hoppers had a problem with structural supports which failed. This problem was corrected by reducing the length of the support cable.

12.2 LIMESTONE PREPARATION AND HANDLING

12.2.1 System Description

The limestone handling system provides for receiving, transferring, storing, and preparing the limestone before it is injected into the boiler. Schematics of the system are shown in Figures 12-4 and 12-5.

Raw limestone is delivered from a local quarry by truck and is dumped into a receiving hopper equipped with a pneumatic dust suppression system. A vibrating feeder delivers the limestone into a reversible hammermill that reduces the stone from roughly 10" x 0 to 3/4" x 0. A belt conveyor, with an integral weigh scale and magnetic separator, delivers the crushed product to a bucket elevator which transfers it to an outdoor storage silo. This portion of the system is rated at 68 tons/h. The silo has a storage capacity of 772 tons, which is equivalent to requirements for 70 hours of full load operation.

The storage silo transfers limestone to the pulverizer via a vibrating bin cone and vibrating feeder. The pulverizer is rated at 8.2 tons/h and reduces the 3/4" x 0 product to 150 micron average size. The pulverizer also contains a burner system, shown in Figure 12-5, that dries the product to less than 1% moisture. The pulverizer is an air-swept pendulum-type roller mill. The pulverizer outlet limestone and air mixture are classified by a motor-driven spin separator that returns large size particles back to the pulverizer. Material that passes through the classifier is directed to a

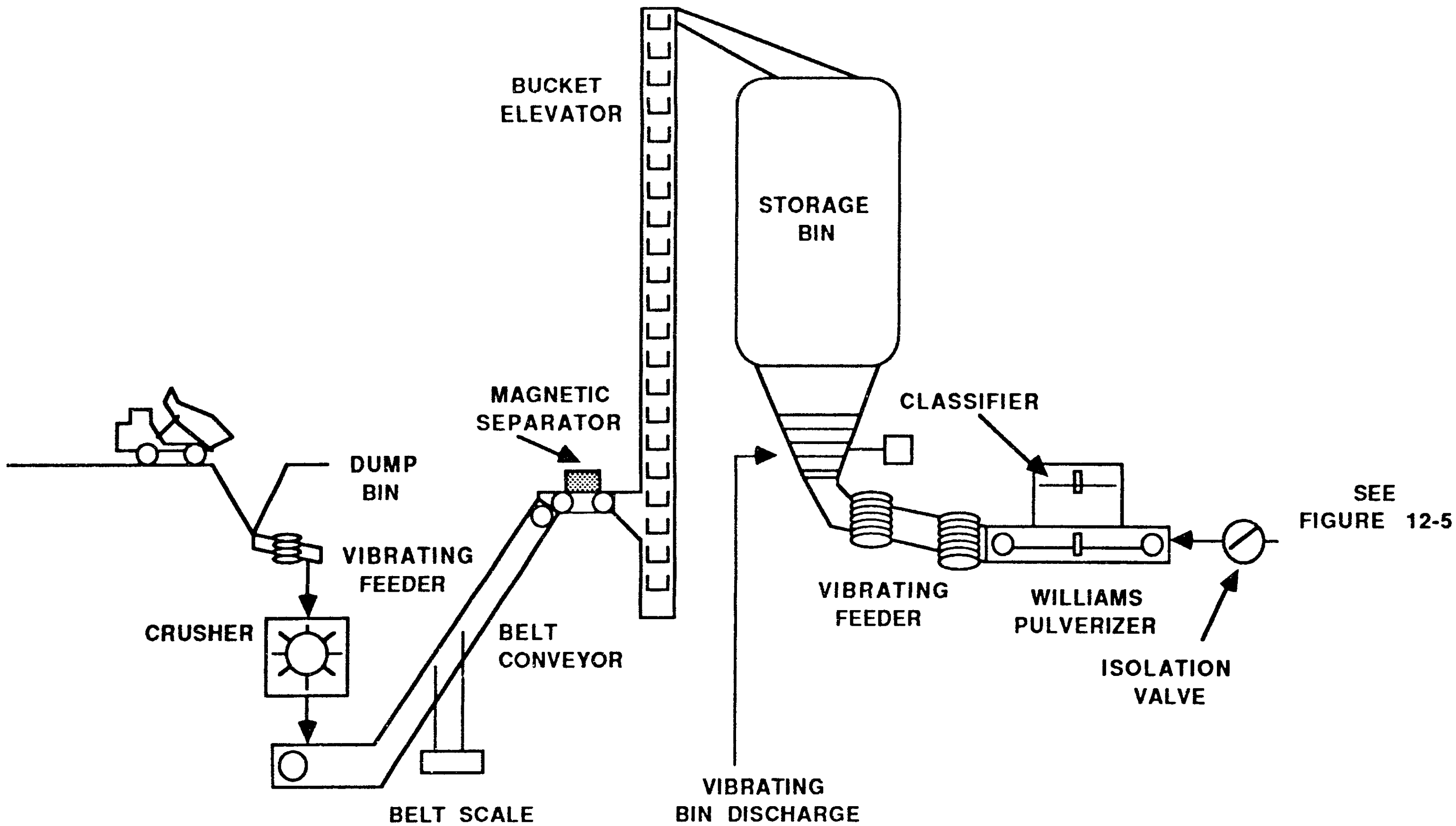


Figure 12-4. Partial Schematic of Limestone Preparation System

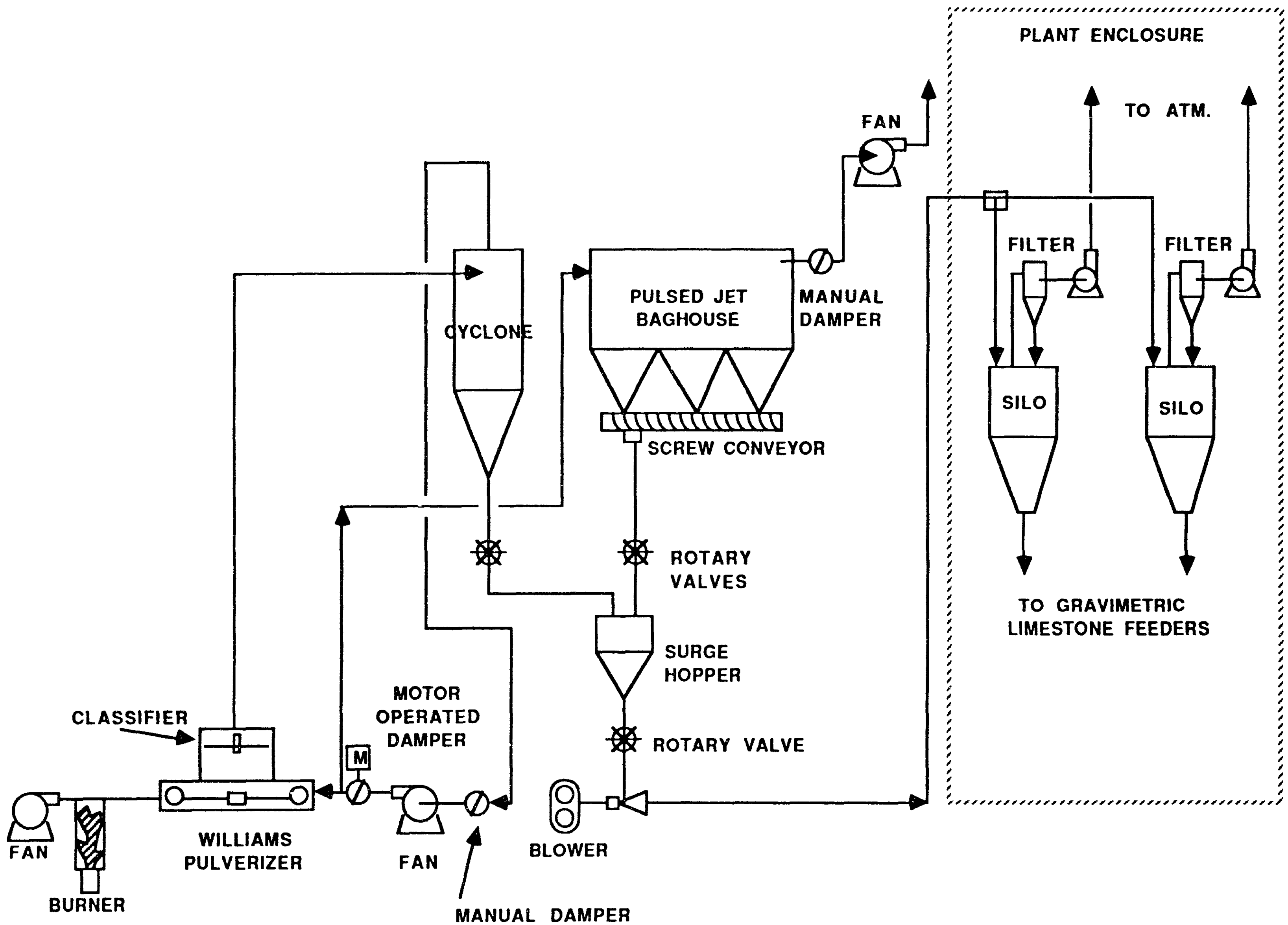
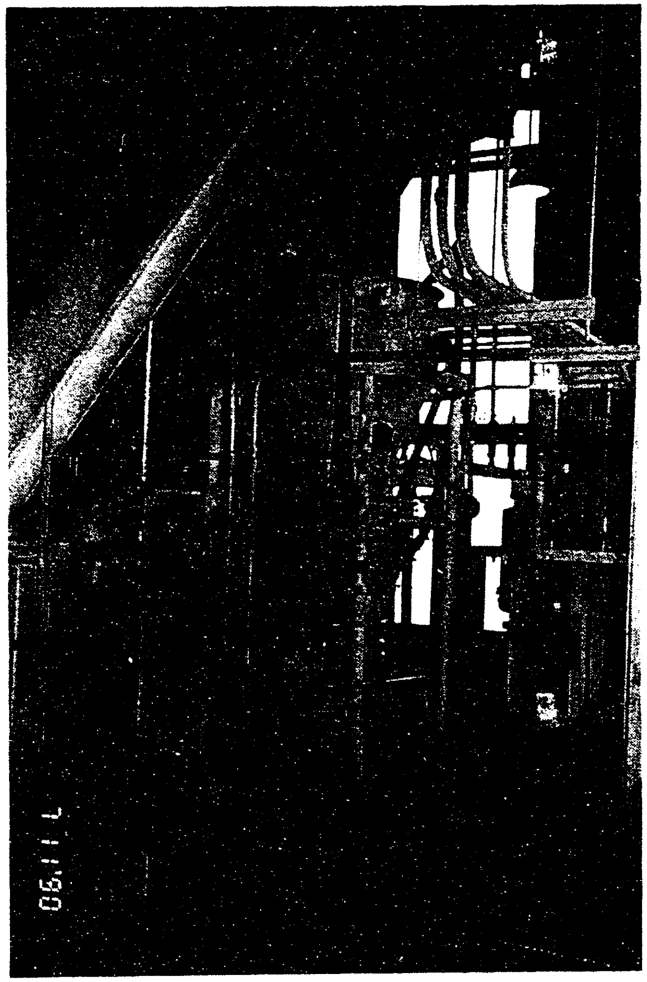


Figure 12-5. Schematic of Limestone Preparation System.



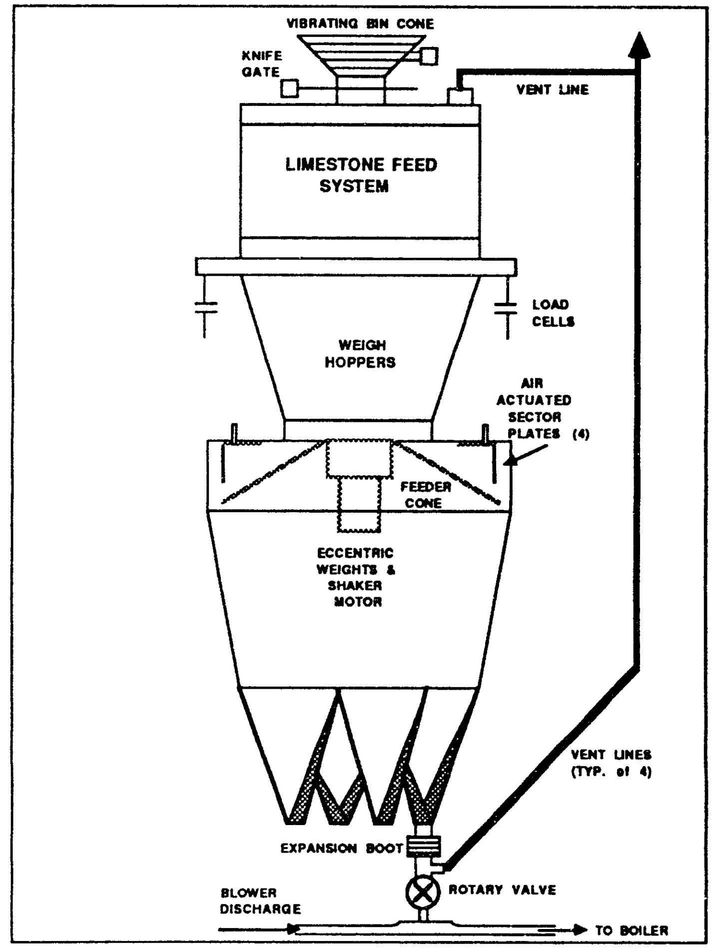


Figure 12-6. Schematic of Limestone Feed System (typical of two).

cyclone separator. The discharge from the cyclone returns to the inlet of the pulverizer fan which recirculates the air to the mill. Heated make-up air is provided by the fan and burner system. The separated limestone in the cyclone drops through a rotary feeder into a surge hopper (see Figure 12-5).

Transport air is bled from the pulverizer fan discharge to a fabric filter collector and exhaust fan. The entire limestone pulverizer system is maintained at a slightly negative pressure by the fabric filter exhaust fan. The fabric filter discharges collected limestone via a screw feeder and rotary valve to the surge hopper where it joins with the cyclone collection stream.

Pulverized limestone collected in the surge hopper is transported to the inside storage silos by a pressurized pneumatic conveying system at a rate of 8.2 tons/h. The pneumatic conveying line is isolated from the surge hopper by a rotary valve. Each of the two in-plant storage silos serves on combustion chamber and has an individual storage capacity of 123 tons. This size provides storage capacity sufficient to sustain 12 hours of full-load operation on design "A" coal. Each silo is equipped with a fabric filter for collection of entrained limestone in the limestone feeder vents and the pneumatic transport air.

Processed limestone passes through a vibrating bin on the bottom of the storage silo into a weigh hopper. A piston-actuated slide gate isolation valve separates the silo from the weigh hopper. The weigh hopper is mounted on load cells, as shown in Figure 12-6, and is filled by the storage silo at a preset weight. The load cell output is electronically monitored over a period of time to obtain an integrated rate of limestone feed. Each feeder is automatically adjusted in direct relation to combustion chamber coal flow and trimmed base on the flue gas SO_2 concentration.

Limestone is fed from the weigh hopper to a second small hopper by a shaker cone that vibrates by eccentric weights attached to the shaker motor. Both of these are housed below the shaker cone in the lower storage hopper. Four piston actuated "sector" plates control the tolerance between the plates and the shaker cone, and therefore establish the rate of limestone feed to the lower hopper for a given shaker motor speed. Only opposite pairs of sector plates can be completely closed (if necessary) so that the shaker cone is still free to vibrate. From the lower hopper, limestone passes through four small conical hoppers each equipped with a rotary valve. These valves isolate the lower surge hopper from four pressurized pneumatic transport lines. Each of the four conical legs of the surge hopper has its own transport blower, transport line, and rotary valve. As mentioned, only opposite feed lines, as dictated by the relation of the conical leg to the sector plate location, can be isolated should system repairs be required. In addition, any individual feed system can be removed from service.

Each of the four feed lines on each limestone feed system transport limestone to the combustion chambers. A motor-actuated valve isolates each feed line from the boiler should repairs or maintenance be required. Two limestone transport lines feed directly under the coal feed ports along the front walls of the combustor. One transport line feeds to the side wall and one directly into the loop seal recycle return on the rear wall. The limestone feed locations are shown schematically in Figure 12-7.

12.2.2 Summary of Limestone System Operating Problems

The feeding mechanism in the loss-in-weight feeder is a cone attached to an eccentrically loaded variable speed motor shaft (shaker). The original design consisted of an unenclosed motor coupled to eccentric weights. During the first year and a half of operation, both feeders suffered multiple eccentric weight bearing failures and motor burnouts. Because the shaker motor hangs suspended within the feeder in contact with limestone, a probable cause for failure was limestone leakage into the motor housing and bearings. The system was replaced with totally enclosed motors, integral bearings, and eccentric weights. The speed of the new assembly is 3600 rpm, as opposed to 1800 rpm on the previous shaker motors. Since these replacements, there have been no additional failures.

Feeder stability has been poor due to pressurization of the charge hopper from transport air leaking past the rotary valves. In the second quarter of 1989, examination of rotary valve clearances indicated excessive wear had taken place since these clearances had last been set. The leakage resulting from wear to both the rotor tips and casing was estimated at nearly 50% of the transport blower flow rate. This, in turn, causes increased back pressure below the rotary valve, particularly at high conveying rates. Various venting configurations were tried with limited success.

Pocket vents in the casing of each rotary valve, installed to relieve rotor pocket pressure, were found to be ineffective because of pluggage. The vent located above the feeder cone was not sufficient to prevent pressure buildup throughout the system. The initial modification made to the feeder system was the removal of the pocket vents and the installation of an additional vent line located in the feeder bin below the feeder cone. This additional venting capacity increased the stable flow range up to 7000 lb/h, but flow instability was still present at higher flow rates.

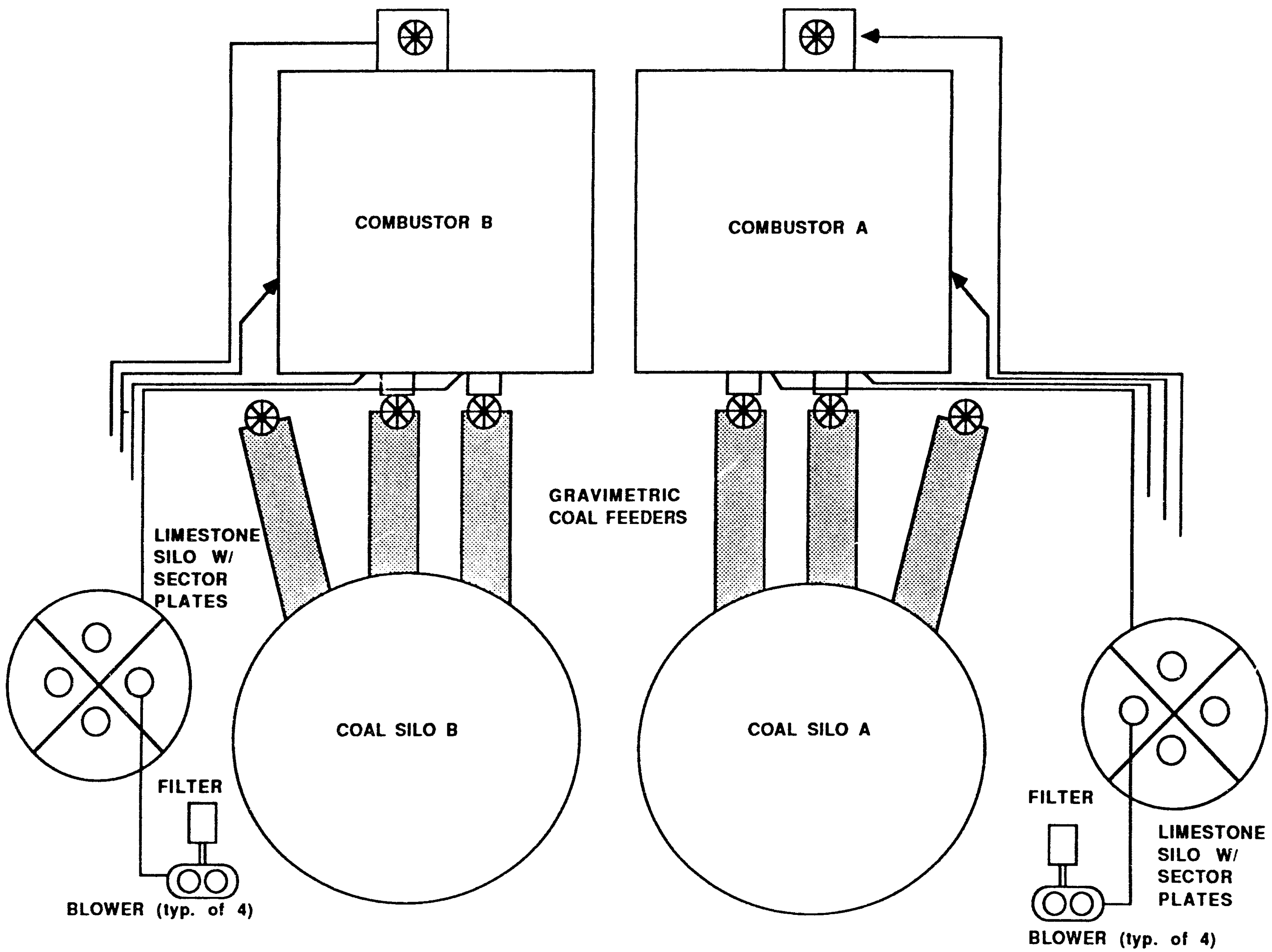


Figure 12-7. Plan View of Limestone Feed Configuration.

In addition to high pressure below the feeder cone, another characteristic of the flow instability was a high pressure drop across the feeder cone. Three pressure equalizing lines were added that connected the feeder bin volume, the volume just above the feeder cone, and the volume below the knife gate. Pressurized operation resulted in limestone leakage through flange connections. In addition, flushing occurred when the knife gate opened to fill the weigh hopper. This resulted in failure of the expansion boots above the rotary valves and loss of a significant amount of limestone to the plant.

In the next modification, the uppermost vent line was moved to the top of each coal silo. This isolated the feeder from the limestone preparation and provided a negative pressure (by way of the coal dust suppression system) for drawing the limestone fines through the vent. This modification improved feeder stability for limestone feed rates between 5000 and 8000 lb/h. At the conclusion of the test program, reliable operation at rated capacity (12000 lb/h) had not been demonstrated.

Section 13

ASH HANDLING SYSTEM PERFORMANCE AND OPERATING EXPERIENCE

13.1 BOTTOM ASH REMOVAL AND DISPOSAL SYSTEM

13.1.1 System Description

The bottom ash removal and disposal system provides for the classification, removal, cooling, transfer, storage and disposal of bottom ash from the boiler. The system also provides for reinjection of bottom ash from the storage silo back into the combustion chambers for boiler start-up. The system includes all equipment from the combustion chamber sidewall bottom ash ports to the truck filling facility and the reinjection equipment. A schematic of the system is shown in Figure 13-1.

As coal and limestone are fed into the combustion chambers, the inventory of bed ash particles increases. This causes a measurable increase in the pressure required to support and circulate the weight of the bed. The pressure, and consequently the bed inventory, are controlled by extracting bed ash through the bottom ash removal system. Hot 1600 °F bottom ash is removed through bottom ash ports located on the outside walls of the lower combustion chambers.

Two 100% capacity fluid bed bottom ash coolers are used to cool and classify bottom ash before it is drained through rotary valves. One variable speed rotary valve is located under each ash cooler. The cooling mediums for the bottom ash coolers consist of water walls and air provided by an ash cooling fan. The water walls are included in a closed cooling water system which recovers heat from the bottom ash and transfers it to the low-pressure feed water system. A single fan provides air to the bottom ash coolers to cool and classify the ash.

Ash is admitted to the bottom ash coolers by means of inlet fluidizing nozzles which maintain a preset range of pressures in the ash coolers. The cooling air and classified bed material flow from the top of the bottom ash coolers to the combustion chambers via upper return ports. Bottom ash is removed from each cooler through a drain line containing a variable-speed rotary valve. The speed is regulated by the operator to control the inventory of bed material in the ash coolers. Two fluid bed ash coolers serve each combustion chamber and discharge into a single bottom ash surge hopper which is mounted on load cells.

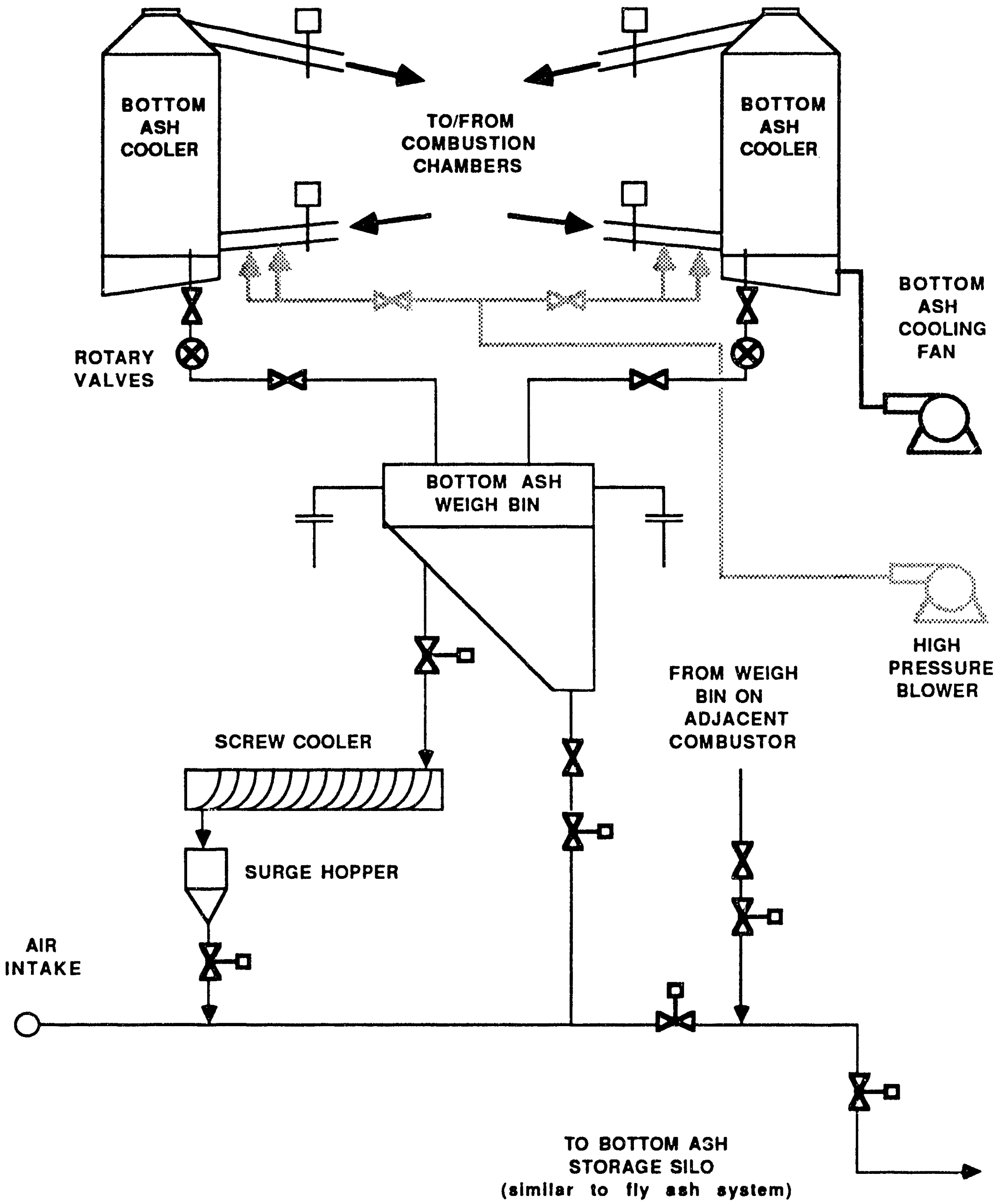


Figure 13-1. Schematic of Bottom Ash Removal System (typical of two).

When a single bottom ash cooler is operating on one combustion chamber, the expected ash exit temperature is approximately 450 °F and the ash requires additional cooling. For this reason, a separate water-cooled screw conveyor is installed near the outlet of the surge hopper to provide additional cooling. During normal operation of the boiler, either both ash coolers or one ash cooler and the screw cooler on each combustion chamber are required. This arrangement provided the plant with redundancy should maintenance or repairs be necessary on one of the ash coolers. The heat removed from the screw coolers is also rejected to the closed cooling water system.

A 20 ton/h vacuum-type pneumatic conveying system is provided to transfer the bottom ash from the surge hoppers, or from the screw coolers, to the existing bottom ash storage silo. A continuously operating cyclone separator and pulsed-jet bag filter are installed on the silo roof to separate bottom ash from the conveying air. Two existing vacuum blowers, one operating and one spare, have been reconditioned and upgraded to provide the conveying motive force.

A pressurized ash reinjection subsystem is provided as part of the bottom ash handling system, which includes one gravity airlock feeder for transferring ash from the storage silo to a pressurized pneumatic conveying line. This pneumatic system conveys bottom ash back to each combustion chamber through a single reinjection port located in the loop seals on the rear wall of each combustion chamber. A single blower provides the pressurized conveying medium.

13.1.2 Bottom Ash Handling System Operating Problems

The bottom ash handling system has undergone several changes since the original installation. The general areas of these changes include amendment of the ash cooler to classifier, modifications to the ash cooler discharge lines and modifications to increase ash handling capacity.

Concerning amendment of the ash cooler to classifier, the initial design of the bottom ash cooler entrance was found to be inadequate to convey coarse bed material through the spout from the combustion chamber into the ash coolers. To facilitate coarse particle flow into the ash cooler, the following modifications were made:

- A high pressure air tube was installed at the inlet of each bottom ash spout, with the air passing through 1/8 in. diameter holes, to facilitate conveying coarse materials into the ash cooler.

- The control logics were altered to regulate the total air flow rate to each cooler in order to maintain the classifying velocity at a preset value. This was accomplished by adding motor-actuated butterfly dampers to each inlet air line. Air flow is measured in this line with an annubar. Classifying velocity in the ash coolers is determined based on the air flow rate, the cooler cross-sectional area, and the temperature and pressure in the ash cooler. Flow is then modulated to maintain a constant velocity. In the original control scheme, the air flow rate was held constant to each cooler and classifying velocity fluctuated with cooler operating temperatures and pressures.

- Refractory bricks were added to cover 34% of the ash cooler cross-sectional area at the grid level to increase air velocity for ash classification. At the same time, approximately 20% of the cooling tube surface area was covered by refractory. The resulting decrease in cooling capacity was within acceptable limits.

A minor modification was made in the ash cooler discharge line from the ash cooler to the bottom ash hopper to facilitate removal of material that could potentially plug the discharge line upstream of the rotary valves. A door was installed in the line to allow inspection of the duct above the rotary valve and removal of any accumulated agglomerated bed material.

Concerning modifications to increase ash handling capacity, the bottom ash handling and conveying system removes bottom ash from the boiler at a rate sufficient to maintain constant solids inventory (and therefore constant bed pressure) in the combustor over the full operating range. The design removal rate capacity is 20 tph, which is the rate required for ash removal with high ash (35 wt.%) coal. Attempts to operate at full load with either the high ash or high sulfur coals were unsuccessful because of capacity limitations of approximately 8 tph.

After a thorough investigation by the bottom ash transport system vendor, major changes to the system were made. These included modifying/simplifying the piping layout, increasing pipe size, increasing transport flow from 3800 to 5000 ft3/min, and adding water sprays at the transport exhauster inlets.

Changes in piping layout and pipe size with the revised system were necessary to reduce friction losses in the ash transport line and to increase ash handling capacity. The piping arrangement within the ash pit was improved to form a single conveying line instead of two parallel lines to each combustion chamber. This eliminated the purge time and increased time for conveyance. For ease of maintenance and reduced friction loss, the number of bends was reduced and 90° elbows were replaced by more gradual bends. The size of the conveying line from the plant building to the top of the bottom ash silo was increased from 8 to 10 in. to reduce pressure drop at the higher conveying volume. Also, the air line from the separator to the exhausters was enlarged for the same purpose. All of these modifications were expected to reduce the friction loss by about 50 percent, and are shown in Figure 13-2.

To increase the volumetric capacity, the sheaves on the exhauster drive motor were replaced to increase the operating speed from 1500 to 1750 rpm. Also, to increase mass flow rate and efficiency, water sprays were added at the transport exhausters. The water injection provided a better seal and also lowered the temperature resulting in a higher vacuum.

The conveyor pickup velocity had been designed for 3800 ft^3/min after taking into account the actual sizing of the bottom ash generated at the Nucla unit. Of particular concern was the fraction of large size material not present during the pilot plant test burn. In addition to reducing system maintenance, these changes have eliminated the flow rate restriction in the transport line that limited full-load operation with high ash coal.

Demonstration of sustained operability on high ash coal was initially unsuccessful due to excessive temperatures of bed material discharging from the ash classifiers at full load. The temperatures were reduced to acceptable levels by operating both ash classifiers and the water-cooled screw cooler on each combustion chamber. The ash classifiers operate in parallel and the water-cooled screw cooler operates in series with either or both of the ash classifiers.

To reduce bed material drain temperatures from the ash classifiers under extreme operating conditions, two water sprays were added to each of the bottom ash cooler/classifiers. A water flow of 2 gpm to each spray was sufficient to control ash temperature during sustained operation on high ash coal.

An additional change to the bottom ash removal system at Nucla included modifications to the bottom ash hoppers at the inlet to cooling screws. The inlet to the screw cooler was lowered and a bend was incorporated in the line to eliminate blockage of the inlet. This modification is shown in Figure 13-3.

13.1.3 Bottom Ash Cooler Inspections

Generally, bottom ash cooler material performance has been good. However, inspections in June of 1989 revealed some relatively minor signs of wear in the firebrick linings, the refractory linings, and the water-wall tubes. Early failure

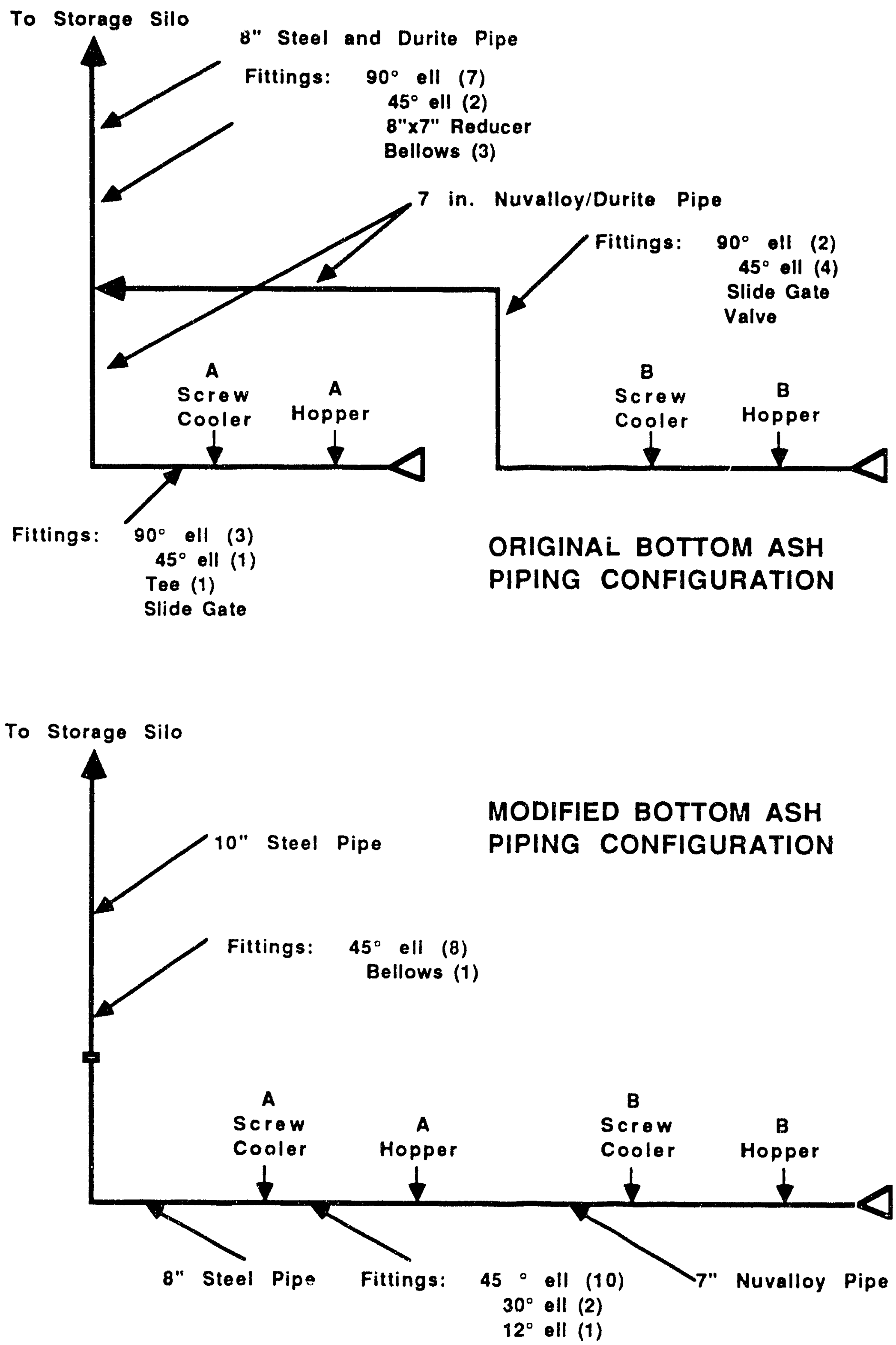


Figure 13-2. Bottom Ash Piping Modification.

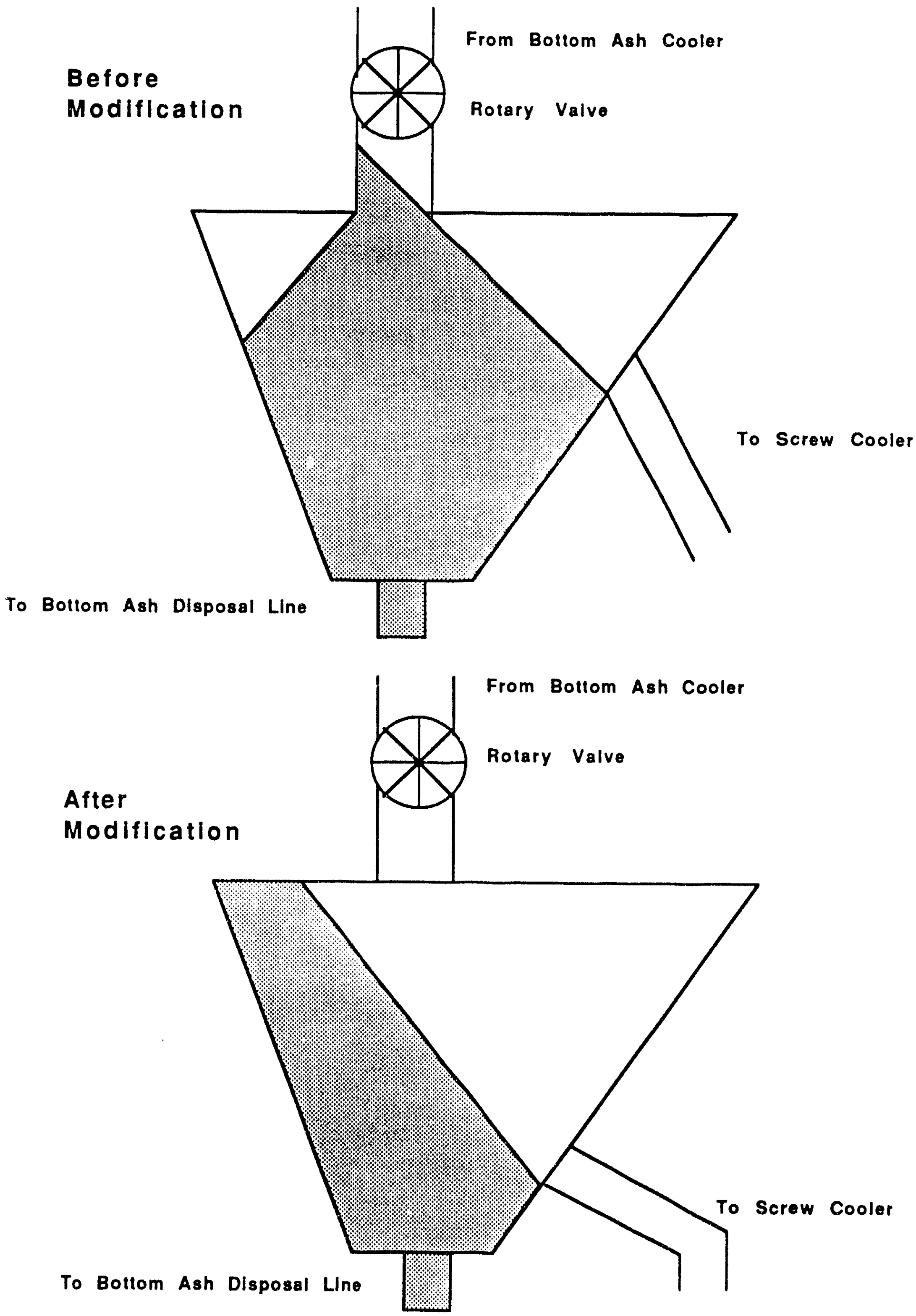


Figure 13-3. Modifications to Bottom Ash Weigh Hopper.

of bearings in the screw coolers has been eliminated by a regular lubrication schedule.

The refractory transition at the base of the "top hats" have shown wear. Some return bends have been exposed, as shown in Figure 13-4.

In March of 1989, a tube leak developed in bottom ash cooler 4D due to impingement from a cooling water spray line and caused a small area of localized erosion adjacent to the leak site. There has also been periodic bubble cap loss, but only a small percentage of the total number of bubble caps have been affected.

13.2 FLY ASH HANDLING SYSTEM

13.2.1 Fly Ash Handling System Description

The fly ash handling system provides for removal, transfer, storage and disposal of fly ash from hoppers located on the bottom of the convection pass and air heater enclosures, and on the old and new baghouse hoppers. Fly ash is transported to a 720 ton capacity storage silo before being discharged via a conditioning system to trucks for disposal. The system includes all fly ash handling equipment and components from the various collection hoppers to the fly ash storage silo and truck loading facility. The system is shown schematically in Figure 13-5.

Two independent 27 ton/h, vacuum-type pneumatic conveying systems are provided to transfer fly ash from the collection hoppers to a new fly ash silo. One system serves the three existing baghouses; the second system services the new baghouse, the boiler convection pass hoppers and the air heater hoppers.

Fly ash is conveyed to a new 60,000 cubic foot mass flow storage silo. The two trains operate continuously and each have cyclone separators operating in series with pulsed-jet bag filters. The bag filters are sized for a maximum air-to-cloth ratio of 3.5 acfm/ft2. Three identical vacuum blowers are provided; one for each fly ash conveying network and one spare.

A fly ash silo rotary drum unloader/conditioner with a capacity of 160 tons/h is provided. The unloader is fed by a screw feeder equipped with a charge hopper and operates on a batch basis. The unloader mixes a controlled amount of water with the fly ash to prevent dusting during unloading, transport, and disposal.

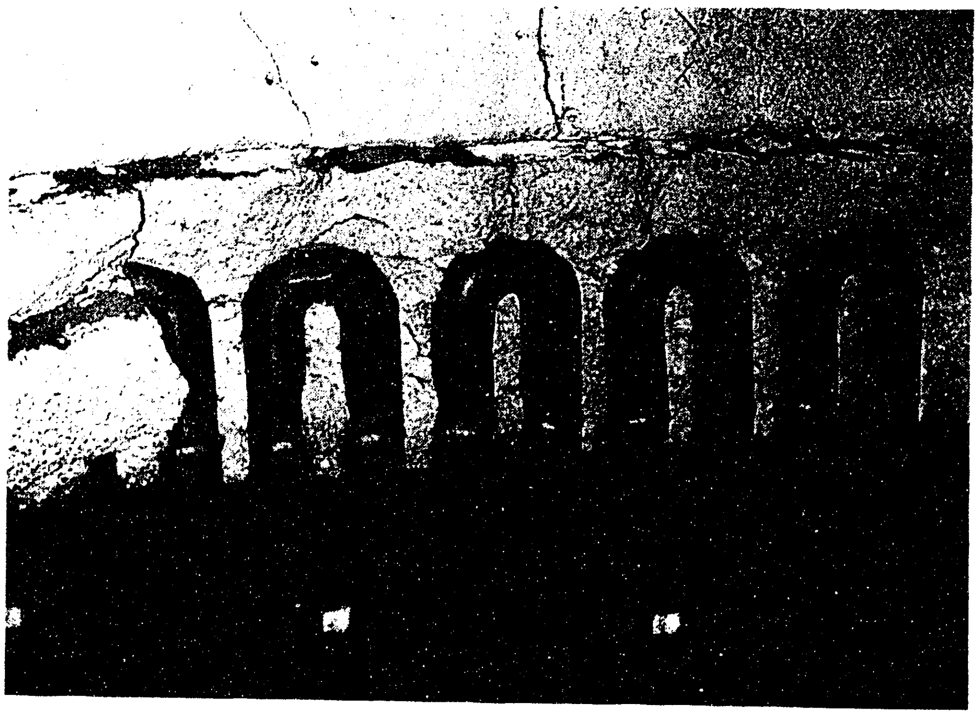


Figure 13-4. Exposed Return Bends.

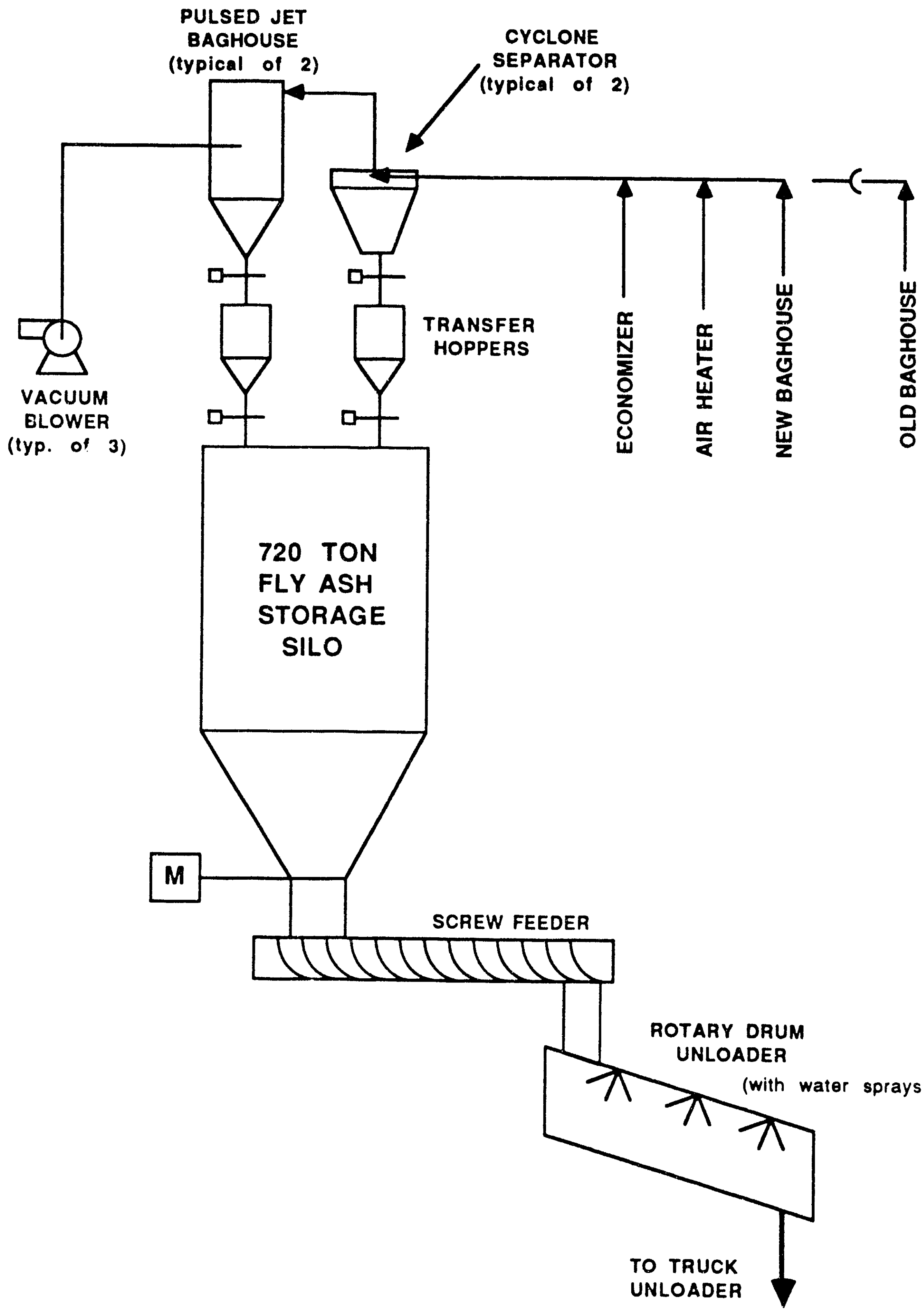


Figure 13-5. Schematic of Fly Ash Disposal System.

13.2.2 Fly Ash Handling System Operating Problems

Problem areas with this system have included erosion of solids separation equipment, high pressure drop across the transport system due to baghouse filter pluggage, and fly ash leakage around the shaft of the screw feeder at the discharge of the fly ash storage silo. These problems have resulted in high maintenance requirements, but have not caused anything but temporary reductions in unit capacity.

Erosion has occurred mainly on the inlet target area of the cyclone separator and around the dump valves on each side of the transfer hoppers. A modified inlet design to the cyclone has prevented additional erosion failures. Presently, new plate and seal materials are being tested to circumvent the dump valve erosion.

With high ash loads from high ash fuel, bag filters have plugged on the pulse-jet baghouse separator. Typically, the transport blowers are shut down and the baghouse is allowed to time through several cleaning cycles before being put back into service. Bags have been changed on this system once since initial start-up. The addition of a longer vortex finder on the upstream cyclone may reduce solids loading to the baghouse and improve performance.

Leakage of fly ash around the screw feeder shaft seals at the base of the fly ash storage silo has been a source of high maintenance. Shaft seals have been replaced on several occasions, although fugitive dust emissions continue to be a periodic problem.

Section 14

TUBULAR AIR HEATER PERFORMANCE

14.1 OBJECTIVES AND SYSTEM DESCRIPTION

The air heater at the Nucla CFB is of tubular-type design containing over 150,000 square feet of surface area. Flue gas flows inside the tubes and heats both primary and secondary air, which flows over the tubes in multiple passes. There are a total of three primary air passes and two secondary air passes within the air heater, as shown in Figure 14-1.

A methodology was developed for calculating the effectiveness of this air heater design. Knowledge of air heater effectiveness will aid designers and planners in matching surface area requirements with desired outlet temperatures. This information may also improve capital cost estimates and allow better cost comparisons to be made between alternative air heater designs.

14.2 OPERATIONAL PERFORMANCE

The tubular air heater at Nucla has performed well during the Phase I and II test periods and has not required maintenance of any components comprising the air heater design. Periodic inspections of the air heater have not revealed any fouling or erosion at the gas-side inlet or outlet. O_2 measurements at the inlet and outlet during unit acceptance tests in July and October 1988 confirmed the absence of air-to-gas-side leakage.

However, problems with air leakage from the primary to secondary air flow paths became apparent during early operation of the unit in 1987 and 1988. This leakage is more pronounced at half load when the difference between primary and secondary air pressures is greatest and secondary air flows are reduced to a minimum. Temperature and pressure measurements at the inlet to the secondary air fan at half load indicate a reversal of flow from the primary air fan back through the secondary air fan.

During investigations for the cause of this problem, the tube sheets separating the primary and secondary flow paths, shown in Figure 14-1, were found to have 0.25-0.5 inch gaps along lines formed where the four sections of the air heater were joined together during construction. These gaps were welded shut during the operating period prior to the first

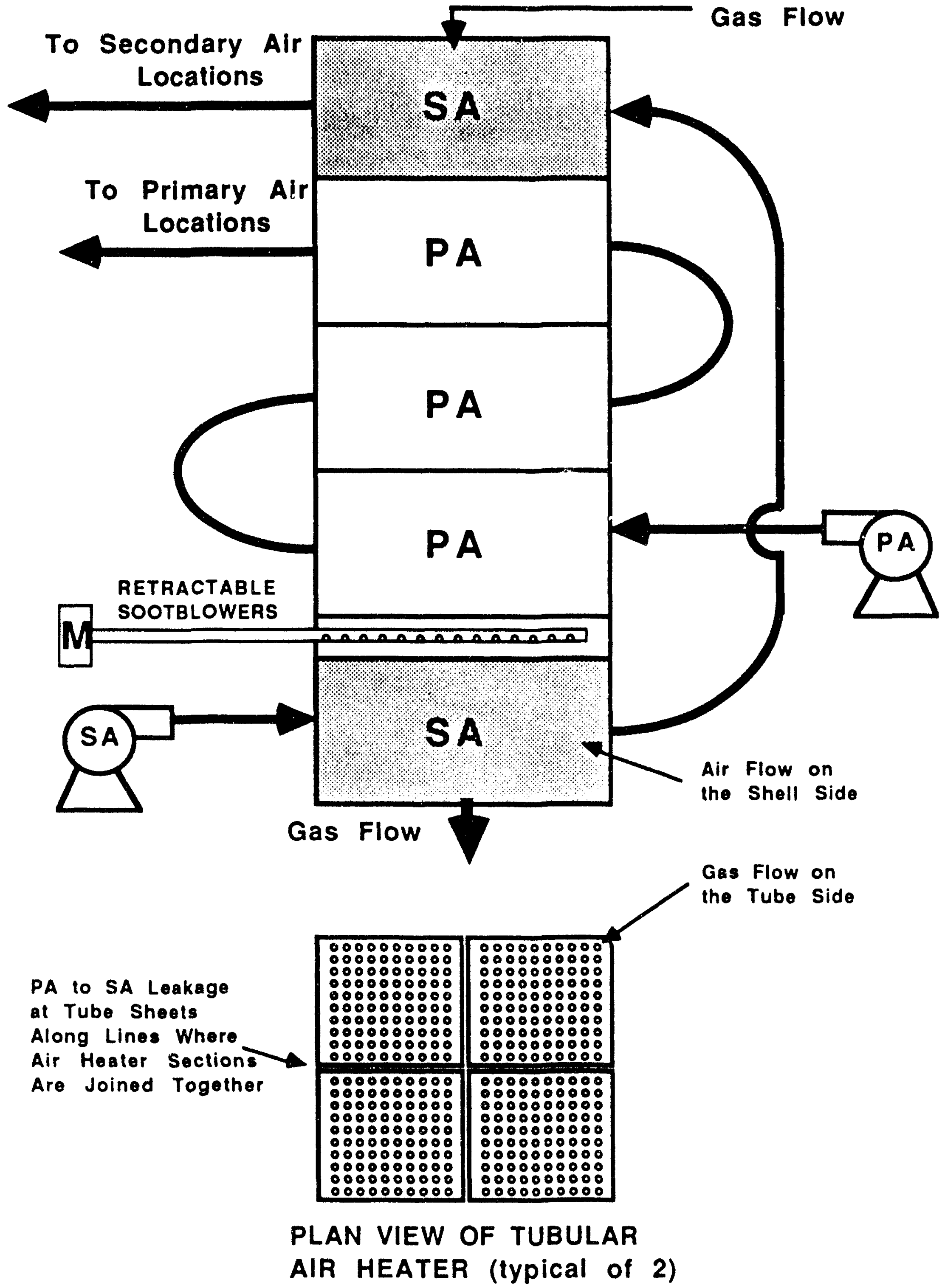


Figure 14-1. Schematic of Tubular Air Heater Arrangement.

acceptance test in July 1988. This correction reduced the problem, although subsequent operating data at half load indicated some degree of leakage from the primary to the secondary air flow paths.

Primary to secondary air leakage of the tubular air heater does not affect the CFB boiler, but does have a negative impact on secondary air fan performance and auxiliary power consumption at half load. The effect on air heater performance (if any) was not quantified. This leakage may occur around tube penetrations through the tube sheets separating the primary and secondary flow paths, or through some undiscovered flow path. At the conclusion of the Phase II test program, the source of this leakage had not been identified.

14.3 CALCULATION OF AIR HEATER EFFECTIVENESS

The heat exchanger effectiveness, E, is calculated using the following equation:

$$E = \frac{q}{q_{max}} = \frac{\text{MFFG CPF (FTMP1 - FTMP2)}}{\text{MFA CPA}\left(\text{FTMP1} - \dfrac{\text{MFPA PTMP1 + MFSA STMP1}}{\text{MFPA + MFSA}}\right)}$$

Where:

q	= Heat transfer in the air heater
q_{max}	= Maximum possible heat transfer. This would occur if the fluid with the minimum product of mass flow rate and heat capacity underwent a temperature change equal to the maximum temperature difference in the heat exchanger
CPA	= Heat Capacity of Primary and Secondary Air
CPF	= Heat Capacity of Flue Gas
FTMP1	= Average Bulk Flue Gas Temperature at the Air Heater Inlet
FTMP2	= Average Bulk Flue Gas Temperature at the Air Heater Outlet
MFFG	= Flue Gas Flow Rate
MFPA	= Primary Air Flow Rate
MFSA	= Secondary Air Flow Rate
PTMP1	= Primary Air Inlet Temperature
STMP1	= Secondary Air Inlet

This method of calculating the air heater effectiveness considers the air heater as a "black box" with a flue gas stream (cooled fluid) and both primary and secondary air streams (heated fluids) entering and leaving the air heater. The internal arrangement of the passes in the air heater is disregarded. The total air through the air heater is obtained using the O_2 method.

The assumptions implicit in the above equation are:

- The heat capacity of the flue gas, primary air, and secondary air do not vary with temperature and are therefore constant in all parts of the heat exchanger. The derivation for log mean temperature difference (LMTD) involves this assumption which is normally not restricting.

- The primary air, secondary air, and flue gas flow rates are uniform in all parts of the heat exchanger.

- Heat losses are negligible.

- Air leakage from the primary or secondary air side of the air heater to the flue gas side does not occur. A provision to adjust for air leakage of this type will be added as necessary.

- The ratio of primary air flow to secondary air flow given by MFPA and MFSA are approximately correct. This ratio is used to calculate a weight averaged air heater air inlet temperature.

14.4 RESULTS

Air heater effectiveness values were calculated for Phase I and Phase II tests for Peabody, Salt Creek and Dorchester coals. Figure 14-2 is a plot of air heater effectiveness versus gross unit output for both Phase I and Phase II steady state tests. Effectiveness values for Phase I tests ranged from 69.6% to 75.5% over the load range of 54.9 MW to 110.9 MW. Effectiveness values for Phase II tests ranged from 71.5% to 83.8% over the load range of 55.1 MW to 111.4 MW. Air heater effectiveness generally decreased with load, particularly for the Phase II tests. The Phase I air heater effectiveness values remained fairly constant over the load range.

Air heater effectiveness is plotted versus flue gas inlet temperature in Figure 14-3, which shows a slight general trend toward higher air heater effectiveness with decreasing flue gas inlet temperature, and is particularly evident with the Salt Creek coal Phase II test results. Air heater effectiveness increased somewhat with increasing flue gas temperature for the Dorchester coal tests. Scatter in the results for total air heater effectiveness may be due, in part, to differences in the inlet flue gas temperatures between combustors.

Figure 14-4 shows a general trend of increasing air heater effectiveness with decreasing flue gas moisture, particularly for the Phase II tests.

Figure 14-5 shows a plot of the air heater effectiveness versus the air heater log mean temperature difference. This figure

Figure 14-2. Air Heater Effectiveness Versus Gross Boiler Load

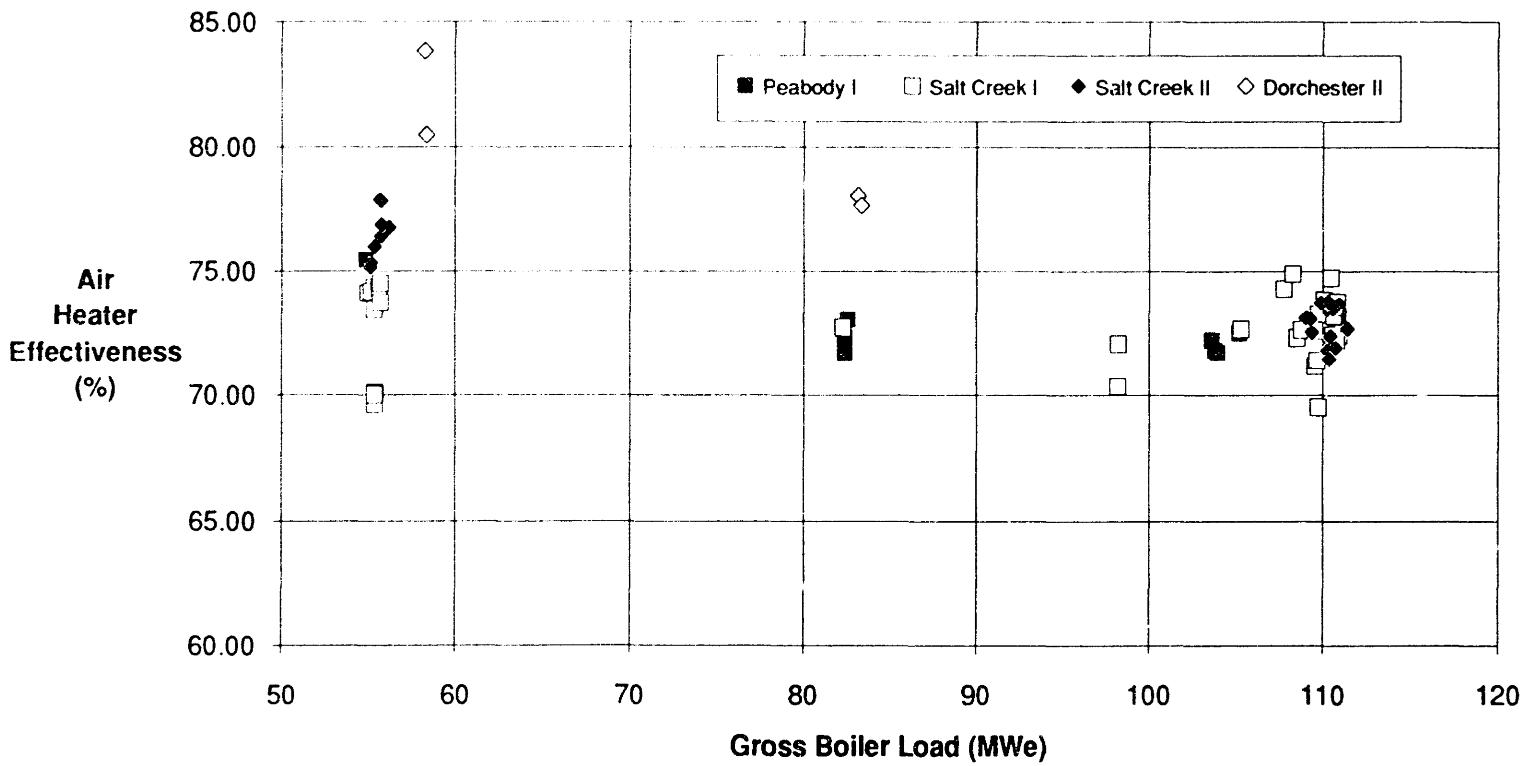


Figure 14-3. Air Heater Effectiveness Versus Air Heater Inlet Flue Gas Temperature

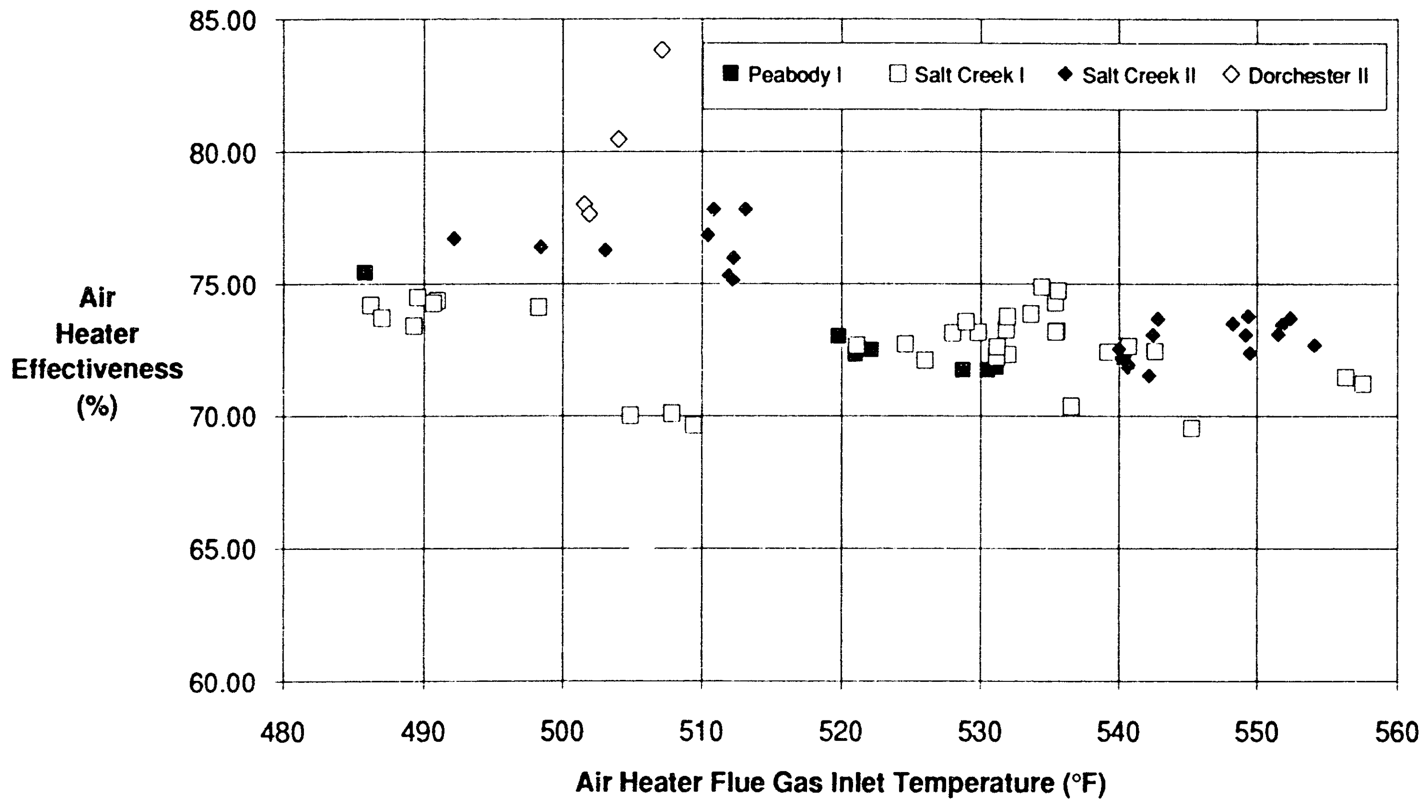


Figure 14-4. Air Heater Effectiveness Versus Flue Gas Moisture (wt %)

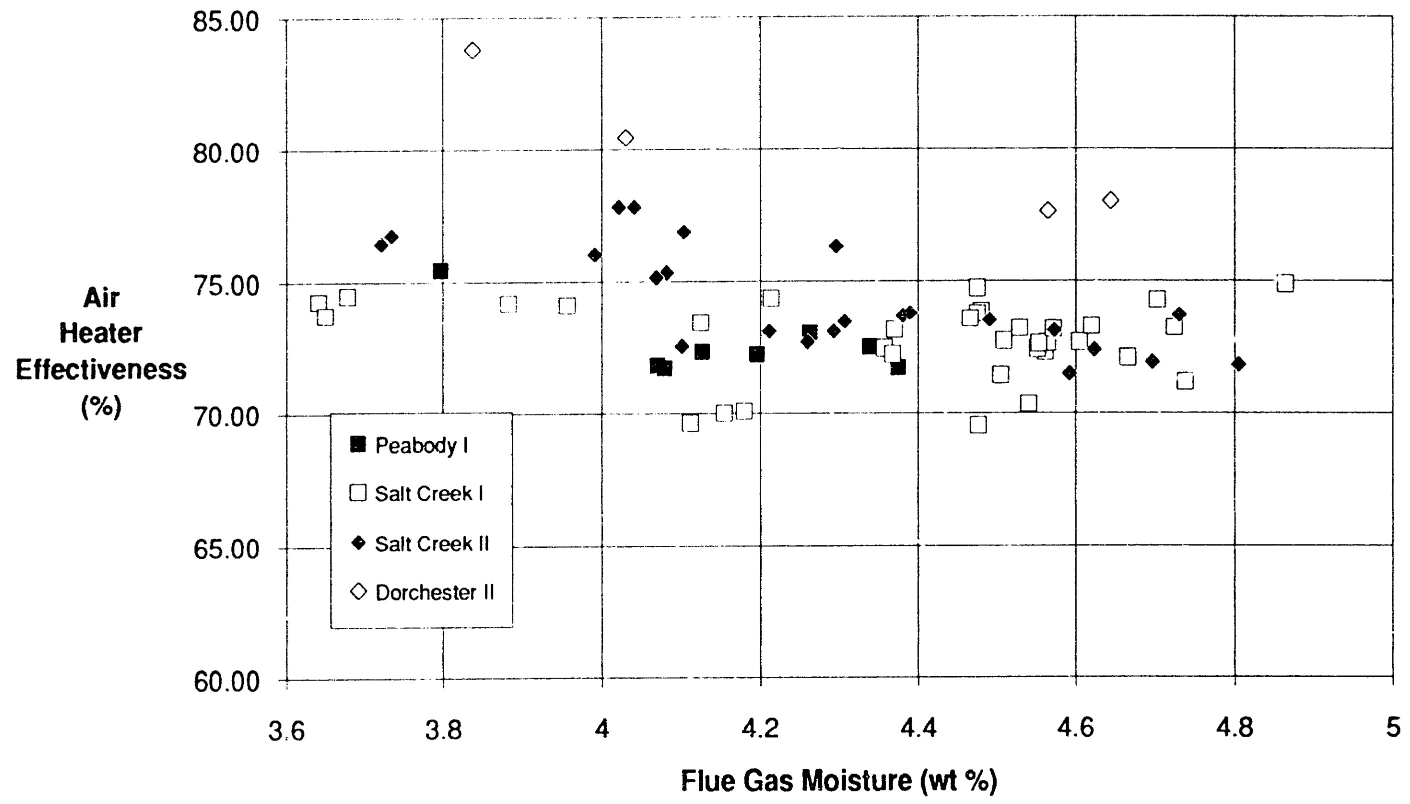
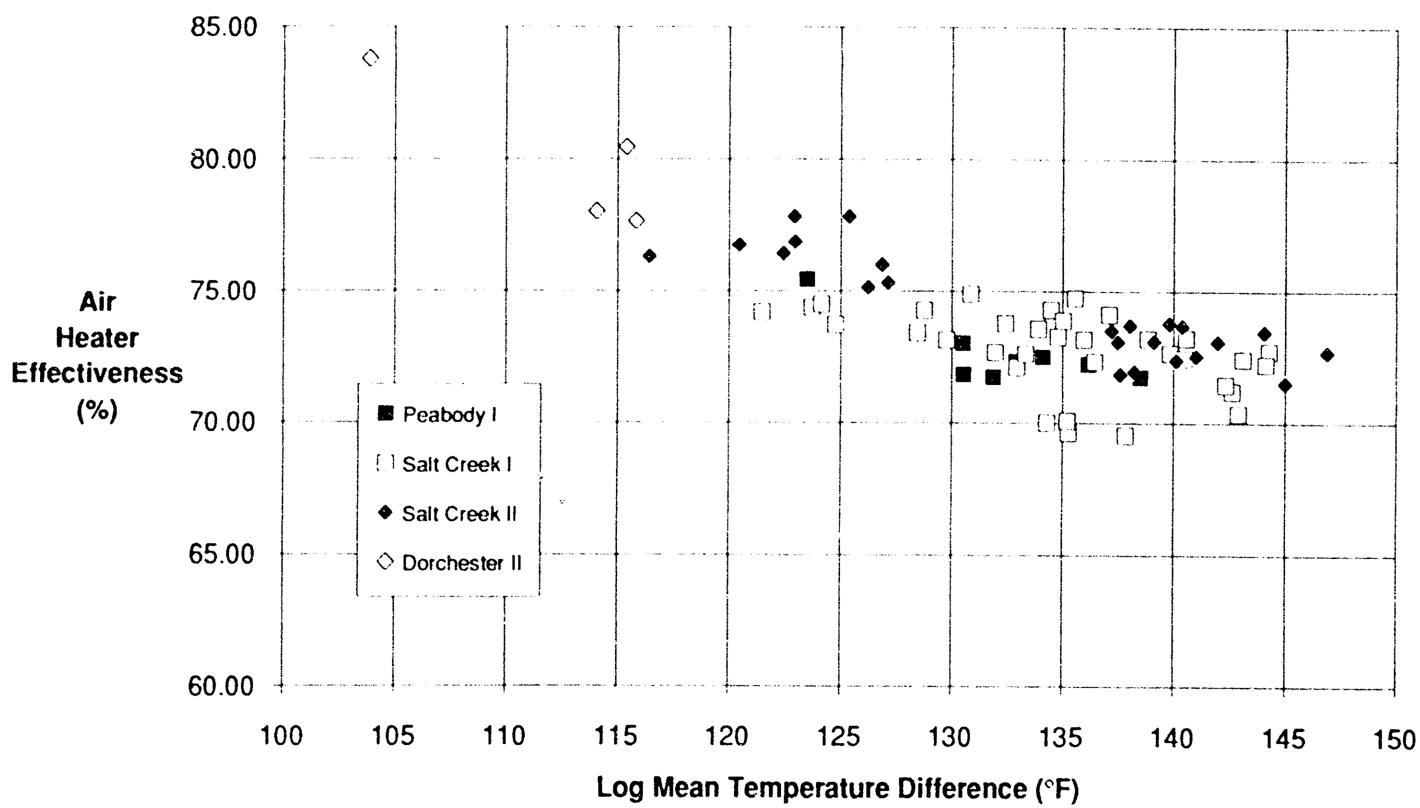


Figure 14-5. Air Heater Effectiveness Versus Air Heater Log Mean Temperature Differential



shows a good correlation between increasing air heater effectiveness with decreasing log mean temperature difference. The Salt Creek coal tests, which did not follow the general trend in Figure 14-3, show good agreement at the lower end of the log mean temperature difference scale.

14.5 EFFECT OF SOOT BLOWING ON AIR HEATER GAS OUTLET TEMPERATURES

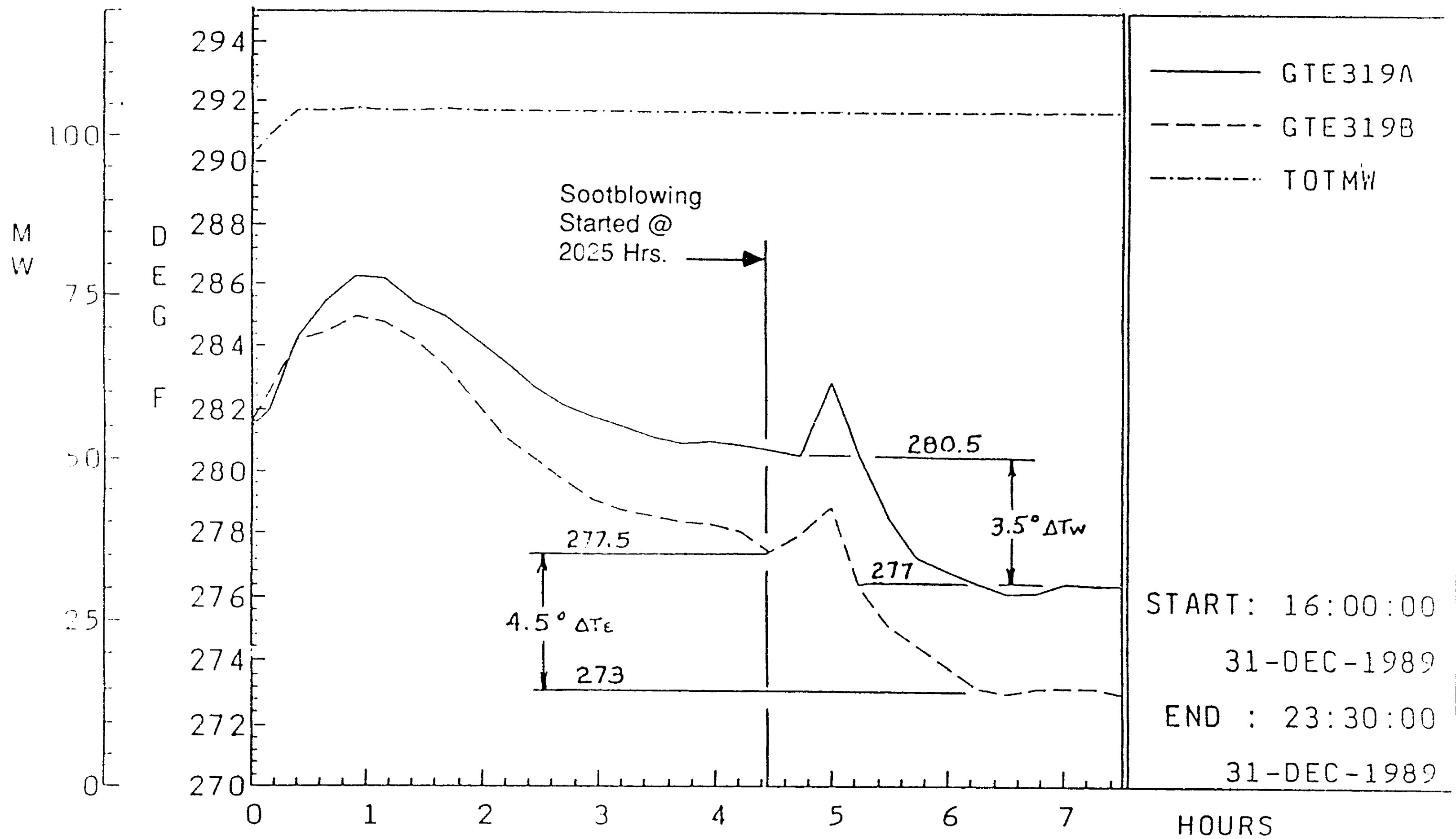
During a limited number of controlled soot blowing sequences, data were collected to determine the effect of soot blowing on air heater performance. Steam from the four air heater soot blowers at Nucla is provided from the superheater I outlet header and is reduced to 600 psig. The four air heater soot blowers are retractable lance-type soot blowers and are located in the area between the air heater tube sections.

Six soot blowing tests were carried out under full load conditions. Results are shown in Table 14-1.

Table 14-1.
Air Heater Gas Outlet Temperature Decrease

Test	Date	East Grid (°F)	West Grid (°F)	Remarks
1	3/19/89	2	1	
2	3/24/89	-	-	Unit Trip
3	7/16/89	1.2	0.8	
4	9/23/89	-	-	Unit Trip
5	11/30/89	-	-	Procedure revised
6	12/31/89	4	3.5	

Data for test 6 is shown in Figure 14-6. The reduction in air heater gas outlet temperatures after a one-week soot blowing sequence of the economizer and air heater resulted in a gain in boiler efficiency of approximately 0.1%. A soot blowing interval should be established that will provide the maximum improvement in performance relative to steam generation costs.



GTE319A-AH GAS OUTLET TEMP W GRID   GTE319B-AH GAS OUTLET TEMP E GRID
TOTMW-TOTAL LOAD IN MW 1,2,3,4

Figure 14-6. Effect of Air Heater Soot Blowing

Section 15

BAGHOUSE OPERATION AND PERFORMANCE

15.1 OBJECTIVES AND APPROACH

An extensive baghouse monitoring program was performed during the test program. The objectives of this program were to develop operating data on baghouse operation of CFB's and to establish design specification parameters for CFB baghouses. Data collection involved continuous measurement of baghouse ΔP, tube sheet ΔP, and flue gas flow rate. In addition, several isokinetic measurements were taken to determine the collection efficiency, fractional collection efficiency, and size distribution of the inlet and outlet fly ash. Samples of the fly ash were analyzed both chemically and mechanically to determine properties important to baghouse specifications. Individual bag flow monitoring (IBFM) devices were installed to obtain detailed operating data on individual bags.

Data were also obtained on bag materials. Two bag types were tested in the Nucla baghouses. Most of the bags installed in the baghouses are manufactured with the fabric oriented in the normal warp-out configuration. This means that the texturized side of the fabric is facing the dirty gas stream. This fabric material has a 3 x 1 twill weave, with 75 percent of the texturized fill yarns facing the dirty gas (sometimes referred to as having a 75% exposed surface texturization). In compartment Q of unit 2 baghouse, the bags were manufactured "inside out", and therefore had a warp-in construction. In these bags, the bag has a 25% exposed surface texturization. The bag material is the same, only the smooth side is facing the gas. Previous testing at EPRI's Arapahoe Test Facility with reverse-gas cleaning indicated that a lower surface texturization could result in lower residual dust cake weights, providing the possibility for lower drag without compromising particulate emissions. Measurements made on the two bag types included IBFM devices, bag weight measurements, and residual dust cake drag measurements.

During the course of the Phase I and Phase II test programs, the Nucla baghouses experienced numerous bag failures, equal to approximately 8% of the total number of installed bags. Considerable effort went into identifying the cause of the failures and finding remedies to the problem. These operational difficulties are also discussed in this section.

15.2 SYSTEM DESCRIPTION

The CFB boiler at Nucla is equipped with four separate baghouses that operate in parallel. The first three, units 1, 2, and 3, were existing baghouses that serviced the three 12 MWe stoker-fired boilers that the CFB replaced. These three baghouse were built by Wheelabrator-Frye and were the first utility scale shake/deflate baghouses used in the United States. The fourth baghouse, unit 4, was a new baghouse built by Research-Cottrell and also utilizes the shake/deflate cleaning method. Table 15-1 lists design information for the four baghouses. Figure 15-1 shows the general layout of the four baghouses at Nucla.

Table 15-1. Design Information for the Nucla Baghouses

	Baghouse #1, #2, & #3	Baghouse #4
Baghouse manufacturer	Wheelabrator-Frye	Research-Cottrell
Number of compartments per Baghouse	6	12
Bags per compartment	112	180
Bag size	8 in x 22 ft, 2 5/8 in.	8 in x 22 ft
Bag manufacturer	Fabric Filters	Fabric Filters
Bag model number	#504	#504
Bag fabric	3x1 twill, warp out	3x1 twill, warp out
Bag finish	10% Teflon B	10% Teflon B
Bag cleaning method	Shake/deflate	Shake/deflate
Cloth area per bag ft^2	44.31	44.31
Cloth area/compartment ft^2	4,962	7,976
Cloth area/baghouse ft^2	29,778	95,712
Total cloth area ft^2	185,045	
Gross air/cloth ratio $acfm/ft^2$	2.24	
Net air/cloth ratio $acfm/ft^2$	2.50	
Net-net air/cloth ratio $acfm/ft^2$	2.76	

The baghouse cleaning cycle is initiated by the flange-to-flange pressure drop across the baghouse. Units 1, 2, and 3 have the same cleaning cycles, while baghouse 4 has a slightly different cycle. The three small baghouses have a slow and a fast cleaning cycle. When the flange-to-flange pressure drop across any of the baghouses reaches 5 inches wg., a slow cleaning mode cycle is initiated. In the slow cycle, all three baghouses are cleaned one compartment at a time with a 25 second pause between compartment cleaning. The entire cleaning cycle takes about 33 minutes to clean all 18 compartments. If the pressure drop across any of the baghouses reaches 6 inches wg., the fast cleaning cycle is initiated. In this cycle, the pause between compartments is

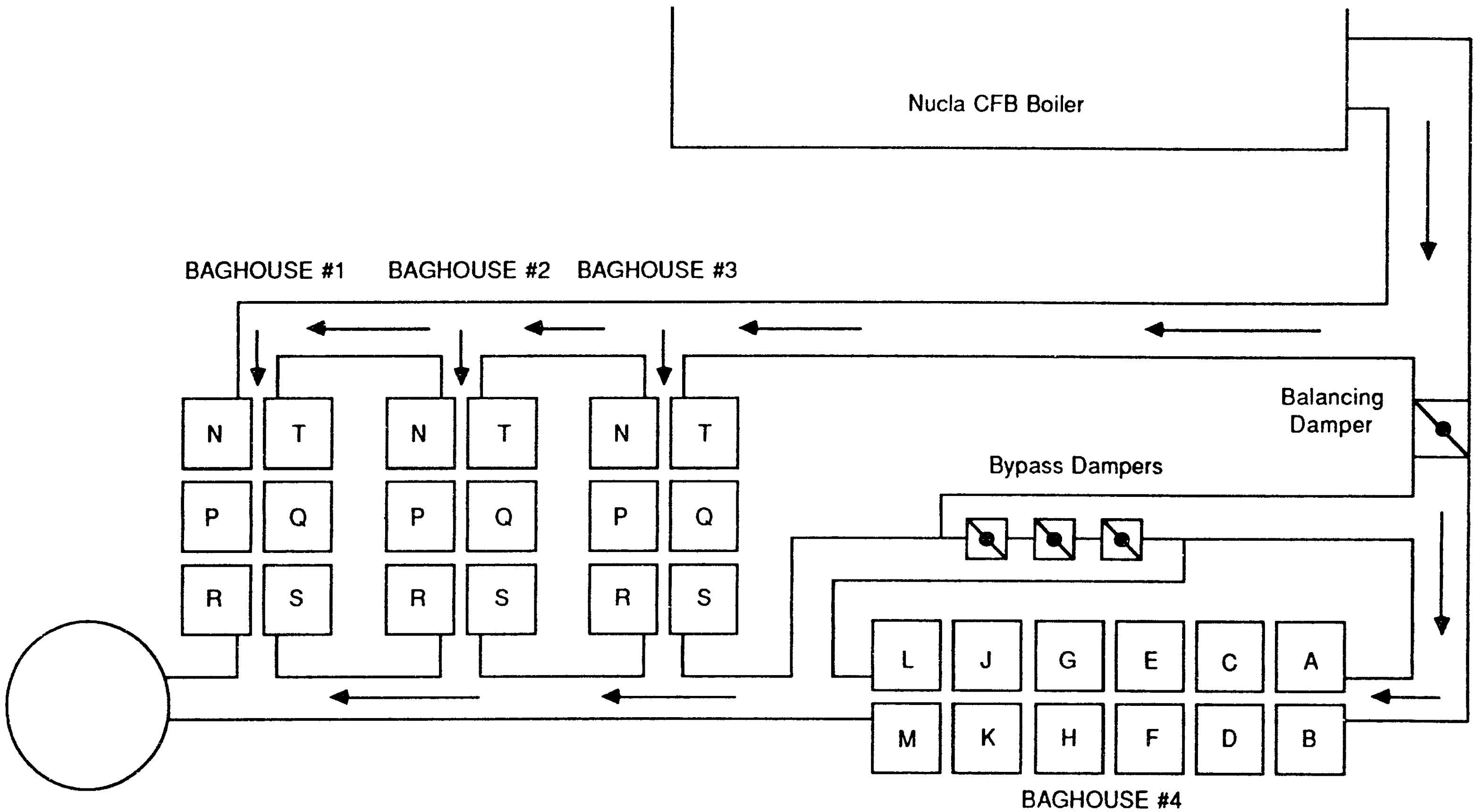


Figure 15-1. General arrangement of the baghouses at Nucla

reduced to 10 seconds and the total cycle takes about 28 minutes. If the pressure drop reaches 7 inches wg., an alarm sounds in the control room and appropriate action is taken.

Baghouse number 4 also has a slow and fast cleaning cycle. When the flange-to-flange pressure drop reaches 6 inches wg, the slow cleaning cycle is initiated. In the slow cleaning cycle, there is a 360 second pause between compartment cleanings. The slow cycle requires 90 minutes to clean all 12 compartments. If the pressure drop reaches 7 inches wg., then the fast cleaning cycle is initiated. In this mode there is only a 10 second delay between compartments, and the entire cycle requires 19 minutes to clean all 12 compartments. If the pressure drop reaches 8 inches wg., an alarm will sound at the control room. At 9 inches wg. pressure drop, the bypass dampers will open to protect the baghouse and the flue gas will bypass the baghouse.

In order to study the performance of two different bag materials, individual bag flow monitor (IBFM) sensors were installed in six bags in compartments P and Q of the number 2 baghouse. Five other IBFM sensors were installed in compartment E of baghouse 4. The IBFM sensors are orifice plate devices that fit into the inlet thimble on an individual bag. These orifices allow measurement of the gas flow through the bag for calculation of the air-to-cloth ratio and drag.

15.3 OPERATIONAL AND PERFORMANCE DATA

Measurements made during the baghouse monitoring program included inlet and outlet particulate loadings, inlet and outlet size distribution and fractional collection efficiency, chemical and physical analyses of the baghouse ash, flow rate and pressure drop measurements and IBFM measurements on individual bags to compare two types of bag construction (warp-in versus warp-out). Results of these measurements are discussed in separate sections below.

15.3.1 Inlet and Outlet Particulate Loading

Inlet and outlet particulate loading measurements were made twice during the test program. The first time was on June 20 and 21, 1989 when the unit was burning Peabody coal. These tests were conducted around the unit 4 baghouse. The second test was conducted using Salt Creek coal on September 19 and 22, 1989, again around the unit 4 baghouse. Table 15-2 gives the results of both test periods.

On June 20 and 21, 1989, isokinetic measurements of the inlet and outlet dust loadings were taken around baghouse 4. These measurements were taken just after test A08 was completed, and operating conditions were not changed. Isokinetic measurements of inlet and outlet dust loadings were made on

Table 15-2

Nucla Unit 4 Baghouse Inlet and Outlet Particulate Concentration Data

Date	Coal	Inlet					Outlet					Particulate Emissions	Efficiency	Penetration
		Particualte Loading		Gas Flow		Temp	Particualte Loading		Gas Flow		Temp			
		gr/acf	gr/scf	acfm	scfm	°F	gr/acf	gr/scf	acfm	scfm	°F	lb/MBtu	%	% (2)
6/20/89	Peabody	3.56	6.40	241,840(1)	133,904(1)	299	0.0037	0.0068	243,376(1)	133,904(1)	292	0.0141	99.894	0.106
6/21/89	Peabody	3.42	6.16				0.0029	0.0052				0.0109	99.915	0.085
Average	Peabody	3.49	6.28	241,840	133,904	299	0.0033	0.0060	243,376	133,904	292	0.0125	99.905	0.096
9/19/89	Salt Creek	4.34	8.85	274,000	134,300	296	0.0017	0.0036	264,900	130,000	284	0.0069	99.959	0.041
	Salt Creek	4.39	9.14	256,700	123,300	309	0.0017	0.0034	245,000	119,200	291	0.0067	99.963	0.037
9/22/89	Salt Creek	4.34	8.76	244,900	121,400	297	0.0020	0.0040	242,900	121,100	279	0.0080	99.954	0.046
	Salt Creek	4.21	8.65	254,700	124,000	309	0.0018	0.0036	240,600	118,100	289	0.0071	99.958	0.042
Average	Salt Creek	4.32	8.85	257,575	125,750	303	0.0018	0.0037	248,350	122,100	286	0.0072	99.959	0.041

(1) Flow and temperature data taken from test A08. Values assumed constant for both days of testing.
(2) Penetration is defined as (100 - collection efficiency).

both days. The inlet mass flow rate of solids was 7,350 lb/hr on June 20 and 7,066 lb/hr on June 21. The outlet mass flow rate of solids was 7.762 lb/hr on June 20 and 6.02 lb/hr on June 21. Collection efficiency averaged over the two days was 99.905%. The particulates emissions from these two tests averaged 0.0125 lb/MBtu, which is well below the New Source Performance Standards (NSPS) of 0.03 lb/MBtu.

On September 19 and 22, 1989, isokinetic tests were conducted while the unit was firing Salt Creek coal. During these test periods, two 96-minute tests were conducted each day at both the inlet and outlet of baghouse 4. Also during this time period, tests were conducted to determine the size distribution of the inlet and outlet baghouse streams. The size distribution data is discussed in the next section. The average inlet concentration of the baghouse for these tests was 8.85 grains/standard cubic foot (gr/SCF). The average outlet dust loading was 0.0037 gr/SCF. Collection efficiency averaged 99.959% and the particulate emissions averaged 0.0072 lb/MBtu.

Based on these tests, it appears that the Salt Creek coal ash had a slightly better collection efficiency over the Peabody coal ash. This may be due to different properties of the two coal ashes, or to operational problems in the baghouse during the Peabody tests. The differences between the two coals will be examined in other sections of this report.

15.3.2 Flow Rate Versus Pressure Drop

Table 15-3 lists baghouse 4 performance data for a selected number of tests. The data are plotted in Figure 15-2 as flange-to-flange pressure drop versus air-to-cloth ratio. Figure 15-3 shows the same plot for all of the performance tests conducted during the test program. The points identified as Salt Creek I were tests conducted during Phase I testing and the ones marked Salt Creek II were conducted during Phase II testing. There is considerable scatter in the data, particularly at the lower loads. Figure 15-4 shows the tube sheet pressure drop versus the air-to-cloth ratio from this data compared to the data obtained from the TVA 20 MW baghouse. This figure shows that the Nucla baghouse, using shake/deflate cleaning, appears to be operating at a lower ΔP than the cleaning methods used at TVA.

From Figures 15-2 and 15-3, it is difficult to determine if any of the coals operate at lower bag pressure drops. This is because of the large amount of scatter in the data. The reason for this scatter can be seen in Figure 15-5. This figure shows a plot of baghouses 4 and 1's pressure drops versus time for Peabody and Salt Creek coal during operation at 60 MW and 101 MW. (Note that at 60 MW the pressure drop across the bags takes between 7 and 8 hours after cleaning to increase to the point where another cleaning cycle is

Table 15-3

Nucla Unit 4 Baghouse Performance Data

Test Number	Date	Coal Type	Percent Oxygen	Load MWe	Ca/S Ratio	Air-Cloth Ratio	Baghouse ΔP in.wc.	Inlet Temp °F	Outlet Temp °F
PHM1,2	3/7/89	Peabody	4.2	100	1.79	2.52	5.45	-	-
PHM5a,6	3/8/89	Peabody	4.1	100	1.84	2.52	5.25	-	-
A01	4/21/89	Peabody	4.0	82	1.50	2.85	5.70	293	280
A07	5/26/89	Peabody	5.5	55	1.50	2.19	5.15	264	254
A04	6/6/89	Peabody	3.5	82	1.50	2.34	6.40	290	278
AO8	6/19/89	Peabody	3.3	104	1.50	2.51	5.91	298	268
FGAS4	6/20/89	Peabody	-	104	1.50	2.53	5.73	-	
SD1	3/13/89	Salt Creek	3.9	105	1.41	2.85	6.25	290	278
P30	3/20/89	Salt Creek	5.7	55	1.50	1.45	4.65	275	260
P31	3/21/89	Salt Creek	4.0	82	1.50	2.01	5.15	285	275
P50	7/19/89	Salt Creek	3.5	98	3.54	2.47	5.40	299	292
P39	8/9/89	Salt Creek	6.0	55	2.60	2.62	5.97	283	282
P52	8/17/89	Salt Creek	6.3	55	2.80	2.93	6.42	281	272
P55	11/29/89	Salt Creek	3.3	108	4.76	2.80	6.39	286	267
P56	11/30/89	Salt Creek	2.3	108	5.10	2.60	5.90	286	274
P20	1/11/90	Salt Creek	5.5	55	1.40	2.40	6.07	270	252
P57	1/15/90	Salt Creek	6.3	55	0.00	2.55	6.40	263	246
P58	1/17/90	Salt Creek	6.3	55	3.30	2.50	6.17	266	248
P60	1/23/90	Salt Creek	2.3	108	4.86	2.60	5.98	284	265
P61	1/25/90	Salt Creek	2.3	108	4.57	2.55	5.83	289	270
P67	4/2/90	Salt Creek	3.0	111	3.45	2.72	5.93	283	266
P68	4/5/90	Salt Creek	3.0	111	3.89	2.69	5.80	278	261
P07	4/6/90	Salt Creek	3.1	111	3.25	2.68	5.90	283	266
P08	4/11/90	Salt Creek	3.0	111	3.47	2.93	5.93	283	267
P69	4/13/90	Salt Creek	3.0	110	2.90	2.92	6.41	281	265
P36	4/17/90	Salt Creek	3.0	110	3.60	3.15	6.87	286	269
P70	4/18/90	Salt Creek	3.0	110	3.70	3.09	6.70	281	265
P71	4/27/90	Salt Creek	3.0	111	3.80	2.98	6.54	280	262

Figure 15-2. Nucla Baghouse #4 Pressure Drop Versus Air-to-Cloth Ratio for Peabody and Salt Creek Coal

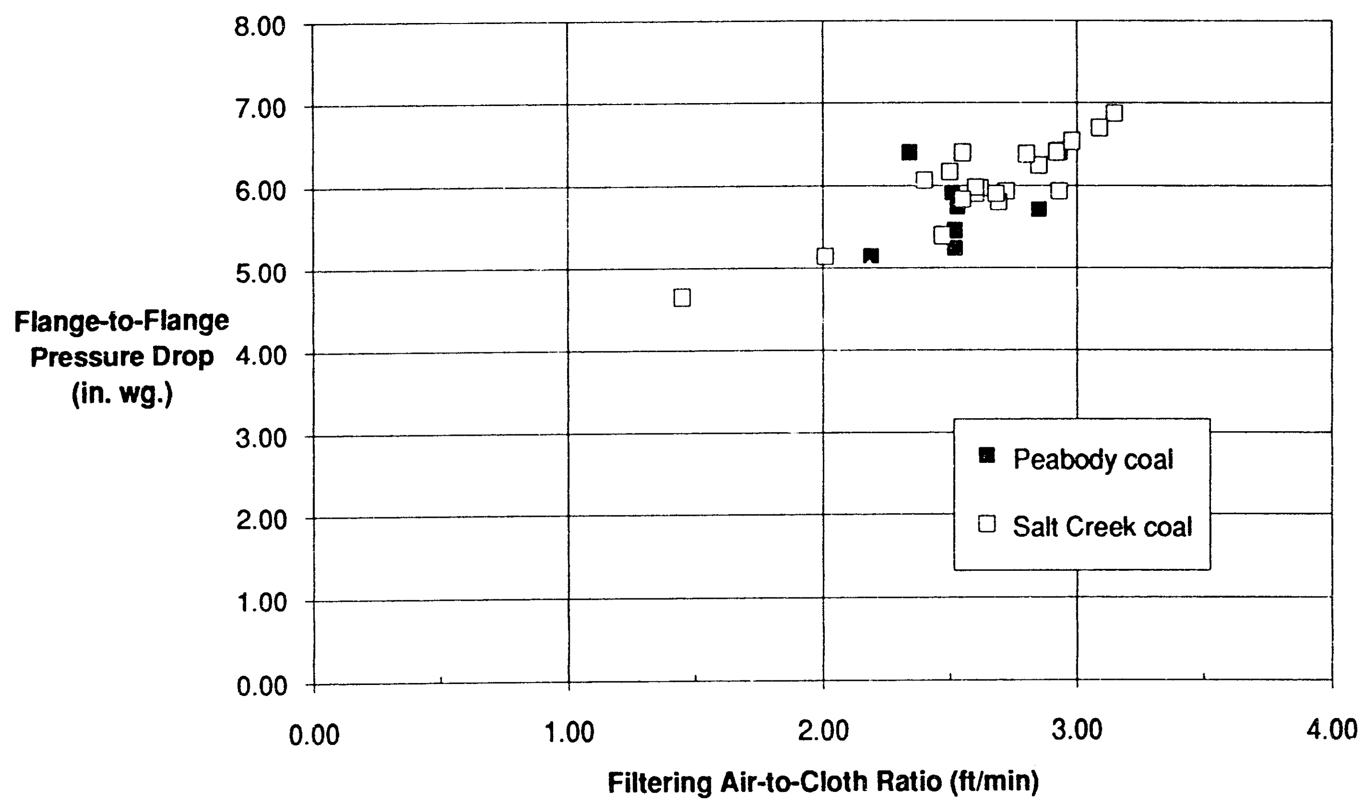
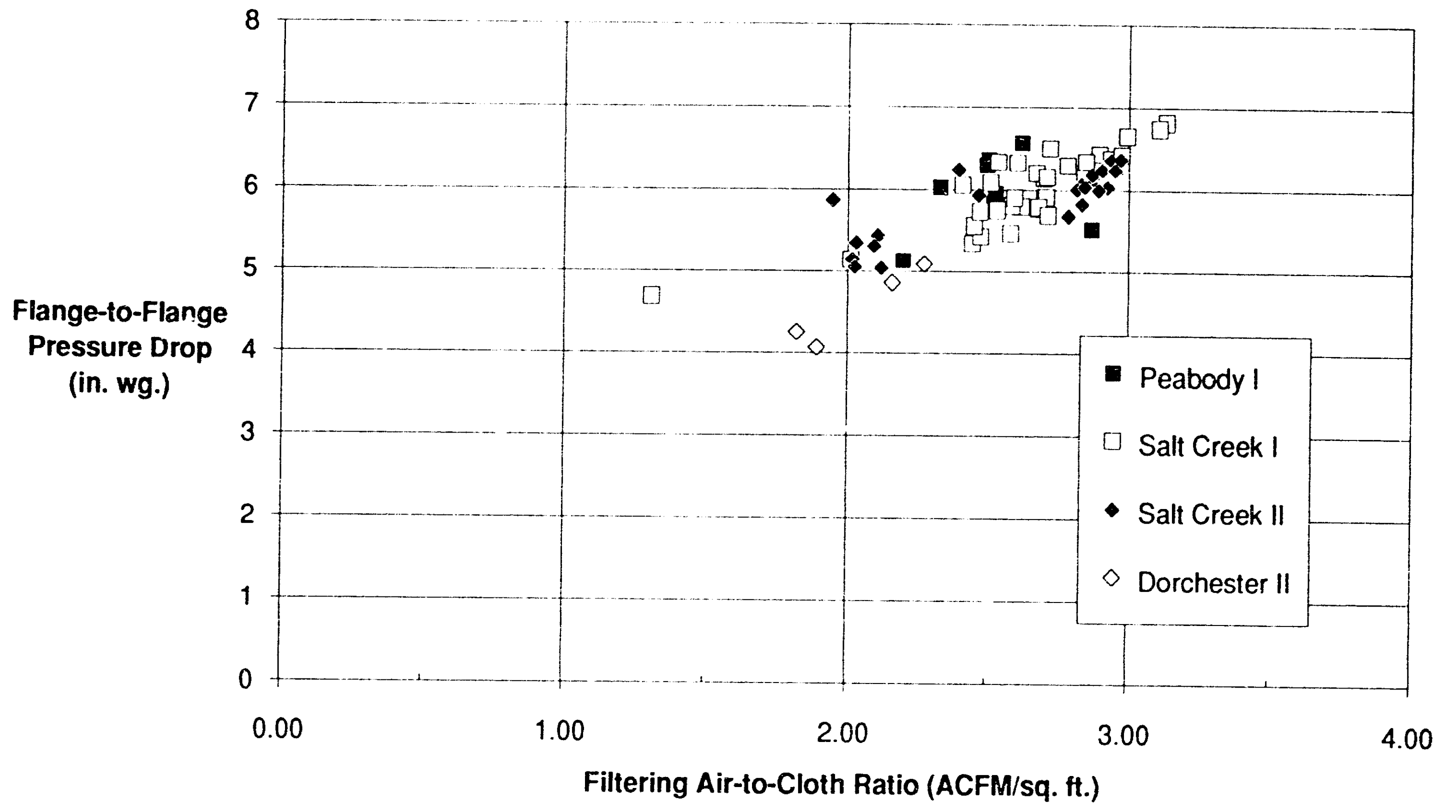


Figure 15-3. Nucla Baghouse #4 Pressure Drop Versus Air-to-Cloth Ratio for All Coals Tested



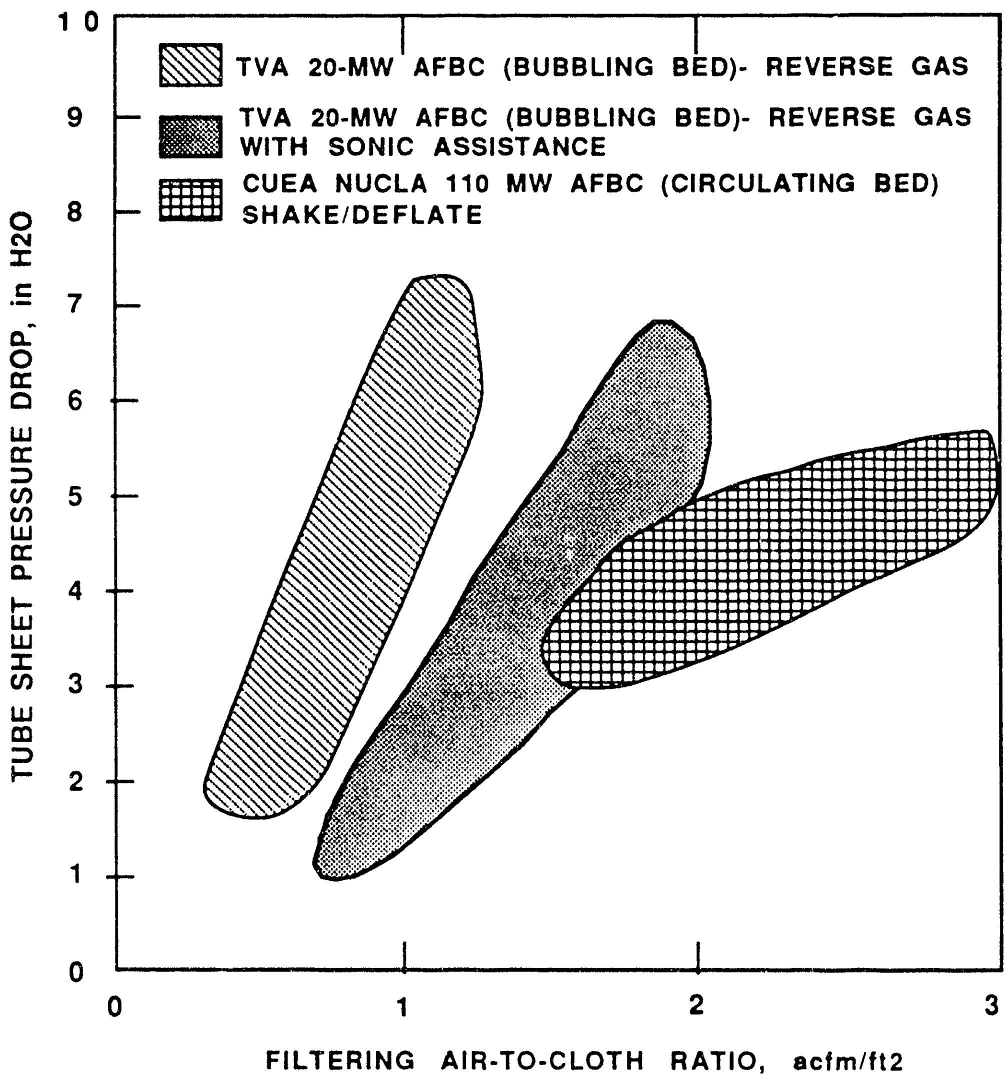


Figure 15-4. Comparison of tubesheet pressure drop versus air-to-cloth ratio for the Nucla #4 baghouse and the TVA 20MW AFBC baghouse.

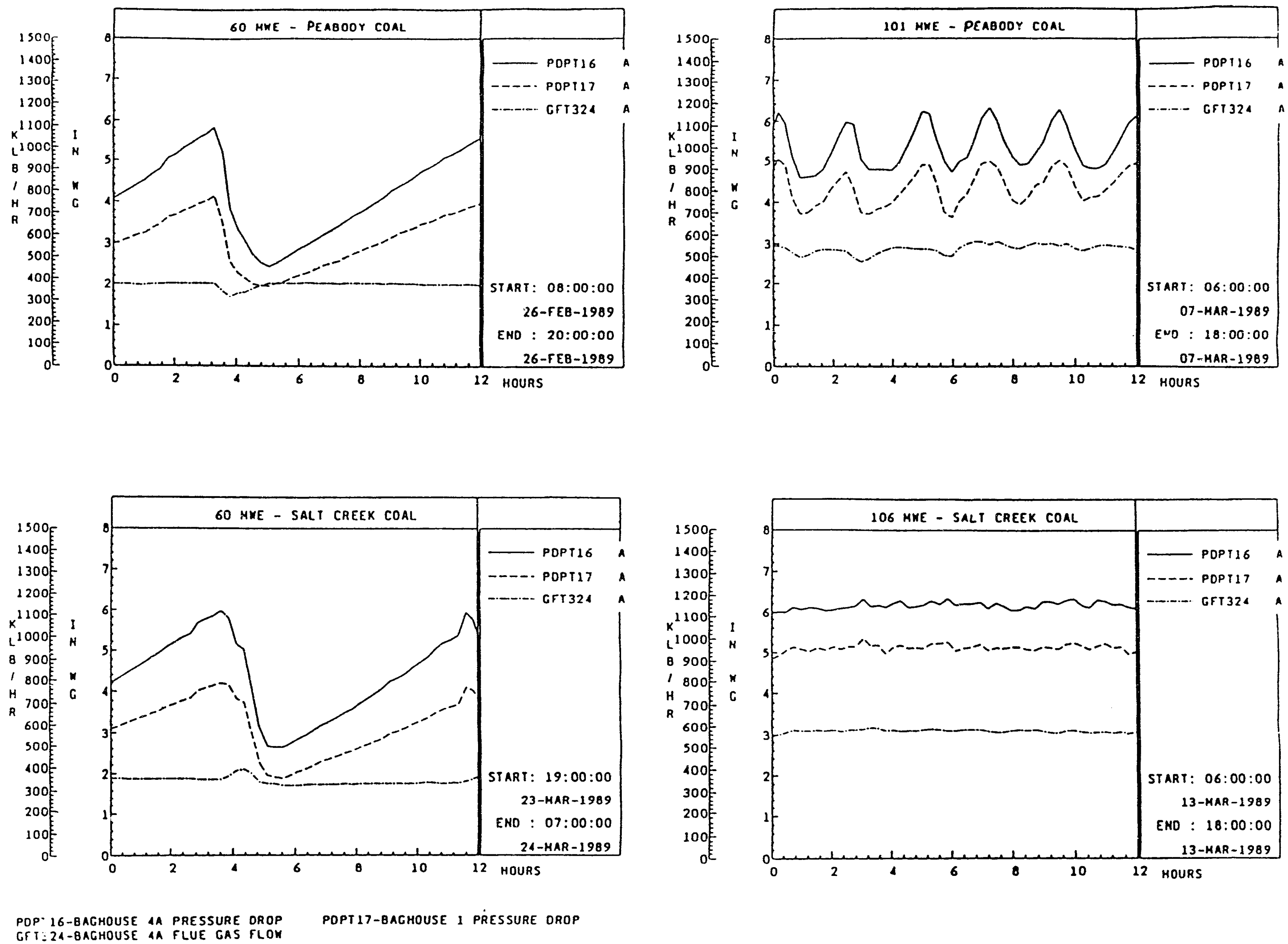


Figure 15-5. Pressure drop versus time data for baghouse #1 and #4 for Salt Creek and Peabody coals at 60 MW and 101 MW.

initiated). Since a performance test is approximately 8 hours long, the pressure drop averaged over this time period will be strongly dependent on the time in the cleaning cycle when the test was started. At full load, the pressure drop rise is so fast that the unit is cleaning almost continuously. For the Salt Creek coal the rise is such that the unit operates continuously in the slow clean cycle. The Peabody coal at full load cleans about once every 3 hours. These faster cycles will improve the accuracy of the average value, thereby reducing the scatter in the data. However, the slopes of these graphs do indicate that Salt creek is building a filter cake at a faster rate than Peabody coal. This observation is validated by the higher inlet dust loadings for Salt Creek in Table 15-2.

15.3.3 Inlet and Outlet Particle Size Distribution

During the September 18 to 22, 1990 baghouse tests, samples were collected to allow calculation of the fractional collection efficiency of the baghouse. Particle size distribution measurements were conducted at the inlet and outlet of baghouse 4. Sixteen inlet measurements were made using six-stage modified Brink Cascade Impactors with a cyclone precollector. Eight outlet size distributions were made using seven-stage University of Washington Mark III Source Test Cascade Impactors with an impaction-type precollector.

The mass median diameter (physical) of the particles in the inlet flue gas stream was determined to be 17.3 microns. The mass median diameter of the outlet stream was determined to be 8.3 microns. However, further analysis of the data by Southern Research Institute, the contractor that performed the tests, revealed that the inlet particle size data were biased toward the larger particles. This was due to the small diameter nozzle required on the Brink Impactors for isokinetic sampling and the subsequent impaction losses that occurred in the cyclone precollector due to high gas velocity exiting the nozzle. In order to obtain information on the baghouse inlet particle size distribution, the mass samples collected during measurements of the inlet mass concentration (Method 17) were submitted for particle size classification. The samples were analyzed by the Southern Research Institute using a BACHO analyzer.

The particle size distribution curve for the baghouse inlet sample is shown in Figure 15-6. This graph shows the cumulative weight percent of the inlet sample obtained by the BACHO analysis. The inlet distribution below 1.5 microns was estimated due to the fact that the BACHO is not able to fractionate below this particle size. The mass median diameter of the inlet sample was 7.1 microns, which is considerably smaller than the size determined by the impact cascaders. The outlet particle size distribution data are

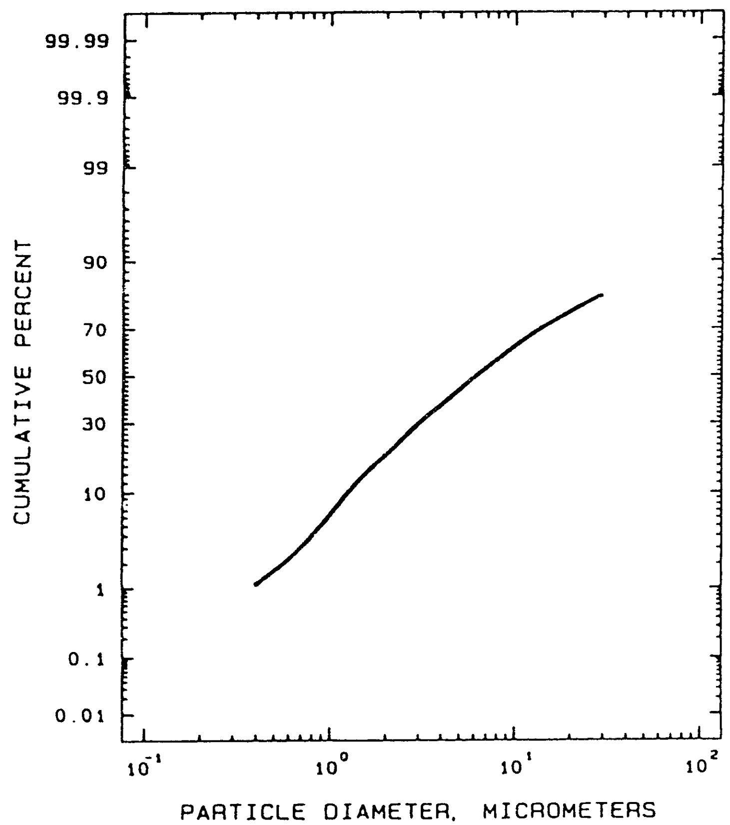


Figure 15-6. Average cumulative percent mass less than indicated size for the Nucla Unit #4 baghouse inlet September 19-22, 1989

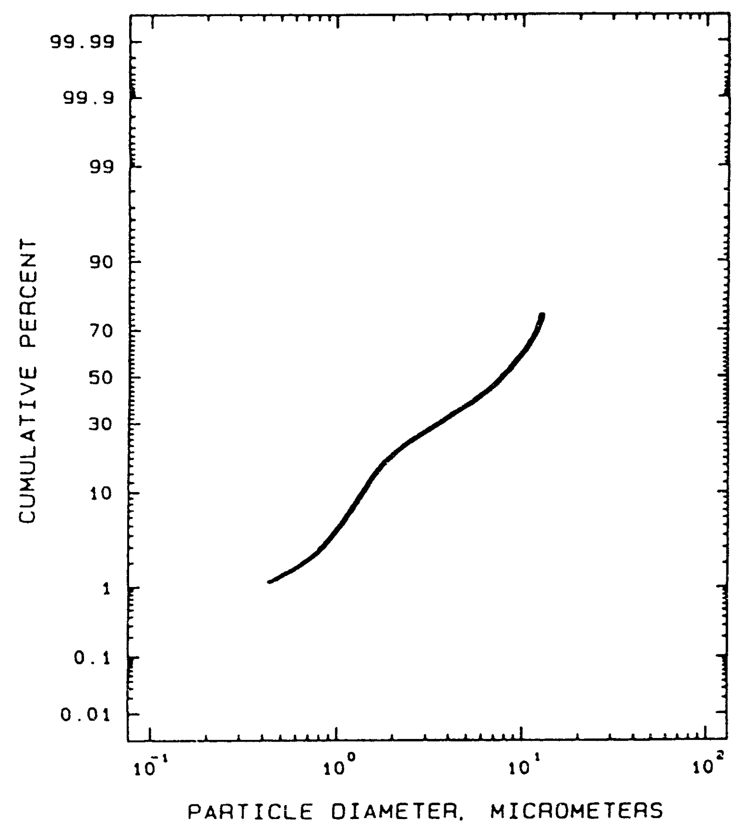


Figure 15-7. Average cumulative percent mass less than indicated size for the Nucla Unit #4 baghouse outlet September 19-22, 1989

presented in Figure 15-7. This graph shows the data presented in the same manner as Figure 15-6. The mass median diameter of the outlet dust is 8.0 microns, indicating that the baghouse apparently has a higher collection efficiency on smaller particles.

The data in Figures 15-6 and 15-7, along with the flow rate data in Table 15-2, were used to calculate the fractional collection efficiency for the baghouse. The results of this calculation are shown in Figure 15-8. This figure shows that the collection efficiency does drop off slightly as the particle size increases.

15.3.4 Chemical and Physical Properties of Ash

Five samples of dust cake ash were removed from baghouse 4 and were analyzed by Southern Research Institute. Three of the samples were taken during operation with Salt Creek coal and two were taken during operation with Peabody coal. No samples were obtained during operation with Dorchester coal.

The results of the analyses are given in Table 15-4. The Salt Creek coal was found to have a higher gas flow resistance factor. The Salt Creek coal was also found to have a slightly smaller particle size. These analyses indicate that under identical operation conditions, the Salt Creek coal should operate at a higher baghouse ΔP than the Peabody coal. The increased ΔP combined with the higher inlet dust loadings explain the operating curves that were discussed in Section 15.3.2.

15.3.5 Comparison of Warp-in Versus Warp-out Bags

Comparison of the warp-in versus warp-out bag material concentrated on measurements of the residual dust cake and measurements made with the IBFM meters. As was stated in Section 15.2, the experimental warp-in bags were installed in compartment Q of baghouse 2. IBFM flow meters were installed in six bags in compartment 2Q. Six monitors were also installed in compartment P of baghouse 2 and an additional five monitors were installed in compartment E of baghouse 4.

Bags from compartments 2Q, 2P, and 4E were removed and weighed just after a cleaning cycle to determine the weight of the residual dust cake. Three bags were removed from compartment 2P. The weights of these bags were 12, 11, and 16 lbs. An additional four bags were removed from compartment 4E. These bags were found to weigh 15, 14 ,16, and 17 lbs. The average weight of the warp-out bags was 14.4 lb. Six bags removed from compartment 2Q and were found to weigh 8, 6, 7, 6, 6, and 6 lbs, for an average weight of the warp-in bags of 6.5 lbs. A clean new bag weighs 4 pounds. Thus the residual dust cake weight was 10.4 lb for the warp-out bags and 2.5 lb for the warp-in bags. The residual dust

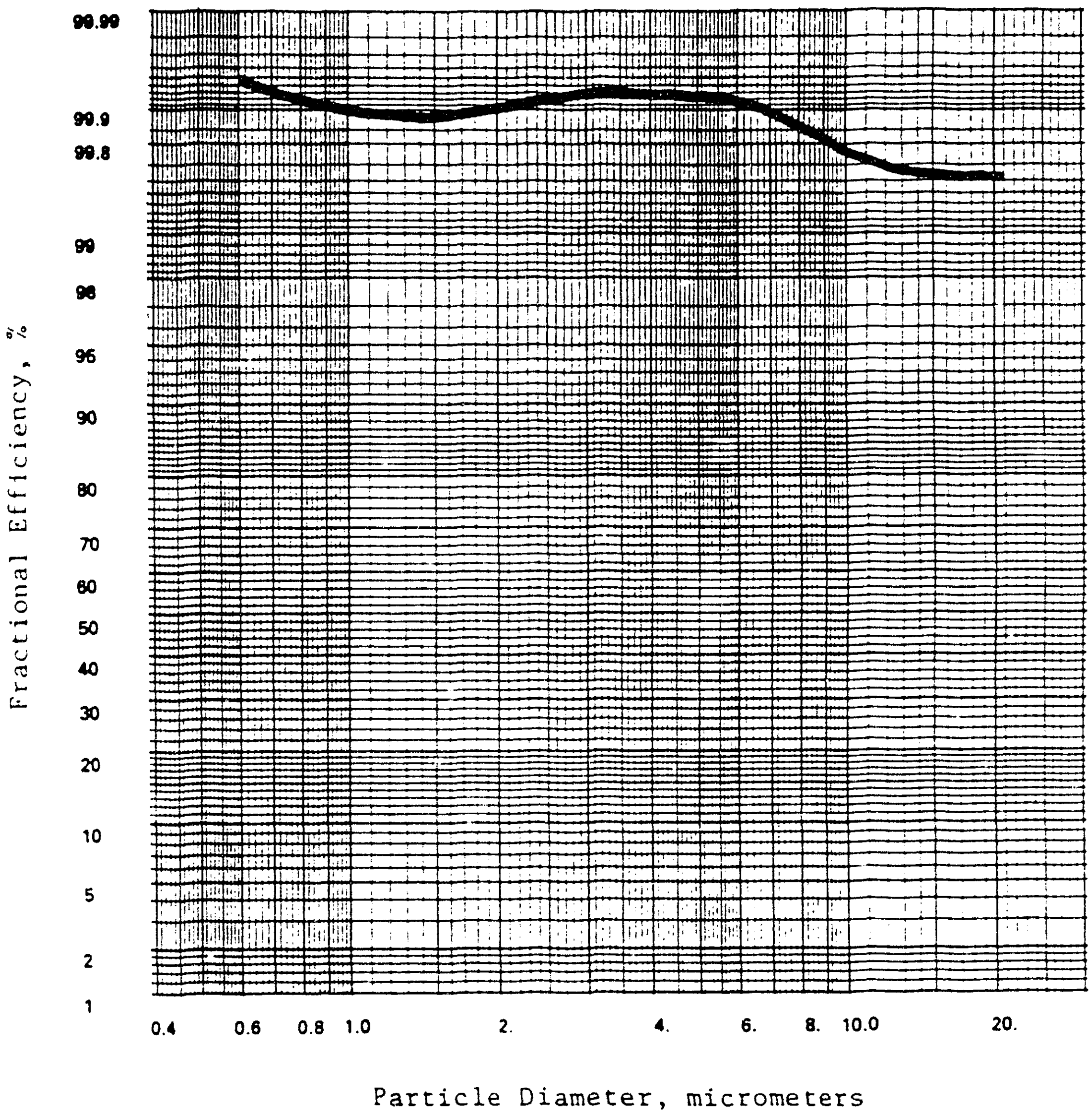


Figure 15-8. Average fractional efficiency versus particle size for the Nucla Unit #4 baghouse, September 19-22, 1989

Table 15-4

Summary of Laboratory Analyses of Dustcake Ashes

Coal	Date Obtained	Equilibrium PH	Measured Diameters, microns			Specific Surface Area m2/g	Compacted Bulk Porosity %	Density g/cc	Relative Gas Flow Resistance * wg min ft/lb	Morphology Factor	Effective Angle of Internal Friction *
			BACHO	Coulter	Drag-Equivalent						
Peabody	Apr-88	11.4	5.70	3.2	0.91	10.6	68.2	2.73	7.7	16.7	46.8
	Jan-89	11.2	6.49	8.8	0.91	16.1	71.5	2.65	5.8	65.9	48.0
Peabody	Average	11.3	6.1	6.0	0.9	13.4	69.9	2.7	6.8	41.3	47.4
Salt Creek	Mar-89	11.0	5.91	4.9	1.03	15.1	64.8	2.59	8.1	37.5	-
	Mar-89	11.0	4.98	4.4	0.92	15.3	65.5	2.58	10.3	34.3	-
	Sep-89	11.6	5.40	-	0.96	11.1	65.7	2.67	9.1	-	45.3
Salt Creek	Average	11.2	5.4	4.7	1.0	13.8	65.3	2.6	9.2	35.9	45.3

Chemical Analyses, wt %

Coal	Date Obtained	Li2O	Na2O	K2O	MgO	CaO	Fe2O3	Al2O3	SiO2	TiO2	P2)5	SO3	LOI	Soluble SO4
Peabody	Apr-88	0.03	0.18	0.93	0.81	16.4	3.8	23.9	45.1	1.0	0.04	5.8	8.8	6.6
	Jan-89	0.02	0.24	0.72	0.73	14.7	8.0	23.2	41.6	1.1	0.05	7.8	10.0	8.2
Peabody	Average	0.03	0.21	0.83	0.77	15.55	5.90	23.55	43.35	1.05	0.05	6.80	9.40	7.40
Salt Creek	Mar-89	0.03	0.39	0.56	1.20	11.0	3.0	25.9	51.5	2.2	0.67	2.5	9.7	3.6
	Mar-89	0.03	0.40	0.55	1.20	11.0	3.0	26.2	50.8	2.2	0.72	2.6	9.8	3.7
	Sep-89	0.02	0.50	0.46	0.70	19.2	2.0	24.2	44.6	1.3	0.59	4.6	6.4	5.5
Salt Creek	Average	0.0	0.4	0.5	1.0	13.7	2.7	25.4	49.0	1.9	0.7	3.2	8.6	4.3

cake areal density was 0.23 lb/ft^3 for the warp-out bags and 0.06 lb/ft^3 for the warp-in bags. These tests indicate that the warp-out bag retains a significant amount of dust cake compared to the warp-in bags.

Table 15-5 shows the IBFM results from compartments 2P and 2Q of baghouse 2. These data show that there is apparently no significant difference between the two types of bags, despite the considerable differences in the residual dust cake. This result indicates that the residual dust cake does not significantly contribute to the drag of the cleaned bag. Apparently, the only dust that contributes to the residual drag is the dust that fills the interstices of the bag fibers.

Table 15-5.
Average Flow and Pressure Drop Data
For Warp-in and Warp-out Bags

	Comp. 2Q Warp-In	Comp. 2P Warp-Out
Air-to-cloth ratio, $acfm/ft^2$	1.7	1.6
Pressure drop, in. wg.	5.5	5.1
Drag, in. wg./fpm	3.3	3.1
Residual drag, in. wg./fpm	2.3	2.2
Drag Coefficient, in. wg. min	13.7	13.9

15.4 SUMMARY OF BAG FAILURES

Between October 1988 and May 1990 a total of 381 bag failures had been reported. Table 15-6 lists the the bag failures experienced at Nucla along with the reason for the failures. This number of failures represents a failure rate of 0.46%/month, which is unacceptably high. However, most of these failures were concentrated in baghouse 2 (313 bag failures = 2.33 %/month). The failure rates for the other baghouses are: baghouse 1 = 0.15%/month; baghouse 3 = 0.05%/month; and baghouse 4 = 0.09%/month. The high failure rate was found to be due to high deflate air flow rates in baghouse 2. Baghouse 1 also operated with very high deflate air flow rates for an undetermined period of time, although not as long as baghouse 2.

As a result of this analysis, the deflate flow rate to the older baghouses was adjusted to equal the deflate pressure in baghouse 4, the new baghouse, in May of 1989. Furthermore, the shake mechanism timer was changed to shake the bags after the deflate cycle is complete, rather than during the deflate cycle. Since the adjustment, the bag failure rate has decreased dramatically. The average failure rate before the adjustment was 1.61%/month for all four baghouses. After the adjustment, the failure rate dropped to 0.29%/month for all

Table 15-6
Page (1 of 2)

CUEA Nucla Station - Bag Failure Documentation

Date	Unit	Compartment	Number of Bags	Comment
10/5/88	2	S	1	Bottom of bag, ash abrasion
10/6/88	2	S	5	Bottom of bag, ash abrasion
10/7/88	1	T	3	Top of bag, 1 in. holes
	2	P	2	Bottom of bag, ash abrasion
	2	S	3	Bottom of bag, ash abrasion
10/13/88	2	S	3	Bottom of bag, ash abrasion
12/7/88	2	S	23	Bottom of bag, ash abrasion
12/8/88	2	P	24	Bottom of bag, ash abrasion
12/9/88	4	E	5	Rubbing on IFBM
	4	E	11	Bottom of bag, ash abrasion/impengement
12/22/88	2	Q	17	Bottom of bag, ash abrasion
12/28/88	2	S	26	Bottom of bag, ash abrasion
1/4/89	2	N	18	Bottom of bag, ash abrasion
1/16/89	1	R	3	Bottom of bag, ash abrasion
	1	S	1	Bottom of bag, ash abrasion
	2	N	8	Bottom of bag, ash abrasion
	2	P	5	Bottom of bag, ash abrasion
	2	Q	11	Bottom of bag, ash abrasion
	2	S	13	Bottom of bag, ash abrasion
	2	T	8	Bottom of bag, ash abrasion
1/17/89	2	R	4	Bottom of bag, ash abrasion
	4	E	1	Bottom of bag, ash abrasion
1/18/89	4	B	1	Rubbing on top railing
	4	E	5	Bottom of bag, ash abrasion
	4	F	1	Bottom of bag, ash abrasion
				Bottom of bag, ash abrasion
3/27/89	1	O	1	Bottom of bag, ash abrasion
	1	R	1	Bottom of bag, ash abrasion
	2	N	6	Bottom of bag, ash abrasion
	2	P	3	Bottom of bag, ash abrasion
	2	Q	1	Bottom of bag, ash abrasion
	2	R	2	Bottom of bag, ash abrasion
	2	S	3	Bottom of bag, ash abrasion
	3	Q	1	Bottom of bag, manufacturing defect
3/28/89	4	L	1	Bottom of bag, ash abrasion
6/6/89	2	S	5	Bottom of bag, ash abrasion
6/12/89	2	S	5	Bottom of bag, ash abrasion
	4	E	4	Bottom of bag, ash abrasion
6/14/89	2	Q	4	Bottom of bag, ash abrasion
9/17/89	2	Q	1	Torn by IBFM sensor
9/22/89	2	S	2	Bottom of bag, ash abrasion
9/25/89	2	N	12	Bottom of bag, ash abrasion
	2	T	3	Bottom of bag, ash abrasion
	2	P	3	Bottom of bag, ash abrasion
	2	Q	7	Bottom of bag, ash abrasion
	2	R	1	Bottom of bag, ash abrasion
	2	S	10	Bottom of bag, ash abrasion

Table 15-6
Page (2 of 2)

CUEA Nucla Station - Bag Failure Documentation

Date	Unit	Compartment	Number of Bags	Comment
9/26/89	1	R	1	Bottom of bag, ash abrasion
	1	S	1	Bottom of bag, ash abrasion
10/26/89	2	Q	2	Bottom of bag, ash abrasion
	2	S	5	Bottom of bag, ash abrasion
11/9/89	1	N	1	Bottom of bag, ash abrasion
	1	R	1	Bottom of bag, ash abrasion
11/21/89	3	S	2	Bottom of bag, ash abrasion
11/28/89	4	A	4	Bottom of bag, ash abrasion
	2	Q	5	Bottom of bag, ash abrasion
	2	P	4	Bottom of bag, ash abrasion
12/4/89	3	N	4	Torn approximately 1 ft from top
12/20/89	2	S	3	Bottom of bag, ash abrasion
12/21/89	2	S	1	Bottom of bag, ash abrasion
	2	Q	1	Bottom of bag, ash abrasion
12/26/89	2	Q	9	Bottom of bag, ash abrasion
	4	E	4	Ash impingement from failed adjacent IBFM gasket
1/3/90	4	E	4	Ash impingement from failed adjacent IBFM gasket
1/15/90	2	S	1	Bottom of bag, ash abrasion
	2	Q	2	Bottom of bag, ash abrasion
	1	R	2	Bottom of bag, ash abrasion
1/26/90	2	T	4	Bottom of bag, ash abrasion
2/23/90	2	N	5	Bottom of bag, ash abrasion
3/12/90	2	Q	4	Bottom of bag, ash abrasion
3/14/90	1	S	5	Bottom of bag, ash abrasion
4/16/90	2	S	4	Bottom of bag, ash abrasion
4/17/90	2	Q	13	Bottom of bag, ash abrasion
5/1/90	2	S	4	Bottom of bag, ash abrasion
5/23/90	2	S	4	Bottom of bag, ash abrasion
5/24/90	2	S	3	Bottom of bag, ash abrasion

Total Failures by Baghouse: Unit #1= 20, Unit#2 = 313, Unit #3 = 7, Unit #4 = 41
Note: Ash abrasion is the primary or secondary cause for bag failure.

four baghouses. The change in baghouse 2 was the most dramatic, having a failure rate of 6.4%/month before the adjustment and 1.46%/month after the change. The failure rate in baghouse 2 is still unacceptable. However, it is believed that the bags were damaged during the initial operations with the high deflate air flow rate.

Further analysis of baghouse 4 bag failures revealed that of the 41 bag failures reported during the 20 month period, 13 of these were caused by the IBFM monitors. Since these monitors are not normally installed in a baghouse, subtracting these failures from the total gives an average failure rate of 0.06%/month.

By far, the majority of the bag failures occurred in the bottom two feet of the bag, where the dirty gas enters the bags. These failures are identified as "Bottom of bag, ash abrasion". These failures are believed to be caused by abrasion of the bag material by the entering ash. The high deflate pressures experienced early in the program exacerbated the problem. This failure mechanism continues even after the adjustments to the deflate air pressure, although at a substantially reduced rate. Other causes of bag failures were due to the improper installation of the bags. This caused the bags to rub onto either a railing or another bag. A few of the bags were found to be torn. These could have been due to the bag rubbing another bag and bursting from the gas pressure.

In order to determine the remaining life of the bags, samples of bags were removed and shipped to Southern Research Institute for testing. Mullen burst strength tests were performed after 5,000 hours of operation and after 11,000 hours of operation. The average strength of the bags was 362 psi after 5,000 hours and 302 psi after 11,000 hours. These strengths correspond to a loss in strength of 39% after 5,000 hours and 49% after 11,000 hours. The current strength of the bags is considered serviceable. The abraded areas had slightly higher Mullen strength than the bag as a whole. In contrast, the bags from compartment 2S that failed at the bottom had a strength loss of 68% in the worn-but-not-yet-failed areas.

15.5 CONCLUSIONS

Despite numerous early bag failures, the baghouses at Nucla have performed as required during the test program. The baghouses are capable of providing low emissions rates for particulates (0.0072 to 0.0125 lb/MBtu) at high air-to-cloth ratios (2.0 to 3.4 acfm/ft^2) with low to moderate tube sheet (3.7 to 5.7 in.wg.) and flange-to flange (5 to 7 in. wg.) pressure differentials at near full load conditions. The shake/deflate cleaning method appears to allow operation at higher air-to-cloth ratios than the methods tested at the TVA 20 MWe AFBC pilot plant (reverse gas, and reverse gas with sonic assist).

The majority of bag failures experienced at Nucla have been attributed to the bag attachment mechanism that allows ash-laden gas to contact the lower two feet of the bags. These failures were intensified by high deflate air pressures and operation of the shake mechanism during the deflate cycle. One possible solution to the ash abrasion problem is to install bags that have an anti-collapse ring 8.5 inches above the bottom of the bag. This would prevent the bags from collapsing into the gas stream. One compartment of baghouse 2 had these bags installed just prior to the completion of the test program. Follow-up investigations of these bags is strongly recommended.

The bag failure problem was found to be a strong function of the deflate pressure. The deflate pressure for all of the baghouses have all been set to a range of 1 to 1.5 inches of water at full load. Further reductions to the deflate pressure could provide some additional improvement to the bag life. Southern Research Institute has recommended setting the deflate pressure to the range 0.25 to 0.5 in. wg.

Section 16

MATERIALS MONITORING

This section summarizes the condition of the Nucla CFB boiler components at the conclusion of four years of unit operation with over 15,000 unit operating hours on coal. The results encompass the following components: windboxes, air distributor plate and bubble caps, lower combustor refractory, combustor water walls, secondary superheater panels, bottom ash coolers, cyclone refractory and vortex finder, cyclone downcomer and loop seals, convection pass, and tubular air heater. Also included are descriptions of significant materials-related events in each of the outlined areas which forced or extended unit outages. Details of periodic inspections over the duration of the test program are contained in the Annual Reports for 1987-1988, 1989, and 1990-1991.

16.1 OVERVIEW AND SUMMARY

The Nucla CFB represents one of the first large scale applications of circulating fluidized bed technology. In 1987, CUEA was the first utility in the United States to apply this technology for power generation. At the time, it was also the largest CFB boiler in operation in the world. The design and materials selection of several components at Nucla represent "first generation" CFB design. Based on operating experience at Nucla and other units, new "second generation" designs are being offered which address many of the problems encountered with the early units.

Despite several materials-related problems during the first four years of operation of the Nucla CFB, there have been few significant changes in design and/or materials selection to circumvent problems which developed. Those of significance include, 1) a design change to refractory anchors and the addition of refractory "stops" in certain damaged regions of the cyclones, 2) a switch to brick and hard castable refractory in certain sections of the loop seals that had previously used "gunned-on" refractory, 3) a design modification to a percentage of air distributor bubble caps to reduce backsifting of bed material into the windbox and to improve retention, 4) the addition of 6" shelves over the top row of one secondary superheater panel (second panel from the bottom) to prevent tube erosion from the downward flow of solids.

A temporary change in unit operating philosophy was used to address a problem with overheating of the secondary superheaters located in the upper freeboard region of each combustion chamber. Although this operating modification addressed the immediate problem and improved unit availability, it did result in an increase in the plant heat rate of approximately 2 percent. Other problem areas have been addressed with periodic maintenance performed during unit outages with some minor design changes which are discussed in more detail below.

Localized water-wall and secondary superheater erosion has been one area that has required a degree of attention and periodic maintenance. As will be discussed, generalized water-wall and superheater tube erosion was not detectable after 5500 hours of unit operation on coal. Although this should be substantiated sometime in the following years, this conclusion is favorable for the Nucla CFB and if applicable, for other CFB's burning a similar fuel type. Although localized erosion is undesirable, it is believed that design changes on "second-generation" CFB's can significantly reduce or eliminate such occurrences.

From 1988 through 1990, the Nucla CFB was restarted over 165 times following outages which varied from one hour to over 500 hours. There are many factors which contributed to this high number of unit outages discussed elsewhere in this report. The impact of this frequency of thermal cycling on materials components is probably significant. This should be kept in mind with the discussion presented below.

At the conclusion of nearly four years of unit operation from June 1987 through February 1991, the significant problem areas of the Nucla CFB, which are currently being addressed with periodic maintenance, are:

1. Degradation of lower combustor refractory particularly around the recycle return line, manways, and ports for coal, start-up burners, limestone, and air.

2. Distributor plate bubble cap retention and erosion.

3. Water-wall tube erosion at the refractory/water-wall interface.

4. Water-wall tube erosion along warped (bowed) sections of wall left over from the overheat incident in October 1987. This is particularly troublesome on a section of water wall in combustor A approximately 22 feet above the distributor plate.

5. Secondary superheater erosion in regions conducive to channeling of the downward flow of solids.

6. Long-term overheat of secondary superheater tubes. This has been temporarily addressed through operating changes to the desuperheater sprays, but has resulted in a 40 °F drop in final superheat temperature.

7. Long-term integrity of the cyclone vortex finder structure.

8. Refractory breakage around the "bull nose" section of the cyclone inlets.

9. Refractory erosion/abrasion along the impact/target area of the cyclone.

10. Periodic refractory spalling in the conical section of the cyclone and cyclone downcomers.

16.2 OBJECTIVES AND APPROACH

The objective of the Materials Plan at Nucla was to monitor selected boiler pressure and non-pressure components over the course of the Phase I and II test programs to determine:

1. Refractory integrity in several areas of application including the lower combustor regions, cyclones, cyclone downcomers, and loop seals.

2. Erosion/corrosion/fatigue of non-pressure components including air distributor bubble caps, tube hangers and supports, the combustion chamber windboxes, the cyclone vortex finders, tubular air heater, and miscellaneous fireside components.

3. Erosion/corrosion/fatigue of boiler pressure components including water walls, superheaters, economizer, water-cooled superheater support tubes, steam cooled convection pass, and ash coolers.

In March 1987 prior to first fires in the boiler, a baseline inspection of the Nucla CFB was conducted. This inspection included tube thickness measurements in certain regions of the water-wall, superheater, and economizer tubes. An extensive photographic survey was completed and a detailed inspection plan was developed to serve as a guideline for future outages.

During the course of the four year test program, inspections were performed during unit outages which occurred over the normal course of operation (i.e., the inspections did not initiate outages). The duration and nature of the outages dictated the level of detail and extent to which the inspection plan was conducted. Each inspection included photographs, tube thickness measurements (where appropriate), and an inspection report. A summary of this information is included in the 1987-1988, 1989, and 1990 Annual Reports.

In fulfilling the objectives of the Materials Monitoring Plan, this information has provided a basis for identifying "root causes" and corrective changes in design and materials selection in certain regions of the Nucla CFB. Coupled with operating experience on other CFB units, it has also been beneficial in the "second-generation" design of CFB boilers.

16.3 SUMMARY OF INSPECTIONS

Table 16-1 summarizes the major inspections that were conducted during unit outages over the course of the test program. Tube wall thickness measurements were taken during a portion of these outages and the availability of these data in the Annual Reports is indicated in the table for each inspection.

During the baseline inspection and after 600 hours of unit operation on coal, an extensive tube thickness measurement matrix was completed over sections of the water walls, superheaters, economizer, and water-cooled superheater tube supports. The objective was to quantify any generalized erosion that might be occurring in these areas. During the inspection after 600 hours of operation on coal, measurements were taken on water-wall tubes in both combustors at the centerline, -30° and +30° from centerline on every tenth tube. This grid started at 20 feet above the air distributor plate and proceeded every 10 feet to the top of the combustor. These measurements were repeated on every twentieth tube at the same elevations in January, 1989 after 5500 hours of operation on coal. These data are summarized in the 1989 Annual Report.

The results of these measurements indicated that no generalized erosion could be quantified on the water walls. Tube thickness measurements of the superheater and economizer surfaces during other outage inspections indicated the same result. However, erosion was visible in localized areas of the water walls and secondary superheaters that was not detected using a broad measurement matrix. Based on these findings, the emphasis for tube thickness measurements during subsequent inspections shifted to areas where localized erosion was apparent. These included water-wall tubes at the water-wall/refractory interface and sections of the secondary superheaters.

Quantifying and monitoring the progress of localized erosion using tube thickness measurements also has proven to be difficult. This is due to the nature of this erosion which can be characterized by "gouging" or "grooving" as opposed to "polishing" and "smoothing" that has been detected on in-bed tubes in bubbling bed FBC's. Erosion marks at Nucla are

Table 16-1. Summary of Unit Inspections

DATE	COAL HOURS	REPORTABLE TUBE THICKNESS MEASUREMENTS
March, 1987	baseline	yes
November, 1987	600	yes
August, 1988	3600	yes
January, 1989	5500	yes
June, 1989	7600	yes
September, 1989	8750	yes
October, 1989	8850	no *
January, 1990	10300	no *
February, 1990	10500	no *
May, 1990	11800	no *
June, 1990	12100	no *
August, 1990	13000	no *
September, 1990	13150	no *
October, 1990	13600	no *
February, 1991	15800	yes

* some localized tube thickness measurements were taken.

often too narrow and uneven (but often deep) to obtain a reliable, repeatable measurement using an ultrasonic thickness (UT) measurement device. The presence of a non-uniform sacrificial weld overlay in certain areas also contributes to the difficulty taking these measurements.

During inspections subsequent to the 5500 hour outage, tube thickness measurements were taken (where possible) in localized erosion areas to identify tubes that required additional sacrificial "pad" welding. Even using this preventative maintenance approach, visual inspections, photographs, plaster casts of the most severe tubes, and the inspection reports proved to be more useful for identifying problem areas and tracking the progression of erosion.

As a result, detailed data on tube thickness measurements are not presented in the Final Report. Summaries of these data can be found in the Annual Reports where reportable data are available. The descriptions which follow highlight significant materials-related issues which developed over the course of four years of unit operation, along with any corrective actions taken. Where appropriate, some tube thickness data are presented for the water-wall tubes. An attempt has been made to include photographs and descriptions from the most recent inspection that occurred during the February 1991 outage at the conclusion of the Phase II Test Program.

16.4 SUMMARY OF MATERIALS RELATED PROBLEMS

The following is a description of materials-related problems that developed between 1987 and early 1991 in the areas listed below. Only significant CFB-related problems are discussed and photographs are used for clarification where appropriate.

- Windboxes
- Lower Combustor Refractory
- Air Distributor
- Water Walls
- Superheater II Tubes
- Bottom Ash Coolers
- Cyclone Refractory and Vortex Finder
- Downcomer and Loop Seal Refractory and Outer Shell
- Convection Pass (Economizer and Superheaters)
- Tubular Air Heater

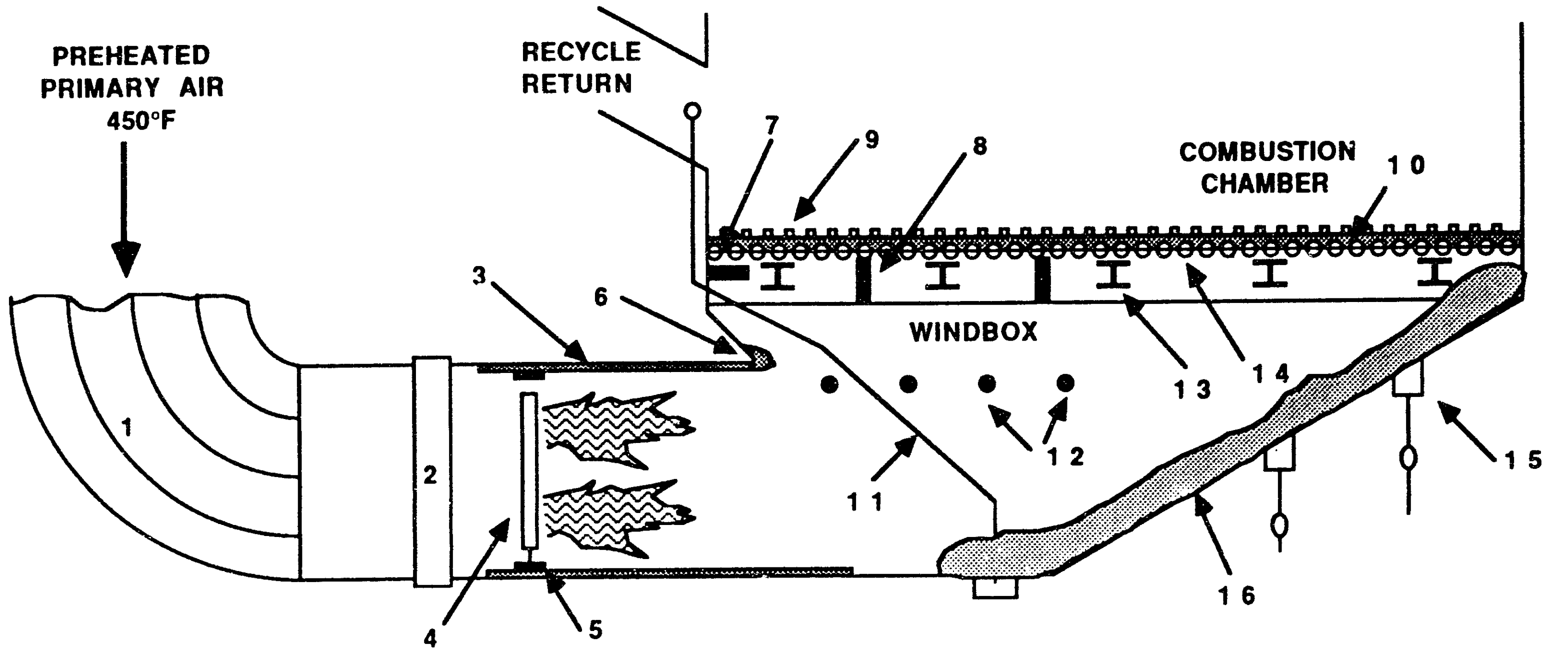
16.4.1 Windboxes

The windboxes on the Nucla CFB are situated below the air distribution plate and serve to direct pre-heated combustion air at 450 °F through the distributor plate into each combustion chamber. Each windbox uses plate steel construction, which is welded directly to the water-cooled air distributor floor near to the point at which the floor tubes attach to an outside header. A duct burner, used during unit start-up, is located in the primary air duct just upstream of the windbox (see Figure 16-1). During start-up, temperatures downstream of the duct burners reach 850 °F. As a result, the ductwork just upstream of the windbox is refractory-lined around all four walls. The windbox casing is not refractory-lined except for the bull nose section shown in the same figure.

Problem areas with the windboxes have been related to differential expansion and backsifting of bed material through the air distribution plate. High temperatures downstream of the duct burners during start-up have caused warping and cracking of the shell plates, welds, and auxiliary hardware. Backsifting of bed material has been mostly an operational problem of removing build-ups in the windboxes during unit operation. If not removed, these build-ups can block air flow to the front wall air nozzles. The hardware added during the first year of operation to remove bed material accumulations have suffered from both design and material limitations. Although none of these problems can be considered major or technology limiting, they have been a source of relatively high maintenance over the first four years of unit operation. Using lessons learned at Nucla coupled with good design, most of these problems can be eliminated in "second-generation" designs. Each are discussed in more detail below.

1. The *duct burners* shown in Figure 16-1 were subject to fouling in the first year of unit operation. The build-up of soot from a rich propane mixture caused some sections of the front burner face to over-carburize and become brittle. Some burner sections required replacement after the first year of operation. To increase primary air flow through the duct burner, the duct cross-sectional area immediately surrounding the burner was decreased to divert more air flow through the burner (see location Figure 16-1, item 5). This modification, along with adjusted firing rates during start-up, has nearly eliminated this problem.

2. The *refractory lining* (item 3), which surrounds the duct burners and extends partially into the windbox, has suffered cracking and breakage. The refractory used in this application is relatively soft with good insulating properties. Part of the problem with breakage is related to warping of the underlying shell plates. This is particularly true around the bull nose region (item 6) of each windbox. Another major contributor was the presence of mechanical stiffeners (item 12) which were used to strengthen the windbox. These warped from high temperatures associated with the duct burners and consequently, distorted the windbox sidewalls at the point of attachment. Refractory in the vicinity of the mechanical stiffeners on the sidewalls



1. Inlet PA duct
2. Expansion Joint
3. Refractory Lining
4. Duct Burner
5. Burner Modification
6. Windbox Bullnose
7. Crack Location
8. Expansion Slots
9. Air Distributor Bubble Caps
10. Air Distributor Refractory Floor
11. Backsifting Reinjection Line
12. Location of Lifting Rods
13. Structural I-Beam Support
14. Water-Cooled Floor Tubes
15. Backsifting Collection Canisters
16. Backsifted Bed Material

Figure 16-1. Side View Schematic of Windbox Layout (not to scale) eventually broke away. To correct the problem, the front two mechanical stiffeners closest to the duct burners were removed in each windbox. Overall refractory performance in this area has been relatively good since this correction.

3. Cracks in the *shell casing* welds forming the windbox enclosure have occurred on several occasions. The location of these cracks is primarily to the rear of the windbox near the water-cooled air distributor floor (location 7). These windbox casing leaks result in leaks of pre-heated combustion air and entrained backsifted bed material to the outside boiler room. On three occasions, differential expansion between the water-cooled floor tube headers and the windbox shell plates have caused floor tube leaks which resulted in unit outages. The addition of expansion slots in the shell casing at location 8 has corrected this latter problem. Cracks still form in the rear corners of the windbox (location 7) and around the bull nose area. These are repaired periodically during unit outages.

4. Bed material backsifts from the combustion chambers through the air distributor bubble caps into the windboxes and accumulates on the sloped floor as shown in Figure 16-1 (item 16). This occurs to the greatest extent during shutdown, start-up, and low load operation when underbed air flows are at a minimum. Visual observation indicates that most of the material backsifts through bubble caps located in front of the recycle return, at the entrance to the side-mounted bottom ash coolers, and along the corners of the front wall. As bed material builds up in the windbox around the front structural I-beam shown in the figure, air flow becomes restricted to the bubble caps along the front rows of the combustor.

In order to provide on-line reinjection and removal of backsifted material, a *reinjection line* (item 11) was installed to transport accumulated material from the floor region to the loop seal return leg using windbox pressure for transport. In addition, *collection canisters* (item 15) were installed on the sloped floor to drain bed material accumulations in the front of the windbox. Drain lines were added to the bottom of these canisters to transport material directly into the bottom ash disposal system.

These design modifications have not worked well and, at the conclusion of the Phase II test program, were not operational. Since the windbox floor is not tapered towards either the reinjection line drain or the collection canisters, bed material can only be removed in the immediate vicinity of these locations. The bulk of accumulated material is not served by these drains. The reinjection line suffered from over-temperature due to its location directly in front of the duct burners. This problem was exacerbated by blockage of the line and loss of transport air which serves as the cooling medium. The drain pipes from the collection canisters to the bottom ash disposal line were too shallow in slope and eventually blocked and became hard-packed. Currently, accumulated backsifted bed material is shoveled from the windbox during unit outages. The effect of this material on flow distribution through the air distributor plate and the associated impact on combustion performance is not known.

16.4.2 Lower Combustion Chamber Refractory

The "gunned-on" refractory in the lower combustion chambers has not stood up well to conditions in the first four years of unit operation. Refractory breakage and spalling have been common over most surfaces and have been particularly pronounced around the the lower 2 to 3 feet above the air distribution plate, near the water-wall interface, around the recycle return line, and around start-up burners and manways. Each of these are discussed in more detail below.

1. During construction, the refractory thickness near the air distributor was increased to approximately 18 inches to close off the outside two rows of bubble caps. This reduces the open area of the air distributor and increases fluidizing velocities in the lower combustor. The latter assists in moving and lifting the dense bed in the bottom of the combustor. However, effective anchoring of this thickness of refractory has proven to be difficult.

Figures 16-2 and 16-3 show the condition of this refractory after the February 1991 outage following over 15,000 hours of unit operation on coal. Severe breakage and exposure of refractory anchors is apparent in this region. The electrical cord in Figure 16-2 is exiting the combustion chamber from a manway door. On occasion, dislodged pieces have blocked the entrances to the bottom ash drain coolers which have forced unit outages for removal. No major repairs have been made to this area since initial start-up in June 1987.

2. Refractory breakage has been common around the perimeter of the combustion chambers at the water-wall interface. Figure 16-4 is a photograph taken after 2 years of unit operation showing the region involved. In this example, "blue ram" plastic refractory (alumina phosphate bonding) has been used to replace a failed section. The refractory is tapered in this region from 2 to 4 inches thick to provide a gradual transition into the water walls. This reduces the degree of discontinuity at this location which is known to contribute to water-wall erosion. However, the top 1 to 2 feet of this refractory was not anchored during the original installation. The downward flow of solids along the water walls initially tends to undercut the tapered, un-anchored section. Bed material works in behind the refractory when

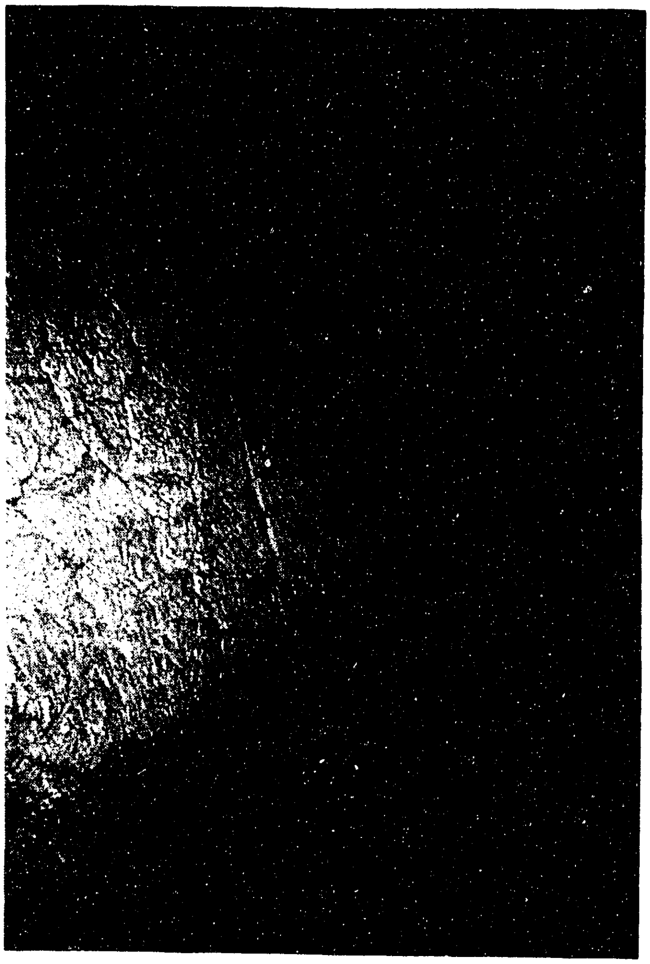


Figure 16-2. Combustor A Lower West Wall Refractory Condition (February 1991 Outage).

Figure 16-3. Combustor A Lower Refractory Condition (February 1991 Outage).

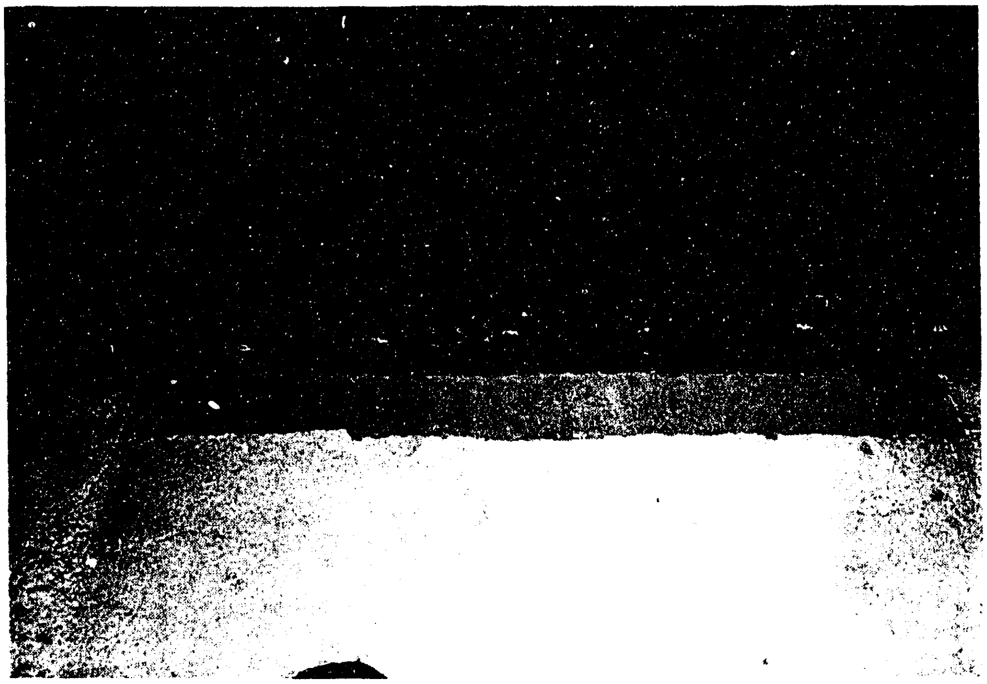


Figure 16-4. Refractory Breakage at Refractory/ Water-wall Interface in Combustor B.

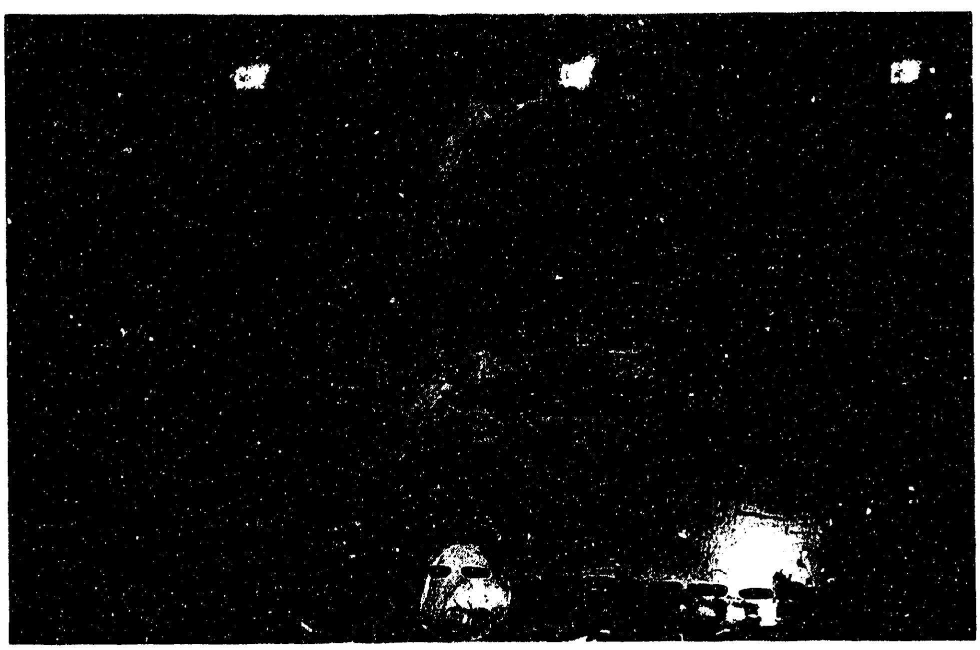


Figure 16-5. Refractory Condition Around Recycle Return in Combustor A (February 1991 Outage).

the water walls are hot and fully expanded. During cool-down, bed material is compressed in this region and through repetition, forms hard packed layers. Eventually, the build-up "jacks" the refractory off the wall. During the inspection outage at the conclusion of the Phase II test program, this problem was still apparent and additional maintenance was required. Improved anchoring in this region may help resolve the problem unless a design change is incorporated.

3. Refractory breakage around the recycle return has been severe and repeated over the first four years of unit operation. Figure 16-5 shows the general condition during the outage in February 1991. The region below and to the right of the recycle port (outlined) has recently been repaired with "blue ram" refractory and is still in relatively good condition. The area to the left of the recycle line is badly damaged with numerous exposed anchors and, on past occasions, water-wall tubes. The amount of breakage and movement of refractory in this area is beyond what is possible by "jacking". The recurring nature of this problem suggests inadequate anchoring and/or some degree of wall movement in this vicinity. Since the expansion joint on the loop seal has been inoperable for the past 2-3 years of operation, it is possible that differential expansion or movement between the refractory-lined recycle line and the combustion chamber produces a force on the rear wall and causes a deflection. To address this problem, the root cause must be further explored by studying the movement of the recycle system relative to the combustion chambers. At the conclusion of the test program, this remains an area of high maintenance.

16.4.3 Air Distributor

The air distributor at Nucla is water-cooled with a thin refractory layer covering the combustion-side surface. Stainless steel pipe nipples extend between rows of water-cooled floor tubes through the protective refractory layer. A bubble cap is then affixed to the top of the nipple (see Figure 16-6).

In the original design, a retention washer was used to prevent the bubble cap from coming unscrewed off the threaded pipe nipple. These washers eventually failed due to improper materials selection and, following the loss of numerous bubble caps, were replaced with a stainless steel washer in the manner shown in the figure. The original carbon steel washer was left in place on approximately 25% of the nipples to reduce damage to the pipe nipple when removed. Despite this, threads were damaged during the modification which prevented the bubble cap from being secured tightly onto the threaded pipe nipple. This, along with the prying action of bed material between the bubble cap and the washer,

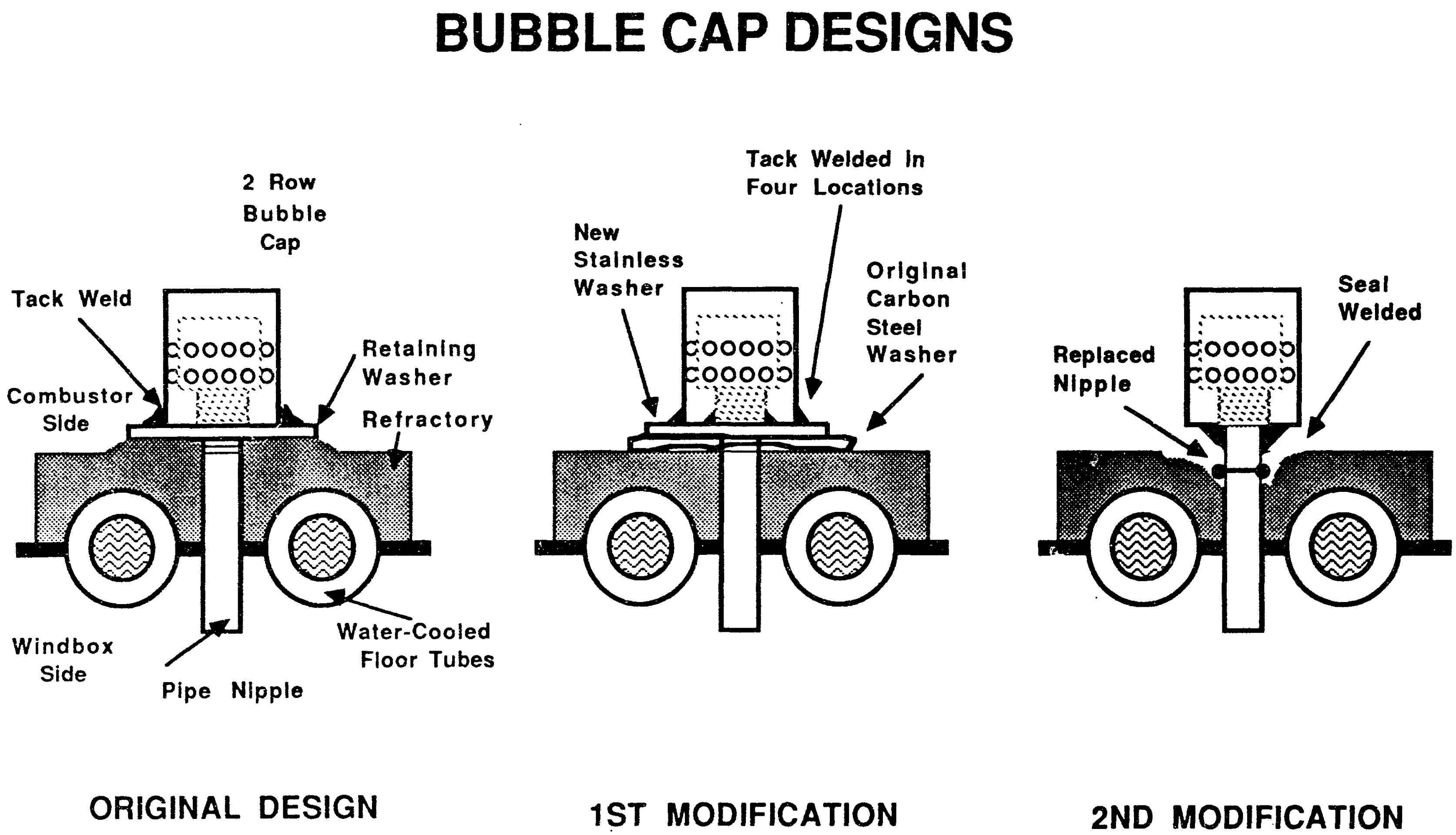


Figure 16-6. Bubble Cap Design Modifications.

eventually resulted in a significant number of additional failures.

A third design is presently used which eliminates the retention washer. Bubble caps are now replaced on an as-failed basis during unit outages by cutting off the pipe nipple below the damaged area. A new bubble cap is seal-welded to a short, matching pipe nipple which is, in turn, welded directly to the existing nipple. Although this has proven to be a more durable design, failures still occur primarily in the region directly in front of the recycle return line. During unit shutdown, a significant quantity of bed material flows back through the open pipe nipples into the windboxes. This continues to be an area of high maintenance.

Bubble cap erosion has also been pronounced in the region in front of the recycle return line and, on combustor A, extends three quarters of the distance across the air distributor to the front wall. This is shown in Figure 16-7 along with smaller affected areas directly in front of the bottom ash cooler inlets. An example of this erosion is shown in Figure 16-8. This figure also illustrates the two techniques currently used for affixing the bubble cap to the pipe nipple (with and without the retention washer). On many bubble caps, erosion has either progressed to the point of wearing through the top of the cap or has become severe enough that replacement has been required.

Three different bubble cap air hole configurations are currently in use. Most caps contain two rows of air holes drilled at a slight upward angle to prevent backsifting when bed material is slumped around the bubble cap. In order to increase fluidizing air flow and reduce backsifting, caps with three rows of air holes were added around the perimeter of the combustion chamber and in front of the recycle return line. Bubble caps using air holes with a steeper drill angle have also been added directly in front of the ash cooler inlets to reduce backsifting. It is difficult to evaluate the effectiveness of these design modifications in reducing backsifting.

16.4.4 Combustor Water Walls

The water walls have suffered from localized particle erosion in four areas, each of which are described below. As discussed in the summary, generalized erosion of water-wall tubes was not detectable following the completion of an extensive tube thickness measurement matrix after 5500 hours of operation on coal. Periodic visual inspections and "spot check" tube thickness measurements have not revealed any change in this condition.

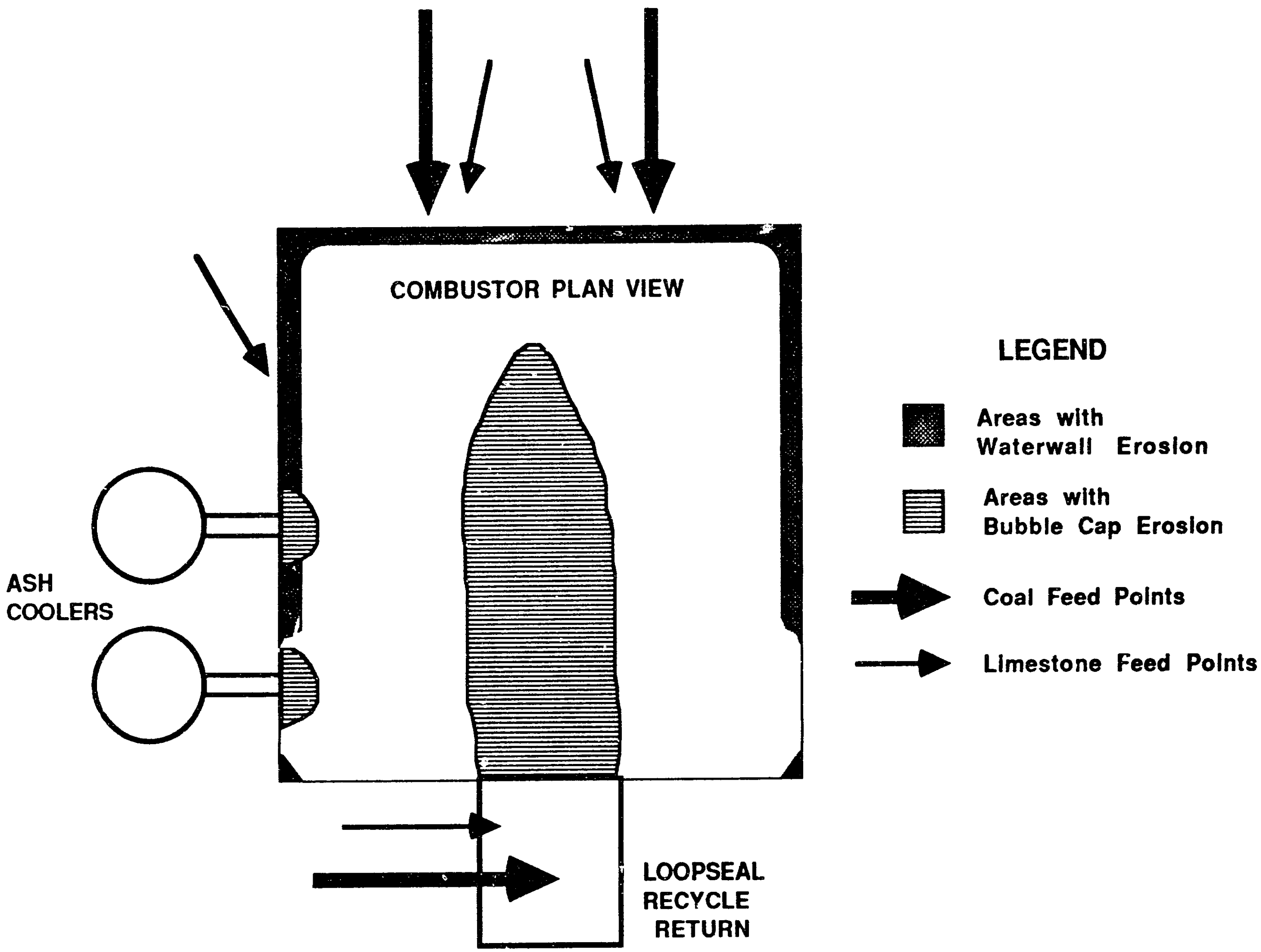


Figure 16-7. Plan View of Combustor Showing Areas of Waterwall and Bubble Cap Erosion.

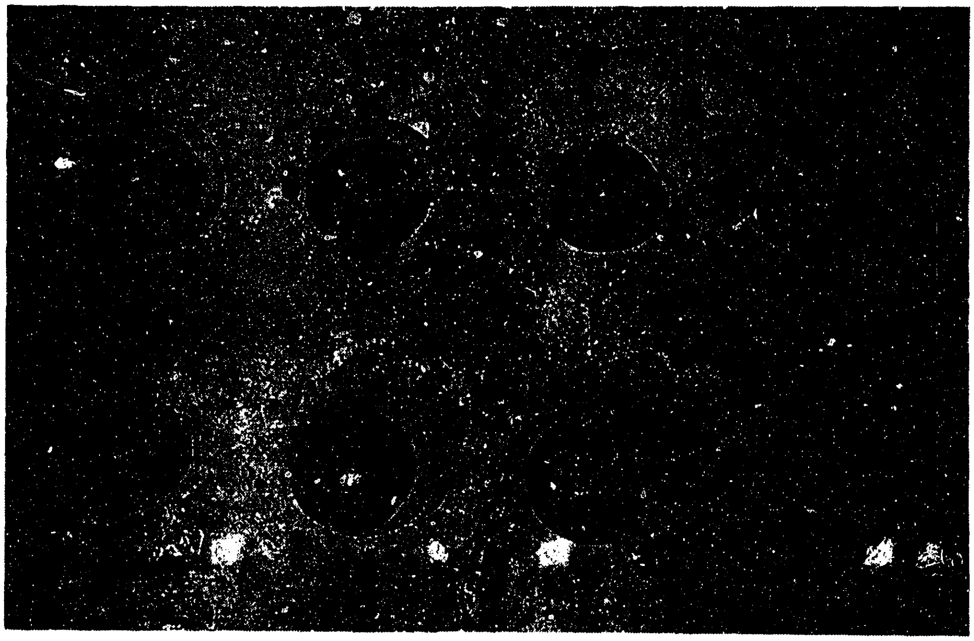


Figure 16-8. Bubble Cap Erosion in Combustor A (February 1991 Outage).

1. Erosion at the water-wall/refractory interface has been common on CFB's and is widely reported in the literature. At Nucla, water-wall tubes in this region are protected with a hard, horizontal weld overlay that extends approximately 4 inches above the top of the lower combustor refractory. Figure 16-9 is an example of the sacrificial weld overlay in almost "as new" condition during the inspection in February 1991 with over 15,000 operating hours on coal. Some erosion and loss of weld overlay is visible near the top of the weld, but does not extend down into the base tube metal in this example.

This type of erosion is not uniform around the perimeter of the combustion chambers. As shown in Figure 16-7, it is more severe along the front walls and the front two thirds of the side walls opposite the recycle return line. Within this shaded region, the corners of the combustor appear more eroded, suggesting a greater amount of solids down-flow in these areas. In some instances, erosion of the weld overlay will progress beyond that shown in Figure 16-9 to that shown in Figure 16-10 and eventually to Figure 16-11. In these examples, erosion has not progressed into the underlying tube metal and in this regard, the sacrificial weld overlay has performed as intended, but remains a potentially high maintenance item.

However, in other areas as shown in Figure 16-12 and Figure 16-13, small ledges form in the weld overlay and erosion begins to cut into the underlying tube metal. When this occurs, the ledge is ground off and smoothed during unit outages and new weld overlay is applied in areas with significant tube metal loss. In other instances, erosion will progress in the weld overlay in strange, unpredictable patterns. The term "cat scratch" erosion has been coined to describe these patterns. Again, if a shelf or major discontinuity forms, it is ground off and weld overlay is applied to areas with significant losses in base tube metal thickness.

A major contributor to the most severe erosion in this area is the presence of horizontal weld overlay in the membranes between tubes. During the original application in 1987, the horizontal weld overlay extended around the tubes and across the membrane. Since a large portion of the downward flow of solids along the water walls is in the membrane, the discontinuity created by this overlay acted as an initiation site for erosion to surrounding tubes. This pattern is illustrated in Figure 16-14. To the best extent possible, the top of this overlay has been ground smooth during unit outages. However, with time, this discontinuity reappears in certain areas and begins to deflect solids flow from the membrane into surrounding tubes. This is clearly illustrated in Figures 16-15 and 16-16.

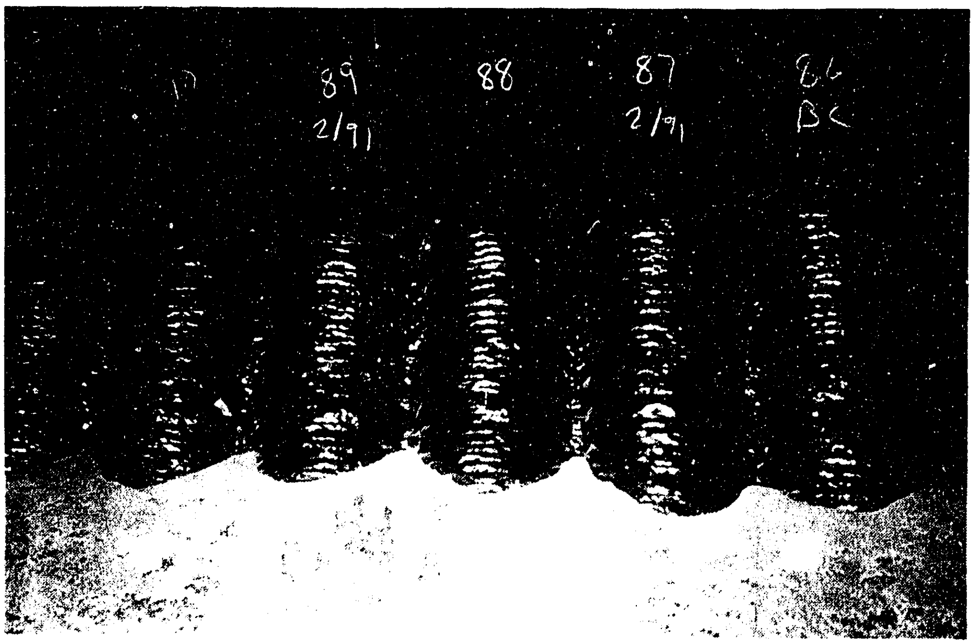


Figure 16-9. Weld Overlay in Good Condition at Refractory/Water-wall Interface in Combustor B (February 1991 Outage).

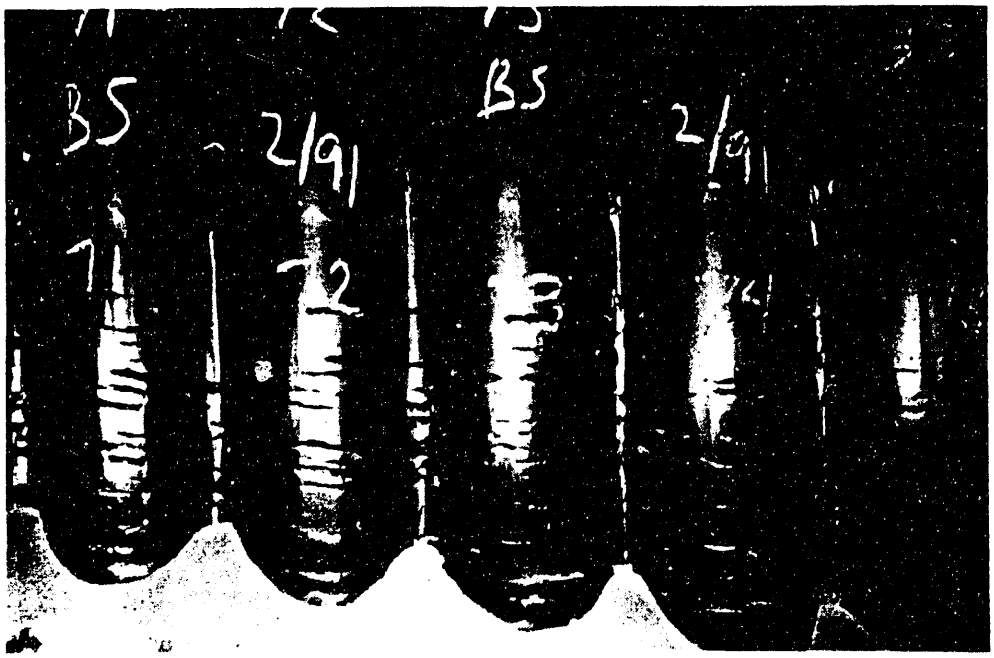


Figure 16-10. Worn Weld Overlay at Refractory/
Water-wall Interface in Combustor B (February 1991 Outage).

Figure 16-11. Worn Weld Overlay at Refractory/
Water-wall Interface in Combustor B (February 1991 Outage).

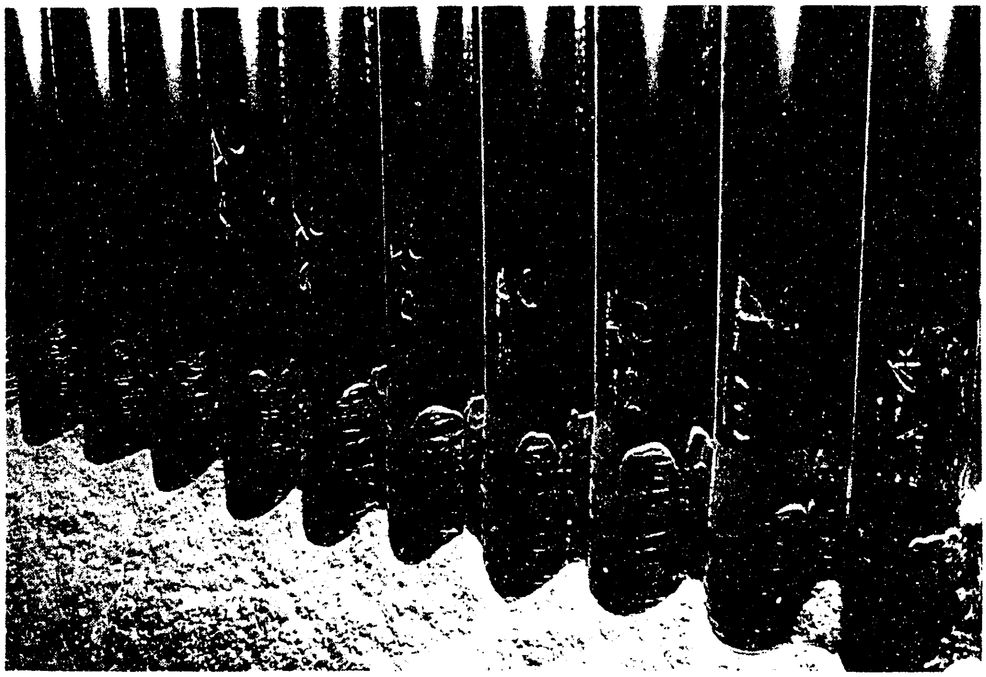


Figure 16-12. Shelf Formation in the Weld Overlay in Combustor A (February 1991 Outage).

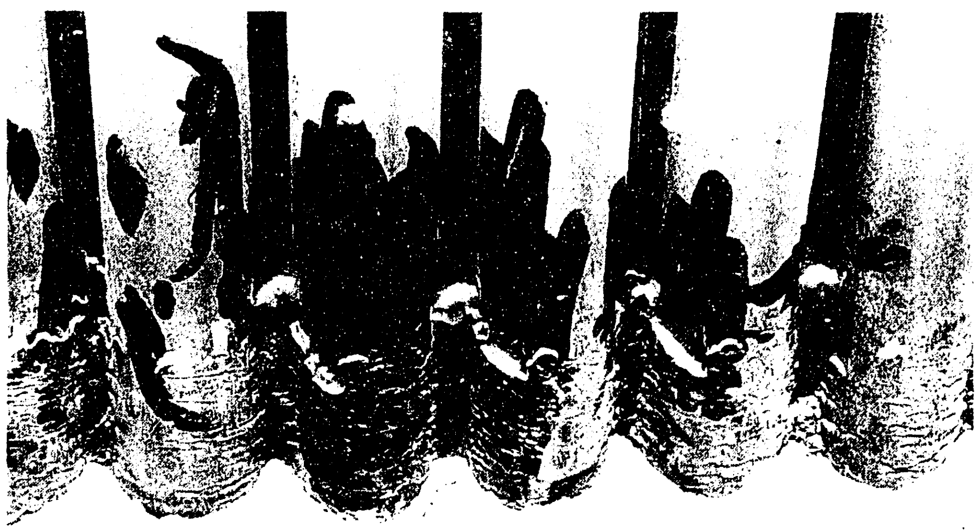


Figure 16-13. Shelf Formation in the Weld Overlay in Combustor A (February 1991 Outage).

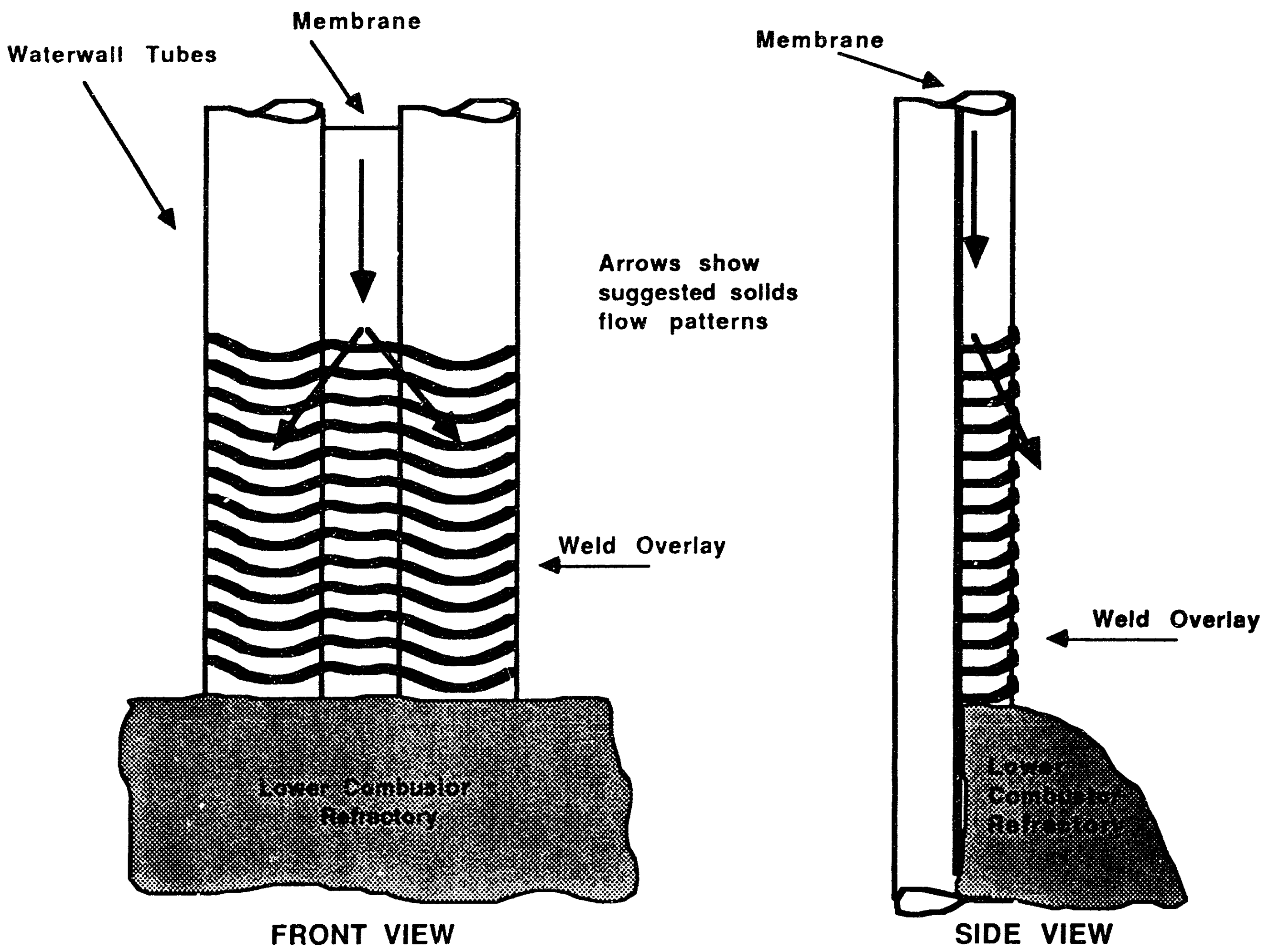


Figure 16-14. Schematic of Waterwall Tube Erosion.

Figure 16-15. Erosion Patterns Initiating from the Membrane in Combustor A (February 1991 Outage).

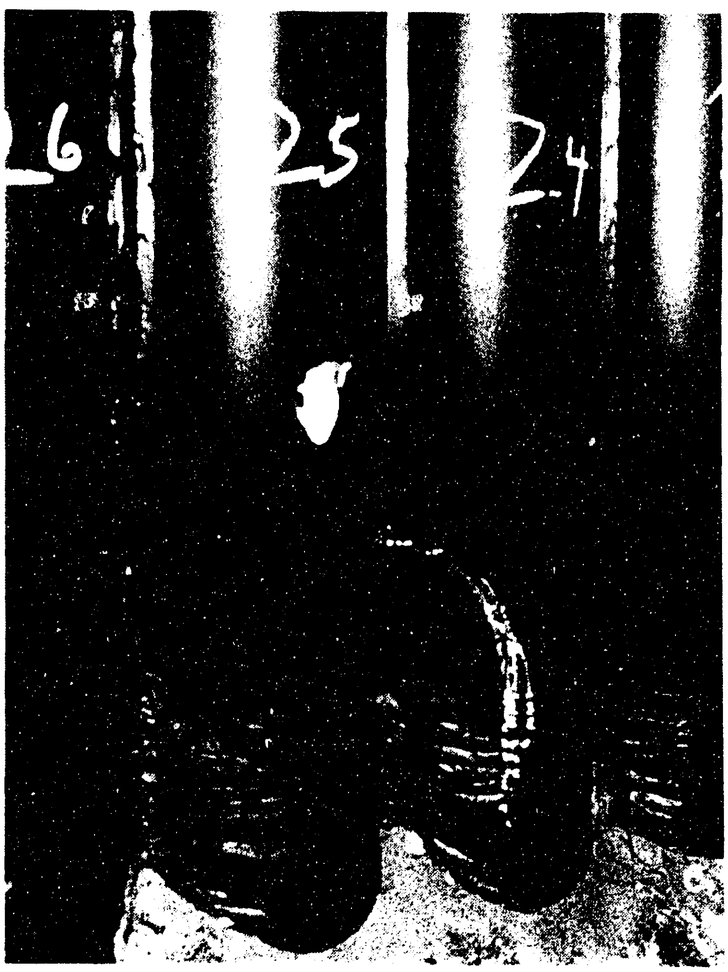


Figure 16-16. Erosion Patterns Initiating from the Membrane in Combustor B (February 1991 Outage).

Because of the narrow, uneven nature of this type of localized erosion, tube thickness measurements as part of preventative maintenance are difficult. There may be several such locations on a single tube which further compounds the problem. In most instances, tube thickness measurements are made in areas with the greatest visual erosion. During the February 1991 inspection, a total of 66 tubes were measured with spots less than 180 mils. Of theses tubes, 33 were measured with thicknesses less than 150 mils. The original tube wall thickness without weld overlay is a nominal 220 mils.

It is difficult to correct the erosion problem at the water-wall/refractory interface at Nucla without major design changes to the water walls and refractory. Currently, the problem is being controlled with periodic maintenance by applying weld overlay to eroded areas during unit outages. Grinding of "ledges", which form in the weld overlay on tubes and in the membrane, is also performed on an as-needed basis.

2. Erosion has also occurred on water-wall tubes at butt welds where water-wall panels were joined together during construction, as shown in Figure 16-17. Not all welds display this type of erosion pattern. There are three contributing factors which influence the degree of erosion at these locations (if present). The first of these, tube alignment, creates a problem if the lower tube projects slightly into the furnace section relative to the upper tube. In this case, the butt weld wears smooth but the downward flow of solids begins to undercut into the lower tube. The second is the quality of the weld, particularly in the adjacent membrane. In Figure 16-17, bar stock has been welded into the gap in the membrane from the back side (cold side), creating a significant discontinuity. Third, the water-wall location is important. Butt welds on the front walls (opposite the recycle line) show more instances of erosion than those on the rear walls (directly above the recycle line). After 15,000 hours of operation, no corrective action (i.e. weld overlay), has been taken in these areas. This erosion area continues to be monitored closely by the plant.

3. During the overheat incident in October 1987 (see 1987-1988 Annual Report), a permanent deflection of the water walls occurred due to differential expansion between the two combustion chambers. This "bowing" of the water walls was corrected to $\pm$ 1.5 inches from the true centerline during the ensuing repair outage. The deflections are more severe in combustion chamber A and occur approximately every 10 feet up the water walls, or the distance between the buckstays on the outside of the boiler. On combustion chamber B, only one deflection exists approximately half way up the center wall.

Figure 16-17. Erosion of Butt Welds at Adjoining Water-wall Panels (February 1991 Outage).

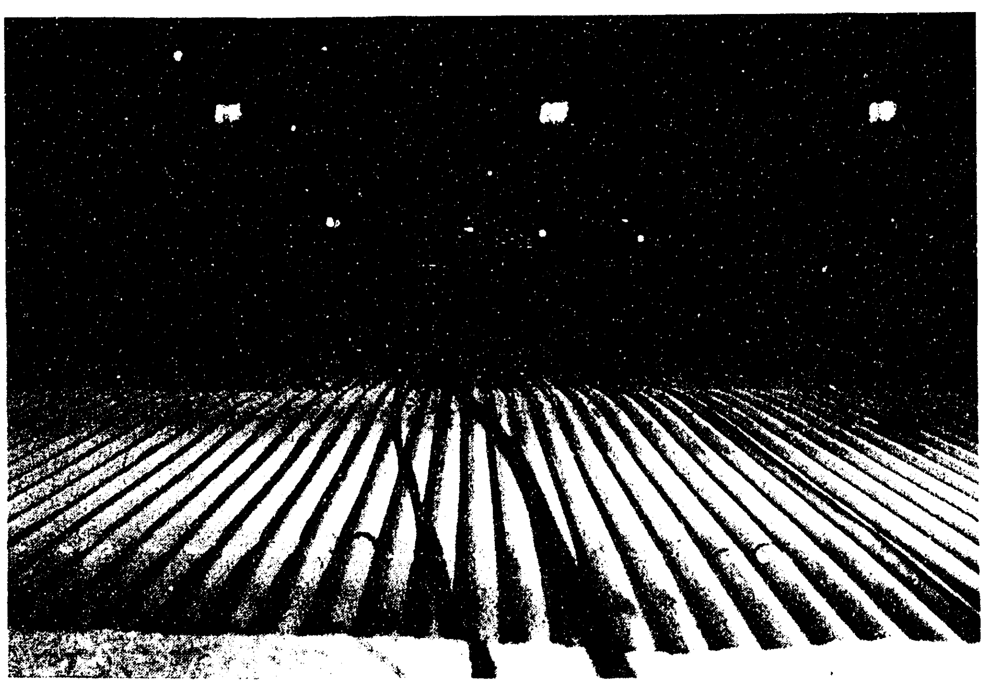


Figure 16-18. Bowed Section of Waterwall on Front Wall of Combustor A (February 1991 Outage).

A photograph of this deflection can be seen in Figure 16-18 from the front wall of combustion chamber A.

The crest or "nose" of one of these bows on the front wall of combustion chamber A has eroded severely since the time of the repairs in December 1987. This can be seen in the photograph taken in February 1990 (see Figure 16-19). The location of this bow is approximately 22 feet above the air distributor. It appears that this deflection has a deeper and sharper radius compared to other locations. The erosion extends across all tubes at this location to within 5 to 10 tubes of the side walls. The length of this "cat scratch" erosion pattern is approximately 2 to 3 feet. Areas with deep gouging have been pad welded during unit outages in 1990. During the February 1991 outage, a total of 7 tubes were identified with erosion spots having less that 180 mils of tube thickness. As with the erosion area at the water-wall/refractory interface, tube thickness measurements for identifying sites for pad welding are difficult. There have been no tube failures in this region to date and this, as well as other areas, continue to be closely monitored by the plant during unit outages.

4. Also during the overheat incident in October 1987, a hard 10 mil scale deposit was left on water-wall tubes in combustion chamber A. In time, some of this scale becomes dislodged and exposes the underlying tube. In certain isolated locations, the discontinuities created by these deposits will form erosion sites. An example of this is shown in Figure 16-20. The extent and frequency of these occurrences is probably related to the relative location of these deposits to the water-wall "bows". The problem is difficult to monitor since it is isolated. To date, no action has been taken on this type of erosion.

16.4.5 Superheater II Tubes

The wrap-around superheater panels are situated in the upper freeboard region of each combustion chamber. There are four panels in each chamber, each consisting of 64 tubes (see Figure 16-21). Each panel is situated against the water walls with approximately a 2" spacing between the water-wall tubes and the superheater tubes. From October 1989 to January 1991, there have been a total of 7 separate tube failures of the secondary superheaters accounting for a total of 2718 outage hours for repairs. A comparison of these outages to other unit outages during the period is shown in Table 16-2.

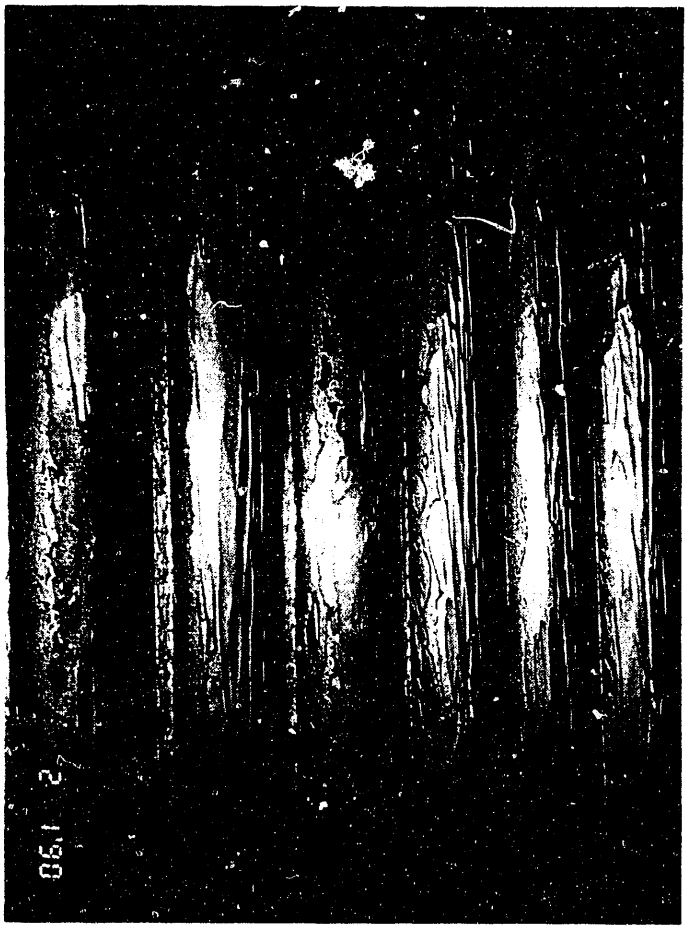


Figure 16-19. Erosion in Waterwalls at the Nose of the Bowed Water-wall Section, Combustor A at 22 ft Elevation (February 1991 Outage).

Figure 16-20. Localized Water-wall Erosion Site at the Location of a Scale Discontinuity

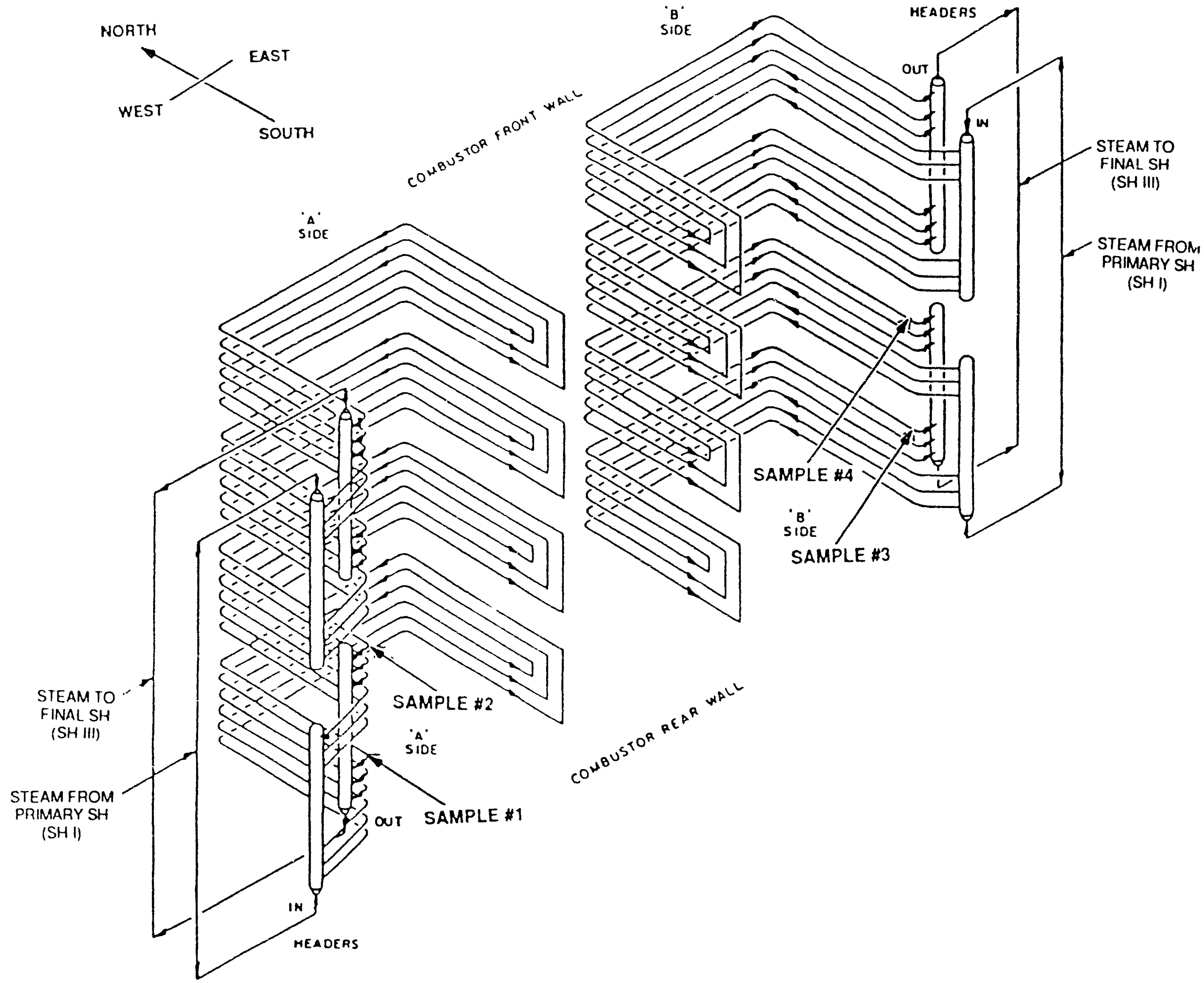


Figure 16-21. Location of Tube Samples in Superheater II.

Table 16-2.
Outage Summary from October 1989 to January 1990.

Outage Description	Outage %	Hours	No.of Outages
Superheater II Failures	70.4	2718	7
Cyclone Vortex Finder	10.7	414	2
PA, SA, & ID Fans	8.0	307	12
Generator Exciter/Relay	4.7	183	5
Boiler Water-wall Tubes	4.1	158	2
Miscellaneous	2.1	82	10
Totals	100	3862	38
Outage Duration	35.2%	3862	
Operating Availability	64.8%	7106	
Period Hours	100.0%	10968	

There are three causes for the high failure rate of the secondary superheater tubes. These include particle erosion, long term overheat, and short term overheat from flow restrictions. Each are discussed in more detail below.

1. The first of the superheater II failures occurred in October 1989 on the center-wall of combustion chamber B on the second superheater panel from the bottom. The initial leak occurred on the inside bottom radius of the lower tubes where the steam flow reverses direction and exits the boiler through the same path as the inlet tubes. Subsequent steam/ash washing resulted in additional superheater and water-wall tube failures. Damaged areas were removed from the boiler and were laid out for inspection as shown in Figure 16-22. The superheater tube bends are shown lying on top of a center water-wall panel section that was also damaged and removed. The water-wall tubes in the left of the photograph (with the 6 inch cut-out) are from an adjacent panel on the rear wall that was also damaged.

During a detailed inspection of the superheaters which followed this initial failure, erosion was discovered at other locations. Although the sites are localized and somewhat random, they seem to occur on the lower three panels in regions conducive to solids flow channeling. These sites include the vertical superheater tubes that form the wrap-around superheat panels (all other superheater tube runs are horizontal), the corners of the panels, and around the vertical water tube supports which hold the panels in place.

Erosion in these areas almost always takes place on tubes that project out into the downward solids flow path or force a

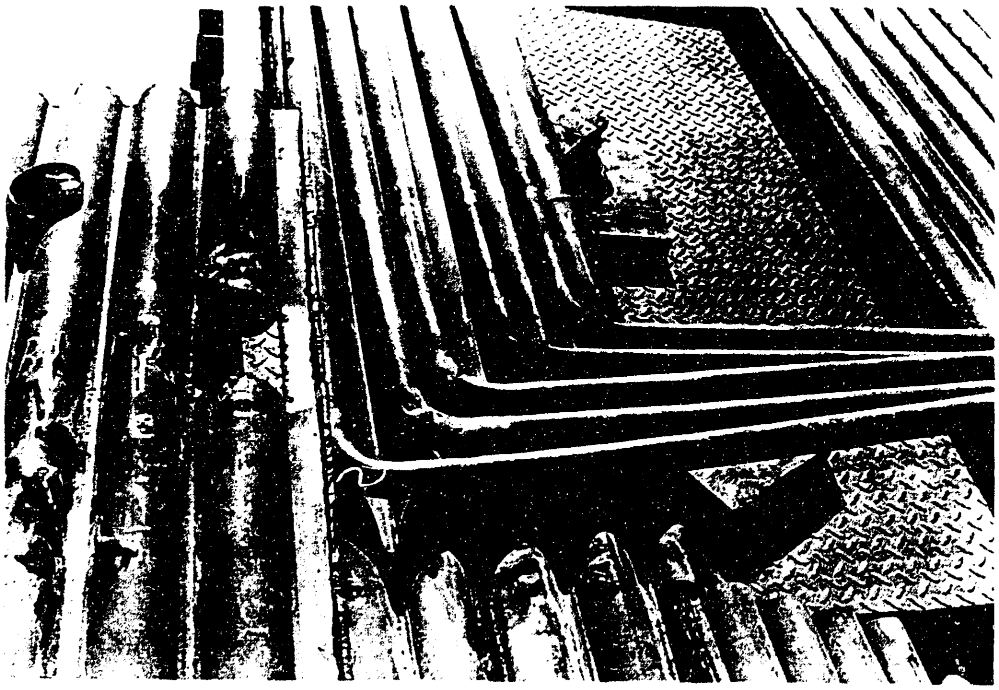


Figure 16-22. Superheater Tube Failures from Combustor B, Second Panel from Erosion on Inside Radius (October 1989 Outage).

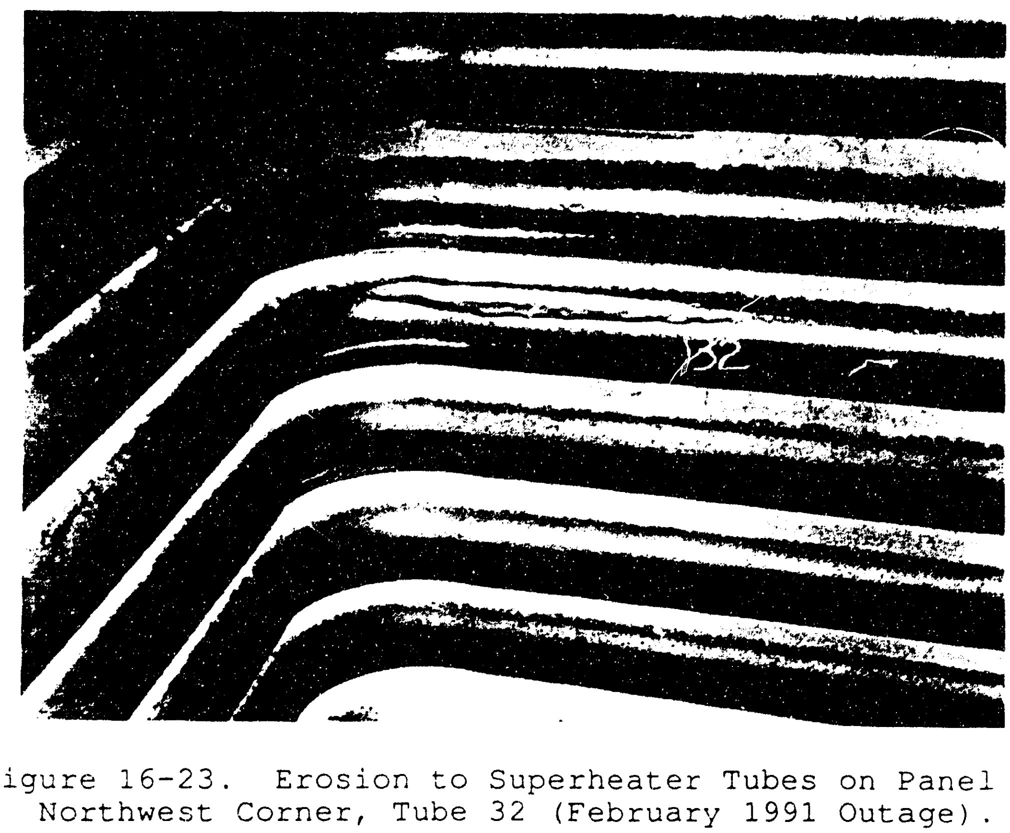


Figure 16-23. Erosion to Superheater Tubes on Panel 3, Northwest Corner, Tube 32 (February 1991 Outage).

directional change in solids flow, such as the failure described above. An example of corner erosion is shown in Figure 16-23 where tube number 32 projects slightly out of alignment into the combustion chamber. Similar erosion patterns can be found on some superheater tubes that are out of alignment along straight sections of panel. Erosion can also be found on superheater tubes immediately surrounding the water-wall tube supports and on the lower bends of the tube supports. These areas are marked in Figure 16-24. More alarming, erosion was discovered on the back-side of the superheater tubes and adjacent water-wall sections during the repair from the failure shown in Figure 16-22. These locations are impossible to see or measure during routine inspections and were only discovered in one area because of removal of a section of superheater II panel for repairs.

To address this problem, horizontal shelves were installed along the top tube of the second superheater panel and at locations directly above the water-wall tube support as shown in Figure 16-24. Shelves were not installed on any of the other three panels. The intent of these shelves is to break up and deflect the downward flow of solids back out into the combustion chamber. At the same time, this concept prevents solids from flowing behind the panel and eroding the backside of superheater tubes and adjacent water-wall tubes. Since October 1989, this shelf design has not held up well in this application and has suffered numerous failures. It is also difficult to evaluate the effectiveness of this design in reducing particle erosion. The fact that a good shelf design protects the top tubes on each panel and prevents solids from flowing behind the panel does seem to hold some merit.

Currently, the superheaters are inspected during periodic outages and any major erosion sites, such as that shown in Figure 16-23, are pad-welded during the outage. There have been no additional failures of superheater tubes from erosion damage since the October 1989 failure.

2. A series of five superheater tube failures occurred in February, May, July, and September of 1990 as the result of long-term overheat. This type of failure is shown in Figure 16-25, which is located in combustor A on the top tube of the first superheater panel near to where the tubes exit the combustion chamber and tie into the outlet header. Failures typically have occurred on the top tubes in each of the two lower panels. These tubes have a higher surface area exposure to boiler heat sources than other tubes in the panel and are also subjected to direct impingement from the downward flow of hot solids.

Sections of failed tubes were sent off to an outside testing laboratory for analysis. The conclusions from tests performed on these specimens were that the tubes had suffered from long-term overheat (creep damage) and that this was not related to

Figure 16-24. Secondary Superheater Shelf Arrangement and Erosion Locations Around Water-Tube Supports (February 1991 Outage).

Figure 16-25. Failed Superheater Tube on Combustor A in Southwest Corner, Panel 1.

the overheat incident in October 1987. Details from this report are contained in the 4th Quarterly Report for 1990 and in the 1990 Annual Report. Damaged outside tubes (tube nos. 1, 2, 63, and 64) on panel 1 in combustor A were removed and blanked-off following a series of failures in May, June, and September 1990.

To determine the root cause for overheat, thermocouples were mounted on select superheater tubes near the outlet header and the metal temperatures were measured during unit operation. The data indicated higher operating temperatures on the outside tubes compared to other locations. Metal temperatures as high as 1075 °F were recorded during full load operation. A series of attemperator spray flow tests were then performed to reduce this metal temperature to 1025 °F. To accomplish this, superheater II inlet spray flows were increased from 40 klb/hr to approximately 60 klb/hr. This lowered the final steam temperature to the turbine from 1000 °F to 960 °F, resulting in 2 percent increase in plant heat rate.

In this instance, an operational change was made to temporarily correct the problem with long-term overheat of superheater tubes. There have been no additional failures since the modification to the attemperator spray flow logic in early October 1990. Superheater tube failures of this sort typically require a two week outage for repairs. In several instances, the initial leak resulted in a cascade of additional water-wall and superheater tube failures to the surrounding areas. Water-wall tube leaks have also resulted in the agglomeration bed material. Removal of this hardened material is time consuming, particularly when bubble cap air holes become plugged.

The plant now regularly monitors process performance parameters to identify initial failures and prevent additional tube damage. Induced draft fan speed and inlet pressure, furnace temperatures and pressures, attemperator spray flows, and carbon monoxide emissions are among the variables monitored. In the event of a water-wall tube leak, which normally results in the sudden loss of drum level and a unit MFT, fans are slowly restarted to percolate air flow through the bed and prevent agglomeration. Bed material is then removed from the combustion chambers through the ash coolers.

3. Following a tube leak, air flow is slowly initiated through the bed and bed material is removed through the ash coolers. During this process, solids are suspended in the freeboard region of the combustion chambers and become ingested into the opening left by the tube leak(s). If undetected during repairs, this material causes flow blockages in water-wall and superheater tubes. These blockages result in tubes overheating from lack of an adequate cooling medium.

This phenomenon contributed to some of the later superheater tube failures in July and September 1990. It was also directly responsible for two water-wall tube failures during the same period in August 1990. In this instance, cemented bed material was found at various locations in the lower water-wall tube headers and inside the two failed tubes. To reduce the likelihood of solids ingestion into failed tubes, plant operations now waits until drum pressure has decreased to below 25 psig before restarting fans. At this time, a steam tie is opened from the auxiliary boiler to maintain a positive pressure at the rupture location. Following repairs and restart of the unit, boiler chemistry, including silica levels, are closely monitored. Since the water-wall failure in September 1990, there have been no further superheater or water-wall tube failures caused by flow restrictions.

16.4.6 Bottom Ash Coolers

There have been no major problems with the main ash cooler hardware other than infrequent losses of bubble caps. Minor problem areas are listed below.

1. The drains from the combustors leading to the ash coolers have occasionally blocked with refractory and with large pieces of bed material. To dislodge these, an air lance is inserted into a port near the bottom of the ash cooler and through the inlet drain. The auxiliary hardware for fluidizing these inlet drains have suffered from some blockage by bed material, erosion, and damage from the air lances (see Figure 16-26). In isolated instances while burning high ash coals, restrictions in these lines prevented removal of bed material from the combustors and forced unit outages. This is probably more of a design-related issue rather than a materials issue.

2. At the inlet and outlet of the ash coolers between the combustors, manual isolation gates were installed in the original design to allow for maintenance work during unit operation. In addition to becoming warped, the slides pack with bed material and have not been operational throughout the period of the test program.

16.4.7 Cyclone Refractory and Vortex Finders

The "gunned-on" hydro-bonded refractory used in the cyclones has not held up well over the first four years of unit operation. Two 6 inch layers of insulating and abrasion resistant refractory are used on all internal cyclone surfaces for a total thickness of 1 ft. This refractory was applied during construction after the cyclone shell and structural supports were in place. While the cyclone roofs and outlet ducts have held up well, the abrasion resistant layers on the inlet spirals, cyclone barrels, and conical sections of the

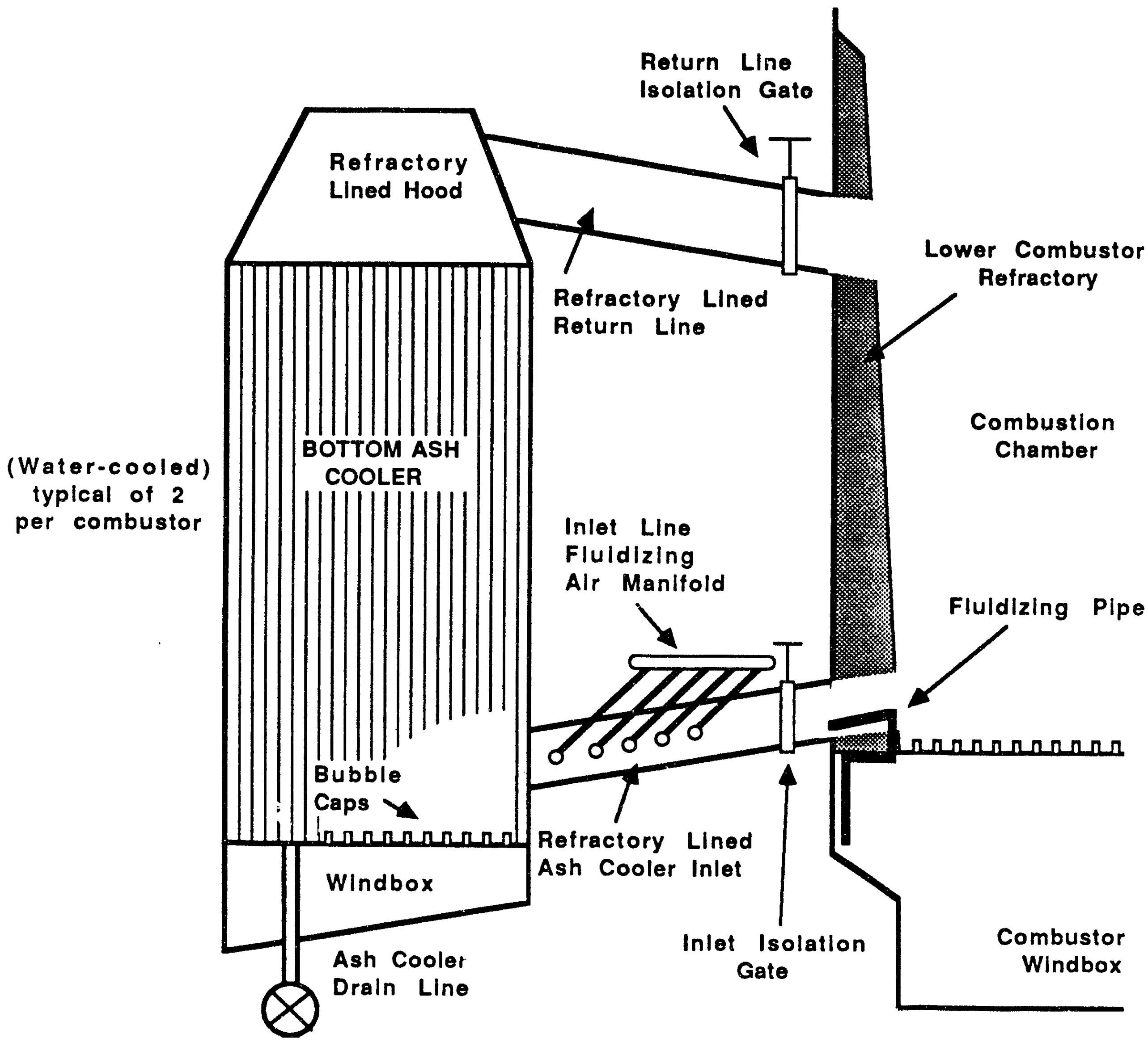


Figure 16-26. Bottom Ash Cooler Arrangement.

cyclones have suffered from spalling and breakage (see Figure 16-27 for locations).

Refractory loss in the cyclones is undesirable for two reasons. First, it can lead to hot spots on the outside shell if breakage and erosion progresses through the outside insulating layer. Second, loose refractory pieces accumulate in the loop seals located at the bottom of the cyclone downcomers. This accumulation can restrict recycle flow through the loop seals and force unit outages. Because of these occurrences, a major refractory repair outage was initiated in January 1989 after 5500 unit operating hours on coal. The outage duration was approximately 950 hours.

During this outage, the abrasion resistant layer was removed around the inlet spiral shelves, the inlet "bull noses", and the conical section of the cyclone. Modified refractory anchors were installed in certain regions and refractory "stops" were placed around the bull nose to reduce movement and breakage. Other than these design changes, refractory spalling and breakage during the first 5500 hours of service were attributed to poor installation. The primary cause cited was the excessive shrinkage of the abrasion layer due to high water content during installation. The latter resulted from low refractory mix temperatures which necessitated the addition of excess water to improve workability.

Following these repairs and 10,000 additional operating hours on coal, problems with "pinch" spalling and refractory breakage in the cyclones have reappeared. Repairs are periodically made to damaged areas using "blue ram" phosphate-bonded refractory. These areas are discussed in more detail below.

1. The inlet spiral shelves on both cyclones have been subjected to refractory breakage, primarily due to poor anchoring. The location of this shelf is shown in Figure 16-27. Major sections of the shelf were replaced with improved anchoring during the January 1989 repairs. This shelf continues to break and is repaired during unit outages using "blue ram" refractory

2. Large sections of the "bull nose" on both cyclones have broken away on repeated occasions. The location of the bull nose is shown in Figure 16-27 and the general condition during the outage inspection at the conclusion of the Phase II test program in February 1991 is shown in Figure 16-28. As the result of similar breakage after 5500 hours of service, refractory "stops" or plates were installed at two locations in the cyclone shown in Figure 16-27 and refractory was reapplied using new refractory anchors. This modification has not improved the performance of this section of the cyclone and periodic repairs are required during unit outages. It may be possible that cyclone movement, as opposed to refractory

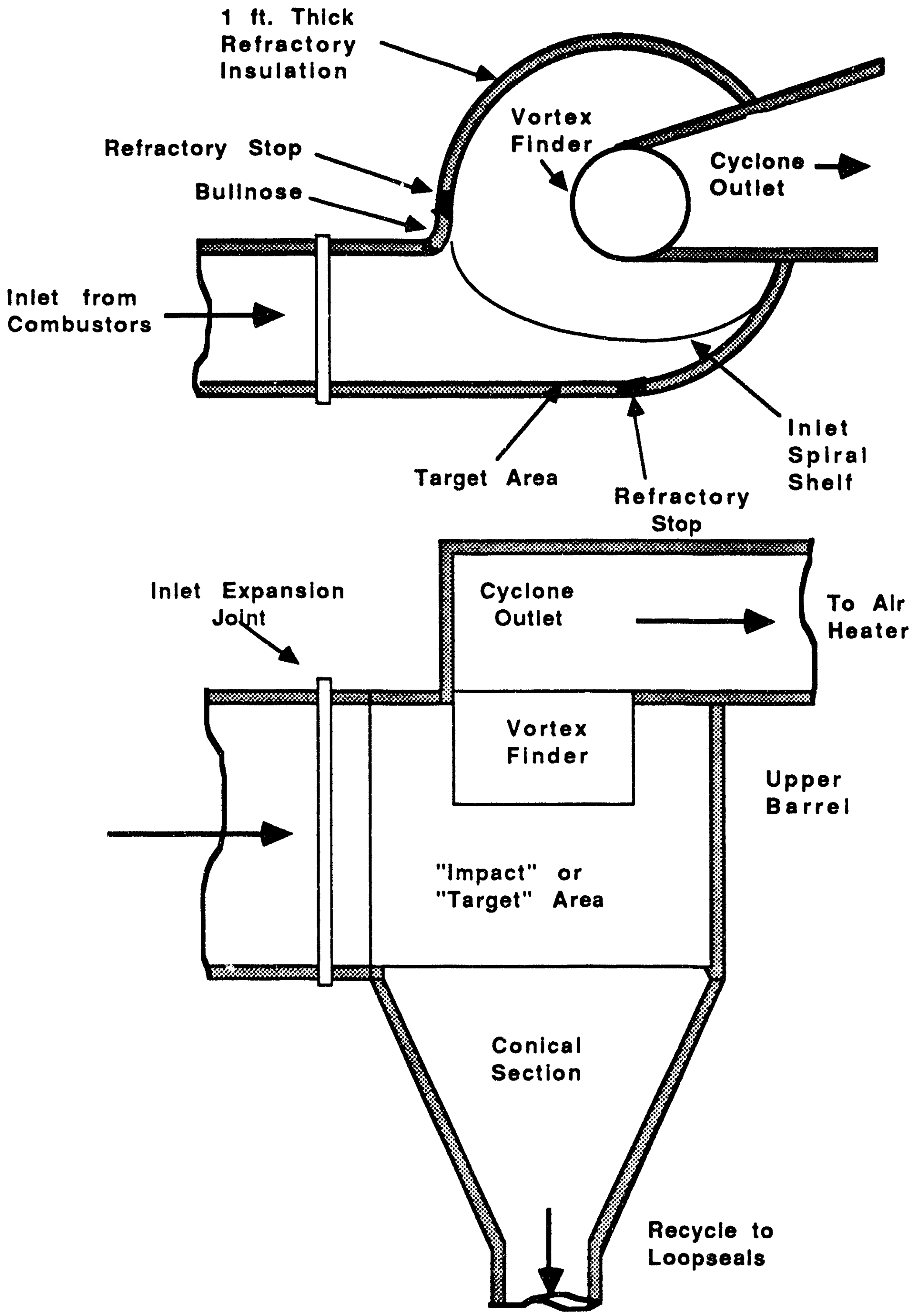


Figure 16-27. Schematic of Cyclone Arrangement (typical of two)

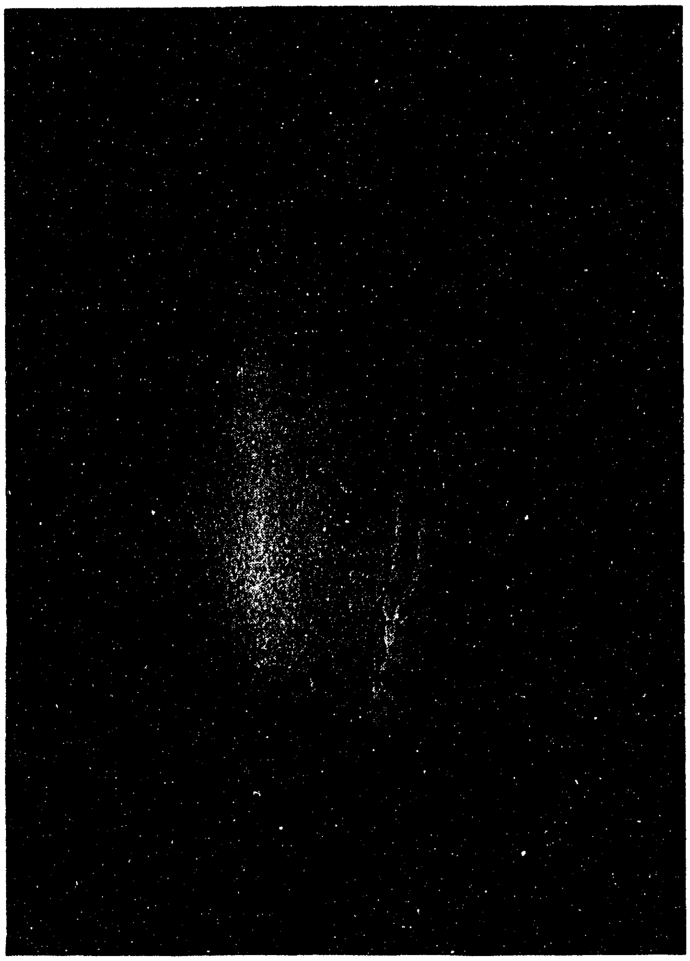


Figure 16-28. "Bullnose" Refractory Condition (February 1991 Outage).

Figure 16-29. Refractory Erosion at Impact Area on Cyclone B (February 1991 Outage).

expansion, is the cause for breakage in this area. The problem remains under investigation.

3. The "impact" or "target" area of the cyclones shown in Figure 16-27 shows significant particle erosion following 15,000 hours of service. The condition during the February 1991 outage is shown in Figure 16-29. In areas, the outer 6" abrasion resistant refractory layer has worn almost completely through and refractory anchors are exposed in several locations. The refractory shown in this photograph is the original gunnite abrasion resistant layer. Repairs to the most severe areas are periodically made during unit outages using blue ram refractory. The severity of this problem could probably be reduced using a harder abrasion resistant brick. The problem continues to be monitored by the plant.

4. The inlet expansion joint shown in Figure 16-27 is packed with a hard mineral wool insulation on the hot side. This material has suffered from particle erosion and has been replaced on two occasions during 15,000 hours of unit service. There have been no problems with the expansion joint on the outside casing.

5. The conical sections of the cyclones have suffered from repeated refractory spalling and breakage. This area has not faired as well as the upper barrel section of the cyclone, the cyclone roof, and the outlet ducts. This is probably due to the higher concentration of solids coupled with the effects of gravity, which forces solids down into openings. Much of the problem occurs at cold joints which are formed during installation at shift changes. These joints also provide some tolerance for expansion. During operation, solids work into these expanded joints and become trapped during cool-down and contraction. Through repetition of this process, solids become layered and packed in the joint as shown in Figure 16-30. Eventually, the strength of the compacted material exceeds the strength of the surrounding refractory. When this occurs, pieces of refractory break away around the crack, increasing the size of the opening. This phenomena is known as "pinch spalling". In this type of application and service, there is not much that can be done to prevent it from occurring. Brick applications also suffer from pinch spalling (an example is shown below), but the damaged area is usually confined to the surrounding bricks.

During the refractory repair outage in January 1989 following 5500 hours of service, the outer 6" abrasion resistant layer was completely replaced in the conical section of both cyclones. New refractory anchors were installed and improved quality control was applied during installation of the abrasion resistant layer. The latter included 1) careful control of the refractory mix water content, 2) square-edged cold joints were formed where necessary, 3) the application proceeded from bottom to top to reduce the amount of "rebound"

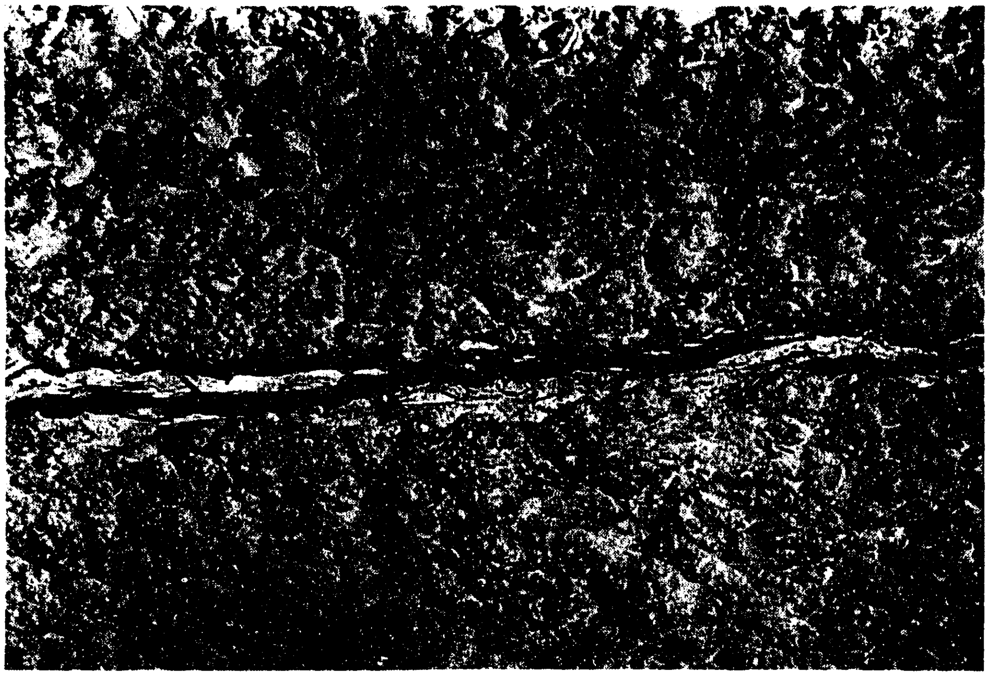


Figure 16-30. Example of Solids Layering at a Cold Joint.

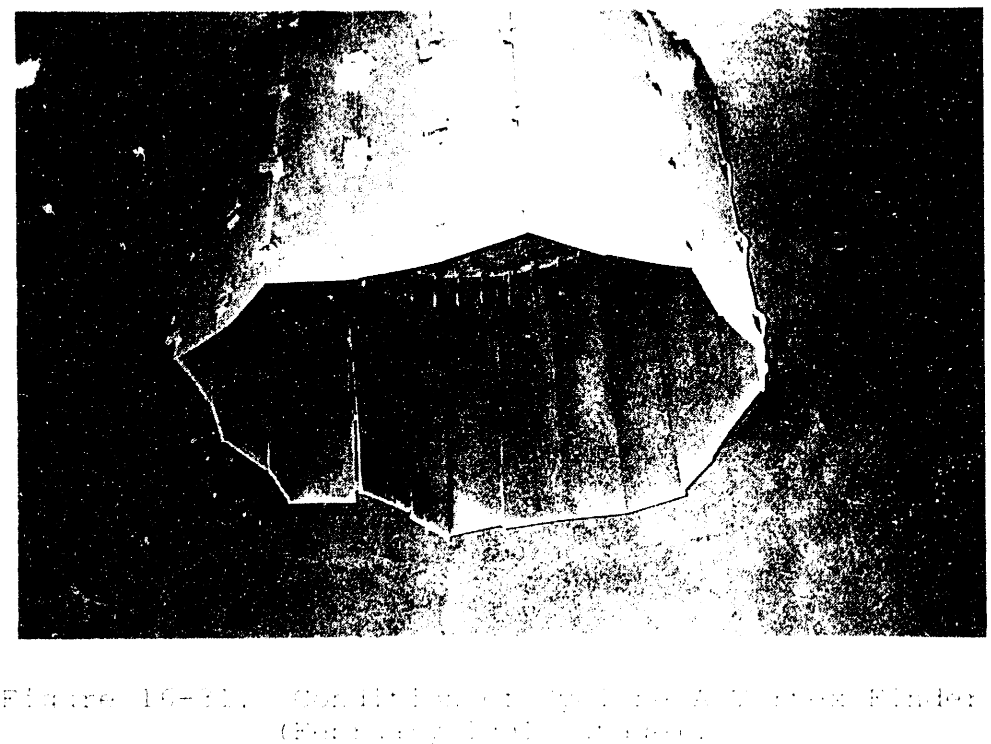


Figure 16-31. [illegible] Binder
([illegible]).

material contaminating the anchors. Rebound is an unwanted dry refractory material present in the gunning process.

These changes have not improved refractory performance in the conical sections of the cyclones. Refractory spalling and breakage at cold joints still occurs and accumulates in the recycle loop seals. The area is carefully inspected during all outages and requires periodic repairs with blue ram refractory. Frequent cold unit start-ups have been experienced at Nucla during the first four years of service. These are probably not conducive to refractory life in this type of application.

6. The cyclone vortex finders are situated at the cyclone outlets and are constructed from high alloy steel plates approximately 8 ft. in length (see location in Figure 16-27). These have distorted in service and plate sections were replaced during an outage in March 1990. Since this time, the vortex finders have continued to distort as shown in Figure 16-31, which is a photograph taken during the February 1991 outage. Solid construction of the vortex finders or a shorter plate length may correct this problem. Currently, the distortion is monitored and the problem remains under investigation.

16.4.8 Downcomer and Loop Seal Refractory

The loop seals represent a severe application for refractory due to the density of the high temperature recycled solids coupled with directional changes in flow. Prior to the refractory repair outage in January 1989, a hot spot developed on the outside shell of the loop seals in the vicinity of the archways (see Figure 16-32 for location). Stress cracks in the outside shell near the archways were also discovered at this time and were repaired.

The original archways were formed using an abrasion resistant gunnite layer which suffered severe breakage after 5500 hours of service (resulting in the hot spot). During the outage, the original refractory was removed and a combination of brick, castable refractory, and gunned-on refractory were reapplied. Figure 16-33 shows two layers of abrasion resistant and insulating refractory brick being applied in the cyclone loop seals. The archways were cast with a high density hydro-bonded abrasion resistant refractory. These modifications have held up well in the 10,000 hours of service since these repairs. As shown in Figure 16-34, pinch spalling still occurs at the brick joints, but is localized and confined to the area of the brick. Some breakage was apparent around the loop seal arches during the February 1991 inspection. These areas were repaired and will be inspected during future outages.

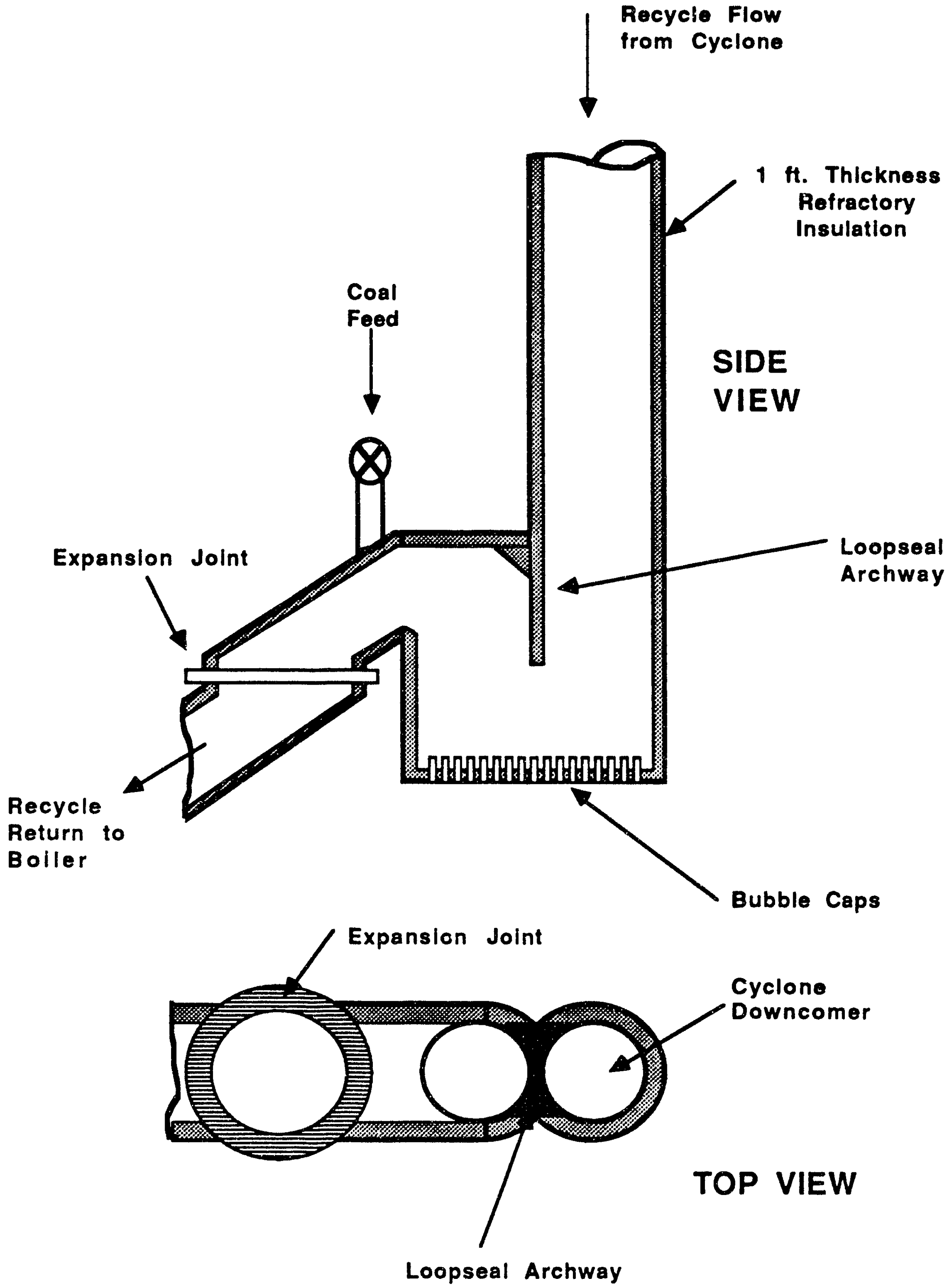


Figure 16-32. Schematic of Loopseal Arrangement.

Figure 16-33. Brick Reconstruction in Loop Seals (January 1989 Outage).

Figure 16-34. Pinch Spalling at Brick Joints in the Loop Seals.

During the first year of unit operation, the area directly below the coal feed point to each loop seal showed signs of erosion from falling coal particles. An area directly below the coal feed points was replaced at this time with a hard abrasion resistant brick. This has held up well in the following three years of unit service.

The expansion joints located in the loop seals (see Figure 16-32) were damaged during the overheat incident in October 1987 and were repaired. Sometime after this incident, the air space around the joints became packed with bed material. Based on visual observation of the inside of these joints, there does not appear to be movement between the upper and lower sections. The apparent inoperability of this joint remains under investigation.

Refractory in the downcomers connecting the lower cyclones to the loop seals was not in good condition during the inspection outage in February 1990. Refractory in this area represents the original gunned-on insulating and abrasion resistant layers. Damaged areas in the downcomers were repaired during the refractory outage in January 1989. This area is a good application for brick refractory since it is a confined area difficult to maneuver in when applying gunnite. The condition of the gunned-on refractory should be carefully monitored in the future and replaced at some point in a manner similar to that shown for the loop seals.

16.4.9 Backpass (Economizer and Superheaters)

There are no major materials-related problems to report with the economizer and superheater bundles, and the water-cooled superheater hanger tubes. There have been no signs of erosion or corrosion on these tubes following detailed tube thickness measurements after 5500 hours of service and periodic inspections since this time. The tube clips on the economizer and superheaters are functional and all components were generally in good condition as of the inspection in February 1991.

There is a significant ash build-up in the primary and final superheater bundles between adjacent vertical tubes. This ash build-up is soft and can be removed easily with a finger. Since soot blowers were provided on the economizer tubes and since the tube spacing is wider, there is no build-up in this area. Ports were provided for soot blowers on the superheater bundles in the original convection pass design. If final steam temperatures deteriorate in the future, the installation of soot blowers should be considered on the superheater tube bundles.

16.4.10 Tubular Air Heater

The back end of the tubular air heater has been inspected periodically during the course of the test program for corrosion. As of February 1991, there are no signs of corrosion or fouling in the final gas pass through the air heater and there are no other materials-related problems to report.

The tubular air heater has suffered from leakage of primary air into the secondary air paths during low loads. In April 1988, gaps between air heater sections that were left during construction were welded closed. Although this reduced the cross-leakage, the problem is still persistent at low loads. This remains under investigation and is more of a design problem than a materials-related problem.

Section 17

RELIABILITY MONITORING

The reliability monitoring plan for the Nucla CFB was conceived by the Electric Power Research Institute (EPRI) as a means of developing an equipment reliability database strictly for atmospheric fluidized bed combustion (AFBC) boilers. The intent was to complement and expand on the North American Electricity Reliability Council/Generation Availability Data System (NERC/GADS) database for fossil-fired units. The new database would accommodate plant equipment components and causes for failure unique to this new technology. The database could then be used for the following:

- Predicting the availability of future commercial AFBC plants
- Evaluating the reliability of proposed designs
- Assessing the impact of design changes on system reliability
- Evaluating life extension work on specific plant components
- Allocating research and development funds for reliability improvement

By tracking the frequency of equipment failures, the equipment run time between failures, and the time required for repair, it was intended to predict the mean time to failure (MTTF) and mean time to repair (MTTR) for specific AFBC plant equipment components. This quantitative information could then be used as a planning tool to satisfy the objectives outlined above.

Accomplishing this plan required three steps. First, uniform codes, established by EPRI, were given to plant equipment components on three utility AFBC's under construction or in start-up: Northern States Power's 125 MWe Black Dog Bubbling Bed AFBC, TVA's 160 MWe Bubbling Bed AFBC, and Colorado-Ute Electric Association's 110 MWe Nucla CFB. This would eventually allow direct comparisons to be made between these three plants. Second, the equipment codes, cause of failure codes, and time required for repair were added to the plant maintenance work request forms. This information could be manually or automatically collected into a database. Third, equipment component run times were collected by either the plant digital control system (DCS) or by a host computer using specially developed software.

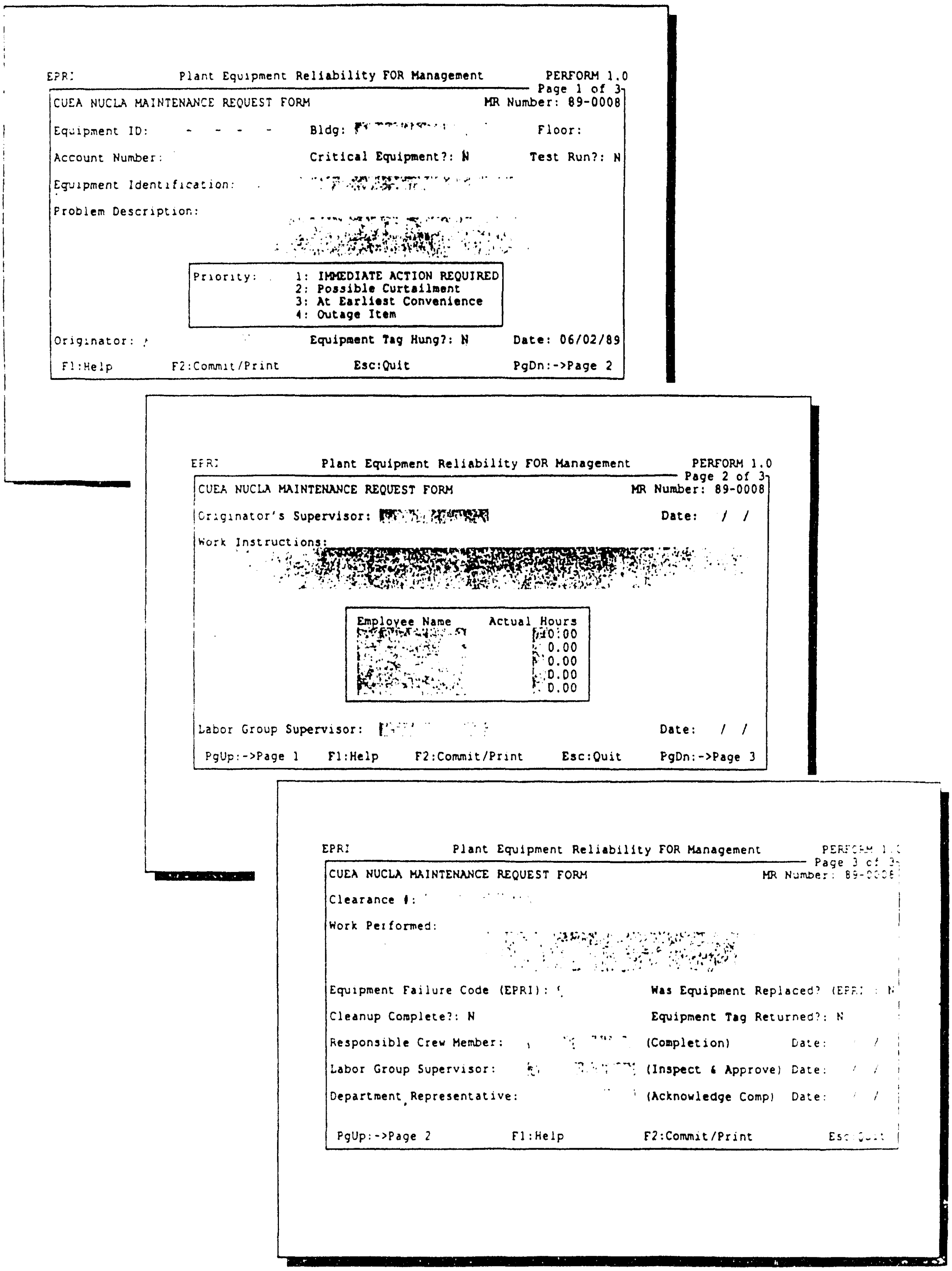
The first step was completed during the cold-mode shakedown period of the Demonstration Program at Nucla. Fifteen digit numbers were assigned to approximately 620 pieces of plant equipment to a level of detail consistent with that presented on the P&ID drawings. For example, the limestone feed system was broken down into transport blowers, transport piping, weigh system, rotary valves, bin shaker, isolation gate, shaker motor, vent system, etc. For identical equipment used on several systems (i.e., two limestone feed systems) each equipment component was given a unique equipment identification number. The same numbering scheme was used at the other demonstration plants.

To accomplish the second step at Nucla, a software program called PERFORM was developed by EPRI for generating hard copy maintenance work requests (MWR's). This program contains the uniform equipment codes assigned to each piece of plant hardware in step 1 (see Reliability Monitoring Database pages 17-5 through 17-13). As MWR's are generated by the plant, the cause and nature of the failure (if any), the work priority of the problem (1. Immediate Action Required, 2. Possible Curtailment, 3. At Earliest Convenience, 4. Outage Item), the hours required for repair, the date, and other information are automatically stored in a database. The software allows MWR's to be sorted by MR number, equipment ID number, and date. This software has been in use at the Nucla CFB since the fourth quarter of 1988 and remains the system by which the plant generates maintenance work requests. The three PERFORM software set-up sheets to be completed by the plant maintenance staff in order to generate an MWR are shown in Figure 17-1.

To complete the third step, software was developed to run on the Demonstration Program's DEC VAX computer which is tied directly into the plant's Westinghouse WDPF control system. Analog and digital information are recorded on the VAX via the WDPF for over 540 points. These data are used to accumulate run times for the 620 pieces of equipment identified as part of reliability monitoring.

At periodic intervals (i.e., once per month), data from the Perform software identified in step 2 were collected along with the run time data in step 3. These data were transferred on floppy disk to an off-site EPRI contractor for analysis and comparison with the other demonstration programs.

Due to difficulties outside of the work completed at the Nucla CFB, the program was cancelled in late 1989. As a result, collection of run time data as part of step 3 was terminated. However, the PERFORM software for generating



EPRI Plant Equipment Reliability FOR Management PERFORM 1.0
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CUEA NUCLA MAINTENANCE REQUEST FORM MR Number: 89-0008

Equipment ID: - - - - Bldg: Floor:
Account Number: Critical Equipment?: N Test Run?: N
Equipment Identification:
Problem Description:

Priority: 1: IMMEDIATE ACTION REQUIRED
2: Possible Curtailment
3: At Earliest Convenience
4: Outage Item

Originator: Equipment Tag Hung?: N Date: 06/02/89
F1:Help F2:Commit/Print Esc:Quit PgDn:->Page 2

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CUEA NUCLA MAINTENANCE REQUEST FORM MR Number: 89-0008

Originator's Supervisor: Date: / /
Work Instructions:

Employee Name	Actual Hours
	0.00
	0.00
	0.00
	0.00
	0.00

Labor Group Supervisor: Date: / /
PgUp:->Page 1 F1:Help F2:Commit/Print Esc:Quit PgDn:->Page 3

EPRI Plant Equipment Reliability FOR Management PERFORM 1.0
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CUEA NUCLA MAINTENANCE REQUEST FORM MR Number: 89-0008

Clearance #:
Work Performed:

Equipment Failure Code (EPRI): Was Equipment Replaced? (EPRI): N
Cleanup Complete?: N Equipment Tag Returned?: N
Responsible Crew Member: (Completion) Date: /
Labor Group Supervisor: (Inspect & Approve) Date: / /
Department Representative: (Acknowledge Comp) Date: / /
PgUp:->Page 2 F1:Help F2:Commit/Print Esc:Quit

Figure 17-1. PERFORM Reliability Monitoring Set-up Sheets Required for Generating MWR's.

maintenance work requests remains in use at Nucla and a substantial database is being generated. Although it will not be possible to calculate mean time to failure and repair for specific equipment components for comparisons to other plants, the frequency of failures for each equipment component at Nucla can be tracked. This will allow the following type of analyses to be performed:

1. Relative comparisons can be made between plant equipment areas. Equipment with the highest failure rates and/or maintenance requirements can be identified.

2. The effect of equipment upgrades on overall plant and component reliability can be assessed by comparing quarterly or annual "frequency of failure" charts and plant operating data.

3. Data can be used as a planning tool for maintenance outages. Equipment areas with the highest frequency of maintenance repair can be identified.

4. Prospective owners and designers of a plant can use the database as a means of selecting equipment components which provide a high level of overall equipment reliability and availability.

The 1989 annual report contains information on the frequency of failure for the coal and limestone feed systems for the period between September 1988 and September 1989. These data are not totally representative of normal plant operation because the information was collected before the completion of unit acceptance tests. During this period, a portion of the repair work was performed by the boiler vendor outside of normal plant maintenance work request system. A more reliable database will be generated for the 3 to 5 year period subsequent to the acceptance tests completed in October 1989.

RELIABILITY MONITORING DATABASE - 1

CUEA No.			EPRI No.			Description	TAG No.
002409001494001	C4		02147010	03	01	SERVICE WATER PIPING	CLT62
002409001001001	C4		02147010	01	01	SERVICE WATER SYSTEM MISC	CLT62
002409001601001	C5					SERVICE WATER VALVES, MISC	CLT62
002413001001001	C4		02146010	06	01	INST AIR SYS PIPES AND VLVS	CPT50
002413001560001	C4	2	02146010	04	01	INSTR AIR RECEIVER TANKS	CPT50
002413001601001	C4		02146010	05	01	INSTR AIR SAFETY VALVES	CPT50
002613001001001	C3		02146002	01	01	INSTRUMENT AIR SYSTEM	CPT50
002413001222001	C4		02146010	01	01	INSTR AIR COMPRESSOR 4A	CZS1
002413001851001	C4		02146010	01	01	INSTR AIR COMPRESSOR 4A MOTOR	CZS1
002413001183001	C4		02146010	02	01	INSTR AIR COMPRESSOR AFTER COOLER	CZS1
002413501222001	C4		02146010	03	01	SERVICE AIR COMPRESSOR 4A	CZS2
002413501851001	C4		02146010	03	01	SERVICE AIR COMPRESSOR 4A MOTOR	CZS2
002413501222003	C4		02146010	03	03	SERVICE AIR COMPRESSOR STANDBY	CZS2,3,51
002413501850001	C4		02146010	03	01	SERVICE AIR COMPRESSOR STANDBY MTR	CZS2,3,51
002413501560001	C4	2	02146010	04	01	SERVICE AIR RECEIVER TANKS	CZS2,3,51
002413501601001	C4		02146010	05	01	SERVICE AIR SAFETY VALVES	CZS2,3,51
002413501001001	C4		02146010	06	01	SERVICE AIR SYS PIPES AND VLVS	CZS2,3,51
002413501222002	C4		02146010	03	02	SERVICE AIR COMPRESSOR 4B	CZS3
002413501851002	C4		02146010	03	02	SERVICE AIR COMPRESSOR 4B MOTOR	CZS3
002413501850002	C4		02146010	03	01	SERVICE AIR COMPRESSOR EMERG MTR	CZS51
002413501222004	C4		02146010	03	04	SERVICE AIR COMPRESSOR EMERGENCY	CZS51
002601501001001	C		02141611	01	01	BOILER STEAM DRUM, MISC	DPT1
002601501001002	N		02141611	03	01	BOILER STM DRUM, INTERNALS	DPT1
002601501587001	C	3	02141611	02	01	BOILER STM DRUM, SAFETY VALVES	DPT1
002601503545001	C		02141409	03	01	BOILER WATER COOLED HANGER RODS	DPT1
002601511545001	C		02141409	01	01	BOILER WATER WALL 4A TUBES	DPT1
002601511545002	C		02141409	01	02	BOILER WATER WALL 4B TUBES	DPT1
002601511545003	C2		02141409	02	01	BOILER WTR WALL 4A HNGR TUBES	DPT1
002601511545004	C2		02141409	02	02	BOILER WTR WALL 4B HNGR TUBES	DPT1
002601503001001	C		02141407	01	01	ECONOMIZER TUBES, CONV. PASS	DPT1
002601502545002	C		02141405	05	01	SUPERHEAT 4A TBS,SEC,RAD.FRBD	DPT1
002601502545003	C		02141405	05	02	SUPERHEAT 4B TBS,SEC,RAD.FRBD	DPT1
002601502587001	C	1	02141211	01	01	SUPERHEAT SAFETY VALVES	DPT1
002601502545004	C		02141404	01	01	SUPERHEAT TUBES,FNSHG,CON.PASS	DPT1
002601502545001	C		02141406	01	01	SUPERHEAT TUBES,PRI,CONV.PASS	DPT1
002602002290001	C3		02143401	01	02	FEEDWATER HTR 4D, HIGH PRESS	EPT3
002602002290002	C3		02143401	01	01	FEEDWATER HTR 4E, HIGH PRESS	EPT3
002602001494001	C4		02143610	01	01	FEEDWATER PIPING	EPT3
002602001579002	C		02143213	02	01	FEEDWATER REG VALVE-STARTUP 3"	EPT3
002602001579001	C		02143213	01	01	FEEDWATER REGULATOR VLV - 8"	EPT3
002601508709004	C2		02143243	02	04	ATTEMPERATOR 4D, FLOW ELEMENT	ETCV10
002601508001004	C		02143243	01	04	ATTEMPERATOR 4D, MISC	ETCV10
002601508582004	C2		02143243	03	04	ATTEMPERATOR 4D, SPRAY VALVE	ETCV10
002601508709001	C2		02143243	02	01	ATTEMPERATOR 4A, FLOW ELEMENT	ETCV7
002601508001001	C		02143243	01	01	ATTEMPERATOR 4A, MISC	ETCV7
002601508582001	C2		02143243	03	01	ATTEMPERATOR 4A, SPRAY VALVE	ETCV7
002601508709002	C2		02143243	02	02	ATTEMPERATOR 4B, FLOW ELEMENT	ETCV8
002601508001002	C		02143243	01	02	ATTEMPERATOR 4B, MISC	ETCV8
002601508582002	C2		02143243	03	02	ATTEMPERATOR 4B, SPRAY VALVE	ETCV8
002601508709003	C2		02143243	02	03	ATTEMPERATOR 4C, FLOW ELEMENT	ETCV9
002601508001003	C		02143243	01	03	ATTEMPERATOR 4C, MISC	ETCV9
002601508582003	C2		02143243	03	03	ATTEMPERATOR 4C, SPRAY VALVE	ETCV9
002602001852002	C		02143104	04	02	BOILER FEED PUMP 4B MOTOR	EZS1
002602001500002	C		02143104	01	02	BOILER FEED PUMP 4B, MISC	EZS1
002602001001001	C		02143050	01	01	FEEDWATER SYSTEM INSTR.& CNTRL	EZS1,2
002602001852001	C		02143104	04	01	BOILER FEED PUMP 4A MOTOR	EZS2
002602001500001	C		02143104	01	01	BOILER FEED PUMP 4A, MISC	EZS2
002601514494001	C4		02144010	03	01	PROPANE FUEL PIPING	GASFLOW
002601514001001	C4		02144010	01	01	PROPANE FUEL SYS - MISC	GASFLOW
002601514601001	C4		02144010	04	01	PROPANE FUEL VALVES	GASFLOW
002601503705001	C		02140056	01	03	GAS ANALYZER-O2, ECON IN EAST	GAT9A
002601503705002	C		02140056	01	04	GAS ANALYZER-O2, ECON IN WEST	GAT9B
002605509130001	C2		02141503	03	01	BAGHOUSE BAL DFT DMPR (OLD/#4)	GMT20
002604506710001	C2		02145401	07	01	BTM ASH CLR 4A INLET AERATION	GPT4
002604506710002	C2		02145401	07	02	BTM ASH CLR 4B INLET AERATION	GPT4
002604506710003	C2		02145401	07	03	BTM ASH CLR 4C INLET AERATION	GPT4
002604506710004	C2		02145401	07	04	BTM ASH CLR 4D INLET AERATION	GPT4
002601516181001	C2		02149201	02	01	RECYCLE LOOP SEAL 4A AIR NZLS	GPT4
002601516001001	C		02149201	05	01	RECYCLE LOOP SEAL 4A FLUID SYS	GPT4
002601516181002	C2		02149201	02	02	RECYCLE LOOP SEAL 4B AIR NZLS	GPT4

RELIABILITY MONITORING DATABASE - 2

CUEA No.	EPRI No.	Description	TAG No.
002601516001002 C	02149201 05	02 RECYCLE LOOP SEAL 4B FLUID SYS	GPT4
002603509266001 C4	02141610 01	01 BOILER DUCT - PRIMARY AIR	GWM325
002601510181001 N	02141620 03	01 DISTR PLATE 4A AIR NOZZLES	GWM325
002601510181002 N	02141620 03	02 DISTR PLATE 4B AIR NOZZLES	GWM325
002601510263001 N	02141620 01	01 DISTRIBUTOR PLATE 4A, MISC	GWM325
002601510263002 N	02141620 01	02 DISTRIBUTOR PLATE 4B, MISC	GWM325
002603509709001 C2	02141621 01	01 PA 4A AIR FOIL, 4A	GWM325
002603509709002 C2	02141621 01	02 PA 4A AIR FOIL, 4B	GWM325
002603509228001 C2	02141622 02	01 PA 4A DAMPER AUTO CONTRLR, 4A	GWM325
002603509228002 C2	02141622 02	02 PA 4A DAMPER AUTO CONTRLR, 4B	GWM325
002603509130001 C2	02141622 01	01 PA 4A DAMPER, 4A	GWM325
002603509130002 C2	02141622 01	02 PA 4A DAMPER, 4B	GWM325
002603509250001 C	02141140 02	01 PA 4A FAN COUPLING	GWM325
002603509516001 C	02141140 04	01 PA 4A FAN DC REACTOR, 4A	GWM325
002603509516002 C	02141140 04	02 PA 4A FAN DC REACTOR, 4B	GWM325
002603509860001 C	02141140 07	01 PA 4A FAN ISOLATION TRANSFORMR	GWM325
002603509562001 C	02141140 09	01 PA 4A FAN LUBE OIL CONSOLE	GWM325
002603509852001 C	02141140 11	01 PA 4A FAN MOTOR	GWM325
002606531228004 C	02141140 13	01 PA 4A FAN VARI SD DR CNTR-STRT	GWM325
002606531228003 C	02141140 12	01 PA 4A FAN VARI SPD DR CNTR-RUN	GWM325
002603509340001 C	02141140 01	01 PA 4A FAN, MISC	GWM325
002603007290001 C	02141404 01	01 AIR PREHEATER - TUBULAR	GWM327
002408509228001 C	02140003 01	01 BOILER AIR FLOW/DRAFT CONTRL	GWM327
002603001266001 C4	2141615 01	01 BOILER DUCT - FLUE GAS	GWM327
002408509228003 N	02140005 01	01 COMBUSTION CONTROL	GWM327
002603001250001 C	02141102 02	01 ID FAN 4A COUPLING	GWM327
002603001516001 C	02141102 04	01 ID FAN 4A DC REACTOR, 4A	GWM327
002603001516002 C	02141102 04	01 ID FAN 4A DC REACTOR, 4B	GWM327
002603001860001 C	02141102 07	01 ID FAN 4A ISOLATION TRANSFORMR	GWM327
002603001560001 C	02141102 08	01 ID FAN 4A LUBE OIL CONSOLE	GWM327
002603001560002 C	02141102 10	01 ID FAN 4A LUBE OIL PUMP	GWM327
002603001852001 C	02141102 11	01 ID FAN 4A MOTOR	GWM327
002606531228002 C	02141102 13	01 ID FAN 4A VARI SD DR CNTR-STRT	GWM327
002606531228001 C	02141102 12	01 ID FAN 4A VARI SPD DR CNTR-RUN	GWM327
002603001341001 C	02141102 01	01 ID FAN 4A, MISC	GWM327
002603004001 01 C2	02141613 01	01 STACK	GWM327
002603511266001 C4	02141610 02	01 BOILER DUCT - SECONDARY AIR	GZS2
002603511709001 C2	02141623 01	01 SA 4A AIR FOIL 4A	GZS2
002603511709002 C2	02141624 01	02 SA 4A AIR FOIL 4B	GZS2
002603511228001 C2	02141624 02	01 SA 4A DAMPER AUTO, 4A	GZS2
002603511228002 C2	02141624 02	02 SA 4A DAMPER AUTO, 4B	GZS2
002603511130001 C2	02141624 01	01 SA 4A DAMPER, 4A	GZS2
002603511130002 C2	02141624 01	02 SA 4A DAMPER, 4B	GZS2
002606504228006 C	02141141 14	01 SA 4A FAN BACKUP STARTER	GZS2
002603511250001 C	02141141 02	01 SA 4A FAN COUPLING	GZS2
002603511516001 C	02141141 04	01 SA 4A FAN DC REACTOR	GZS2
002603511860001 C	02141141 07	01 SA 4A FAN ISOLATION TRANSFORMR	GZS2
002603511852001 C	02141141 11	01 SA 4A FAN MOTOR	GZS2
002606531228005 C	02141141 12	01 SA 4A FAN VARI SPD DR CONTR	GZS2
002603511341001 C	02141141 01	01 SA 4A FAN, MISC	GZS2
002601516341001 C	02149127 01	01 RECYCLE HP FLUID BLOWER 4A	GZS4A
002601516851001 C	02149127 03	01 RECYCLE HP FLUID BLOWER 4A MTR	GZS4A
002601516250001 C	02149127 02	01 RECYCLE HP FLUID BLWR 4A CPLNG	GZS4A
002601516341002 C	02149127 01	02 RECYCLE HP FLUID BLOWER 4B	GZS4B
002601516851002 C	02149127 03	02 RECYCLE HP FLUID BLOWER 4B MTR	GZS4B
002601516250002 C	02149127 02	02 RECYCLE HP FLUID BLWR 4B CPLNG	GZS4B
002604506130002 C2	02145401 02	02 BOM ASH CLR 4B AIR CNTRL DMPR	GZS5
002604506263001 C2	02145401 05	01 BOTTOM ASH CLR 4A DISTR PLATE	GZS5
002604506263002 C2	02145401 05	02 BOTTOM ASH CLR 4B DISTR PLATE	GZS5
002604506263003 C2	02145401 05	03 BOTTOM ASH CLR 4C DISTR PLATE	GZS5
002604506263004 C2	02145401 05	04 BOTTOM ASH CLR 4D DISTR PLATE	GZS5
002604506181001 C2	02145401 04	01 BOTTOM ASH COOLER 4A AIR NZL	GZS5
002604506264001 C2	02145401 06	01 BOTTOM ASH COOLER 4A DRAIN	GZS5
002604506181002 C2	02145401 04	02 BOTTOM ASH COOLER 4B AIR NZL	GZS5
002604506264002 C2	02145401 06	02 BOTTOM ASH COOLER 4B DRAIN	GZS5
002604506181003 C2	02145401 04	03 BOTTOM ASH COOLER 4C AIR NZL	GZS5
002604506264003 C2	02145401 06	03 BOTTOM ASH COOLER 4C DRAIN	GZS5
002604506181004 C2	02145401 04	04 BOTTOM ASH COOLER 4D AIR NZL	GZS5
002604506264004 C2	02145401 06	04 BOTTOM ASH COOLER 4D DRAIN	GZS5
002604506341001 C	02145101 01	01 BOTTOM ASH COOLING FAN	GZS5

RELIABILITY MONITORING DATABASE - 3

CUEA No.			EPRI No.			Description	TAG No.
002504506250001	C		02145101	01	02	BOTTOM ASH COOLING FAN CPLNG	GZS5
002604506851001	C		02145101	01	03	BOTTOM ASH COOLING FAN MOTOR	GZS5
002604501351001	C		02145665	01	01	BOTTOM ASH ROTARY AIR LOCK 4A	GZS5
002604501351002	C		02145665	01	02	BOTTOM ASH ROTARY AIR LOCK 4B	GZS5
002604501351003	C		02145665	01	03	BOTTOM ASH ROTARY AIR LOCK 4C	GZS5
002604501351004	C		02145665	01	04	BOTTOM ASH ROTARY AIR LOCK 4D	GZS5
002604506130001	C2		02145401	02	01	BTM ASH CLR 4A AIR CNTRL DMPR	GZS5
002604506709001	C2		02145401	03	01	BTM ASH CLR 4A AIR FLOW SNSR	GZS5
002604506709002	C2		02145401	03	02	BTM ASH CLR 4A AIR FLOW SNSR	GZS5
002604506130003	C2		02145401	02	03	BTM ASH CLR 4C AIR CNTRL DMPR	GZS5
002604506709003	C2		02145401	03	03	BTM ASH CLR 4C AIR FLOW SNSR	GZS5
002604506130004	C2		02145401	02	04	BTM ASH CLR 4D AIR CNTRL DMPR	GZS5
002604506709004	C2		02145401	03	04	BTM ASH CLR 4D AIR FLOW SNSR	GZS5
002604506374001	C		02145401	09	01	BTM ASH COOLER 4A SLIDE GATE	GZS5
002604506251001	N		02145401	01	01	BTM ASH COOLER 4A, MISC	GZS5
002604506374002	C		02145401	09	02	BTM ASH COOLER 4B SLIDE GATE	GZS5
002604506251002	N		02145401	01	02	BTM ASH COOLER 4B, MISC	GZS5
002604506374003	C		02145401	09	03	BTM ASH COOLER 4C SLIDE GATE	GZS5
002604506251003	N		02145401	01	03	BTM ASH COOLER 4C, MISC	GZS5
002604506374004	C		02145401	09	04	BTM ASH COOLER 4D SLIDE GATE	GZS5
002604506251004	N		02145401	01	04	BTM ASH COOLER 4D, MISC	GZS5
002604506378001	C2		02145661	02	01	BTM ASH HPR 4A COLD DIV GATE	GZS5
002604506378003	C2		02145661	03	01	BTM ASH HPR 4A HOT DIV GATE	GZS5
002604506378002	C2		02145661	02	02	BTM ASH HPR 4B COLD DIV GATE	GZS5
002604506378004	C2		02145661	03	02	BTM ASH HPR 4B HOT DIV GATE	GZS5
002604505850001	C		02145665	02	01	BTM ASH ROTARY AIR LCK 4A MTR	GZS5
002604505850002	C		02145665	02	02	BTM ASH ROTARY AIR LCK 4B MTR	GZS5
002604505850003	C		02145665	02	03	BTM ASH ROTARY AIR LCK 4C MTR	GZS5
002604505850004	C		02145665	02	04	BTM ASH ROTARY AIR LCK 4D MTR	GZS5
002602502290001	C3		02143402	01	02	FEEDWATER HTR 4A, LOW PRESS	HFT3
002602502290002	C3		02143402	01	01	FEEDWATER HTR 4B, LOW PRESS	HFT3
002602503290001	C3		02143410	01	04	DEAERATOR, (HEATER 4C) UNIT 4	HLT3
002602501001001	C3		02148410	01	02	CONDENSER, UNIT 4	HPT72
002602501510001	C3		02143110	01	07	HOTWELL PUMP 4A	HZS1
002602501850001	C3		02143110	02	07	HOTWELL PUMP 4A MOTOR	HZS1
002602501510002	C3		02143110	01	08	HOTWELL PUMP 4B	HZS2
002602501850002	C3		02143110	02	08	HOTWELL PUMP 4B MOTOR	HZS2
002614501001001	C3		02140648	01	01	AUX STM(#s 002614501xxxxxxx)	JPT1
002602501397001	C3		02148410	02	04	CONDENSER #4 HTWLL (DRN RCVR)	KPT2
002602002495001	C4	2	02143401	02	01	FEEDWATER HTR, HP-EXTR PPING	KPT2
002602502495001	C4	8	01243402	02	01	FEEDWATER HTR, LP EXTR PPING	KPT2
002600104598001	C		02142329	26	04	TURBINE CONTROL VALVES, UNIT 4	KPT2
002900106495001	C4		02142329	36	04	TURBINE EXT PIPING, UNIT 4	KPT2
002600106581001	N		02142329	28	04	TURBINE EXTRACT VLVS, UNIT 4	KPT2
002600100001001	C2		02142329	01	04	TURBINE, MISC UNIT 4	KPT2
002701001001001	C3		02142330	03	01	GENERATOR EXCITER, UNIT 1	LMW1
002700500001001	C		02142330	01	01	GENERATOR UNIT 1, MISC	LMW1
002606501001001	C4		02142710	01	01	TRANSFORMER, UNIT 1 GENERATOR	LMW1
002801001001001	C3		02142330	03	02	GENERATOR EXCITER, UNIT 2	LMW2
002800500001002	C		02142330	01	02	GENERATOR UNIT 2, MISC	LMW2
002706501001001	C4		02142710	01	02	TRANSFORMER, UNIT 2 GENERATOR	LMW2
002901001001001	C3		02142330	03	03	GENERATOR EXCITER, UNIT 3	LMW3
002900500001003	C		02142330	01	03	GENERATOR UNIT 3, MISC	LMW3
002806501001001	C4		02142710	01	03	TRANSFORMER, UNIT 3 GENERATOR	LMW3
002702501397001	C3		02148410	02	01	CONDENSER #1 HTWLL (DRN RCVR)	LPT64
002700104598001	C		02142329	26	01	TURBINE CONTROL VALVES, UNIT 1	LPT64
002600106495001	C4		02142329	36	01	TURBINE EXT PIPING, UNIT 1	LPT64
002700106581001	C		02142329	28	01	TURBINE EXTRACT VLVS, UNIT 1	LPT64
002700100001001	C2		02142329	01	01	TURBINE, MISC UNIT 1	LPT64
002802501397001	C3		02148410	02	02	CONDENSER #2 HTWLL (DRN RCVR)	LPT65
002800104598001	C		02142329	26	02	TURBINE CONTROL VALVES, UNIT 2	LPT65
002700106495001	C4		02142329	36	02	TURBINE EXT PIPING, UNIT 2	LPT65
002800106581001	N		02142329	28	02	TURBINE EXTRACT VLVS, UNIT 2	LPT65
002800100001001	C2		02142329	01	02	TURBINE, MISC UNIT 2	LPT65
002902501397001	C3		02148410	02	03	CONDENSER #3 HTWLL (DRN RCVR)	LPT66
002900104598001	C		02142329	26	03	TURBINE CONTROL VALVES, UNIT 3	LPT66
002800106495001	C4		02142329	36	03	TURBINE EXT PIPING, UNIT 3	LPT66
002900106581001	N		02142329	28	03	TURBINE EXTRACT VLVS, UNIT 3	LPT66
002900100001001	C2		02142329	01	03	TURBINE, MISC UNIT 3	LPT66
002702502290001	C3		02143402	01	08	FEEDWATER HTR 1A, LOW PRESS	NFT105

CUEA No.	EPRI No.	Description	TAG No.
002702502290002 C3	02143402 01	07 FEEDWATER HTR 1B, LOW PRESS	NFT105
002802502290001 C3	02143402 01	06 FEEDWATER HTR 2A, LOW PRESS	NFT106
002802502290002 C3	02143402 01	05 FEEDWATER HTR 2B, LOW PRESS	NFT106
002902502290001 C3	02143402 01	04 FEEDWATER HTR 3A, LOW PRESS	NFT107
002902502290002 C3	02143402 01	03 FEEDWATER HTR 3B, LOW PRESS	NFT107
002702503290001 C3	02143410 01	01 DEAERATOR, (HEATER 1C) UNIT 1	NLT58
002802503290001 C3	02143410 01	02 DEAERATOR, (HEATER 2C) UNIT 2	NLT63
002902503290001 C3	02143410 01	03 DEAERATOR, (HEATER 3C) UNIT 3	NLT68
002702501001001		UNIT 1 CONDENSER	NPT108
002802501001001		UNIT 2 CONDENSER	NPT109
002902501001001		UNIT 3 CONDENSER	NPT110
002702501510001 C3	02143110 01	01 HOTWELL PUMP 1A	NZS11
002702501850001 C3	02143110 02	01 HOTWELL PUMP 1A MOTOR	NZS11
002702501510002 C3	02143110 01	02 HOTWELL PUMP 1B	NZS12
002702501850002 C3	02143110 02	02 HOTWELL PUMP 1B MOTOR	NZS12
002702503850001 C3	02143120 02	01 CONDENSATE FORW PUMP 1A MTR	NZS13
002702503500001 C3	02143120 01	01 CONDENSATE FORW PUMP 1A, MISC	NZS13
002802501510001 C3	02143110 01	03 HOTWELL PUMP 2A	NZS21
002802501850001 C3	02143110 02	03 HOTWELL PUMP 2A MOTOR	NZS21
002802501510002 C3	02143110 01	04 HOTWELL PUMP 2B	NZS22
002802501850002 C3	02143110 02	04 HOTWELL PUMP 2B MOTOR	NZS22
002802503850002 C3	02143120 02	02 CONDENSATE FORW PUMP 2A MTR	NZS23
002802503500002 C3	02143120 01	02 CONDENSATE FORW PUMP 2A, MISC	NZS23
002902501510001 C3	02143110 01	05 HOTWELL PUMP 3A	NZS31
002902501850001 C3	02143110 02	05 HOTWELL PUMP 3A MOTOR	NZS31
002902501510002 C3	02143110 01	06 HOTWELL PUMP 3B	NZS32
002902501850002 C3	02143110 02	06 HOTWELL PUMP 3B MOTOR	NZS32
002902503850003 C3	02143120 02	03 CONDENSATE FORW PUMP 3A MTR	NZS33
002902503500003 C3	02143120 01	03 CONDENSATE FORW PUMP 3A, MISC	NZS33
002601511517001 C	02141400 06	01 BOILER BED ZONE 4A REFRACTORY	0001X195
002601511570001 C	02141400 02	01 BOILER CASING	0001X195
002601515517001 C2	02141801 02	01 BOILER CYCLONE 4A REFRACTORY	0001X195
002601515530001 C	02141801 01	01 BOILER CYCLONE, COMB 4A	0001X195
002616008001001 C2	02141400 03	01 BOILER FRAMING	0001X195
002616008001001 C2	02141400 04	01 BOILER INSULATION	0001X195
002616008001002 C2	02141400 05	01 BOILER LAGGING	0001X195
002604506517001 C2	02145401 08	01 BTM ASH COOLER 4A REFRACTORY	0001X195
002604506517002 C2	02145401 08	02 BTM ASH COOLER 4B REFRACTORY	0001X195
002601510517001 N	02141620 02	01 DISTRIBUTOR PLT COMB 4A REFRCT	0001X195
002601516844001 C	02149201 03	01 RECYCLE LOOP SEAL 4A EXP JNT	0001X195
002601516517003 C2	02149201 06	01 RECYCLE LOOP SEAL 4A REFRCTRY	0001X195
002601516435001 C	02149201 01	01 RECYCLE LOOP SEAL, COMB 4A	0001X195
002601511517002 C	02141400 06	02 BOILER BED ZONE 4B REFRACTORY	0003X115
002601515517002 C2	02141801 02	02 BOILER CYCLONE 4B REFRACTORY	0003X115
002601515530002 C	02141801 01	02 BOILER CYCLONE, COMB 4B	0003X115
002604506517003 C2	02145401 08	03 BTM ASH COOLER 4C REFRACTORY	0003X115
002604506517004 C2	02145401 08	04 BTM ASH COOLER 4D REFRACTORY	0003X115
002601510517002 N	02141620 02	02 DISTRIBUTOR PLT COMB 4B REFRCT	0003X115
002601516844002 C	02149201 03	02 RECYCLE LOOP SEAL 4B EXP JNT	0003X115
002601516517004 C2	02149201 06	02 RECYCLE LOOP SEAL 4B REFRCTRY	0003X115
002601516435002 C	02149201 01	02 RECYCLE LOOP SEAL, COMB 4B	0003X115
002601514190005 C	02141662 02	05 BURNER, START-UP, 4E	OFT10
002601514190006 C	02141662 02	06 BURNER, START-UP, 4F	OFT12
002601514190008 C	02141662 01	01 BURNER 4A, PRIMARY AIR DUCT	OFT14
002601514190007 C	02141662 01	02 BURNER 4B, PRIMARY AIR DUCT	OFT16
002601514190001 C	02141662 02	01 BURNER, START-UP, 4A	OFT2
002601514190002 C	02141662 02	02 BURNER, START-UP, 4B	OFT4
002601514190003 C	02141662 02	03 BURNER, START-UP, 4C	OFT6
002601514190004 C	02141662 02	04 BURNER, START-UP, 4D	OFT8
002605506340001 C	02141503 10	01 BAGHOUSE #4 PURGE AIR FAN	PSWI71
002605505850001 C	02141503 11	02 BAGHOUSE #4 PURGE AIR FAN MTR	PSWI71
002605505341001 N	02141503 06	04 BAGHOUSE #4 DEFLATE AIR FAN	PSWI72
002605505850004 N	02141503 07	04 BAGHOUSE #4 DEFLATE FAN MOTOR	PSWI72
002605505341002 C	02141503 06	01 BAGHOUSE #1 DEFLATE AIR FAN	PSWO10
002605505850001 C	02141503 07	01 BAGHOUSE #1 DEFLATE FAN MOTOR	PSWO10
002605505341003 N	02141503 06	02 BAGHOUSE #2 DEFLATE AIR FAN	PSWO11
002605505850002 N	02141503 07	02 BAGHOUSE #2 DEFLATE FAN MOTOR	PSWO11
002605505341004 N	02141503 06	03 BAGHOUSE #3 DEFLATE AIR FAN	PSWO12
002605505850003 N	02141503 07	03 BAGHOUSE #3 DEFLATE FAN MOTOR	PSWO12
002603502350002 C	02144621 01	02 COAL FEEDER 4B GRAVAMTRIC MISC	QFT1

CUEA No.	EPRI No.		Description	TAG No.
002603502850002 C4	02144621	02	02 COAL FEEDER 4B GRAVAMTRIC MTR	QFT1
002603502850008 C	02144622	02	02 COAL FEEDER 4B MOTOR - ROTARY	QFT1
002603502378002 C2	02144626	01	02 COAL FEEDER 4B ROTARY ISO GATE	QFT1
002603502540002 C	02144623	01	02 COAL FEEDER 4B SCALE	QFT1
002603502377002 C	02144624	01	02 COAL FEEDER 4B SLIDE GATE	QFT1
002603502228002 C	02144625	01	02 COAL FEEDER 4B SPEED CONTROL	QFT1
002603502351002 C	02144622	01	02 COAL FEEDER 4B - ROTARY MISC	QFT1
002603502350003 C	02144621	01	03 COAL FEEDER 4C GRAVAMTRIC MISC	QFT2
002603502850003 C4	02144621	02	03 COAL FEEDER 4C GRAVAMTRIC MTR	QFT2
002603502850009 C	02144622	02	03 COAL FEEDER 4C MOTOR - ROTARY	QFT2
002603502378003 C2	02144626	01	03 COAL FEEDER 4C ROTARY ISO GATE	QFT2
002603502540003 C	02144623	01	03 COAL FEEDER 4C SCALE	QFT2
002603502377003 C	02144624	01	03 COAL FEEDER 4C SLIDE GATE	QFT2
002603502228003 C	02144625	01	03 COAL FEEDER 4C SPEED CONTROL	QFT2
002603502351003 C	02144622	01	03 COAL FEEDER 4C - ROTARY MISC	QFT2
002603502244003 C	02144630	01	01 COAL CONVEYOR 4A HORIZ MISC	QFT25
002603502850015			COAL CONVEYOR 4A HORIZ MTR	QFT25
002603502244001 C	02144630	01	02 COAL CONVEYOR 4A INCLINED MISC	QFT25
002603502850013 C	02144630	04	02 COAL CONVEYOR 4A INCLINED MTR	QFT25
002603502350001 C	02144621	01	01 COAL FEEDER 4A GRAVAMTRIC MISC	QFT25
002603502850001 C4	02144621	02	01 COAL FEEDER 4A GRAVAMTRIC MTR	QFT25
002603502850007 C	02144622	02	01 COAL FEEDER 4A MOTOR - ROTARY	QFT25
002603502378001 C2	02144626	01	01 COAL FEEDER 4A ROTARY ISO GATE	QFT25
002603502540001 C	02144623	01	01 COAL FEEDER 4A SCALE	QFT25
002603502377001 C	02144624	01	01 COAL FEEDER 4A SLIDE GATE	QFT25
002603502228001 C	02144665	01	01 COAL FEEDER 4A SPEED CONTROL	QFT25
002603502351001 C	02144622	01	01 COAL FEEDER 4A - ROTARY MISC	QFT25
002603502244004 C	02144630	01	03 COAL CONVEYOR 4D HORIZ MISC	QFT26
002603502850016 C	02144630	04	03 COAL CONVEYOR 4D HORIZ MTR	QFT26
002603502244002 C	02144630	01	04 COAL CONVEYOR 4D INCLINED MISC	QFT26
002603502850014 C	02144630	04	04 COAL CONVEYOR 4D INCLINED MTR	QFT26
002603502350004 C	02144621	01	04 COAL FEEDER 4D GRAVAMTRIC MISC	QFT26
002603502850004 C4	02144621	02	04 COAL FEEDER 4D GRAVAMTRIC MTR	QFT26
002603502850010 C	02144622	02	04 COAL FEEDER 4D MOTOR - ROTARY	QFT26
002603502378004 C2	02144626	01	04 COAL FEEDER 4D ROTARY ISO GATE	QFT26
002603502540004 C	02144623	01	04 COAL FEEDER 4D SCALE	QFT26
002603502377004 C	02144624	01	04 COAL FEEDER 4D SLIDE GATE	QFT26
002603502228004 C	02144625	01	04 COAL FEEDER 4D SPEED CONTROL	QFT26
002603502351004 C	02144622	01	04 COAL FEEDER 4D - ROTARY MISC	QFT26
002603502350006 C	02144621	01	06 COAL FEEDER 4F GRAVAMTRIC MISC	QFT3
002603502850006 C4	02144621	02	06 COAL FEEDER 4F GRAVAMTRIC MTR	QFT3
002603502850012 C	02144622	02	06 COAL FEEDER 4F MOTOR - ROTARY	QFT3
002603502378006 C2	02144626	01	06 COAL FEEDER 4F ROTARY ISO GATE	QFT3
002603502540006 C	02144623	01	06 COAL FEEDER 4F SCALE	QFT3
002603502377006 C	02144624	01	06 COAL FEEDER 4F SLIDE GATE	QFT3
002603502228006 C	02144625	01	06 COAL FEEDER 4F SPEED CONTROL	QFT3
002603502351006 C	02144622	01	06 COAL FEEDER 4F - ROTARY MISC	QFT3
002603502350005 C	02144621	01	05 COAL FEEDER 4E GRAVAMTRIC MISC	QFT4
002603502850005 C4	02144621	02	05 COAL FEEDER 4E GRAVAMTRIC MTR	QFT4
002603502850011 C	02144622	02	05 COAL FEEDER 4E MOTOR - ROTARY	QFT4
002603502378005 C2	02144626	01	05 COAL FEEDER 4E ROTARY ISO GATE	QFT4
002603502540005 C	02144623	01	05 COAL FEEDER 4E SCALE	QFT4
002603502377005 C	02144624	01	05 COAL FEEDER 4E SLIDE GATE	QFT4
002603502228005 C	02144625	01	05 COAL FEEDER 4E SPEED CONTROL	QFT4
002603502351005 C	02144622	01	05 COAL FEEDER 4E - ROTARY MISC	QFT4
002601503705003 C	02140057	01	01 GAS ANALYZER-SO2, ECON 4A OUT	RAT1
002601503705004 C	02140057	01	02 GAS ANALYZER-SO2, ECON 4B OUT	RAT2
002606001352002 C4			SORB SILO 4B VIBR BIN DISCH	RFT13
002606030529002 C2	02144665	04	02 SORBENT LOS WT FDR 4B SCTR PLT	RFT13
002606030378002 C	02144665	05	02 SORBENT LOS WT FDR 4B SLD GATE	RFT13
002606030228002 C	02144665	02	02 SORBENT LOSS WT FDR 4B MICPROS	RFT13
002606030350002 C	02144665	01	02 SORBENT LOSS WT FDR 4B MISC	RFT13
002606030850002 C	02144665	03	02 SORBENT LOSS WT FDR 4B MOTOR	RFT13
002606030245002 C 4	02144664	01	02 SORBENT TRANSPORT PIPING, 4B	RFT13
002606001352001			SORB SILO 4A VIBR BIN DISCH	RFT4
002606030529001 C2	02144665	04	01 SORBENT LOS WT FDR 4A SCTR PLT	RFT4
002606030378001 C	02144665	05	01 SORBENT LOS WT FDR 4A SLD GATE	RFT4
002606030228001 C	02144665	02	01 SORBENT LOSS WT FDR 4A MICPROS	RFT4
002606030350001 C	02144665	01	01 SORBENT LOSS WT FDR 4A MISC	RFT4
002606030850001 C	02144665	03	01 SORBENT LOSS WT FDR 4A MOTOR	RFT4

CUEA No.		EPRI No.			Description	TAG No.
002606030245001	C 4	02144664	01	01	SORBENT TRANSPORT PIPING, 4A	RFT4
002408509228002	N	02140005	01	01	Ca/S RATIO CONTROL	RFT4,13
002606030185005	C	02144663	01	05	SORBENT BLOWER 4E, MISC	RZS16A
002606030850005	C	02144663	02	05	SORBENT BLOWER MOTOR, 4E	RZS16A
002606030579005	C2	02144667	01	05	SORBENT BOILER ISO GATE VLV 4E	RZS16A
002606030351005	C	02144666	01	05	SORBENT ROTARY FEEDER 4E MISC	RZS16A
002606030350013	C	02144666	02	05	SORBENT ROTARY FEEDER 4E MTR	RZS16A
002606030185006	C	02144663	01	06	SORBENT BLOWER 4F, MISC	RZS16B
002606030850006	C	02144663	02	06	SORBENT BLOWER MOTOR, 4F	RZS16B
002606030579006	C2	02144667	01	06	SORBENT BOILER ISO GATE VLV 4F	RZS16B
002606030351006	C	02144666	01	06	SORBENT ROTARY FEEDER 4F MISC	RZS16B
002606030350014	C	02144666	02	06	SORBENT ROTARY FEEDER 4F MTR	RZS16B
002606030185007	C	02144663	01	07	SORBENT BLOWER 4G, MISC	RZS16C
002606030850007	C	02144663	02	07	SORBENT BLOWER MOTOR, 4G	RZS16C
002606030579007	C2	02144667	01	07	SORBENT BOILER ISO GATE VLV 4G	RZS16C
002606030351007	C	02144666	01	07	SORBENT ROTARY FEEDER 4G MISC	RZS16C
002606030350015	C	02144666	02	07	SORBENT ROTARY FEEDER 4G MTR	RZS16C
002606030185008	C	02144663	01	08	SORBENT BLOWER 4H, MISC	RZS16D
002606030850008	C	02144663	02	08	SORBENT BLOWER MOTOR, 4H	RZS16D
002606030579008	C2	02144667	01	08	SORBENT BOILER ISO GATE VLV 4H	RZS16D
002606030351008	C	02144666	01	08	SORBENT ROTARY FEEDER 4H MISC	RZS16D
002606030350016	C	02144666	02	08	SORBENT ROTARY FEEDER 4H MTR	RZS16D
002606030185001	C	02144663	01	01	SORBENT BLOWER 4A, MISC	RZS7A
002606030850001	C	02144663	02	01	SORBENT BLOWER MOTOR, 4A	RZS7A
002606030579001	C2	02144667	01	01	SORBENT BOILER ISO GATE VLV 4A	RZS7A
002606030351001	C	02144666	01	01	SORBENT ROTARY FEEDER 4A MISC	RZS7A
002606030350009	C	02144666	02	01	SORBENT ROTARY FEEDER 4A MTR	RZS7A
002606030185002	C	02144663	01	02	SORBENT BLOWER 4B, MISC	RZS7B
002606030850002	C	02144663	02	02	SORBENT BLOWER MOTOR, 4B	RZS7B
002606030579002	C2	02144667	01	02	SORBENT BOILER ISO GATE VLV 4B	RZS7B
002606030351002	C	02144666	01	02	SORBENT ROTARY FEEDER 4B MISC	RZS7B
002606030350010	C	02144666	02	02	SORBENT ROTARY FEEDER 4B MTR	RZS7B
002606030185003	C	02144663	01	03	SORBENT BLOWER 4C, MISC	RZS7C
002606030850003	C	02144663	02	03	SORBENT BLOWER MOTOR, 4C	RZS7C
002606030579003	C2	02144667	01	03	SORBENT BOILER ISO GATE VLV 4C	RZS7C
002606030351003	C	02144666	01	03	SORBENT ROTARY FEEDER 4C MISC	RZS7C
002606030350011	C	02144666	02	03	SORBENT ROTARY FEEDER 4C MTR	RZS7C
002606030185004	C	02144663	01	04	SORBENT BLOWER 4D, MISC	RZS7D
002606030850004	C	02144663	02	04	SORBENT BLOWER MOTOR, 4D	RZS7D
002606030579004	C2	02144667	01	04	SORBENT BOILER ISO GATE VLV 4D	RZS7D
002606030351004	C	02144666	01	04	SORBENT ROTARY FEEDER 4D MISC	RZS7D
002606030350012	C	02144666	02	04	SORBENT ROTARY FEEDER 4D MTR	RZS7D
002603005460001	C4	02140027	01	01	OPACITY MONITORING SYSTEM	SAT50
002603005705002					GAS ANALYZER-NOX CEM	SAT51
002603005705003					GAS ANALYZER-SO2 CEM	SAT52
002604503528001	C	02145125	01	01	FLYASH EXHAUSTER 4A MISC	TAEA52A
002604503851001	C	02145125	02	01	FLYASH EXHAUSTER 4A MOTOR	TAEA52A
002604503528002	C	02145125	01	02	FLYASH EXHAUSTER 4B MISC	TAEB52A
002604503851002	C	02145125	02	02	FLYASH EXHAUSTER 4B MOTOR	TAEB52A
002604503528003	C	02145125	01	03	FLYASH EXHAUSTER 4C MISC	TAEC52A
002604503851003	C	02145125	02	03	FLYASH EXHAUSTER 4C MOTOR	TAEC52A
002604506251005	C	02145402	01	01	BOTTOM ASH 4A SCREW COOLER	TCSA52AS,F
002604506850001	C	02145402	02	01	BTM ASH SCREW COOLER 4A MOTOR	TCSA52AS,F
002604506251006	C	02145402	01	02	BOTTOM ASH 4B SCREW COOLER	TCSB52AS,F
002604506850002	C	02145402	02	02	BTM ASH SCREW COOLER 4B MOTOR	TCSB52AS,F
002604503590004	C 14	02145216	01	01	BAGHOUSE 4 TRANS LINE ISO VLV	TPT31
002604503330002	C	02141503	09	04	BAGHOUSE ASH MECH SEP FILTR 4B	TPT31
002604503530002	C	02141503	09	02	BAGHOUSE ASH MECH SEPARATOR 4B	TPT31
002605503850001	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4A	TPT31
002605503850002	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4B	TPT31
002605503850003	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4C	TPT31
002605503850004	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4D	TPT31
002605503850005	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4E	TPT31
002605503850006	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4F	TPT31
002605503850007	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4G	TPT31
002605503850008	C2	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4H	TPT31
002605503850009	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4J	TPT31
002605503850010	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4K	TPT31
002605503850011	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4L	TPT31
002605503850012	C	02141503	13	04	BAGHOUSE SHAKER MOTOR,COMP 4M	TPT31

RELIABILITY MONITORING DATABASE - 7

CUEA No.			EPRI No.			Description	TAG No.
002605503330004	C	1440	02141503	02	04	BAGHOUSE #4 BAGS	TPT31
002604503590004	N	12	02141503	05	04	BAGHOUSE #4 CMP HPR DUST VALVE	TPT31
002605503525004	C	12	02141503	12	04	BAGHOUSE #4 SHAKER	TPT31
002605508130001	C		02141503	04	01	BAGHOUSE #4, BYPASS DAMPER 1	TPT31
002605508130002	C		02141503	04	02	BAGHOUSE #4, BYPASS DAMPER 2	TPT31
002605508130003	C		02141503	04	03	BAGHOUSE #4, BYPASS DAMPER 3	TPT31
002601503001004	C		02141503	01	04	BAGHOUSE #4, MISC	TPT31
002604503245001	C		02145640	01	01	FLYASH TRANSPORT PIPING	TPT31,34
002604503330001	C		02141503	09	03	BAGHOUSE ASH MECH SEP FILTR 4A	TPT34
002604503530001	C		02141503	09	01	BAGHOUSE ASH MECH SEPARATOR 4A	TPT34
002605503850013	C		02141503	13	01	BAGHOUSE SHAKER MOTOR,COMP 1N	TPT34
002605503850014	C		02141503	13	01	BAGHOUSE SHAKER MOTOR,COMP 1P	TPT34
002605503850015	C		02141503	13	01	BAGHOUSE SHAKER MOTOR,COMP 1Q	TPT34
002605503850016	C		02141503	13	01	BAGHOUSE SHAKER MOTOR,COMP 1R	TPT34
002605503850017	C		02141503	13	01	BAGHOUSE SHAKER MOTOR,COMP 1S	TPT34
002605503850018	C		02141503	13	01	BAGHOUSE SHAKER MOTOR,COMP 1T	TPT34
002605503850019	C		02141503	13	02	BAGHOUSE SHAKER MOTOR,COMP 2N	TPT34
002605503850020	C		02141503	13	02	BAGHOUSE SHAKER MOTOR,COMP 2P	TPT34
002605503850021	C		02141503	13	02	BAGHOUSE SHAKER MOTOR,COMP 2Q	TPT34
002605503850022	C		02141503	13	02	BAGHOUSE SHAKER MOTOR,COMP 2R	TPT34
002605503850023	C		02141503	13	02	BAGHOUSE SHAKER MOTOR,COMP 2S	TPT34
002605503850024	C		02141503	13	02	BAGHOUSE SHAKER MOTOR,COMP 2T	TPT34
002605503850025	C		02141503	13	03	BAGHOUSE SHAKER MOTOR,COMP 3N	TPT34
002605503850026	C		02141503	13	03	BAGHOUSE SHAKER MOTOR,COMP 3P	TPT34
002605503850027	C		02141503	13	03	BAGHOUSE SHAKER MOTOR,COMP 3Q	TPT34
002605503850028	C		02141503	13	03	BAGHOUSE SHAKER MOTOR,COMP 3R	TPT34
002605503850029	C		02141503	13	03	BAGHOUSE SHAKER MOTOR,COMP 3S	TPT34
002605503850030	C		02141503	13	03	BAGHOUSE SHAKER MOTOR,COMP 3T	TPT34
002605503330001	C	672	02141503	02	01	BAGHOUSE #1 BAGS	TPT34
002604503590001	C2	6	02141503	05	01	BAGHOUSE #1 CMP HPR DUST VALVE	TPT34
002605503525001	C	6	02141503	12	01	BAGHOUSE #1 SHAKER	TPT34
002601503001001	C		02141503	01	01	BAGHOUSE #1, MISC	TPT34
002605503330002	C	672	02141503	02	02	BAGHOUSE #2 BAGS	TPT34
002604503590002	N	6	02141503	05	02	BAGHOUSE #2 CMP HPR DUST VALVE	TPT34
002605503525002	C	6	02141503	12	02	BAGHOUSE #2 SHAKER	TPT34
002601503001002	C		02141503	01	02	BAGHOUSE #2, MISC	TPT34
002605503330003	C	672	02141503	02	03	BAGHOUSE #3 BAGS	TPT34
002604503590003	N	6	02141503	05	03	BAGHOUSE #3 CMP HPR DUST VALVE	TPT34
002605503525003	C	6	02141503	12	03	BAGHOUSE #3 SHAKER	TPT34
002601503001003	C		02141503	01	03	BAGHOUSE #3, MISC	TPT34
002604505330001	C		02145667	01	01	BOTTOM ASH CONVEYING BAG FILTR	TPT39
002604505245001	C		02145665	01	01	BOTTOM ASH TRANSPORT PIPING	TPT39
002604505330001	N		02145662	02	01	BTM ASH MECHANICAL SEP FILTER	TPT39
002604505530001	C		02145662	01	01	BTM ASH MECHANICAL SEPARATOR	TPT39
002604506222001	N		02145666	05	01	BTM ASH SILO PULS CLNG CMP	TPT39
002604505850005	C		02145666	06	01	BTM ASH SILO PULS CLNG CMP MTR	TPT39
002604505280001	C		02145123	01	01	BOTTOM ASH EXHAUSTER 4A	TSEA52A
002604505851001	C		02145123	02	01	BOTTOM ASH EXHAUSTER 4A MTR	TSEA52A
002604505280002	C		02145123	01	02	BOTTOM ASH EXHAUSTER 4B	TSEB52A
002604505851002	C		02145123	02	02	BOTTOM ASH EXHAUSTER 4B MTR	TSEB52A
002600112252001	C4		02142329	12	04	TURBINE OIL COOLER U4	VPT50
002600112330001	C4		02142329	15	04	TURBINE OIL FILTER U4	VPT50
002600112850001	C4		02142329	10	04	TURB OIL AUX LUBE PMP MTR U4	VZS1A
002600112509001	C4		02142329	09	04	TURBINE OIL AUX LUBE PMP U4	VZS1A
002604003851002	C4		02148109	02	02	CONDENSER CIRC PMP 4A MTR	WZS1
002604003500002	C4		02148109	01	02	CONDENSER CIRC PUMP 4A	WZS1
002604001001001	N		02148425	01	04	COOLING TOWER #4A	WZS1,2
002604003851001	C4		02148109	02	01	CONDENSER CIRC PMP 4B MTR	WZS2
002604003500001	C4		02148109	01	01	CONDENSER'CIRC PUMP 4B	WZS2
002504003851001	C4		02148109	02	01	CONDENSER CIRC PMP 1 MTR	WZS61
002504003499001	C4		02148109	01	01	CONDENSER CIRC PUMP 1	WZS61
002504001001001	C3		02148425	01	01	COOLING TOWER EXISTING	WZS61,62,63
002504003851002	C4		02148109	02	02	CONDENSER CIRC PMP 2 MTR	WZS62
002504003499002	C4		02148109	01	02	CONDENSER CIRC PUMP 2	WZS62
002504003851003	C4		02148109	02	03	CONDENSER CIRC PMP 3 MTR	WZS63
002504003499003	C4		02148109	01	03	CONDENSER CIRC PUMP 3	WZS63
002604008290001	C		02145102	03	01	BOTTOM ASH COOLING WTR HT EXCH	XFT300
002604506545001	C2		02145401	10	01	BTM ASH COOLER 4A WATERWALLS	XFT300
002604506545002	C2		02145401	10	02	BTM ASH COOLER 4B WATERWALLS	XFT300
002604506545003	C2		02145401	10	03	BTM ASH COOLER 4C WATERWALLS	XFT300

CUEA No.			EPRI No.			Description	TAG No.
002604506545004	C2		02145401	10	04	BTM ASH COOLER 4D WATERWALLS	XFT300
002604004290001	C4		02148010	02	04	CLOSED COOLING WTR CLR 4A	XZS1
002604004850001	C4		02148010	04	01	CLOSED COOLING WTR PMP MTR 4A	XZS1
002604004500001	C4		02148010	03	04	CLOSED COOLING WTR PUMP 4A	XZS1
002604004001001	C4		02148010	01	01	CLOSED COOLING WATER SYS	XZS1,2
002604004560001	C4		02148010	05	01	CLOSED COOLING WTR HEAD TANK	XZS1,2
002604004290002	C4		02148010	02	05	CLOSED COOLING WTR CLR 4B	XZS2
002604004850002	C4		02148010	05	01	CLOSED COOLING WTR PMP MTR 4B	XZS2
002604004500002	C4		02148010	03	05	CLOSED COOLING WTR PUMP 4B	XZS2
002604008850001	C		02145102	02	01	BOTTOM ASH CLNG WTR PMP 4A MTR	XZS4
002604008500001	C		02145102	01	01	BOTTOM ASH COOLING WTR PMP, 4A	XZS4
002604008500002	N		02145102	02	02	BOTTOM ASH CLNG WTR PMP 4B MTR	XZS6
002604008290002	N		02145102	01	02	BOTTOM ASH COOLING WTR PMP, 4B	XZS6
002607002001001	C4		01240740	01	01	ELECTRICAL UNINTER PWR SUP	YAL44
002607001001001	C4		01240740	01	01	ELECTRICAL SW GEAR 125V DC	YAL46
002606502001001	C4		01240710	01	01	ELECTRICAL ISO-PHASE BUSS	YAM14
002601001001001	C3		02142330	03	04	GENERATOR EXCITER, UNIT 4	YAM14
002600500001004	C		02142330	01	04	GENERATOR UNIT 4, MISC	YAM14
002906501001001	C4		02142710	01	04	TRANSFORMER, UNIT 4 GENERATOR	YAM14
002606508837001	C4		01240702	01	01	ELECTRICAL SW GEAR 4160V	YVM23
002406505001001	C4	6	02142713	01	01	TRANSFORMERS, LOAD CENTER	YVM23
002406503001001	C4		02142711	01	01	TRANSFORMER, UNIT AUX	YVM23
002601504187001	C		02141009	01	01	AIR HTR SOOTBLOWER #1	
002601504187002	C		02141009	01	02	AIR HTR SOOTBLOWER #2	
002601504187003	C		02141009	01	03	AIR HTR SOOTBLOWER #3	
002601504187004	C		02141009	01	04	AIR HTR SOOTBLOWER #4	
002604504350001	C		02145663	01	01	BOTTOM ASH REINJ (NUVA) FDR	
002604504280001	N		02145124	01	01	BOTTOM ASH REINJECT BLWR MISC	
002604504850001	N		02145124	02	01	BOTTOM ASH REINJECT BLWR MTR	
002004504245002	C		02145664	01	01	BOTTOM ASH REINJECTION PIPING	
002612001001001	C4		02144640	01	01	COAL CONVEYOR 1A MISC	
002612001850001	C4		02144640	02	01	COAL CONVEYOR 1A MOTOR	
002612001001002	C4		02144640	01	02	COAL CONVEYOR A MISC	
002612001850002	C4		02144640	02	02	COAL CONVEYOR A MOTOR	
002612001001003	C4		02144640	01	03	COAL CONVEYOR B MISC	
002612001850003	C4		02144640	02	03	COAL CONVEYOR B MOTOR	
002612001001004	C4		02144640	01	04	COAL CONVEYOR C MISC	
002612001850004	C4		02144640	02	04	COAL CONVEYOR C MOTOR	
002612005398001	C4					COAL CONVEYOR SURGE HOPPER	
002612015540001	C4		2144013	01	01	COAL CONVEYOR WEIGHTOMETER	
002612006530001	C4		02144640	03	01	COAL CONVEYOR - MAG SEP	
002612010255003	C		02144631	01	01	COAL CRUSHER 4A	
002612010851001	N		02144631	02	01	COAL CRUSHER 4A,MTR	
002612010255004	C		02144631	01	02	COAL CRUSHER 4B	
002612010851002	N		02144631	02	02	COAL CRUSHER 4B,MTR	
002612001244005						COAL HANDL INCL CONVEYOR D MISC	
002612010850005						COAL HANDL INCL CONVEYOR D MTR	
002612001244006						COAL HANDL INCL CONVEYOR E MISC	
002612010850006						COAL HANDL INCL CONVEYOR E MTR	
002612009352001	C4		02144640	04	01	COAL HANDL PRIMARY FEEDER # 1	
002612001376001	C4	3	02144235	01	01	COAL HANDLING FLOP GATES	
002612009352002	C4		02144640	04	02	COAL HANDLING PRIMARY FEEDER # 2	
002612002374001						COAL HDL TRIP CONVEY MAN SLIDE GATES	
002612002378001						COAL HDL TRIP CONVEY PNEUMA SLIDE GATES	
002612005398007						COAL HDL TRIPPER CONVEYOR F MISC	
002612005850007						COAL HDL TRIPPER CONVEYOR F MTR	
002612005398008						COAL HDL TRIPPER CONVEYOR G MISC	
002612005850008						COAL HDL TRIPPER CONVEYOR G MTR	
002612010255001						COAL PRIMARY CRUSHER	
002612010850003						COAL PRIMARY CRUSHER MTR	
002612009352004	C4		02144640	04	04	COAL RECLAIM VIBRATION FEEDER	
002612014515001	C5					COAL SAMPLING SYS- AUTO AS FIRED	
002612014515002	C5					COAL SAMPLING SYS- AUTO AS REC	
002612010255002						COAL SECONDARY CRUSHER	
002612009352003	C4		02144640	04	03	COAL SECONDARY CRUSHER FEEDER	
002612010850004						COAL SECONDARY CRUSHER MTR	
002612009352005	C4		02144640	04	05	COAL VIBRATING FEEDER 4A	
002612009352006	C4		02144640	04	06	COAL VIBRATING FEEDER 4B	
002408509001001	C2		02140005	01	01	COMPUTER, WDPF	
002612012001001	C4		02144090	01	01	DUST COLLECTION SYSTEM-COAL	

CUEA No.			EPRI No.			Description
002606009001001	C4		02144091	01	01	DUST COLLECTION SYSTEM-SORB
002613302001001	C4		01240728	01	01	ELECTRICAL RELAYS - MISC
002606508838001	C4		01240705	01	01	ELECTRICAL SW GEAR 480V
002604503500002	C		02147102	01	01	FLYASH CND WTR PMP (OLD) MISC
002604503500001	C		02147102	01	02	FLYASH COND WTR PMP 4A MISC
002604503850001	C		02147102	02	02	FLYASH COND WTR PMP 4A MTR
002604503850002	C		02147102	02	01	FLYASH COND WTR PMP (OLD) MTR
002604503850003	C		02145641	09	01	FLYASH PLS AIR CLNG CMP 4A MTR
002604503850004	C		02145641	09	02	FLYASH PLS AIR CLNG CMP 4B MTR
002604503222001	C		02145641	08	01	FLYASH PULSE AIR CLNG CMP 4A
002604503222002	C		02145641	08	02	FLYASH PULSE AIR CLNG CMP 4B
002604503291001	C		02145642	01	01	FLYASH UNLOADER
002604503850005	C		02145642	02	01	FLYASH UNLOADER MOTOR
002604503242001	C		02145643	01	01	FLYASH UNLOADER SCRW CONV
002604503850006	C		02145643	02	01	FLYASH UNLOADER SCRW CONV MTR
002603005705001						GAS ANALYZER-CO2 CEM
002409001519001	C4		02147010	06	01	SERV WTR TRAVELING SCREENS
002409001500001	C4	2	02147010	04	01	SERVICE WATER PUMP MISC
002409001851001	C4	2	02147010	05	01	SERVICE WATER PUMP MOTOR
002601504228002	C		02141007	01	01	SOOTBLOWER CONTROLS
002601504185001	C		02141008	01	01	SOOTBLOWER CONV PASS #1
002601504185010	C		02141008	01	10	SOOTBLOWER CONV PASS #10
002601504185011	C		02141008	01	11	SOOTBLOWER CONV PASS #11
002601504185012	C		02141008	01	12	SOOTBLOWER CONV PASS #12
002601504185002	C		02141008	01	02	SOOTBLOWER CONV PASS #2
002601504185003	C		02141008	01	03	SOOTBLOWER CONV PASS #3
002601504185004	C		02141008	01	04	SOOTBLOWER CONV PASS #4
002601504185005	C		02141008	01	05	SOOTBLOWER CONV PASS #5
002601504185006	C		02141008	01	06	SOOTBLOWER CONV PASS #6
002601504185007	C		02141008	01	07	SOOTBLOWER CONV PASS #7
002601504185008	C		02141008	01	08	SOOTBLOWER CONV PASS #8
002601504185009	C		02141008	01	09	SOOTBLOWER CONV PASS #9
002601504579001	C		02141007	01	02	SOOTBLOWER STM SUP VLV
002606001001001	C2		02144660	01	01	SORB PREP (#S 002606001xxx)
002606001302001	C4		02144672	01	01	SORBENT BUCKET ELEVATOR
002606001394001	C4		02144671	04	01	SORBENT CHUTE/HOPPER
002606001850001	C4		02144671	02	01	SORBENT CONVEYOR MTR-BELT
002606001540001	C4		02144014	01	01	SORBENT CONVEYOR WEIGHTMTR
002606001240001	C4		02144671	01	01	SORBENT CONVEYOR - BELT
002606002255001	C3		02144661	01	01	SORBENT CRUSHER
002606001352001	C4		02144671	03	01	SORBENT FEEDER VIBRATING
002606001530001	C4		02144673	01	01	SORBENT MAG SEPARATOR-BELT
002606001388001	C4		02144662	03	01	SORBENT PLVRZR AIR HTR/DRY
002606002440001	C4		02144662	01	01	SORBENT PULVERIZER
002606009246001	C4		02144662	04	01	SORBENT PULVERIZER CYCL
002606009001001	C4		02144662	05	01	SORBENT PULVERIZER DST COL
002606001341001	C4		02144662	06	01	SORBENT PULVERIZER FAN
002606001851001	C4		02144662	02	01	SORBENT PULVERIZER MOTOR
002606030245003	N		02144664	01	03	SORBENT TRANS X-PIPING (4A-B)
002700112850001	C4		02142329	10	01	TURB OIL AUX LUBE PMP MTR U1
002800112850001	C4		02142329	10	02	TURB OIL AUX LUBE PMP MTR U2
002900112850001	C4		02142329	10	03	TURB OIL AUX LUBE PMP MTR U3
002700112509002	C4		02142329	09	01	TURBINE OIL AUX LUBE PMP U1
002800112509001	C4		02142329	09	02	TURBINE OIL AUX LUBE PMP U2
002900112509001	C4		02142329	09	03	TURBINE OIL AUX LUBE PMP U3
002700112252001	C4		02142329	12	01	TURBINE OIL COOLER U1
002800112252001	C4		02142329	12	02	TURBINE OIL COOLER U2
002900112252001	C4		02142329	12	03	TURBINE OIL COOLER U3
002700112330001	C4		02142329	15	01	TURBINE OIL FILTER U1
002800112330001	C4		02142329	15	02	TURBINE OIL FILTER U2
002900112330001	C4		02142329	15	03	TURBINE OIL FILTER U3

Section 18

ALTERNATE FUELS TESTING

During the Phase I and II test programs, two alternate fuels were tested in addition to Salt Creek coal, which formed the baseline fuel for the majority of testing. These fuels included a Peabody coal mined locally some eight miles from the power station, and a Dorchester coal available approximately 100 miles from the plant in western Colorado. Both of these coals are western bituminous grade coals. The plant was originally designed to burn the Peabody coal, which has a high variability in ash, heating value, moisture, and sulfur content. In order to take advantage of a more economical fuel supply, the fuel was switched to Salt Creek coal in the summer of 1989. This fuel is more homogeneous than the Peabody coal with lower ash (17 wt.%) and sulfur contents (0.5 wt.%). Because of its consistency, Salt Creek coal formed a better fuel for comparative performance testing as part of the test program.

Prior to this change, eight steady-state performance tests were conducted on the Peabody coal (0.7 wt.% sulfur). In order to test the effects of higher sulfur content in the fuel on sulfur capture efficiency and overall unit performance, a series of four performance tests were conducted on the Dorchester coal with an average sulfur content of 1.5 wt.%. The fuel properties of these three coals are compared in Table 18-1. Test results for the three coals were compared in Section 6, "Performance Testing", and are also highlighted in this section.

18.1 TEST MATRIX AND FUEL PROPERTIES

Table 18-1 shows the tests conducted on the local Peabody and Dorchester coals, including a summary of pertinent emissions performance data. For two tests on the Dorchester coal (AF08 and AF09), emissions data are presented for each combustion chamber due to a temperature differential that existed during the tests. This necessitates testing each combustion chamber individually for emissions performance since temperature has a strong impact on NO_x, CO, and SO_2 emissions. Combustion and boiler efficiencies are also presented for the averages of the individual tests on each combustor. This is necessary since fly ash samples are common to both combustion chambers and is an important input into these two calculations. In Section 6 (Performance Testing), strong correlations between combustion/boiler efficiency and operating temperatures were

Table 18-1. SUMMARY OF ALTERNATE FUELS TEST RESULTS

DATA SET ID NUMBER	TEST DATE	COAL TYPE	LOAD (MWe)	BED TEMPERATURE (DEG F)	COAL FEED CONFIGURATION	LIMESTONE FEEDERS OUT OF SERVICE	EXCESS AIR (%)	SECONDARY TO PRIMARY AIR RATIO	CALCIUM TO SULFUR RATIO	SULFUR RETENTION (%)	NOX EMISSIONS (PPMV DRY @3% O2)	CO EMISSIONS (PPMV DRY @3% O2)	COMBUSTION EFFICIENCY (%)	BOILER EFFICIENCY (%)
A01	4/21/89	PEABODY	105	1611	BALANCED	-	21	0.7	1.8	73	146	83	97.6	87.6
A07	5/26/89	PEABODY	55	1495	BALANCED	NONE	39	0.7	1.5	78	52	111	97.6	87.4
A04	6/6/89	PEABODY	82	1607	BALANCED	NONE	25	0.6	1.7	75	141	78	98.3	88.2
A05	6/7/89	PEABODY	82	1597	BALANCED	NONE	25	0.7	3.9	98	189	72	97.9	87.6
A06	6/8/89	PEABODY	83	1599	BALANCED	NONE	24	0.7	0.6	37	103	80	97.9	87.9
A02	6/16/89	PEABODY	104	1627	BALANCED	NONE	19	0.7	3.7	98	208	72	98.0	87.9
A03	6/17/89	PEABODY	104	1614	BALANCED	NONE	20	0.6	0.7	45	136	67	97.8	88.3
A08	6/19/89	PEABODY	104	1625	BALANCED	NONE	19	0.7	1.8	73	154	61	97.7	87.7
AF07B	1/11/91	DORCHESTER	58	1515	BALANCED	NONE	43	0.7	2.2	89	100	124		
AF08	1/12/91	DORCHESTER	58	1480	BALANCED	-	42	0.7	2.5	95	87	136	97.8	85.6
AF08A	1/12/91	DORCHESTER	58	1460	BALANCED	1 FW	41	0.6	2.6	95	82	138		
AF08B	1/12/91	DORCHESTER	58	1508	BALANCED	NONE	42	0.7	2.4	95	91	134		
AF09	1/15/91	DORCHESTER	83	1529	BALANCED	-	24	0.5	2.1	87	96	106	97.9	86.6
AF09A	1/15/91	DORCHESTER	83	1521	BALANCED	1 FW	24	0.5	2.4	88	90	108		
AF09B	1/15/91	DORCHESTER	83	1533	BALANCED	NONE	24	0.6	2.1	87	103	104		
AF10	1/16/91	DORCHESTER	83	1531	BALANCED	NONE	25	0.5	2.4	92	113	104	97.8	86.4

not apparent. Therefore, averages of the tests on the individual combustors for these calculations are appropriate.

For test AF07 on Dorchester coal, only combustion chamber B was tested due to differences in solids feed configuration and bed temperatures between combustors. Both tests AF07 and AF08 were conducted at 58 MWe gross output. Data from combustion chamber B represent duplicate operating conditions for these two tests. Data from combustor A for test AF08 represent emissions performance at lower operating temperatures with the sidewall limestone feed point out of service. The maximum load tested on Dorchester coal was 83 MWe gross output due to limitations with the coal handling and preparation equipment from wet coal. There did not appear to be any CFB-related boiler limitations burning Dorchester coal.

For Peabody coal, eight steady-state performance tests were conducted. One test was completed at half load (test A07), three tests at 75% MCR with various Ca/S molar ratios and corresponding sulfur retentions, and four tests at 95% MCR. Three of the 95% MCR tests were completed at different Ca/S molar ratios and the fourth test was a duplicate baseline test whose purpose was to establish repeatability. Load was restricted to 95% MCR for these tests due to primary air fan limitations.

Table 18-2 is a summary of the averages of Salt Creek, Peabody, and Dorchester coal properties for all tests completed during the Phase I and II test programs.

As can be seen from the table, Dorchester coal has the highest ash and sulfur contents, the lowest heating value, and the highest moisture content. Peabody and Salt Creek coal properties are similar except for a slightly higher sulfur content and lower fuel-bound nitrogen content for the Peabody coal. The latter is important in the formation of NO_X emissions. Fuel properties for the Peabody coal were also more variable between tests compared to the other coals.

Table 18-2.
Summary of Fuel Properties for Salt Creek, Peabody, and Dorchester Coals

	Salt Creek	Peabody	Dorchester
• Higher Heating Value (Btu/lb)	10406	10680	9041
• Total Moisture (%)	8.79	6.08	10.97
• Air Dry Loss (%)	3.58	2.63	5.30
• Volatiles (%)	32.3	29.1	30.4
• Fixed Carbon (%)	42.0	46.4	35.8
• Ash (%)	16.9	18.5	22.8
Constituents (%)			
C	60.3	61.4	51.7
H	3.6	3.4	3.1
O	8.7	9.0	8.6
N	1.2	0.8	1.2
S	0.48	0.70	1.53
Ca	0.34	0.47	0.57
Mg	0.07	0.09	0.11
Fe	0.22	0.40	0.58

18.2 TEST RESULTS

Results of performance testing on Peabody and Dorchester coals are presented in Section 6 along with data from the Salt Creek coal tests. Comparative data are shown in the following figures:

- Figure 6-3. Calcium Requirements and Sulfur Retentions for Various Fuels.
- Figure 6-11. NO_X Emissions by Fuel Type.
- Figure 6-15. CO Emissions by Fuel Type.
- Figure 6-18. Temperature versus Combustion Efficiency.

The important conclusions from these tests are presented below.

1. Figure 6-3 shows Ca/S requirements to achieve various sulfur retentions for each of the three coals during tests

with operating temperatures less than 1620 °F. Data indicate no significant differences in performance between Salt Creek and Peabody coals. However, the higher sulfur content of Dorchester coal provides a greater driving force for capture by calcined limestone and results in higher sulfur retentions for similar Ca/S ratios compared with the other coals. Data suggest a 10-15% absolute increase in sulfur retention at Ca/S molar ratios between 2.0 and 2.5 for Dorchester coal compared to Salt Creek and Peabody coals. Test data indicated 95% sulfur retention at Ca/S ratios of 2.5.

Table 18-2 indicates that the calcium content of Dorchester coal is slightly higher than Salt Creek and Peabody coals. Tests conducted on Salt Creek coal without limestone addition indicated a 50% utilization of this calcium for sulfur retention. This will also influence the data to some degree.

2. Combustor operating temperatures for Dorchester coal are generally lower under similar operating conditions compared to the other coals due to higher ash and moisture contents. This is important since operating temperatures have a significant impact on emissions performance, as indicated in Section 6.

3. Figure 6-11 shows NO_x emissions versus operating temperature for the three coals. As can be seen, the Dorchester coal had higher NO_x emissions compared to the other two fuels. The fuel-bound nitrogen content of Salt Creek and Dorchester coals are similar. The difference is probably due to the higher sulfur content of the Dorchester coal, which necessitates a higher limestone feed rate to maintain SO_2 emissions compliance. As is indicated in Section 6, higher limestone feed rates under similar operating conditions results in slightly higher NO_x emissions. This is believed to be a result of the catalyzing effects of CaO on NO_x formation from fuel-bound nitrogen sources.

4. Figure 6-15 is a plot of CO emissions versus bed temperature for the three fuels tested. Dorchester and Salt Creek coals produced comparable CO emissions while those from tests with Peabody coal are slightly below the correlation. As can be seen in Table 18-1, the volatile content of Peabody coal was lower and the fixed carbon content was higher compared to the other two coals. Although the differences are subtle, this may suggest that increased volatile fraction in the fuel may result in higher CO emissions.

5. Figure 6-18 shows combustion efficiencies versus bed temperature for the three fuels tested. Below 1550 °F, combustion efficiencies for Peabody and Dorchester coals were generally lower by approximately 0.5% absolute compared with Salt Creek coal. This may be related to the lower volatile fraction and higher ash contents in these two fuels compared

to Salt Creek coal. Above 1550 °F, data from Peabody and Salt Creek coals fall within the general data scatter.

6. Tables 6-7, 6-8, and 6-9 in Section 6 show the contributions to boiler efficiencies calculated for Salt Creek, Peabody, and Dorchester coals. Tests with Peabody coal exhibited the highest average boiler efficiencies (87.8%), while those of Salt Creek and Dorchester coals averaged 87.4% and 86.3%, respectively. The descending order in efficiencies results primarily from moisture in the fuel and sorbent. In addition, for Dorchester coal, higher losses from the calcination of limestone contribute to the lower efficiencies. This results from the higher sulfur content of the fuel and the correspondingly higher limestone feed requirements for maintaining SO_2 compliance.

Future testing should be attempted on the Nucla CFB with higher sulfur eastern coals (>3% sulfur) duplicating the test matrix completed on the Peabody coal. This would further substantiate that lower Ca/S ratios are required to achieve a similar sulfur retention for high sulfur fuels. This is an important issue in the economics of circulating fluidized bed combustion technology.

Section 19

ENVIRONMENTAL MONITORING

The purpose of this plan is to collect and present an environmental database from the operation of the Nucla Circulating Fluidized Demonstration Project. The database consists of data input as a part of compliance monitoring, as required in permits and regulations, and supplemental or additional monitoring as part of the demonstration test program. This information is presented below.

19.1 SUMMARY OF ENVIRONMENTAL PERMITTING AND APPROVAL PROCESS

Prior to financing and construction, CUEA obtained permits for air emissions, waste-water discharge, and ash disposal. A Prevention of Significant Deterioration (PSD) permit was applied for on April 18, 1984. EPA issued a PSD permit on October 11, 1984 for construction of the Nucla CFB unit. Emission permit applications were for the CFB boiler, coal crushers, ash silos, ash loader, limestone storage silos, limestone pulverizer, limestone handling, coal handling and construction activities. Initial emission permits for these activities were issued on October 25, 1984 by the Colorado Department of Health, Air Pollution Control Division (CAPCD). CUEA submitted an air pollution permit application for the limestone stockpile to the CAPCD on May 27, 1986 and received the permit on September 29, 1986. An air pollution permit application for the propane vaporizer system was submitted on December 18, 1986 to the CAPCD. The permit was issued on March 27, 1987. The last air pollution emission permit application was submitted on February 6, 1987 for the ash disposal facility. CAPCD issued this permit on April 22, 1987.

The Nucla Station had an existing waste-water discharge permit which was modified to allow for additional flow resulting from the increased size of the plant from 36 MWe to 110 MWe (gross). The amended permit was issued on February 21, 1985 by the Colorado Water Quality Control Division (CWQCD).

Colorado Hazardous Materials and Waste Management Division (CHMWMD) regulations require review and approval of an engineering design and operations report prior to commencement of waste disposal. CUEA submitted this report to CHMWMD on February 6, 1987 and received approval on October 19, 1987.

The Rural Electrification Administration (REA) completed an Environmental Assessment prior to construction of the CFB boiler. CUEA initiated this process with submittal of an Environmental Analysis to the REA on March 22, 1984. The REA completed its review and approval on December 7, 1984 and allowed construction to begin on this date.

19.2 COMPLIANCE MONITORING

Compliance monitoring is required by federal and state regulations and permits for air emissions, waste-water discharge, and waste disposal. *Air emissions* are monitored by the Continuous Emissions Monitoring (CEM) system and the coal sampling system. The Model 400 opacity monitor and the Model 200 gaseous emission monitor analyze stack emissions. The data acquisition system (DAS) receives input from the opacity and gaseous monitors and generates emissions monitor reports. Coal samples are collected to determine potential SO_2 emissions. This value is compared with previously monitored emission rates to determine percent reduction of SO_2.

Waste-water discharge compliance monitoring is conducted according to the requirements of the discharge permit issued by the Colorado Water Quality Control Division. The results are summarized each calendar quarter and are reported on the applicable discharge monitoring report forms.

Waste disposal compliance monitoring, as approved by the Colorado Hazardous Materials and Waste Management Division, requires the following monitoring practices:

1. Record waste quantities daily
2. Monitor groundwater annually

These monitoring results were submitted quarterly to the U.S. Department of Energy (DOE).

19.3 ADDITIONAL MONITORING BY THE TEST PROGRAM

A detailed final test plan was developed for the DOE by the Radian Corporation covering aspects of a field study of disposed solid waste from the Nucla CFB. The title of this report is "Field Testing of Disposed Solid Waste from Advanced Coal Processes", which was developed under DOE agreement No. DE-AC21-86MC22118. The report was issued in June 1988. The Electric Power Research Institute (EPRI) is a participant in this research effort with DOE Morgantown Energy Technology Center through a cooperative research agreement.

The overall objective of the study is to develop design and implementation guidelines for the safe disposal of wastes from advanced coal combustion processes. The research will provide greater understanding of the effects which pozzolanic reactions have on in-situ permeability and leachability of these wastes. In addition, the demonstration phase of this research will provide data on the environmental behavior of the wastes to support the acquisition of waste disposal permits.

The Final Test Plan addresses the construction design and environmental monitoring specifications of a field test cell for coal-fired CFB waste at a disposal site near the Nucla Station. The site represents a semi-arid, temperate climate with near-surface geology consisting of mud stones and shales of the Cretaceous Dakota Formation.

The test plan consists of seven major sections covering the following:

1. Description of site characteristics.
2. Test cell design and construction specifications.
3. Procedures related to monitoring meteorological, hydrological, and soils and waste conditions.
4. Guidance for sample preservation and shipping.
5. Physical and chemical characterization procedures to be performed on soil and waste samples collected from the site. Also included is a summary of chemical characterization procedures to be conducted on samples of surface runoff, pore water, and ground water.
6. Quality assurance/quality control procedures for field and laboratory measurements associated with the project.
7. Description of data management procedures for capturing, organizing, reducing, and displaying data.

Additional monitoring was to be performed by EPRI as part of an environmental characterization plan included in their Detailed Test Plan for the Nucla CFB. The plan only involves air emissions (gaseous and particulate) and solid wastes. Air emissions will be sampled between the baghouse and the stack. Solid waste samples will be collected from the bed drain and fly ash hoppers. Testing will be conducted on the design fuel at half and full load. Measurements of gaseous emissions will include on-line gas analysis for determination of SO_2, NO/NO_x, CO_2, O_2 and CO. Particulate and trace metal emissions will be collected isokinetically using a standard EPA method 5 stack sampling train. Volatile organics will be sampled along with nitrosamines using acetic acid in the impinger train.

Physical properties will be determined for solid waste samples (fly ash and bottom ash) including specific gravity, bulk density, particle size distribution, permeability, hygroscopicity, adhesion, compaction and compressive strength. Chemical properties include elemental analysis, organic compounds, pH, and leaching.

19.4 RESULTS FROM COMPLIANCE MONITORING

The following is a summary of the results obtained from compliance monitoring activities conducted between 1988 and the conclusion of the test program during the first quarter of 1991.

19.4.1 Air Emissions Monitoring

Figures 19-1 through 19-4 show the daily average and 30 day rolling average for SO_2 emissions in lbs/MMBtu measured by the stack CEM system from the fourth quarter of 1988 through the first quarter of 1991. The permit level for the 30-day rolling average of 0.4 lbs/MMBtu is shown by the heavy shaded line on the figures. The permit also requires at least 70% reduction of potential SO_2 emissions on the 30-day rolling average basis, however, plots of this are not included. For the period presented, there are no violations of the 30-day rolling average for SO_2 emissions and average values are well below the permit limits. There were some violations of the 30-day rolling average 70% reduction requirement during the summer of 1989. There is no permit restriction on the daily average value, but these values have been included in the figures for completeness. Daily averages were often affected during this period by performance testing as part of the demonstration test program.

Figures 19-5 through 19-8 show the daily average and 30 day rolling average for NO_x emissions in lbs/MMBtu measured by the stack CEM system from the fourth quarter of 1988 through the first quarter of 1991. The permit limit for the 30-day rolling average of 0.55 lbs/MMBtu is shown by the heavy shaded line on the figures. For the period presented, there are no violations of the 30-day rolling average for NOx emissions, and average values are well below the permit limit. Again, there is no permit restriction on the daily average value, but these values have been included for completeness.

There are no permit restrictions on CO emissions. However, as indicated in Section 6, these emissions varied with combustor operating temperature from approximately 140 ppmv at 1450 °F to 70 ppmv at 1700 °F.

Opacity exceedences are based on six minute averages and are submitted to the Colorado Air Pollution Control District on a quarterly basis for opacities greater than 20%. Opacity at Nucla is generally quite low with an average around 5%. This value can exceed 10% if baghouse bag tears become numerous. If this occurs, operators remove baghouse compartments from

Figure 19-1. 4th Quarter 1988 SO2 Emissions Summary
Nucla CFB

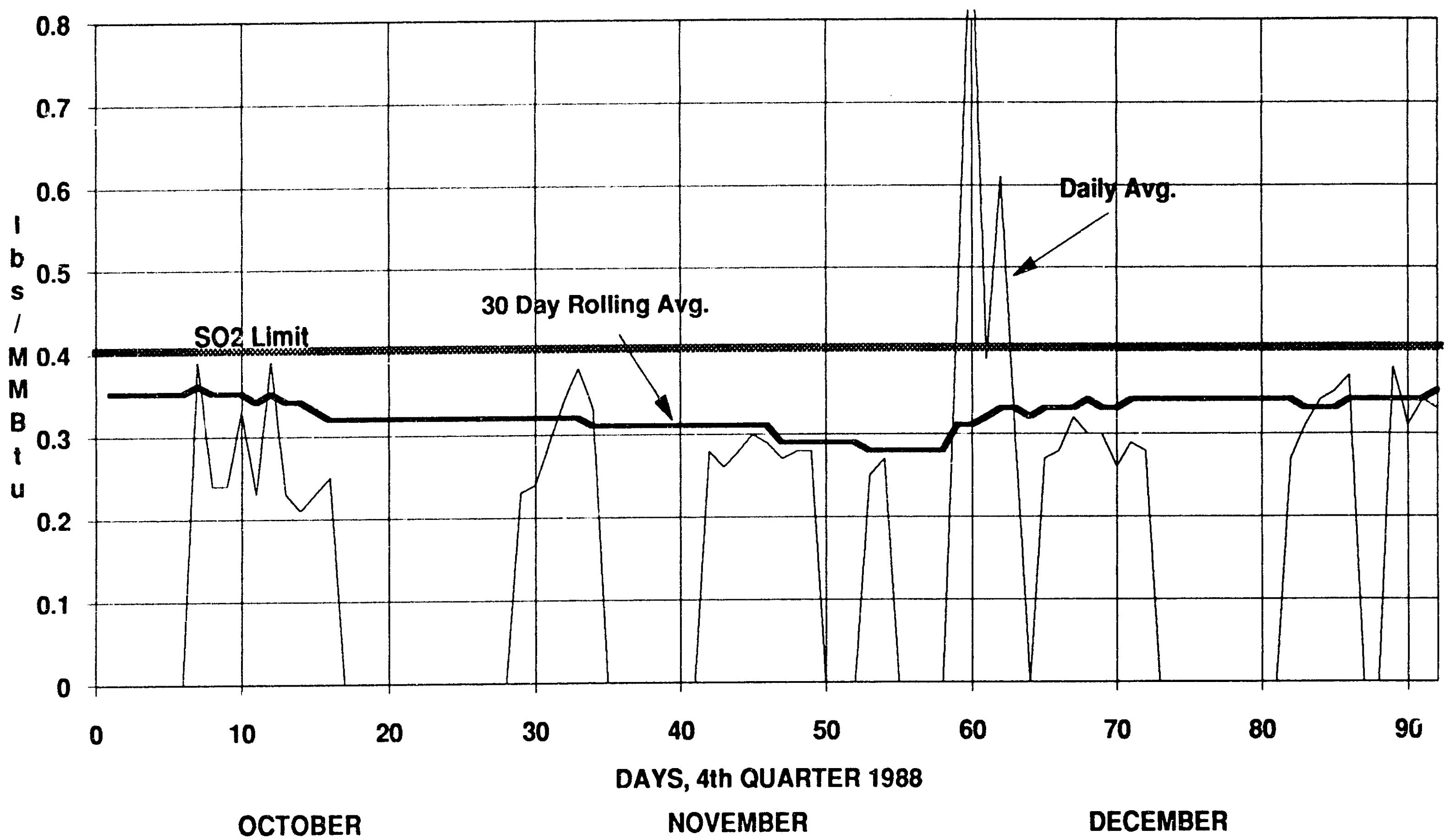


Figure 19-2. 1989 SO2 Emissions Summary Nucla CFB

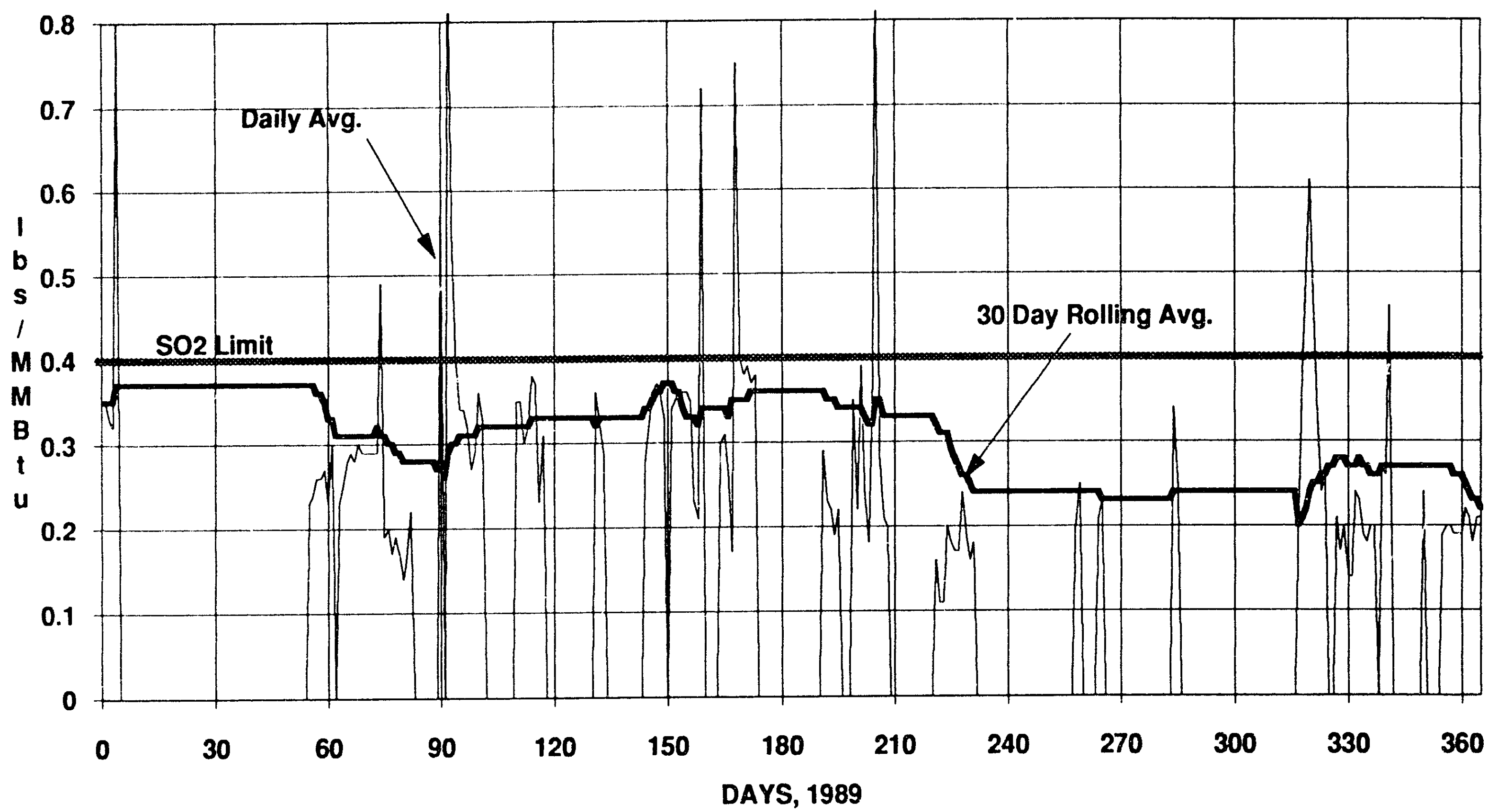


Figure 19-3. 1990 SO2 Emissions Summary
Nucla CFB

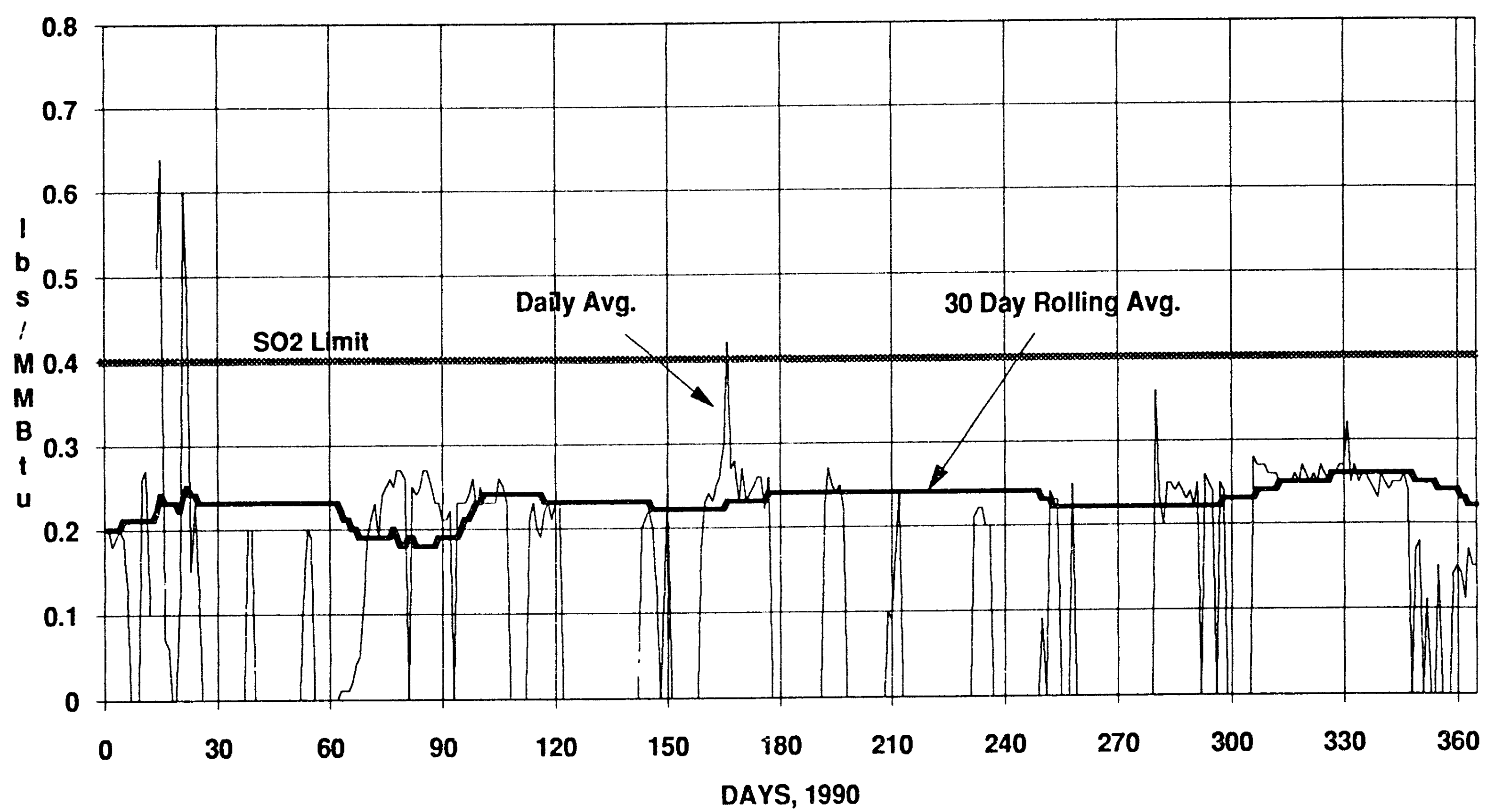


Figure 19-4. 1st Quarter 1991 SO2 Emissions Summary Nucla CFB

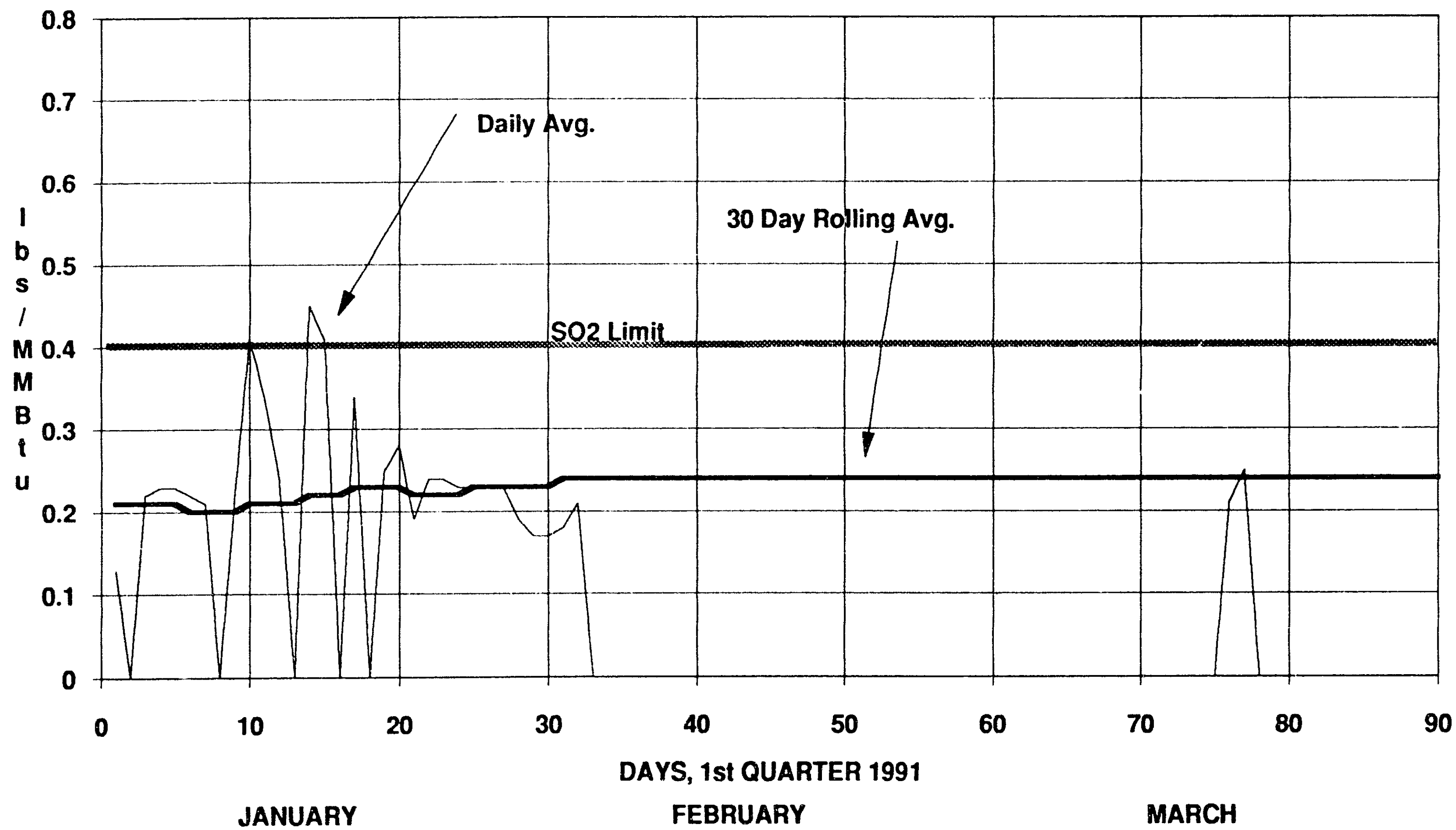


Figure 19-5. 4th Quarter 1988 NOx Emissions Summary
Nucla CFB.

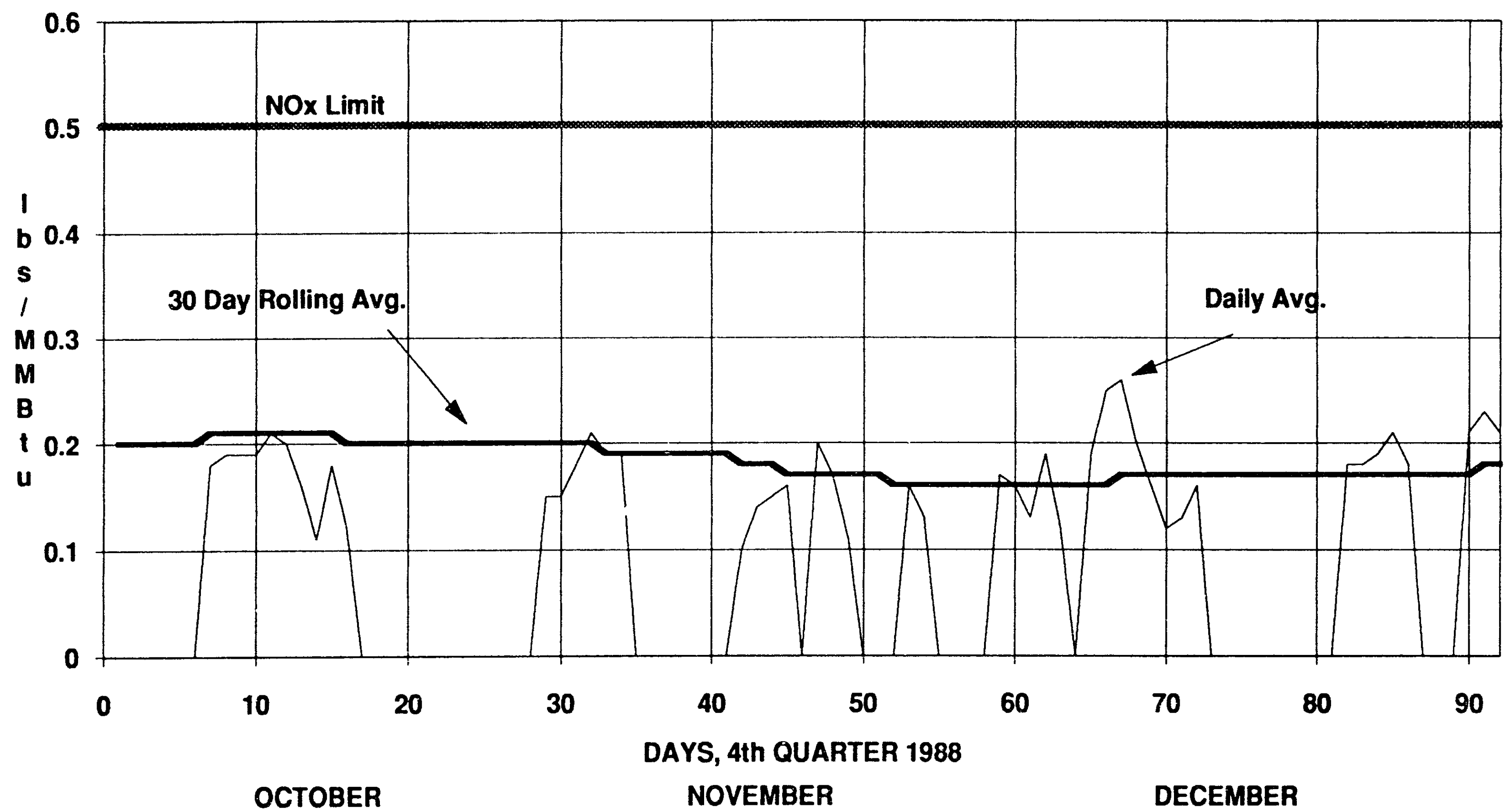


Figure 19-6. 1989 NOx Emissions Summary
Nucla CFB

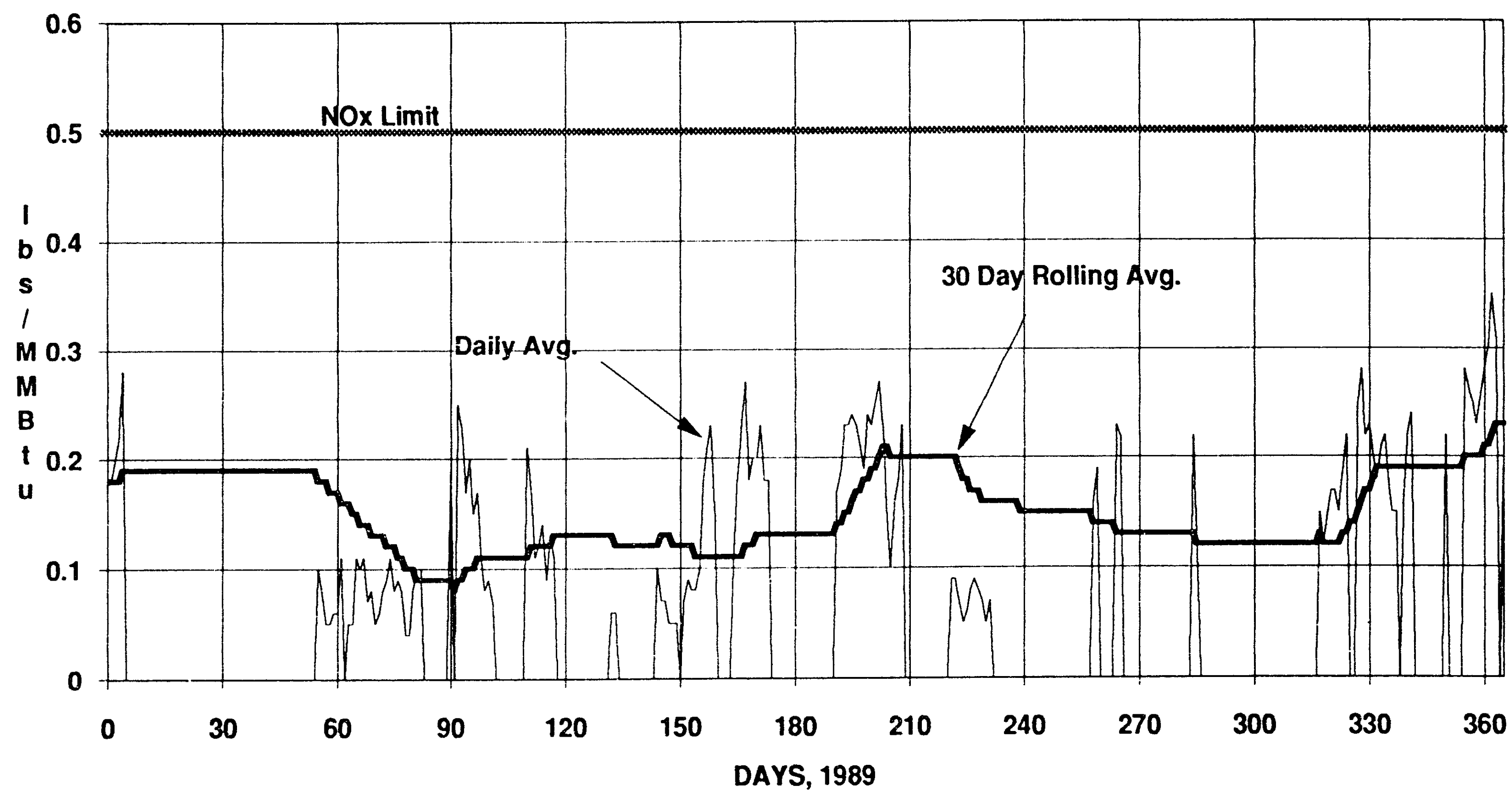


Figure 19-7. 1990 NOx Emissions Summary
Nucla CFB

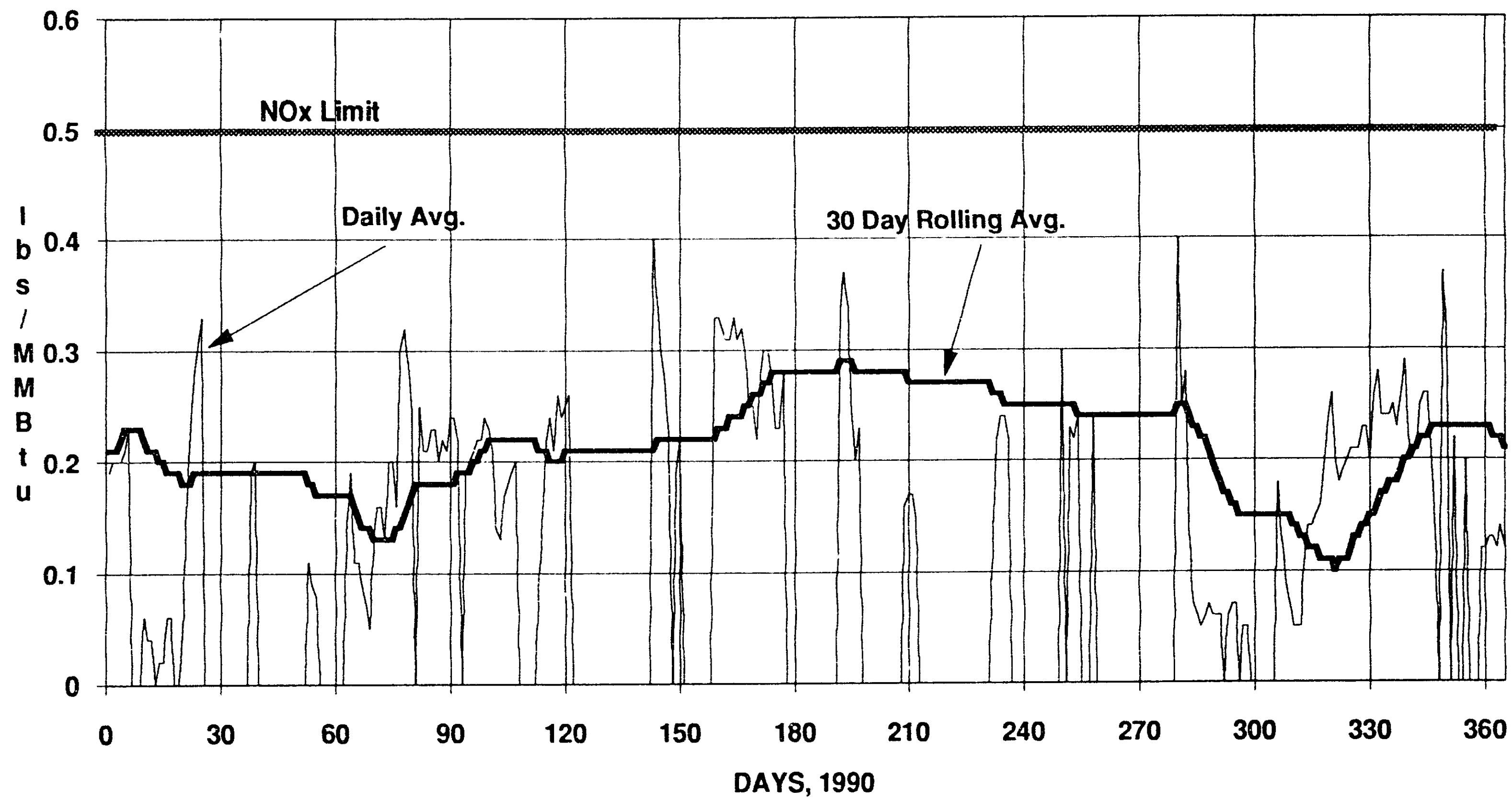
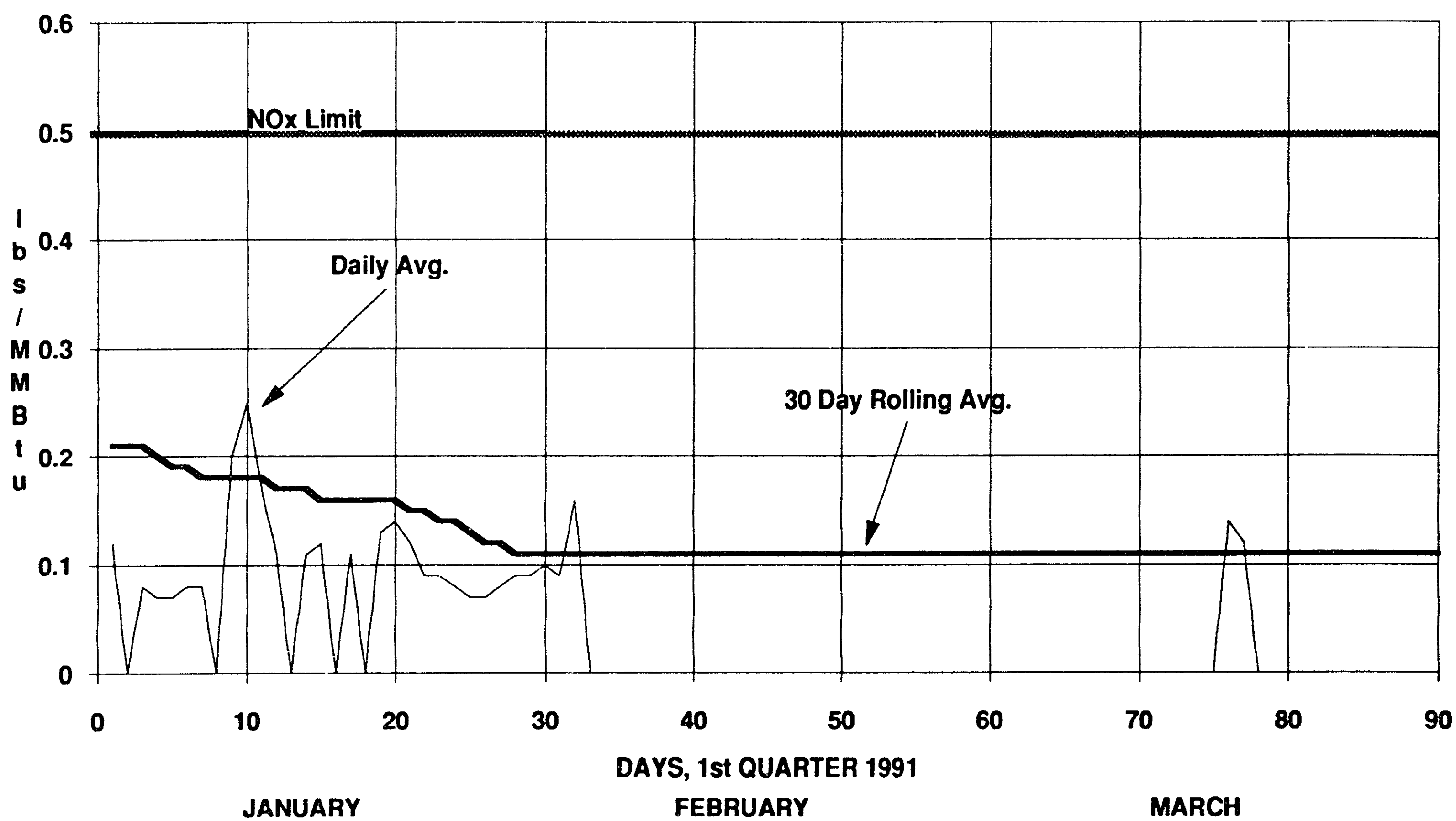


Figure 19-8. 1st Quarter 1991 NOx Emissions Summary
Nucla CFB



service to isolate the location of these tears, and then replace the bags. The frequency of these replacements is summarized in Section 15 on "Baghouse Operation and Performance".

Generally, opacity exceedences will occur during unit start-ups when gas burners are in service and baghouse inlet temperatures are less than 140°F. During these periods, combustion air flows through the bed material in the combustion chambers and carries solids past the baghouses to the stack. Until the baghouse inlet temperature reaches 140°F, the baghouse is bypassed to avoid problems associated with condensation. Opacity will generally exceed 20% during this 1 to 4 hour interval on start-up. During the period covering the test program on the Nucla CFB, there has never been any enforcement action required as a result of excessive opacity exceedences.

19.4.2 Waste-water Discharge

Data from waste-water discharge to the upper and lower cooling ponds are shown in Tables 19-1 through 19-8 from the first quarter of 1988 through the first quarter of 1991. The tables include the minimum, average, and maximum quarterly values (where applicable) for pH, total suspended solids, oil and grease, total copper, total iron, the flow in the conduit of treatment valve, visual oil and grease, total chromium, total chlorine, total zinc, and total dissolved solids. As can be seen from the tables, the same monitoring does not apply to the upper and lower ponds. For both ponds, the permit values are listed for the average and maximum values. The upper pond contains cooling tower blowdown, while the lower pond contains discharge from the boiler system, such as steam drum blowdown.

19.4.3 Waste Disposal

Waste disposal includes summaries of solids waste quantities of fly ash and bottom ash generated during the course of the test program, along with groundwater monitoring. Fly ash and bottom ash quantities generated for 1988, 1989, 1990, and the first quarter of 1991 are summarized in Tables 19-9 through 19-12 respectively. Data are summarized by month and total values are given for each year. The tables include the quantity of fly ash generated by the combustion of coal (adjusted for the addition of limestone), and the quantity of ash removed during the period. The difference is shown in column 10 for each table. All data in these tables should be compared with monthly unit capacity factors presented in Section 3.

A summary of groundwater data is shown in Table 19-13. Data are presented from two wells from the fourth quarter of 1989 through the first quarter of 1991. The maximum standard is

PARAMETER	UNITS	PERMIT Avg	PERMIT Max	1st Quarter 1988 Min	1st Quarter 1988 Avg	1st Quarter 1988 Max	2nd Quarter 1988 Min	2nd Quarter 1988 Avg	2nd Quarter 1988 Max	3rd Quarter 1988 Min	3rd Quarter 1988 Avg	3rd Quarter 1988 Max	4th Quarter 1988 Min	4th Quarter 1988 Avg	4th Quarter 1988 Max
PH	PH	6.5 min	9	7.04		10.17	7.12		9.97	7.39		9.88	7.04		9.3
Tota' Suspended Solids	mg/l	30 30 day avg	100 daily mx	91		124		9	12.1		8.1	24		9.5	16
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx		trace	trace								--	--
Total Copper	mg/l	1 30 day avg	1 daily mx												
Total Iron	mg/l	1 30 day avg	1 daily mx												
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.143	1.6		0.014	0.09		0.042	0.24		0.097	0.26
Oil & Grease (Visual)		report daily mx			yes			no			no			no	
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx		<0.05	<0.05		<0.05	<0.05		0.055	0.065		0.089	0.153
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx		0.025	0.1			0.02		<0.01	<0.01	Not Chlorinating		
Total Zinc	mg/l	1 30 day avg	1 daily mx		0.028	0.028		0.077	0.093		0.051	0.067		0.155	0.191
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx		1350	1350			215.2		921.2	921.2			65

Table 19-1. 1988 Quarterly Upper Pond Discharge Monitoring- #003- Cooling Tower.

PARAMETER	UNITS	PERMIT Avg	PERMIT Max	1st Quarter 1989 Min	1st Quarter 1989 Avg	1st Quarter 1989 Max	2nd Quarter 1989 Min	2nd Quarter 1989 Avg	2nd Quarter 1989 Max	3rd Quarter 1989 Min	3rd Quarter 1989 Avg	3rd Quarter 1989 Max	4th Quarter 1989 Min	4th Quarter 1989 Avg	4th Quarter 1989 Max
PH	PH	6.5 min	9	6.89		9.61	7.3		9.03	7.4		9.46	2.74		8.94
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx		12.3	77.2		9.6	16.1		14.71	54.2		6.85	16.4
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx		--	--	Visual Only-none			Visual Only-none			Visual Only-none		
Total Copper	mg/l	1 30 day avg	1 daily mx												
Total Iron	mg/l	1 30 day avg	1 daily mx												
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.092	0.38		0.13	0.22		0.19	0.5		0.15	0.68
Oil & Grease (Visual)		report daily mx			no			no			no			no	
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx		<0.05	<0.05		0.01	0.01		<0.05	<0.05		<0.05	<0.05
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx	Not Chlorinating				0	0	Not Chlorinating				0	0
Total Zinc	mg/l	1 30 day avg	1 daily mx		0.1	0.161		0.09	0.11		0.07	0.09		0.06	0.1
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx			356		625	625		1350	1350		1339	1920

Table 19-2. 1989 Quarterly Upper Pond Discharge Monitoring- #003- Cooling Tower.

PARAMETER	UNITS	PERMIT		1st Quarter 1990			2nd Quarter 1990			3rd Quarter 1990			4th Quarter 1990		
		Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
PH	PH	6.5 min	9	7.9		9.2	7.2		9.62	7.2		9.22	6.21		8.87
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx		7.76	39.6		8.66	24		6.69	16.2		5.53	8.6
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx	Visual Only-none			Visual Only-none			Visual Only-none			Visual Only-none		
Total Copper	mg/l	1 30 day avg	1 daily mx												
Total Iron	mg/l	1 30 day avg	1 daily mx												
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.2	0.62		0.13	0.47		0.082	0.37		0.151	0.28
Oil & Grease (Visual)		report daily mx			no			no			no			no	
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx		<0.05	<0.05		0.115	0.585		<.05	<.05		<.05	<.05
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx		0	0		0	0		0	0		0	0
Total Zinc	mg/l	1 30 day avg	1 daily mx		0.09	0.1		0.092	0.135		0.089	0.133		0.071	0.126
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx		1171	1790		1545	2010		1195	1630		1261	1520

Table 19-3. 1990 Quarterly Upper Pond Discharge Monitoring- #003- Cooling Tower.

PARAMETER	UNITS	PERMIT Avg	PERMIT Max	1st Quarter 1991 Min	1st Quarter 1991 Avg	1st Quarter 1991 Max	2nd Quarter 1991 Min	2nd Quarter 1991 Avg	2nd Quarter 1991 Max	3rd Quarter 1991 Min	3rd Quarter 1991 Avg	3rd Quarter 1991 Max	4th Quarter 1991 Min	4th Quarter 1991 Avg	4th Quarter 1991 Max
PH	PH	6.5 min	9	7.29		8.9									
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx		8	12.2									
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx		Visual Only-none										
Total Copper	mg/l	1 30 day avg	1 daily mx												
Total Iron	mg/l	1 30 day avg	1 daily mx												
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.065	0.21									
Oil & Grease (Visual)		report daily mx			no										
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx		<0.05	<0.05									
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx		0	0									
Total Zinc	mg/l	1 30 day avg	1 daily mx		0.234	0.309									
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx		1398	1490									

Table 19-4. 1991 1st Quarter Upper Pond Discharge Monitoring- #003- Cooling Tower.

PARAMETER	UNITS	PERMIT Avg	PERMIT Max	1st Quarter 1988 Min	1st Quarter 1988 Avg	1st Quarter 1988 Max	2nd Quarter 1988 Min	2nd Quarter 1988 Avg	2nd Quarter 1988 Max	3rd Quarter 1988 Min	3rd Quarter 1988 Avg	3rd Quarter 1988 Max	4th Quarter 1988 Min	4th Quarter 1988 Avg	4th Quarter 1988 Max
PH	PH	6.5 min	9			9.92	7.58		9.77	6.84		9.44	7.16		9.53
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx					3.8	5		3.2	9.8		6.6	21.8
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx					5.1	6.2		2.9	8.4		3.7	7
Total Copper	mg/l	1 30 day avg	1 daily mx		0.02			<0.1	0.1		0.02	0.022		0.066	0.332
Total Iron	mg/l	1 30 day avg	1 daily mx		0.12			0.31	0.713		0.098	0.2		0.245	0.433
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.07	0.07		0.1	0.54		0.14	0.99		0.191	0.5
Oil & Grease (Visual)		report daily mx			no			no			no			yes	
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx												
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx												
Total Zinc	mg/l	1 30 day avg	1 daily mx												
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx												

Table 19-5. 1988 Quarterly Lower Pond Discharge Monitoring- #004- Boiler System.

PARAMETER	UNITS	PERMIT Avg	PERMIT Max	1st Quarter 1989 Min	1st Quarter 1989 Avg	1st Quarter 1989 Max	2nd Quarter 1989 Min	2nd Quarter 1989 Avg	2nd Quarter 1989 Max	3rd Quarter 1989 Min	3rd Quarter 1989 Avg	3rd Quarter 1989 Max	4th Quarter 1989 Min	4th Quarter 1989 Avg	4th Quarter 1989 Max
PH	PH	6.5 min	9	7.43		9.32	7.63		9.6	7		9.19	7		8.7
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx		4.6	17.8		6.1	11.9		1.9	2.6		4.69	36.2
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx		3.5	20		7.5	12.8		6.2	10		13.33	36
Total Copper	mg/l	1 30 day avg	1 daily mx		0.022	0.03		<0.02	<0.02		<0.02	<0.02		<0.02	<0.02
Total Iron	mg/l	1 30 day avg	1 daily mx		0.085	0.234		0.08	0.3		0.04	0.07		0.07	0.08
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.082	0.225		0.055	0.156		0.296	0.68		0.082	0.24
Oil & Grease (Visual)		report daily mx			no			no			no			yes	
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx												
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx												
Total Zinc	mg/l	1 30 day avg	1 daily mx												
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx												

Table 19-6. 1989 Quarterly Lower Pond Discharge Monitoring- #004- Boiler System.

PARAMETER	UNITS	PERMIT Avg	PERMIT Max	1st Quarter 1990 Min	1st Quarter 1990 Avg	1st Quarter 1990 Max	2nd Quarter 1990 Min	2nd Quarter 1990 Avg	2nd Quarter 1990 Max	3rd Quarter 1990 Min	3rd Quarter 1990 Avg	3rd Quarter 1990 Max	4th Quarter 1990 Min	4th Quarter 1990 Avg	4th Quarter 1990 Max
PH	PH	6.5 min	9	6.92		8.65	6.73		9.17	7.65		9.02	8.2		9.06
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx		3.83	8		5.4	16		3.82	9.4		2.82	7.8
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx		6.36	38		0.3	2		0	0		0.615	6
Total Copper	mg/l	1 30 day avg	1 daily mx		<0.02	<0.02		<0.02	<0.02		<0.02	<0.02		<0.02	<0.02
Total Iron	mg/l	1 30 day avg	1 daily mx		0.05	0.103		0.107	0.221		0.071	0.184		0.067	0.146
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.09	0.173		0.073	0.156		0.131	0.22		0.134	0.327
Oil & Grease (Visual)		report daily mx			yes			no			no			no	
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx												
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx												
Total Zinc	mg/l	1 30 day avg	1 daily mx												
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx												

Table 19-7. 1990 Quarterly Lower Pond Discharge Monitoring- #004- Boiler System.

PARAMETER	UNITS	PERMIT		1st Quarter 1991			2nd Quarter 1991			3rd Quarter 1991			4th Quarter 1991		
		Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
PH	PH	6.5 min	9	7.76		9.35									
Total Suspended Solids	mg/l	30 30 day avg	100 daily mx		3.062	5.6									
Oil & Grease (Freon Extr-Gravimetric)	mg/l	15 daily mx	20 inst mx		0.569	7.4									
Total Copper	mg/l	1 30 day avg	1 daily mx		0.044	0.249									
Total Iron	mg/l	1 30 day avg	1 daily mx		0.165	0.596									
Flow in Conduit or Through Treatment Valve	Million Gal/day	report	report inst mx		0.128	0.24									
Oil & Grease (Visual)		report daily mx			no										
Total Chromium	mg/l	0.2 30 day avg	0.2 daily mx												
Total Chlorine	mg/l	optional 30 day avg	0.065 daily mx												
Total Zinc	mg/l	1 30 day avg	1 daily mx												
Total Dissolved Solids	mg/l	optional 30 day avg	report daily mx												

Table 19-8. 1991 1st Quarter Lower Pond Discharge Monitoring- #004- Boiler System.

NUCLA STATION
1988 ASH ACCOUNTING SPREADSHEET

16-Jan-89

Month	Ash Produced (Using As-Fired Coal Analysis) Coal (tons)	Ash (%)	Ash (tons)	Adjusted * Ash Produced (tons)	Ash Removed: R & R Removal Loads (#)	Loads x 25 (tons)	+ Other Removal (tons)	= Total Removal (tons)	Difference (Adj. Ash Produced Minus Removal) (tons)	Estimate of truck loading (tons/load)
Jan	17,666	16.12	2,848	4,999	221.0	5,525	0	5,525	(526)	22.6
Feb	18,174	16.93	3,077	5,310	239.0	5,975	0	5,975	(665)	22.2
Mar	14,732	18.80	2,770	4,617	245.0	6,125	0	6,125	(1,508)	18.8
Apr	11,436	20.37	2,329	3,787	147.0	3,675	0	3,675	112	25.8
May	15,048	19.90	2,995	4,904	223.0	5,575	0	5,575	(671)	22.0
Jun	19,559	23.60	4,616	7,195	363.0	9,075	0	9,075	(1,880)	19 3
Jul	20,491	18.02	3,692	6,240	315.0	7,875	0	7,875	(1,635)	19.8
Aug	0	0	0	0	45.0	1,125	0	1,125	(1,125)	0.0
Sep	5,428	28.55	1,550	2,302	81.0	2,025	0	2,025	277	28.4
Oct	20,528	23.73	4,871	7,582	275.0	6,875	0	6,875	707	27.6
Nov	20,690	26.54	5,491	8,301	367.0	9,175	0	9,175	(874)	22.6
Dec	21,038	18.20	3,829	6,450	301.0	7,525	0	7,525	(1,075)	21.4
TOTAL	184,789		38,067	61,685	2,822.0	70,550	0	70,550	(8,865)	21.9

* Adjustment = (total ash * .85 * .15) + (total ash * .15 * .05) + (total coal * .10) + total ash
<moisture in flyash> <moisture in bottom ash> <limestone in flyash>

Table 19-9. 1988 Monthly Nucla Station Ash Accounting Spreadsheet.

NUCLA STATION
1989 ASH ACCOUNTING SPREADSHEET

18-Jan-90

Month	Ash Produced (Using As-Fired Coal Analysis)				Ash Removed				Difference (Adj. Ash Produced Minus Removal)	Estimate of truck loading
					R & R Removal +		Other Removal =	Total Removal		
	Coal (tons)	Ash (%)	Ash (tons)	Adjusted * Ash Produced (tons)	Loads (#)	Loads x 25 (tons)	(tons)	(tons)	(tons)	(tons/load)
Jan	4,169	16.52	689	1,199	92	2,300	0	2,300	(1,101)	13.0
Feb	5,340	17.97	960	1,623	64	1,600	0	1,600	23	25.4
Mar	25,393	18.77	4,766	7,949	330	8,250	0	8,250	(301)	24.1
Apr	19,477	20.04	3,903	6,378	303	7,575	0	7,575	(1,197)	21.0
May	7,890	23.70	1,870	2,911	100	2,500	0	2,500	411	29.1
Jun	21,759	19.44	4,230	6,977	330	8,250	0	8,250	(1,273)	21.1
Jul	20,753	14.20	2,947	5,420	236	5,900	0	5,900	(480)	23.0
Aug	9,869	12.96	1,279	2,439	107	2,675	0	2,675	(236)	22.8
Sep	12,141	15.49	1,881	3,349	139	3,475	0	3,475	(126)	24.1
Oct	4,805	28.00	1,345	2,008	88	2,200	0	2,200	(192)	22.8
Nov	24,620	20.38	5,017	8,157	299	7,475	20	7,495	662	27.3
Dec	24,041	18.08	4,347	7,338	306	7,650	48	7,698	(360)	24.0
TOTAL	180,257		33,234	55,746	2,394	59,850	67	59,917	(4,171)	23.3

* Adjustment = (total ash * .85 * .15) + (total ash * .15 * .05) + (total coal * .10) + total ash
‹moisture in flyash› ‹moisture in bottom ash› ‹limestone in flyash›

Table 19-10. 1989 Monthly Nucla Station Ash Accounting Spreadsheet.

NUCLA STATION
1990 ASH ACCOUNTING SPREADSHEET

10-Jan-91

Month	Ash Produced (Using As-Fired Coal Analysis) Coal (tons)	Ash (%)	Ash (tons)	Adjusted * Ash Produced (tons)	Ash Removed: Tri-Park Removal + Loads (#)	Loads x 25 (tons)	Other Removal (tons)	= Total Removal (tons)	Difference (Adj. Ash Produced Minus Removal) (tons)	Estimate of truck loading (tons/load)
Jan	23,418	19.18	4,492	7,440	347	8,675	0	8,675	(1,235)	21.4
Feb	5,765	18.11	1,044	1,761	67	1,675	0	1,675	86	26.3
Mar	32,656	17.31	5,653	9,681	351	8,775	0	8,775	906	27.6
Apr	33,576	17.21	5,778	9,916	431	10,775	0	10,775	(859)	23.0
May	11,226	17.82	2,000	3,393	139	3,475	0	3,475	(82)	24.4
Jun	22,302	16.64	3,711	6,442	345	8,625	26	8,651	(2,209)	18.7
Jul	9,415	17.03	1,603	2,761	110	2,750	0	2,750	11	25.1
Aug	5,041	16.56	835	1,452	70	1,750	0	1,750	(298)	20.7
Sep	7,450	15.91	1,185	2,090	75	1,875	274	2,149	(59)	27.9
Oct	11,818	18.94	2,238	3,722	153	3,825	0	3,825	(103)	24.3
Nov	34,283	17.07	5,852	7,227	408	10,200	0	10,200	(2,973)	17.7
Dec	30,420	19.59	5,959	7,360	348	8,700	0	8,700	(1,340)	21.1
TOTAL	ERR		40,351	63,247	2,844	71,100	300	71,400	(8,153)	20.1

* Adjustment = (total ash * .85 * .15) + (total ash * .15 * .05) + (total coal * .10) + total ash
<moisture in flyash> <moisture in bottom ash> <limestone in flyash>

Table 19-11. 1990 Monthly Nucla Station Ash Accounting Spreadsheet.

NUCLA STATION
1991 ASH ACCOUNTING SPREADSHEET

05-Apr-91

Month	Ash Produced (Using As-Fired Coal Analysis) Coal (tons)	Ash (%)	Ash (tons)	Adjusted * Ash Produced (tons)	Ash Removed: Tri-Park Loads (#)	Tri-Park Removal + Loads x 25 (tons)	Other = Removal (tons)	Total Removal (tons)	Difference (Adj. Ash Produced Minus Removal) (tons)	Estimate of truck loading (tons/load)
Jan	26,039	17.65	4,596	7,820	340	8,500	0	8,500	(680)	23.0
Feb	1,693	25.43	431	658	34	850	0	850	(192)	19.4
Mar	2,202	17.76	391	664	27	675	0	675	(11)	24.6
Apr	0	0.00	0	0	0	0	0	0	0	ERR
May	0	0.00	0	0	0	0	0	0	0	ERR
Jun	0	0.00	0	0	0	0	0	0	0	ERR
Jul	0	0.00	0	0	0	0	0	0	0	ERR
Aug	0	0.00	0	0	0	0	0	0	0	ERR
Sep	0	0.00	0	0	0	0	0	0	0	ERR
Oct	0	0.00	0	0	0	0	0	0	0	ERR
Nov	0	0.00	0	0	0	0	0	0	0	ERR
Dec	0	0.00	0	0	0	0	0	0	0	ERR
TOTAL	29,934		5,418	9,142	401	10,025	0	10,025	(883)	22.8

* Adjustment = (total ash * .85 * .15) + (total ash * .15 * .05) + (total coal * .10) + total ash
<moisture in flyash> <moisture in bottom ash> <limestone in flyash>

Table 19-12. 1991 1st Quarter Monthly Nucla Station Ash Accounting Spreadsheet.

Constituent	Units	Maximum Standard	4th Quarter 1989		1st Quarter 1990		2nd Quarter 1990		3rd Quarter 1990		4th Quarter 1990		1st Quarter 1991	
			Well #1	Well #2	Well #1	Well #2	Well #1	Well #2	Well #1	Well #2	Well #1	Well #2	Well #1	Well #2
		(class 2)												
pH	ph	5.0-9.0	7.3	7.7	7.3	7.2	7.4	7.1	7.4	7.45	7.3	7.3	7.4	7.2
Ammonia (N)	mg/l	0.5	0.007	0.05	0	0.12	0	0.01	0	0	0	0.077	0.007	0.033
Free Cyanide (CN)	mg/l	0.2	0	0	0	0	0	0	0	0	0	0	0	0
Flouride (F)	mg/l	1.4-2.4	0.29	0.95	0.42	0.42	0.19	0.2	0.55	0.63	0.44	0.44	0.38	0.44
Nitrate (N)	mg/l	10	1.59	0.72	0.9	0.365	0.76	0.85	0.8	0.31	0.722	0.245	0.622	0.358
Nitrite (N)	mg/l	1	0.003	0.003	0	0.033	0	0.03	0	0	0	0	0	0
Sulfide (H2S)	mg/l	0.05	0.4	0	0	0	0	0	0	0.06	0	0.16	0	0
Boron (B)	mg/l	none	0.186	0.31	0.08	0.01	0.1	0.12	0.03	0	0	0	0.553	0.424
Chloride (Cl)	mg/l	250	8	19	8	10.4	16.5	15	27	16	12	10	14	12
Sulfate (SO4)	mg/l	250	271	640	225	1180	278	760	337	694	253	744	235	694
Aluminum (Al)	mg/l	none	0.01	0.015	0.01	0.01	0	0	0	0	0.023	0.023	0.007	0.003
Arsenic (As)	mg/l	0.05	0.006	0.008	0	0	0	0.008	0	0	0	0	0	0
Barium (Ba)	mg/l	1	0.38	0.74	0.16	0.3	0.088	0.039	0	0	0.04	0.41	0.16	0.08
Beryllium (Be)	mg/l	none	0	0	0	0	0	0	0	0	0	0	0	0
Cadmium (Cd)	mg/l	0.01	0.0003	0.0004	0.0001	0	0	0.0001	0.0003	0	0	0	0.0007	0
Trivalent Chromium (Cr+3)	mg/l	0.05	0.008	0	0	0.002	0.003	0	0.003	0	0	0	0	0
Hexavalent Chromium (Cr+6)	mg/l	0.05	0	0	0	0	0	0	0	0	0	0	0	0
Copper (Cu)	mg/l	1	0.005	0.001	0.004	0.002	0	0.007	0.004	0.004	0.004	0.002	0.013	0.016
Iron (Fe) (Dissolved)	mg/l	0.3	0	1.91	0	0	0	0.23	0	0	0.06	0.17	0	0
Lead (Pb)	mg/l	0.05	0.002	0.008	0.001	0.001	0.005	0.004	0.003	0.004	0.003	0.004	0.001	0.001
Manganese (Mn) (Dissolved)	mg/l	0.05	0.045	0.863	0.01	1.62	0.028	0.441	0.078	1.13	0.034	2.37	0.054	1.29
Mercury (Hg)	mg/l	0.002	0.00011	0.00033	0	0	0.00011	0	0	0	0.00008	0.00001	0	0
Nickel (Ni)	mg/l	none	0.001	0.001	0.001	0.006	0.005	0.002	0	0	0	0	0	0
Selenium (Se)	mg/l	0.01	0	0	0.001	0	0	0	0.003	0	0	0	0	0
Silver (Ag)	mg/l	0.05	0.0006	0.0039	0	0	0.0007	0.0011	0	0	0	0	0	0
Thallium (Ti)	mg/l	none	0	0	0	0.001	0	0	0	0	0	0	0	0
Zinc (Zn)	mg/l	5	0.047	0.025	0.041	0.227	0.009	0.022	0.054	0.015	0.018	0.018	0.065	0.016
Total Alkalinity (CaCO3)	mg/l	none	400	378	356	176	354	278	316	205	405	240	487	183
Phenol. Alkalinity (CaC03)	mg/l	none	0	0	0	0	0	0	0	0	0	0	0	0
Total Dissolved Solids	mg/l	10000	1100	1590	868	1530	893	1520	921	1100	916	1310	952	1310
Total Organic Carbon	mg/l	none	10.8	14.8	6.8	3.8	9.32	9.66	8.36	6.09	20.3	18	1.7	1.7
Calcium (Ca)	mg/l	none	128	62	98	104	115	57	54	93	97	146	109	127
Magnesium (Mg)	mg/l	none	42.5	14.8	35	29	36	11	32	23	36	41	39	25
Potassium (K)	mg/l	none	5	2	8.7	9	7	12	9	10.4	7.8	8.1	10	9.5

Table 19-13. Nucla CFB Groundwater Monitoring Report Summary.

listed along with each constituent, where applicable. Values in excess of these standards are shown highlighted in gray.

The wells were installed in late 1989 and were sampled for the first time on December 20, 1989. Well #1 is at the northwest corner of the plant site (up gradient), and Well #2 is near the southeast boundary (down gradient). Well #1 is dug approximately 54 feet deep and contains 35 feet of water on average. Well #2 is dug approximately 33 feet deep and contains about 28 feet of water on average. Quarterly sampling continued until the conclusion of the Phase II test program in early 1991. The final sample was taken February 27, 1991.

Certain constituents were generally higher in the down gradient well #2. These are ammonia, sulfate, manganese, and total dissolved solids. Other constituents were higher in the up gradient well, including nitrate, total alkalinity, and magnesium. There were generally no detectable quantities of cyanide, beryllium, hexavalent chromium, thallium, or phenolphthalein alkalinity.

19.5 ADDITIONAL TEST PROGRAM MONITORING

The DOE/METC landfill test cell has been constructed, filled with fly ash from the Nucla CFB, covered, and instrumented. Data from this cell have been collected and preliminary results have been reported at the 1991 11th International Conference on Fluidized Bed Combustion. This report is presented in volume 2, page 865 of the proceedings from this conference which is available from the American Society of Mechanical Engineers. The title of the paper is "Field Study of Wastes from Fluidized Bed Combustion Technologies" by Andrew Weinberg, Larry Holcomb, and Ray Butler. The following is extracted from the conclusions of this report.

Preliminary chemical analysis of the waste and soils in the vicinity of the test cell has been completed. Three sets of quarterly core samples have been analyzed. The work to date has demonstrated that landfill construction using FBC wastes is straight-forward. No problems were encountered with rapid set-up of the conditioned waste, nor with excessive dusting of the material.

Preliminary chemical characterization of the waste indicates that its large available lime content initiates pozzolanic reactions that form secondary cementing phases and clays as weathering products. Waste in the test cell has solidified into a coherent mass due to the cementing action of the pozzolanic reactions, even in the semi-arid conditions of western Colorado. Secondary cement and mineral phases formed by weathering and pozzolanic reactions were confirmed by x-ray diffraction analysis.

The ASTM leachate from the FBC waste is characterized by a high pH, low metals content and high concentrations of calcium, potassium, sodium, chloride and sulfate. The ASTM leachates show the degree of equilibrium with some cementitious phases and weathering products in the land-filled waste. The growth of the secondary phases in the waste may alter the leachate chemistry as these reactions proceed. The secondary phases preferentially incorporate some ions into the new solids, while other ions not compatible with the growing crystal structures enrich the leachate solution.

Solidification of the wastes is expected to decrease their permeability markedly, slowing the infiltration of additional water into the wastes. Laboratory tests have shown permeability values of about 3×10^{-5} cm/sec in the upper 0.3 m (1 ft) of ash and permeabilities of 2×10^{-5} to 1×10^{-5} cm/sec at depths of 0.9 and 1.5 m (3 and 5 ft), respectively. In general, the ash was delivered to the cell with 30% moisture, which is about 7% below the optimum moisture of 37% (at 76 pcf maximum dry density) determined in laboratory testing. The moisture in the ash initiated pozzolanic reactions in the field test cell, resulting in a reduction in the permeability of the material to the observed values of about 2×10^{-5} cm/sec. Very little rainfall has been received at the site since June 1989, limiting further pozzolanic reactions in the ash.

Table 19-14 has been included from this report which includes the initial characterization of the ash. Table 19-15 shows the results of ASTM water extractions from three core samples taken in September 1989, December 1989, and March 1990.

The EPRI Environmental Characterization Plan was implemented by the Radian Corporation at the site in April 1990. The plan called for the collection of three sets of all samples to provide verification of results. During the week of testing, the unit tripped from a superheater tube leak and was down for a three-week repair outage. Only one set of samples were collected prior to this incident. Since the data was not complete and had not been substantiated by back-up samples, it was not published and released by EPRI. In June of 1990, EPRI concluded performance testing on the Nucla unit and the Environmental Characterization Plan was terminated at this time.

	Units	Detection Limit	Fly Ash	Bottom Ash
ICAPES				
Aluminum	mg/kg	20	126000	94100
Antimony	mg/kg	400	<DL	<DL
Barium	mg/kg	1.0	427	157
Boron	mg/kg	1200	<DL	<DL
Calcium	mg/kg	100	81100	113000
Chromium	mg/kg	3	43	26
Cobalt	mg/kg	20	<DL	<DL
Copper	mg/kg	40	45	<DL
Iron	mg/kg	4	226	37900
Magnesium	mg/kg	100	4260	5660
Manganese	mg/kg	1.0	144	250
Molybdenum	mg/kg	5	240	240
Nickel	mg/kg	2	96	51
Potassium	mg/kg	300	7000	10500
Silicon	mg/kg	100	216000	203000
Silver	mg/kg	20	<DL	<DL
Sodium	mg/kg	100	2450	3250
Strontium	mg/kg	0.3	340	280
Tin	mg/kg	140	<DL	<DL
Titanium	mg/kg	12	1500	3600
Vanadium	mg/kg	2.0	200	41
Zinc	mg/kg	5	130	100
Percent recovery (dry weight basis)			86.78%	84.56%
AA				
Arsenic	mg/kg	30	7.1	7.7
Cadmium	mg/kg	0.5	1.7	2.2
Lead	mg/kg	5.0	34	37
Selenium	mg/kg	30	6.7	12
Acid Soluble Sulfur	mg/g as S	0.25	22	50
Water Soluble Sulfate	mg/g as S	0.25	16	14.5
Water Soluble Chloride	mg/g as Cl	0.1	0.5	<DL
Water Soluble Carbonate	mg/g as CO3	2.5	45	60
Water Soluble Fluoride	mg/g as F	0.0012	0.32	0.015
Available Lime Index	mg/g as CaO	NA	68	74
Inorganic Carbon	mg/g as CO3	2	89.5	52.5
Loss on Ignition	%	NA	8.7	1.2
Forms of Sulfur				
Pyritic	mg/g as S	NA	0	0
Sulfate	mg/g as S	NA	19.3	35
Organic	mg/g as S	NA	0	0
		NA		
Total Chromatographable Organics	mg/kg	NA	3.6	3.3
		Regulatory Limit		
RCRA EP				
ICPES				
Barium	mg/L	100	0.082	0.11
Chromium	mg/L	5	0.012	<0.010
Silver	mg/L	5	<0.010	<0.010
AA				
Arsenic	mg/L	5	<0.0050	<0.0050
Cadmium	mg/L	1	0.0011	<0.0003
Lead	mg/L	5	<0.0020	<0.0020
Mercury	mg/L	0.2	<0.0002	0.0002
Selenium	mgL	1	<0.0050	<0.0050
MISC				
pH		$2 \leq pH \leq 12.5$	5.5	11.7

NA - Not Applicable
DL - Method detection limit

Table 19-14. Initial Nucla CFB Fly Ash Characterization.

Parameter	Detection Limit	Initial Fly Ash	September 1989		December 1989		March 1990	
			Average	High/Low	Average	High/Low	Average	High/Low
Arsenic	(0.0050)	ND	0.0059	0.0081/ND	0.005	0.0084/ND	ND	ND
Cadmium	(0.0010)	ND	ND	ND	ND	ND	ND	ND
Lead Selenium	(0.0030)	0.0022	0.0046	0.0089/ND	0.018	0.041/ND	0.0035	0.0097/ND
	(0.0050)	0.0072	3.68	12.6/ND	ND	ND	ND	0.0057/ND
Elements by ICPES								
Aluminum	(0.20)	ND	1.46	3.8/ND	1.31	2.4/0.35	1.24	3.6/ND
Barium	(0.010)	0.10	ND	0.036/ND	0.016	0.024/0.014	0.041	0.092/ND
Boron	(0.60)	0.67	ND	0.78/ND	ND	ND	ND	ND
Calcium	(1.0)	1100.0	0.48	500/380	470	540/400	604	1200/290
Chromium	(0.010)	0.028	426	.018/ND	0.020	0.025/0.011	ND	0.012/ND
Cobalt	(0.010)	ND	0.011	ND	ND	ND	ND	ND
Copper	(0.020)	ND	ND	ND	ND	ND	ND	ND
Magnesium	(1.0)	ND	1.3	2.5/ND	0.88	1.3/ND	ND	ND
Manganese	(0.010)	ND	ND	ND	ND	ND	ND	ND
Molybdenum	(0.050)	0.32	0.082	0.16/ND	0.083	0.12/0.055	0.081	0.14/ND
Nickel	(0.020)	ND	ND	ND	ND	ND	ND	ND
Potassium	(3.0)	6.0	33.8	43/24	29.5	46/21	30.6	48/15
Silicon	(1.0)	NA	2.2	6.2/ND	3.73	10/1.8	2.91	10.7/ND
Sodium	(1.0)	4.2	NA	NA	7.58	9.9/5.3	5.3	7.9/2.9
Strontium	(0.0030)	NA	2.05	3.0/1.6	2.03	2.5/1.5	2.3	3.5/1.1
Vanadium	(0.020)	ND	.07	0.11/0.05	0.024	0.041/ND	0.035	0.071/ND
Zinc	(0.020)	4.9	ND	ND	ND	ND	0.04	0.18/ND
Miscellaneous								
Conductivity (μmhos/cm)	5	5400.0	1808	2125/1470	1685	1900/1430	2059	6200/1100
pH (units)	(0.05)	12.2	10.35	11.6/9.2	10.27	11.1/9.9	10.89	12.0/10.0
Chloride	(0.040)	34.0	32.8	43/22	21.5	25/18	17.8	26/9
Nitrate	(1.0)	ND	ND	ND	ND	0.8/ND	0.74	0.86/0.60
Sulfate	(1.0)	1300.0	1048	1200/990	1163	1400/980	1023	1600/580
Sulfite	(0.40)	ND	10.4	20/8.0	2.9	6.1/ND	6.2	17.6/ND

ND - Not Detected
NA - Not Analyzed

Table 19-15. ASTM Water Extractions of Initial and Landfilled Nucla CFB Fly Ash (mg/L, except as noted).

Appendix A

TEST INSTRUMENTATION CALIBRATION SCHEDULE

INSTRUMENT CALIBRATION DATA

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	USED IN PERFORMANCE CALCULATION NUMBER														SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 6 TST	SEC 9 TST	USED FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
							1	2	3	4	5	6	7	8	9	A	B	C	D	E																			
RELATIVE HUMIDITY	CAT301	%		0	100	X													D											0	100	%	CAPACITOR		10/13/87	NR	-		WTHRTRNCS MODEL 1500
REL. HUM. VOLTS TO CURRENT MODULE	CAT301-VCM	VDC		0	5	X													D											0	5	VDC	.	E/I	10/13/87				MODEL 1630 CHANNEL 1 OR 2
AMBIENT AIR PRESS	CPT302	PSIA	IN HG	21	31	X													D	E												IN WG		AP-5		180			
AMBIENT TEMP	CTE300	DEGF		-40	120	X													D											-40	120	DEGF	100ΩPLAT		10/13/87			X	WTHRTRNCS MODEL 1420A
AMB. TMP. VOLTS TO CURRENT MODULE	CTE300-VCM	VDC		0	5	X													D											0	5	VDC	.	E/I	10/13/87		-		MODEL 1630 CHANNEL 1 OR 2
DRUM LEVEL	DLT1PC		IN	-10	10																																		
WEST BOILER DRUM PRESS	DPT50		PSIG	0	1800																							X		0	1800	PSIG	STATIC TAP	GP-9	1/27/87	180			
STEAM TEMP @ SH I OUTLET(SB STM SOURCE)	DTE52	DEGF		500	1000	X	1	2																								DEGF	E	-		NR	-		
STEAM TEMP @ SH I OUTLET(SB STM SOURCE)	DTE53	DEGF		500	1000	X	1	2																								DEGF	E	-		NR	-		
BOILER DRUM UPPER METAL TEMP	DTE57	DEGF		500	1000																							X				DEGF	K	-		NR	-		
BOILER DRUM LOWER METAL TEMP	DTE58	DEGF		500	1000																							X				DEGF	K	-		NR	-		
BOILER DRUM UPPER METAL TEMP	DTE59	DEGF		500	1000																							X				DEGF	K	-		NR	-		
DRUM METAL TEMPERATURE	DTE60																																						
BOILER DRUM LOWER METAL TEMP	DTE64	DEGF		500	1000																							X				DEGF	K	-		NR	-		
MAIN STEAM FLOW	EFI	KLB/HR		0	1000	X	1																					X		-	-	-	-	-	-	-	-		CLC FRM KPT2,KTE1
SH III SPRAY EAST FLOW	EFT10	KLB/HR		0	18	X	1																							0	20.7	IN WC	ANF	DP-3	4/7/87	180	10/4/87		ANNUBAR
FEEDWATER FLOW RATE	EFT3	KLB/HR		0	1000																								X										
BOILER FEEDWATER FLOW - TEMP COMP	EFT3TC	KLB/HR		0	1000	X	1																					X		0	100	IN WC	FE	2051D		180			EFT3,ETE3
COMB 4A SH II SPRAY FLOW	EFT7	KLB/HR		0	40	X	1																							0	14.7	IN WC	ANF	DP-3	3/25/87	180	9/21/87		ANNUBAR
COMB 4B SH II SPRAY FLOW	EFT8	KLB/HR		0	40	X	1																							0	14.7	IN WC	ANF	DP-3	3/25/87	180	9/21/87		ANNUBAR
SH III SPRAY WEST FLOW	EFT9	KLB/HR		0	18	X	1																							0	20.7	IN WC	ANF	DP-3	4/7/87	180	10/4/87		ANNUBAR
ECON FEEDWATER INLET PRESS	EPT3	PSIA	PSIG	0	2200	X	1																							0	2200	PSIG	STATIC TAP	GP-9	8/11/86	180	2/7/87		
BFP DISCH HDR PRESS (SPRAY SOURCE)	EPTS1	PSIA	PSIG	0	2200	X	1																							0	2200	PSIG	STATIC TAP	GP-9	9/16/87	180	3/14/88		
FINISH SUPERHEATER III A INLET STM TEMP	ETE10A		DEGF	500	1000																																		
FINISH SUPERHEATER III A OUTLET STM TEMP	ETE10B		DEGF	500	1500																																		
ECON FEEDWATER INLET TEMP	ETE3	DEGF		0	600	X	1																					X	X			DEGF	E	-		NR	-		
BFP DISCH HDR TEMP (SPRAY SOURCE)	ETE52	DEGF		0	600	X	1																									DEGF	E	-		NR	-		
RADIANT SUPERHEATER II A INLET TEMP	ETE7A		DEGF	700	1000																																		
RADIANT SUPERHEATER II A OUTLET STM TEMP	ETE7B		DEGF	700	1000																																		
RADIANT SUPERHEATER II B INLET TEMP	ETE8A		DEGF	700	1000																																		
RADIANT SUPERHEATER II B OUTLET STM TEMP	ETE8B		DEGF	700	1000																																		
FINISH SUPERHEATER III B INLET STM TEMP	ETE9A		DEGF	500	1000																																		
FINISH SUPERHEATER III B OUTLET STM TEMP	ETE9B		DEGF	500	1500																																		
BFP 4A WATTS	EWM300	KW		0	3000																		X				X	X											
BFP 4B WATTS	EWM301	KW		0	3000																		X																
GAS ANALYZER SO2 (LOW RANGE)	GAT313	PPM		0	500	X			3				7	8			B				X			X			X	X		0	500	PPM	UV ABSRPT	-					KVB
GAS ANALYZER NOx	GAT314	PPM		0	10000	X								8			B					X		X			X	X		0	1000	PPM	CHEMLUMN	-					KVB
GAS ANALYZER CO	GAT315	PPM		0	5000	X		2		4	5			8			B							X			X	X		0	5000	PPM	NDIR	-					KVB
GAS ANALYZER O2	GAT316	%		0	50	X						6	7	8			B							X			X	X		0	21	%	PARAMAG	-					KVB
GAS ANALYZER SO2 (HIGH RANGE)	GAT317	PPM		0	1500	X			3				7	8			B							X			X	X		0	1500	PPM	UV ABSRPT	-					KVB
GAS ANALYZER CO2	GAT318	%		0	20	X				4				8			B							X			X	X		0	20	%	NDIR	-					KVB
STACK OPACITY	GA/54																																						
LOOP SEAL 4B dP	GDPT311	IN WC		0	100																					X				0	100	IN WC	STATIC TAP	DP4	6/10/87	180	12/7/87		
DRAFT LOSS ACROSS PRIM & FINISH SUPERHEATER	GDPT70		IN WC	0	4																																		
DRAFT LOSS ACROSS ECONOMIZER	GDPT71		IN WC	0	4																																		
DRAFT LOSS ACROSS AIR HEATER GAS SIDE	GDPT75		IN WC	0	5																																		
PA FLOW RATE CMB 4A	GFT1C	KLB/HR		0	340																								X										
COMB 4A PRI AIR FLW (UNDERBED)-TEMP COMP	GFT1CTC	KLB/HR		0	500	X											B			E										0	5.98	IN WC	AIRFOIL	DP3	7/16/87	180	1/12/88		CLC FROM GFT1C,GTE1A,GTE1B
PA FLOW RATE CMB 4B	GFT1D	KLB/HR		0	340																								X										
COMB 4B PRI AIR FLW (UNDERBED) -TEMP COMP	GFT1DTC	KLB/HR		0	500	X											B			E										0	5.98	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1D,GTE1C,GTE1D
LOWER LEVEL INJ AIR 4A REAR	GFT1W	KLB/HR																											X										
4A LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1WTC	KLB/HR	KLB	0	150															E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1W,GTE1A,GTE1B
LOWER LEVEL INJ AIR 4A FRONT	GFT1X	KLB/HR																											X										
4A LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1XTC	KLB/HR	KLB	0	150												B			E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1X,GTE1A,GTE1B
LOWER LEVEL INJ AIR 4B REAR	GFT1Y	KLB/HR																											X										
4B LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1YTC	KLB/HR	KLB	0	150												B			E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1Y,GTE1C,GTE1D
LOWER LEVEL INJ AIR 4B FRONT	GFT1Z	KLB/HR																											X										
4B LOWER INJ PRI AIR FLOW - TEMP COMP	GFT1ZTC	KLB/HR	KLB	0	150												B			E										0	6.99	IN WC	AIRFOIL	DP3	6/15/87	180	12/12/87		CLC FROM GFT1Z,GTE1C,GTE1D
BTM ASH CLR AIR FLOW	GFT25	KLB/HR		0	102	X	1	2									B			E										0	6	IN WC	AIRFOIL	DR2	9/26/87	180	3/24/88		
SA FLOW RATE CMB 4A	GFT2D	KLB/HR		0	137																								X										

DATE 4/26/88

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	USED IN PERFORMANCE CALCULATION NUMBER: 1	2	3	4	5	6	7	8	9	A	B	C	D	E	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 6 TST	SEC 9 TST	USED FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55B	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	-		
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55C	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	-		
TEMP IN COMB 4A 80" ABOVE DIST PLATE	GTE55D	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56A	DEGF		1000	2000																							X				DEGF	K	-	2/26/87	NR	-		
COMB 4B BED TEMP 40" AVERAGE	GTE56AVG			0	100																																		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56B	DEGF		1000	2000																							X				DEGF	K	-	2/27/87	NR	-		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56C	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 40" ABOVE DIST PLATE	GTE56D	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57A	DEGF		1000	2000																							X				DEGF	K	-	2/26/87	NR	-		
COMB 4B BED TEMP 80" AVERAGE	GTE57AVG			0	100																																		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57B	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57C	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
TEMP IN COMB 4B 80" ABOVE DIST PLATE	GTE57D	DEGF		1000	2000																							X				DEGF	K	-		NR	-		
CYCLONE 4A GAS INLET TEMP	GTE58	DEGF		1000	2000	X														E						X						DEGF	K	-		NR	-		
CYCLONE 4A GAS INLET TEMP	GTE59	DEGF		1000	2000	X														E						X	X					DEGF	K	-		NR	-		
CYCLONE 4A GAS OUTLET TEMP	GTE61	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
CYCLONE 4B GAS INLET TEMP	GTE62	DEGF		1000	2000	X														E						X						DEGF	K	-		NR	-		
CYCLONE 4B GAS INLET TEMP	GTE63	DEGF		1000	2000	X														E						X						DEGF	K	-		NR	-		
CYCLONE 4B GAS OUTLET TEMP	GTE64	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
CYCLONE 4B GAS OUTLET TEMP	GTE65	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
LOOP SEAL 4A SOLIDS INLET TEMP	GTE66A	DEGF		300	600																					X				1000	2000	DEGF	K	-		NR	-		
LOOP SEAL 4A SOLIDS INLET TEMP	GTE66B	DEGF		300	600																					X				1000	2000	DEGF	K	-		NR	-		
LOOP SEAL 4B SOLIDS INLET TEMP	GTE67A	DEGF		300	600																					X				1000	2000	DEGF	K	-		NR	-		
LOOP SEAL 4B SOLIDS INLET TEMP	GTE67B	DEGF		300	600																					X				1000	2000	DEGF	K	-		NR	-		
PRIMARY SUPERHEATER GAS OUTLET TEMP	GTE68		DEGF	1000	2000																																		
PRIMARY SUPERHEATER GAS OUTLET TEMP	GTE69		DEGF	1000	2000																																		
CYCLONE 4A GAS OUTLET TEMP	GTE60	DEGF		1000	2000																					X		X				DEGF	K	-		NR	-		
FINISH SUPERHEATER GAS OUTLET TEMP	GTE70		DEGF	1000	2000																																		
CYCLONE 4B OUTLET REFRACTORY TEMP	GTE84A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B OUTLET REFRACTORY TEMP	GTE84B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B OUTLET REFRACTORY TEMP	GTE84C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B UPPER CYCLONE REFR TEMP	GTE85A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B UPPER CYCLONE REFR TEMP	GTE85B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B UPPER CYCLONE REFR TEMP	GTE85C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOWER CYCLONE REFR TEMP	GTE86A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOWER CYCLONE REFR TEMP	GTE86B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOWER CYCLONE REFR TEMP	GTE86C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOOP SEAL REFR TEMP	GTE87A	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOOP SEAL REFR TEMP	GTE87B	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
CYCLONE 4B LOOP SEAL REFR TEMP	GTE87C	DEGF		1000	1800																							X				DEGF	K	-		NR	-		
BTM ASH CLG FAN 4A DISCH TEMP	GTE88	DEGF		0	150	X	1																									DEGF	E	-		NR	-		
COMB 4A BED TEMP AVERAGE	GTEAVG1			0	100																																		
COMB 4B BED TEMP AVERAGE	GTEAVG2			0	100																																		
COMB 4B SA FLOW	GTT2FTC																																						
PA FAN WATTS	GWM325	KW		0	6000																	X																	
SA FAN WATTS	GWM326	KW		0	1500																	X																	
ID FAN WATTS	GWM327	KW		0	6000																	X																	
H.P. BLOWER 4A WATTS	GWM328	KW		0	250																	X																	
H.P. BLOWER 4B WATTS	GWM329	KW		0	250																	X																	
BOTTOM ASH COOLING FAN WATTS	GWM330	KW		0	800																	X																	
TURBINE 4A 1ST STAGE PRESSURE	KPT2	PSIG		0	2000																								X										
FINAL STEAM PRESS	KPT300	PSIG		0	1800	X	1																					X		0	1800	PSIG	STATIC TAP	GPI	10/12/87	180	4/9/88		
FINAL STEAM TEMP	KTE1	DEGF		0	1500	X	1																					X	X			DEGF	E	-		NR	-		
EXT STEAM FROM UNIT 4 TO UNITS 1-3 PRESSURE	LPT63		PSIG	0	800																																		
EXT STEAM FROM UNIT 4 TO UNITS 1-3 TEMP.	LTE61		DEGF	0	1000																																		
COAL FLOW FEEDER TOTAL	O001X115																																						
COMB 4A BED TEMP 20" MEDIAN	O001X195																																						
COMB 4A FURNACE DRAFT	O002X073																																						
COMB 4B FURNACE DRAFT	O002X113																																						
CYCLONE OUTLET MEDIAN GAS PRESSURE	O002X133																																						

DATE: 4/26/88

INSTRUMENT CALIBRATION DATA

LOCATION DESCRIPTION	TAG NUM	UNITS REQ'D	HIWAY UNITS	BOT BAR	TOP BAR	PERF CALC	1	2	3	4	5	6	7	8	9	A	B	C	D	E
COMB 4B BED TEMP 20" MEDIAN	O003X115																			
PA TO S/U BURNER A - TEMP COMP	O007X011	KLB/HR															B			E
PA TO S/U BURNER B - TEMP COMP	O007X041	KLB/HR															B			E
PA TO S/U BURNER C - TEMP COMP	O007X062	KLB/HR															B			E
PA TO S/U BURNER D - TEMP COMP	O007X091	KLB/HR															B			E
PA TO S/U BURNER E - TEMP COMP	O007X112	KLB/HR															B			E
PA TO S/U BURNER F - TEMP COMP	O007X132	KLB/HR															B			E
GAS FLOW TO S/U BURNER 4E	OFT10	KLB/HR	KSCFM	0	50															
GAS FLOW TO S/U BURNER 4F	OFT12	KLB/HR	KSCFM	-20	50															
GAS FLOW TO DUCT BURNER 4A	OFT14	KLB/HR	KSCFM	0	50															
GAS FLOW TO DUCT BURNER 4B	OFT16	KLB/HR	KSCFM	0	50															
GAS FLOW TO S/U BURNER 4A	OFT2	KLB/HR	KSCFM	0	50															
GAS FLOW TO S/U BURNER 4B	OFT4	KLB/HR	KSCFM	0	50															
GAS FLOW TO S/U BURNER 4C	OFT6	KLB/HR	KSCFM	-20	50															
GAS FLOW TO S/U BURNER 4D	OFT8	KLB/HR -	KSCFM	0	50															
PA UNDERBED TEMP TO COMB 4A	OTE1AVG		0	100																
PA UNDERBED TEMP TO COMB 4B	OTE2AVG		0	100																
EXT STEAM FROM UNIT 4 TO UNITS 1-3 FLOW	PFT82																			
BAGHOUSE 1 INLET TEMP	PTE10	DEGF		100	300															
BAGHOUSE 2 INLET TEMP	PTE11	DEGF		100	300															
BAGHOUSE 3 INLET TEMP	PTE12	DEGF		100	300															
BAGHOUSE 4A INLET TEMP	PTT14	DEGF		0	300															
COAL FEEDER 4B (A-FRONT, WEST)	OFT1	KLB/HR		0	72	X	1	2	3	4	5		7				B			
COAL FEEDER 4C (A-FRONT, EAST)	OFT2	KLB/HR		0	72	X	1	2	3	4	5		7				B			
COAL FEEDER 4A (A-REAR)	OFT25	KLB/HR		0	72	X	1	2	3	4	5		7				B			
COAL FEEDER 4D (B-REAR)	OFT26	KLB/HR		0	72	X	1	2	3	4	5		7				B			
COAL FEEDER 4F (B-FRONT, WEST)	OFT3	KLB/HR		0	72	X	1	2	3	4	5		7				B			
COAL FEEDER 4E (B-FRONT, EAST)	OFT4	KLB/HR		0	72	X	1	2	3	4	5		7				B			
CYCLONE A EXIT SO2	RAT1		PPM	100	500															
CYCLONE B EXIT SO2	RAT2		PPM	0	500															
L STONE FEEDER 4B FLOW	RFT13	KLB/HR	LB/HR	0	7200	X	1	2	3	4	5		7				B			
L STONE FEEDER 4A FLOW	RFT4	KLB/HR	LB/HR	0	7200	X	1	2	3	4	5		7				B			
CEM OPACITY (6 MIN AVG)	SAT50	%		0	100															
CEM NOX (LB/MMBTU)	SAT51	LB/MMBTU		0	1000															
CEM SO2 (LB/MMBTU)	SAT52	LB/MMBTU																		
CEM SO2(LB/MMBTU)	SAT53	LB/MMBTU	#/MMBTU	0	1000															
FLY ASH FLOW	TFT305	KLB/HR	TPH	0	60	X		2		4	5		7				B			
BOTTOM ASH HOPPER WEIGHT (4A)	TLT302	KLB		0	50	X		2		4	5		7				B			
BOTTOM ASH HOPPER WEIGHT (4B)	TLT303	KLB		0	50	X		2		4	5		7				B			
4A BED PRESSURE	TPT1A	IN WC		0	75	X														E
4A BED PRESSURE	TPT1B	IN WC		0	75	X														E
4A BED PRESSURE	TPT1C	IN WC		0	75	X														E
4B BED PRESSURE	TPT2A	IN WC		0	75	X														E
4B BED PRESSURE	TPT2B	IN WC		0	75	X														E
4B BED PRESSURE	TPT2C	IN WC		0	75	X														E
BED DRN MATRL TEMP @ SCREW CLR 4A OUTLET	TTE300	DEGF		0	400	X		2												
BED DRN MATRL TEMP @ SCREW CLR 4B OUTLET	TTE301	DEGF		0	400	X		2												
ASH EQUIP COOLING WATER FLOW	XFT300	KLB/HR	GPM	0	500	X		2												
ASH EQUIP COOLING WATER HX INLET TEMP	XTE301	DEGF		0	200	X		2												
ASH EQUIP COOLING WATER HX OUTLET TEMP	XTE50	DEGF		0	200	X		2												
GEN OUTPUT	YAM14	MW		0	120															
UNIT AUX TRANSFORMER LOAD	YWM20	MW		0	21															

TAG NUM	SO2 EMN RTE	NOX EMN RTE	AUX PWR	SEC 11 TST	SEC 12 TST	SEC 13 TST	SEC 6 TST	SEC 9 TST	USED FOR COMP PNT	CALIB RANGE LOW	CALIB RANGE HIGH	CALIB UNITS	ELMNT TYPE	XMTTR TYPE	LAST CAL DATE	CAL INTVL (DAYS)	NEXT CAL DATE	COEFF NEEDS CHKD/CHNGD	REMARKS
O003X115																			
O007X011										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2I,GTE1A,GTE1B
O007X041										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2J,GTE1A,GTE1B
O007X062										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2K,GTE1A,GTE1B
O007X091										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2L,GTE1A,GTE1B
O007X112										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2M,GTE1A,GTE1B
O007X132										0	7.8	IN WC	AIRFOIL	DP		180			CLC FROM GFT2N,GTE1A,GTE1B
OFT10								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OFT12								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OFT14								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OFT16								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OFT2								X		0	100	IN WC		DP4		180			DAMAGED XMTTR RMVD 5/7/87.
OFT4								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OFT6								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OFT8								X		0	100	IN WC		DP4	6/13/87	180	12/10/87		
OTE1AVG																			
OTE2AVG																			
PFT82																			
PTE10								X											
PTE11								X											
PTE12								X											
PTT14								X		100	300	DEGF							THERMO ELECTRIC - 4248
OFT1	X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
OFT2	X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
OFT25	X	X					X			0	60	KLBS/HR		BELT SCA	11/15/87	30	12/15/87		
OFT26	X	X					X			0	60	KLBS/HR		BELT SCA	11/15/87	30	12/15/87		
OFT3	X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
OFT4	X	X					X			0	60	KLBS/HR		BELT SCA	11/3/87	30	12/3/87		
RAT1																			
RAT2																			
RFT13							X			1	2.5	KLBS		LOAD CEL	11/11/87	30	12/11/87		
RFT4							X			1	2.5	KLBS		LOAD CEL	11/15/87	30	12/15/87		
SAT50								X		-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
SAT51		X						X		-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
SAT52	X							X		-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
SAT53										-	-	-	-	-	-	-	-		WE WON'T BE SEEING ANY DOCMNTN
TFT305							X							SCHENCK		60			
TLT302														LOAD CELL		60			
TLT303														LOAD CELL		60			
TPT1A										0	50	IN WC	STATIC TAP	DP4	5/4/87	180	10/31/87		
TPT1B										0	50	IN WC	STATIC TAP	DP4	5/4/87	180	10/31/87		
TPT1C										0	50	IN WC	STATIC TAP	DP4	5/4/87	180	10/31/87		
TPT2A										0	50	IN WC	STATIC TAP	DP4	5/4/87	180	10/31/87		
TPT2B										0	50	IN WC	STATIC TAP	DP4	5/4/87	180	10/31/87		
TPT2C										0	50	IN WC	STATIC TAP	DP4	5/4/87	180	10/31/87		
TTE300												DEGF	E	-	10/15/87	NR	-		
TTE301												DEGF	E	-	10/15/87	NR	-		
XFT300										0	13.3	IN WC	ANF	DP3	10/7/87	180	4/4/88		
XTE301												DEGF	E	-	10/15/87	NR	-		
XTE50												DEGF	E	-		NR	-		
YAM14																			
YWM20			X																

DATE 4/25/88

Appendix B

UNIT START-UP SEQUENCE

In order to facilitate understanding of the start-up and loading procedure for a large CFB boiler in the repowered plant setting, a checklist was made depicting the sequential events. The fairly lengthy sequential process is primarily due to the repowering concept, where four complete turbine generator units must be started. Certain flow, pressure, and temperature criteria required to proceed with the start-up sequence are identified, although specific values are not included.

DETAILED NUCLA STATION START-UP SEQUENCE

1. Verify that the unit 4 cooling tower basin water is full.
2. Check the unit 4 circulating water system valve line up.
3. Check the unit 4 circulating water pump lube oil.
5. Start the unit 4 circulating water pump.
6. Vent circulating water system high points.
7. Vent hydrogen cooler water side.
8. Start closed cooling water system pump.
9. Check that combustion chamber, backpass, air heater, baghouse and ducting doors are closed.
10. Open drum vents.
11. Open main steam lead drains.
12. Open superheater vents and drains.
13. Place condenser hot well sparger in service using steam from aux boiler.
14. Place deaerator 4C storage tank sparger in service using steam from aux boiler.
15. Start one condensate pump on unit 4.
16. Start one boiler feed pump on unit 4 and verify that recirculation system is functional.

17. Fill boiler to 2" below drum centerline.

18. Verify adequate condensate/DI water in storage tanks.

19. Verify adequate propane supply in storage tank.

20. Start propane vaporizers.

21. Isolate baghouses 1-4 and open baghouse bypass.

22. Fill coal bunkers.

23. Fill limestone silos.

24. Verify all PA and SA flow control dampers open.

25. Start ID fan lube oil system.

26. Start PA fan lube oil system.

27. Verify ID fan closed, coupled, and ready.

28. Verify HP air blower closed, coupled, and ready.

29. Verify SA fan closed, coupled, and ready.

30. Verify PA fan closed, coupled, and ready.

31. Place ID fan control selector in manual and run speed demand to minimum.

32. Start ID fan motor.

33. Place back-up HP air blower motor in Auto (Standby) mode.

34. Run inlet butterfly damper to minimum position on HP air blower.

35. Start one HP air blower motor.

36. Verify and adjust fluidizing air flows to various injection ports.

37. Place SA fan control selector in manual and run demand to minimum.

38. Verify SA fan speed demand at minimum.

39. Verify SA fan inlet damper position at minimum stop.

40. Start SA fan motor.

41. Verify furnace draft stable through fan start-up.

42. Place PA fan control selector in manual and run speed demand to minimum.

43. Manually increase ID fan speed until the furnace draft reaches 2.5 inches w.c.

44. Run in-bed start-up burner air dampers to minimum.

45. Start PA fan motor.

46. Pulse up the ID and PA fan motor speeds until flow is established and the bed (if present) fluidizes.

47. Adjust ID fan speed to obtain furnace draft of 0.5 inches w.c.

48. Automate furnace draft loop.

49. Verify furnace draft stability.

50. Bring PA underbed air flow up to minimum.

51. Open SA fan inlet damper.

52. Raise SA fan speed.

53. Adjust SA air flow to in-bed start-up burners above light off interlock.

54. Adjust SA flow to bring total air flow to required purge air flow rate.

55. Verify bottom ash fan closed, coupled, and ready.

56. Run bottom ash cooling air fan inlet damper to minimum.

57. Start bottom ash cooling air fan.

58. Adjust bottom ash cooling air fan inlet damper and control dampers on feed to each ash cooler to achieve desired flows.

59. Automate bottom ash cooling air fan control.

60. Verify all purge permissives satisfied.

61. Initiate purge timer.

62. When purge is complete, unit is ready for light-off.

63. Start bottom ash cooling water pump.

64. Verify flow at bottom ash coolers through sight glasses.

65. Verify that the propane gate valve at the propane pipe entrance to the boiler room is open.

66. Verify all in-bed start-up burner and duct burner gas guns are coupled.

67. Open the main propane gas header safety shutoff valve to pressurize gas header.

68. Verify duct burners coupled.

69. Start duct burners for both combustors.

70. Automate duct burner controls.

71. Adjust duct burner fuel gas flow as necessary to increase bed temperature.

72. Run gas firing rate control valves on in-bed start-up burners to be lighted to minimum.

73. Start a pair of in-bed start-up burners (one in each combustor).

74. Automate primary air flow control to each active in-bed start-up burner.

75. Automate gas flow control to each active in-bed start-up burner and set gas firing rate to each burner to required value (same for each combustor).

76. Light additional burner pairs when the boiler can absorb additional heat input without exceeding rate of warm up limitations while maintaining drum level control.

77. Adjust firing rate as needed to follow the cyclone inlet temperature vs. time curves available in the control room. These curves are based upon the various transient temperature limitations of boiler components including refractory, drum, radiant superheater tubing and steam headers. Specific rate of change restrictions to be monitored include:

    - Rate of saturation temperature rise not greater than 100F/hr;

    - Differential drum metal temperature top to bottom not greater than 200 °F;

    - Cyclone refractory temperature rise not greater than 100 °F/hr;

    - Gas temperature at radiant superheater not greater than 1000 °F until steam flow is established;

    - Radiant and finishing superheater outlet tube metal temperature not greater than 1025 °F.

78. When drum pressure reaches 25 psig (steam billowing from the drum vents) close the drum vent valves, superheater vents and drains, except for the main steam lead drains.

79. Adjust continuous blowdown valve as necessary to dispose of excess water in the drum resulting from swell. Also employ east and west drum drains to the blowdown tank to supplement water disposal.

80. When drum pressure reaches 25 psig, open low load feed water regulator valve to establish water flow.

81. When drum pressure reaches 100 psig, adequate steam pressure should exist to warm up and place in service the auxiliary steam system supplied from the primary superheater source.

82. Initiate main deaerator pegging using the auxiliary steam supply from the main boiler.

83. Secure deaerator storage tank steam sparger steam supply.

84. Place or verify that the main turbine is on turning gear.

85. Start steam packing exhauster.

86. Establish the steam seal system on the no. 4 turbine generator.

87. Establish auxiliary steam supply to the hogging ejector and the trim ejector.

88. Pull vacuum on the no. 4 condenser.

89. Open main steam lead drains to the condenser 3 turns in order to commence steam lead warm up.

90. Determine from turbine metal temperature thermocouples as to whether the unit is in a cold start (rotor metal temperature less than 250 °F) or hot start (rotor metal temperature greater than 250 °F).

91. Refer to Westinghouse data for appropriate heat soak periods, acceleration rates, and initial steam conditions based upon the circumstances of the start-up.

92. Throttle conditions of at least 100 °F superheat but not greater than 800 °F are required to roll the turbine generator.

93. Use superheater and steam lead drains as needed to control pressure rise while attaining adequate superheat.

94. Verify turbine electrohydraulic control system fully in service including EHC fluid pumps and fluid coolers.

95. Latch turbine.

96. When throttle steam conditions are satisfactory, roll turbine to 600 RPM.

97. Check that exhaust hood sprays are in service.

98. Fill the turbine exhaust hood seat trough.

99. Bring speed to 2100 RPM.

100. Heat soak turbine as necessary.

101. Bring speed to 3425 RPM.

102. Prior to valve transfer, verify that throttle temperature meets requirements.

103. Execute valve transfer program.

104. Raise speed to 3600 RPM.

105. If necessary, test overspeed trip mechanism.

106. Select the AC bearing oil pump and backup seal oil pump to auto (standby) and verify that both stop.

107. Establish or verify cooling water flow to the hydrogen coolers.

108. Establish excitation.

109. Synchronize the generator to the system.

110. Close the generator breaker.

111. Raise unit output to approximately 5% generator load (5 MWe).

112. Hold initial load for 30 minutes plus 1 minute for each 3 °F throttle temperature change during this hold period.

113. Place feed water heaters in service starting with low pressure heater and proceeding to top heater.

114. When baghouse #4 inlet temperature reaches 150 °F, open inlet gates and close the bypass damper.

115. Close main steam lead drains.

116. Automate boiler desuperheater sprays.

117. Open coal feeder inlet gate to coal feeders.

118. Automate feed water regulator controls.

119. Verify bottom ash transport exhauster, coupled, and ready.

120. When bed temperature reaches the minimum value necessary for permission to light coal:

- Feed coal intermittently 90 seconds on and 90 seconds off to both combustors simultaneously;
- When bed temperature commences increasing by more than 15 °F, energize feeder continuously;
- Place one feeder in continuously in both combustors.

121. Place throttle pressure limit control in service.

122. Start limestone feed to both combustors.

123. With one coal feeder established in each combustor, raise coal feed in gradual steps keeping fuel input equal between combustors. Limit rate of fuel increase to limit refractory temperature rise at cyclone inlet to not greater than 100 °F/hr. Place additional coal feeders in service.

124. Verify silica within limits prior to exceeding 1250 psig drum pressure.

125. When throttle pressure nears 1450 psig, automate the governor MW loop.

126. Raise MW demand in gradual steps and increase coal firing as needed to hold throttle pressure.

127. When bed temperature is greater than 1400 °F, secure duct burners and start-up burners

128. Automate PA duct pressure control loop.

129. Automate SA duct pressure control loop.

130. Automate PA underbed flow controls.

131. Automate PA overbed flow controls.

132. Automate SA flow controls.

133. Automate coal feeders to the boiler master.

134. When necessary to hold bed inventory, start rotary valves on bottom ash coolers and set valve speed as needed.

135. Using bypass around extraction line stop valve, header vents and header drains, warm up extraction line to old turbines.

136. Place or verify that the available 12 MW unit is on turning gear.

137. Start circulating water system on the 12 MW unit which is available for service. (This keeps as much of the extraction line warm as practicable.)

138. Start a condensate pump on the selected 12 MW unit.

139. When the extraction line to the 12 MW turbines is fully warmed, open the extraction line stop valve.

140. Apply seal steam to the selected 12 MW unit.

141. Pull vacuum on the condenser for the selected unit.

142. When throttle conditions meet existing turbine generator requirements, roll the selected machine.

143. When heat soak is complete, synchronize and tie on the selected unit's generator.

144. Start a condensate forwarding transfer pump from the selected unit's deaerator to the no. 4 deaerator.

145. Assume the minimum load required for the oncoming turbine.

146. Automate boiler master to throttle pressure control.

147. Proceed to the next turbine generator to be started and repeat the starting sequence until desired number of machines are on line for target load.

END

DATE
FILMED
5/13/92