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Issue A

Low NO_X/SO_X Burner Retrofit for Utility Cyclone Boilers

Baseline Test Report

By
K. Moore
L. Martin
J. Smith

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ABSTRACT

The baseline test report provides a summary of the boiler performance and environmental emissions from the unit 1 cyclone boiler of Southern Illinois Power Cooperative near Marion, Illinois. The baseline test program was conducted to assemble an information base for the *Low NO_X/SO_X Burner Retrofit of Utility Cyclone Boilers* project. For a short period in October 1990, the boiler was instrumented and operated at a range of load conditions during which performance and emissions data were taken.

To complete the project, the boiler unit will be further renovated and instrumented, during which time the LNS Burner will be installed. A demonstration program will then be conducted, and a new set of data will be gathered under the same conditions as was generated in the baseline test. Comparison of the data will allow a determination of the LNS Burner's potential to provide the utility industry with a new cost-effective technology to meet the requirements of the 1990 Clean Air Act.

UNIT ABBREVIATIONS

Btu	British thermal unit
°F	degrees Fahrenheit
ft	foot
ft^3	cubic foot
ft/s	feet per second
gpm	gallons per minute
h	hour
hp	horsepower
iwg	inches of water
k	10^3
klb	10^3 lb
kW	kilowatt
kW•h	kilowatt hour
lb	pound
M	10^6
m	meter
μm	10^{-6} meter
MBtu	10^6 Btu
MW	megawatt
MWe	megawatt (electrical)
ppm	parts per million
psia	pounds per square inch absolute
rpm	revolutions per minute
s	second
scfm	standard cubic feet per minute
W	watt
wt. %	weight percent

ACRONYMS

CAE	Clean Air Engineering
CEM	continuous emissions monitoring
ESP	electrostatic precipitator
FEGT	furnace exit gas temperature
IEEE	Institute of Electrical and Electronics Engineers
LNS	Low NO_X/SO_X
MCR	maximum continuous rated boiler load (335,000 lb/h steam)
PTC	Power Test Code
RM	reference method
SIPC	Southern Illinois Power Cooperative

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EXECUTIVE SUMMARY

A series of boiler performance tests was conducted in October 1990 on unit 1 of SIPC's Marion Station. The primary objective of this series, called the baseline tests, was to collect data from the existing plant for comparison after the LNS Burner retrofit. This comparison will confirm the effective low-cost control of NO_X and SO_2 emissions provided by the LNS Burner. Further, these tests will provide operational characteristics of the host unit and some engineering design information that would minimize technical uncertainties in the application of the LNS Burner technology. The baseline tests followed the Demonstration Test Plan (CDOE30101N) as released for baseline tests and collected the data identified in drawings M74-BA01-1 and 2. The results of the baseline test are shown below.

Parameter	Result
Boiler efficiency at full load	83.69
Dust collection efficiency	97.4%
Slag/fly ash ratio	60/40
Emissions at the stack (lb/MBtu)	
SO_2	5.93
NO_X	0.83
CO_2	11.3%
O_2	7.8%

1. INTRODUCTION

The Low NO_X/SO_X (LNS) Burner Retrofit for Utility Cyclone Boilers program consists of the retrofit and subsequent demonstration of the technology at Southern Illinois Power Cooperative's (SIPC's) 33-MW unit 1 cyclone boiler located near Marion, Illinois. The LNS Burner employs a simple innovative combustion process burning high-sulfur Illinois coal to provide substantial SO_2 and NO_X control within the burner.

A complete series of boiler performance and characterization tests, called the baseline tests, was conducted in October 1990 on unit 1 of SIPC's Marion Station. The primary objective of the baseline test was to collect data from the existing plant that could provide a comparison of performance after the LNS Burner retrofit. These data could confirm the LNS Burner's SO_2 and NO_X emissions control and any effect on boiler operation. Further, these tests would provide to the project experience with the operating characteristics of the host unit as well as engineering design information to minimize technical uncertainties in the application of the LNS Burner technology.

This baseline test report documents the three key activities listed in Table 1, which references the section of the report where the results can be found. The tests followed the Demonstration Test Plan (CDOE30101N) as released for baseline tests. The raw data collected are identified in drawings M74-BA01-1 and 2 (see References).

1.1 MANAGEMENT OF BASELINE TEST PROGRAM

The Project Management Plan (CDOE10102N) identified the responsibility and role of each participant in the project. All baseline test activity was monitored by the TransAlta project manager. Bechtel Corporation, reporting to the TransAlta project manager, developed the detail test plans, managed on-site activity, and coordinated the boiler operation and schedule with SIPC. Clean Air Engineering (CAE) provided the independent testing and analysis services for data gathering and environmental monitoring. This included the emissions data at the stack and slag and ash analyses. CAE also provided for waste product analysis. Riley Stoker provided the boiler testing and performance measurement. Their activities included air flow measurements, log of coal flow and analysis, and the high-temperature probe of the furnace during operation. Riley also calculated the boiler efficiency, utilizing information from CAE.

Test scheduling was strongly influenced by SIPC's load demand requirements. Unit 1 was scheduled to be on-line for supplemental power in October when SIPC's large, base-loaded unit 4 would be down for a two-week annual maintenance outage. After that period, unit 1 was scheduled to be removed from service for an extended period for boiler upgrade work and installation of the LNS Burner. Therefore, the baseline test program was scheduled for October 1990.

1.2 REFERENCE DOCUMENTS

This baseline test report has been prepared from the data and analysis received from CAE and Riley Stoker. All the raw data are maintained in project files and are available for review. These documents are listed in the References.

TABLE 1. KEY ACTIVITIES AND RESULTS

Test	Baseline Test Report	Section
Boiler performance tests	Detailed results of the boiler and air preheater performance tests are presented including data required by drawing M74-BA01	2.3 - 2.4
	Material and sulfur balance	2.5
Environmental monitoring	Air quality and precipitator performance	3.3
	Waste analysis results	3.5 - 3.6
Material monitoring program	Condition of boiler, precipitator, and air preheater	4

2. BASELINE TEST PROGRAM SUMMARY

2.1 PRETEST ACTIVITIES

Before baseline testing, Marion unit 1 was inspected for operational readiness to assess plant operability for the baseline test and to assess availability and reliability for the demonstration testing program. The condition of the boiler and all auxiliaries was documented. The as-found condition is reported in Section 4.

A plant betterment program had been conducted earlier for Marion units 1, 2, and 3. Extensive repair and betterment work had begun on the unit 1 boiler during a November-December 1988 outage. Additional work is now under way to bring the units up to utility industry standards of availability for a plant of this age and size.

Pretest activities began with the arrival of the boiler performance and environmental test teams at the site on 15 October 1990 and 19 October 1990, respectively. During this period, test instrumentation was installed, calibrated, and tested. SIPC provided operation and maintenance support for all of the baseline testing phases.

Earlier during a unit 1 outage, Riley installed test ports in the boiler walls to enable thermal probing of the combustion gases in accordance with ASME Power Test Code (PTC). On 19 October 1990, the boiler performance team performed a practice test run. The boiler normally operates at considerable positive pressure. During the checkout, it was discovered that the thermal mapping inspection ports could not control the internal pressure when opened. Further investigation disclosed that the aspirator nozzles were not installed in the inspection port assemblies. Without access to the furnace, boiler gas temperature probe traverses could not be made. Further inspection also determined that unit 1 had developed a tube leak, which it was necessary to repair before the test. The unit was shut down and the necessary repairs were made.

2.2 BOILER PERFORMANCE TESTS

Baseline testing was conducted with the boiler operating continuously for three days during the period 23 to 25 October 1990. The tests were performed in the sequence shown in Table 2 with normal operation of the boiler at the noted ratings.

TABLE 2. BOILER PERFORMANCE TESTS

Test No.	Date	Boiler Load
1	10/23	33 MW–100% MCR
2	10/24	17 MW– 50% MCR
3	10/25	25 MW– 75% MCR

2.2.1 Performance Test No. 1

23 October 1990:
Plant Operating at 33 MW or 100% MCR

On Tuesday, 23 October 1990, unit 1 was on line at 33.0 MW. Earlier, problems with the flame stability on 1B cyclone had required placing the oil-fired ignitor in service to sustain stable combustion conditions. The ignitor was removed from service and adjustments were made to the cyclone tertiary air damper. The flame then appeared stable.

The 100% MCR test began at 10:30 a.m. Emissions and data gathering proceeded normally for over 2 h. At 12:30, the 1A cyclone tripped twice in succession due to loss of coal flow. Operators were employed to rap the coal bunkers with 5-lb hammers. This incident occurred after the completion of the second set and before the start of the third set of emissions testing and data collection, thus negating the need to repeat all or any part of the run. After the unit had again been stabilized, testing resumed and was completed.

Slag was collected successfully at the end of the sluice pipe during the 100% MCR test run, although some material was lost in the overflow from the slag catch tank.

At the conclusion of the 100% MCR performance testing, a "high excess air" test condition was conducted to log any effects of additional excess air on stack emissions. The boiler exit O_2 levels were adjusted so that maximum superheater metal temperatures were not exceeded.

2.2.2 Performance Test No. 2

24 October 1990:
Plant Operating at 17 MW or 50% MCR

The intermediate load (75% MCR) performance testing was scheduled for 7:00 a.m. on Wednesday, 24 October 1990. Trouble was soon noted sustaining a stable fire condition in the 1B cyclone. As fuel oil would be required to support fuel to maintain the fire, the test would be invalidated. On review, the planned test at 75% MCR was aborted, and to take advantage of the tests crews and the day, it was decided to reschedule the unit load to the minimum load (50%

MCR) test point. The 1B cyclone was removed from service, and the half-load test condition was established and allowed to stabilize. The normal half-load operation is to operate one cyclone (1A) at full load and one (1B) off line. The minimum load test was conducted without incident.

After unit 1 was removed from service, inspection of the 1B cyclone revealed a significant amount of slag buildup in the bottom of the barrel and up the right side adjacent to the cyclone inlet. The cause of the buildup was not verified, but was thought to be the result of either a tube leak or a mechanical problem with the tertiary air damper.

Improvements were made to the "slag catching" dumpster with better tailgate sealing to minimize the slag losses. The sluice procedure was also modified to "batch dump" the boiler slag tank 2 h into the test, and again at the end of the test. This allowed using less sluice water and resulted in less slag being lost in the dumpster overflow.

A "high excess air" test was also performed at the conclusion of the 50% test.

2.2.3 Performance Test No. 3

25 October 1990:
Plant Operating at 25 MW or 75% MCR

From the previous day's experience, the test conductor was unsure that this test could be accomplished. SIPC recommended full-load operation overnight with oil co-fired in the 1B cyclone. With time and temperature, it was felt that the slag buildup would be melted away. The expectation was that the testing could then be completed without support fuel before the slagging and flame stability problem would recur.

After the unit was initially stabilized at 75% MCR (both cyclones at low fire), spurious combustion control upsets delayed the start of testing. Also, problems were encountered with the stack gas sampling equipment to the CAE test equipment trailer. The first 2 h of the test went without incident, but then the 1B cyclone combustion condition changed, with the flame color changing from the normal brilliant white steady flame to a generally orange and flickering state. Approximately 30 min later, it was necessary to place the oil fire gun in service to keep the cyclone lit and maintain load. The intermediate load test was terminated as sufficient data had been accumulated to accomplish the baseline test goals.

2.3 BOILER PERFORMANCE RESULTS

The boiler performance data summary and analysis from these tests are presented in Table 4. These data were prepared by Riley Stoker from detail test instrumentation monitored during each ~~test run. Selected boiler performance curves were compiled and are presented in the following figures:~~

• Steam temperatures versus load	Figure 1
• Flue gas temperatures versus load	Figure 2
• Air temperatures versus load	Figure 3
• Air draft loss versus air flow	Figure 5
• Gas draft loss versus flue gas flow	Figure 4

In the boiler performance testing, fly ash samples are collected at the dust collection hoppers and are composited into a sample representative of the boiler exit conditions. The performance calculations are made around the boiler envelope, from inlet to outlet. This approach normally works well. But for the baseline testing, there was concern that this method might introduce significant errors, especially with the high carbon losses from the boiler. Another method that was available was to analyze the carbon content of the isokinetic sample collected during the EPA methods 5 and 17. Because of the very small sample size, special analysis techniques had to be used to confirm the analysis of the composited sample. The results confirmed that the composited sample did reflect the true carbon losses of this boiler. Table 25 is a comparison of boiler efficiency using these two methods. The efficiencies are very similar; the largest difference is the combustible loss, which is directly related to the measurement of carbon loss.

For direct comparison of efficiencies before and after the modification, it is necessary to correct the as-fired efficiencies to the reference fuel and air temperature of 80°F. These corrections, which were performed according to ASME PTC 4.1, are summarized in Table 27. These efficiencies are also depicted in Figure 6 for graphical analysis.

The initial fly ash evaluation showed excessively high carbon. These data were considered incorrect as it could significantly affect the efficiency. A reanalysis of the fly ash confirmed that the heat loss due to the combustible in refuse, calculated at 6.79%, was significantly higher than the original cyclone design value of 0.1%. This difference was attributed to the large fraction of fine sized coal being fired in the cyclone, resulting in unburned carbon in the fly ash.

2.4 AIR PREHEATER PERFORMANCE

The air heater performance was evaluated for both its ability to preheat combustion air and to control bypass leakage from the high pressure air to the exiting combustion gases. Air heater ~~thermal performance is good with hot air temperature approximately 120 to 150 degrees less than the boiler exit gas temperature.~~

The calculated air heater leakage is given in Table 3.

TABLE 3. AIR HEATER LEAKAGE

Load	Leakage
100%	32.1%
75%	35.0%
50%	52.5%

These very high values are indicative of severe seal wear or missing seals. The increase in leakage at lower power levels is expected since the forced draft fan discharge pressure remains constant, with the boiler combustion air throttled for low loads.

Earlier testing had determined the air heater leakage rate to be approximately 16%. The difference noted in this test may be attributed to more accurate oxygen measurements taken with traverse probes. Only a single measuring point was used in the preliminary test.

TABLE 4. PREMODIFICATION BASELINE TESTING DATA SUMMARY AND ANALYSIS
(1 of 3)

TEST NO.		1	2	3
BOILER LOAD	% OF MCR	100	75	50
DATE OF TEST		10/23/90	10/25/90	10/24/90
TIME OF TEST	HOURS	1030-1615	1030-1230	1300-1700
FUEL FIRED		COAL	COAL	COAL
CYCLONES IN SERVICE		A+B	A+B	A
1. STEAM AND WATER FLOWS				
HIGH TEMP. SUPERHEATER	LB/HR	314,936	235,222	165,168
LOW TEMP. SUPERHEATER	LB/HR	309,434	234,817	164,954
SUPERHEAT SPRAY WATER	LB/HR	5,502	404 (a)	214 (a)
FEEDWATER	LB/HR	314,936	235,222	165,168
BLOWDOWN	LB/HR	CLOSED	CLOSED	CLOSED
2. STEAM AND WATER TEMPERATURES				
FINAL SUPERHEAT OUTLET	°F	904	913	831
LTSH OUT AFTER ATTEMPORATOR	°F	692	705	667
LTSH OUT BEFORE ATTEMPORATOR	°F	723	708	670
DRUM SATURATION	°F	536	533	532
FEEDWATER	°F	253	240	223
SUPERHEAT SPRAY WATER	°F	240	172 (b)	154 (b)
3. STEAM AND WATER PRESSURES				
SUPERHEAT OUTLET	PSIG	844	845	860
DRUM	PSIG	918	890	882
FEEDWATER	PSIG	1163	1239 (c)	1136
4. AIR AND GAS TEMPERATURES				
AMBIENT AIR	°F	51	53	57
FD FAN DISCHARGE (BEFORE STEAM COIL)	°F	91	83	92
AIR HEATER AIR INLET (AFTER STEAM COIL)	°F	141	135	137
AIR HEATER AIR OUTLET	°F	481	460	442
GAS @ FURNACE ELEVATION 572'	°F	1963	1772	1526
GAS ENTERING BOILER BANK	°F	974	854	770
GAS LEAVING BOILER BANK	°F	627	589	559
AIR HEATER GAS OUTLET, MEASURED	°F	293	274	250
AIR HEATER GAS OUTLET, NO LEAKAGE	°F	338	319	304
AIR HEATER GAS OUTLET, MEASURED, CORR. TO 80 °F AIR INLET	°F	251	236	208

NOTES:
(a) THIS FLOW REPRESENTS LEAKAGE ACROSS THE CLOSED SPRAY VALVE.
(b) SPRAY VALVE WAS CLOSED.
(c) THIS DATA POINT IS QUESTIONABLE.

Source: Riley Boiler Performance Test Report.

TABLE 4. PREMODIFICATION BASELINE TESTING DATA SUMMARY AND ANALYSIS
(2 of 3)

TEST NO.		1	2	3
~~BOILER LOAD~~	~~% OF MCR~~	~~100~~	~~75~~	~~50~~
DATE OF TEST		10/23/90	10/25/90	10/24/90
TIME OF TEST	HOURS	1030-1615	1030-1230	1300-1700
FUEL FIRED		COAL	COAL	COAL
CYCLONES IN SERVICE		A+B	A+B	A
5. BOILER EXIT GAS ANALYSIS				
OXYGEN	%	3.1	2.4	3.0
CARBON MONOXIDE	PPM	19	96	28
CARBON DIOXIDE, CALCULATED	%	15.2	15.7	15.2
EXCESS AIR, CALCULATED	%	17.2	12.8	16.5
6. AIR HEATER EXIT GAS ANALYSIS				
OXYGEN	%	7.7	7.6	9.6
CARBON DIOXIDE, CALCULATED	%	11.2	11.3	9.6
8. AIR HEATER LEAKAGE, CALCULATED	%	32.1	35.0	52.5
9. AIR AND GAS DRAFTS				
FD FAN DISCHARGE (BEFORE STEAM COIL)	IWC	45.1	37.2	38.7
AIR HEATER AIR INLET (AFTER STEAM COIL)	IWC	44.7	37.7 (a)	38.6
AIR HEATER AIR OUTLET A/B	IWC	39.0/38.6	33.6/33.8	35.0/37.3
FURNACE	IWC	13.5	7.9	5.1
BOILER BANK INLET	IWC	13.5	8.3 (a)	5.0
BOILER BANK OUTLET	IWC	11.1	7.0	4.6
AIR HEATER GAS OUTLET	IWC	0.6	0.4	0.4
10. LOCAL DAMPER POSITIONS				
PRIMARY CYCLONE A/B	%OPEN	45/30	48/32	47/45
SECONDARY CYCLONE A/B	%OPEN	24/26	18/20	23/19
11. AIR FLOWS MEASURED BY PITOT TUBE				
LEFT VENTURI	LB/HR	186,559	NA	204,508
RIGHT VENTURI	LB/HR	195,577	NA	OFF LINE
TOTAL AIR	LB/HR	382,136	NA	204,508
12. VENTURI DIFFERENTIAL PRESSURES				
LEFT VENTURI	IWC	1.7	NA	1.5
RIGHT VENTURI	IWC	2.2	NA	OFF LINE
13. AIR AND GAS FLOWS, CALCULATED BY HEAT BALANCE				
COMBUSTION AIR	LB/HR	392,940	290,515	204,792
FLUE GAS PRODUCED	LB/HR	427,220	317,468	223,158
14. FUEL FLOW, CALCULATED	LB/HR	44,595	36,701	24,523

NOTES:
(a) THIS INCONSISTINENCY IN THE DATA IS CAUSED BY BOILER FLUCTUATIONS AND NONSIMULATANEOUS READINGS.

Source: Riley Boiler Performance Test Report.

TABLE 4. PREMODIFICATION BASELINE TESTING DATA SUMMARY AND ANALYSIS
(3 of 3)

TEST NO.		1	2	3
BOILER LOAD	% OF MCR	100	75	50
DATE OF TEST		10/23/90	10/25/90	10/24/90
TIME OF TEST	HOURS	1030-1615	1030-1230	1300-1700
FUEL FIRED		COAL	COAL	COAL
CYCLONES IN SERVICE		A+B	A+B	A
15. ASH ANALYSIS				
CARBON IN FLYASH	%	54.85	50.25	54.10
CARBON IN SLAG	%	0.48	0.35	0.87
% TOTAL DRY REFUSE AS FLYASH	%	39.95	39.95	39.95
% TOTAL DRY REFUSE AS SLAG	%	60.05	60.05	60.05
16. FUEL ANALYSIS, AS FIRED (AVERAGE)				
CARBON	%	58.65	55.38	56.54
HYDROGEN	%	3.97	3.72	3.86
NITROGEN	%	1.16	1.11	1.13
OXYGEN	%	5.24	4.70	4.84
SULFUR	%	2.95	2.88	2.94
ASH	%	17.28	20.88	19.86
MOISTURE	%	10.75	11.33	10.83
HIGHER HEATING VALUE	BTU/LB	10,526	9,814	10,073
17. BOILER EFFICIENCY, AS FIRED BY HEAT LOSS METHOD				
REFERENCE TEMPERATURE	°F	141	135	137
LOSSES:				
DRY FLUE GAS	%	4.26	3.86	3.62
MOISTURE IN FUEL	%	1.11	1.25	1.15
WATER FROM COMBUSTION OF H2	%	3.65	3.66	3.66
COMBUSTIBLE IN REFUSE	%	6.79	7.85	8.13
RADIATION (ABMA CURVE)	%	0.35	0.40	0.58
UNMEASURED				
- AIR MOISTURE	%	0.05	0.04	0.04
- SENSIBLE HEAT IN SLAG	%	0.64	0.82	0.77
- UNACCOUNTABLE	%	0.50	0.50	0.50
TOTAL LOSSES	%	17.35	18.38	18.45
EFFICIENCY	%	82.65	81.62	81.55

Source: Riley Boiler Performance Test Report.

2.5 MATERIAL AND SULFUR BALANCE

Data were gathered to assemble a material (solids) and sulfur balance across the boiler system. Major stream flows of coal, slag, and ash were analyzed to calculate a material balance. Slag quantities were measured by weighing material collected at the slag pond to verify the calculated value. For the full load test, the sluice water flowed continuously for the entire test period, and some small slag particles were lost in the sluice water carry-over. The collection technique was revised with improved results for the 50% MCR test using a batch collection method. Slag quantity was not determined for the 75% load test.

During testing, the CAE emissions test crew performed isokinetic particulate sample and load tests at the air heater and ESP gas inlet. The fly ash quantity was determined from these data.

With analysis of carbon in the fly ash of samples taken from the boiler hoppers, the fly ash to slag ratio could be calculated. The slag to fly ash ratio was assumed to remain constant for all boiler loads.

Total sulfur balance was calculated across the system from incoming coal to outgoing stack gases, slag, and fly ash. This sulfur balance, presented in Table 5, shows good agreement, with only about 3.5% of the sulfur unaccounted for.

A total ash and slag material balance was performed during tests 1 and 2. The details of the test setup are in Section 3.5. The results of these two tests are presented in Table 6. Solids are

TABLE 5. OVERALL SULFUR BALANCE AT 100% LOAD

Sulfur Stream	Calculated Quantity of Sulfur (lb/h)
Incoming coal	1316
Leaving in stack gases	1163
Leaving in slag	Based on average of two samples is 123
Leaving in fly ash	Based on average of two samples is 76
Unaccounted, sum of incoming minus sum of outgoing sulfur	1316-1163-123-76=-46 lb/h (-3.5%)
Basis: Coal flow was calculated to be 44,595 lb/h using ASME PTC method Stack SO_2 measurement of 6.26 lb/MBtu Fly ash flow based on 0.0887 lb-Refuse(FA)/lb-coal Slag flow based on 0.1334 lb-Refuse(slag)/lb-coal	

TABLE 6. Overall Solids Material Balance, lb/h

Stream	100% Load	75% Load	50% Load	Comment
Coal	44,595	36,701	24,523	
Ash in coal	7,706	7,663	4,870	
Fly ash with carbon	3,956	N/A	2,499	
Carbon in fly ash	1,788	N/A	1,302	
Slag with carbon	5,949	N/A	3,757	
Carbon in slag	27	N/A	32	
Slag captured in pond	4,115	N/A	2,845	Wt. of collected slag, dry basis.
Unaccounted slag	1,834	N/A	912	Slag w/carbon– collected amount
Slag unaccounted	31%		23%	Unaccounted/slag with carbon

Notes: Coal flow calculated using ASME PTC 4.1
Basis–as-fired fuel for each test, composited samples.
See Table 24 for typical calculations

tracked from the coal ash to the fly ash collected by the dust collection system and finally to slag sluiced to the pond and physically collected . As shown in Table 6, the closure is 23 to 31% of the ash material, including carbon that was not accounted for in the balance. Possible losses are in the overflow from the slag "bin" and from inaccuracies in calculated slag and fly ash determinations.

2.6 FUEL AND ASH ANALYSIS

Fuel samples were collected for each test, and ultimate, proximate higher heating value, and size analyses were performed on each sample. The samples for each test were averaged, and the average ultimate analysis was used in calculating boiler operating parameters. These average values are summarized in Table 8. The ash present in the fuel samples was further analyzed as to chemical content and fusion temperatures. This analysis was done for one sample per test. The results are summarized in Table 9. Table 10 provides the results of the Fd factor calculation using EPA method 19, which is used in determining the emission rates presented in Tables 14, 15, and 16.

2.7 UNIT CHARACTERISTICS

Specific unit data were collected during the baseline testing. These characteristics were monitored from the boiler light-off through turbine-generator roll and loading.

The objective of this activity was to obtain baseline data and compare the effects that the LNS Burner modifications may have upon the unit startup parameters. The key parameters observed were:

- Boiler pressure/temperature profile
- Boiler tube metal temperatures
- Boiler turndown
- Boiler/turbine auxiliary systems reference data.

2.8 FURNACE GAS TEMPERATURE CALCULATION

The furnace exit gas temperature (FEGT) was calculated by heat balance for each boiler load from the gas temperatures measured at the boiler bank gas inlet by the high velocity temperature probes. These calculations are summarized in Table 28. FEGTs were then plotted against furnace area heat release rates (Figure 7), to allow comparison to FEGT's to be calculated when the post modification testing is complete.

Gas temperature profiles were plotted for the furnace temperature at elevation 572 ft and the boiler bank inlet traverses as listed in Table 7. Note that the average temperatures (as shown on Figures 8 through 13) from the HVT probes do not include measurement points considered to be too close to the furnace wall.

TABLE 7. GAS TEMPERATURE PROFILE FIGURES

Location	Test	Figure
Furnace gas @ elevation 572 ft	No. 1	8
Furnace gas @ elevation 572 ft	No. 2	9
Furnace gas @ elevation 572 ft	No. 3	10
Boiler bank inlet gas	No. 1	11
Boiler bank inlet gas	No. 2	12
Boiler bank inlet gas	No. 3	13

TABLE 8. PREMODIFICATION BASELINE TESTING FUEL ANALYSIS SUMMARY

TEST NO.		1	2	3
SAMPLE NO.		AVERAGE	AVERAGE	AVERAGE
BOILER LOAD	% OF MCR	100	75	50
DATE OF TEST		10/23/90	10/25/90	10/24/90
TIME OF TEST	HOURS	1030-1615	1030-1230	1300-1700
FUEL FIRED		COAL	COAL	COAL
SIZE ANALYSIS				
GREATER THAN 4 MESH	%	6.5	7.0	9.4
4 TO 6 MESH	%	6.6	6.0	9.2
6 TO 8 MESH	%	7.9	6.9	9.8
8 TO 16 MESH	%	17.3	15.8	16.3
16 TO 30 MESH	%	17.3	15.7	15.7
30 TO 50 MESH	%	22.9	21.7	19.0
LESS THAN 50 MESH	%	21.6	27.1	20.5
PROXIMATE ANALYSIS, AS FIRED				
MOISTURE	%	10.75	11.33	10.83
VOLATILE	%	29.28	27.25	28.33
ASH	%	17.28	20.88	19.85
FIXED CARBON	%	42.68	40.55	41.00
HIGHER HEATING VALUE, AS FIRED	BTU/LB	10,526	9,814	10,073
ULTIMATE ANALYSIS, DRY BASIS				
CARBON	%	65.72	62.45	63.40
HYDROGEN	%	4.45	4.20	4.33
NITROGEN	%	1.30	1.25	1.27
OXYGEN	%	5.87	5.30	5.43
SULFUR	%	3.30	3.25	3.30
ASH	%	19.37	23.55	22.28
ULTIMATE ANALYSIS, AS FIRED				
CARBON	%	58.65	55.38	56.54
HYDROGEN	%	3.97	3.72	3.86
NITROGEN	%	1.16	1.11	1.13
OXYGEN	%	5.24	4.70	4.84
SULFUR	%	2.95	2.88	2.94
ASH	%	17.28	20.88	19.86
MOISTURE	%	10.75	11.33	10.83
TOTAL		100.00	100.00	100.00

Source: Riley Boiler Performance Test Report.

TABLE 9. PREMODIFICATION BASELINE TESTING ASH IN FUEL ANALYSIS SUMMARY

TEST NO.		1	2	3
SAMPLE NO.		2A	2A	2A
BOILER LOAD	% OF MCR	100	75	50
DATE OF TEST		10/23/90	10/25/90	10/24/90
TIME OF TEST	HOURS	1230	1210	1434
FUEL FIRED		COAL	COAL	COAL
PERCENT ASH IN FUEL	%	18.02	21.33	19.40
CHEMICAL ANALYSIS OF ASH IN FUEL				
SILICON DIOXIDE	%	50.30	47.77	48.28
ALUMINUM OXIDE	%	17.24	15.98	16.32
TITANIUM DIOXIDE	%	1.06	0.57	0.96
IRON OXIDE	%	15.01	16.31	16.56
CALCIUM OXIDE	%	4.95	5.53	5.08
MAGNESIUM OXIDE	%	1.80	2.41	2.00
SODIUM OXIDE	%	0.14	0.09	0.13
POTASSIUM OXIDE	%	2.59	2.64	2.59
MANGANESE DIOXIDE	%	--	--	--
PHOSPHORUS PENTOXIDE	%	0.39	0.57	0.50
SULFUR TRIOXIDE	%	5.20	5.65	4.82
UNDETERMINED	%	1.32	2.48	2.59
FUSION TEMPERATURES, REDUCING ATMOSPHERE				
INTIAL DEFORMATION	°F	2100	2100	2100
SOFTENING				
H = W	°F	2110	2120	2110
H = ½W	°F	2120	2140	2120
FLUID	°F	2130	2150	2130
FUSION TEMPERATURES, OXIDIZING ATMOSPHERE				
INTIAL DEFORMATION	°F	2270	2270	2300
SOFTENING				
H = W	°F	2320	2320	2340
H = ½W	°F	2360	2340	2360
FLUID	°F	2420	2400	2410

Source: Riley Boiler Performance Test Report.

TABLE 10. Fd FACTOR CALCULATION USING EPA METHOD 19

%Moisture	10.75
%Ash	17.28
%Carbon	58.65
%Hydrogen	3.97
%Sulfur	2.95
%Nitrogen	1.16
%Oxygen	5.24
BTU	10526
Fd	9844

Source: CAE Report dated 27 March 1991.

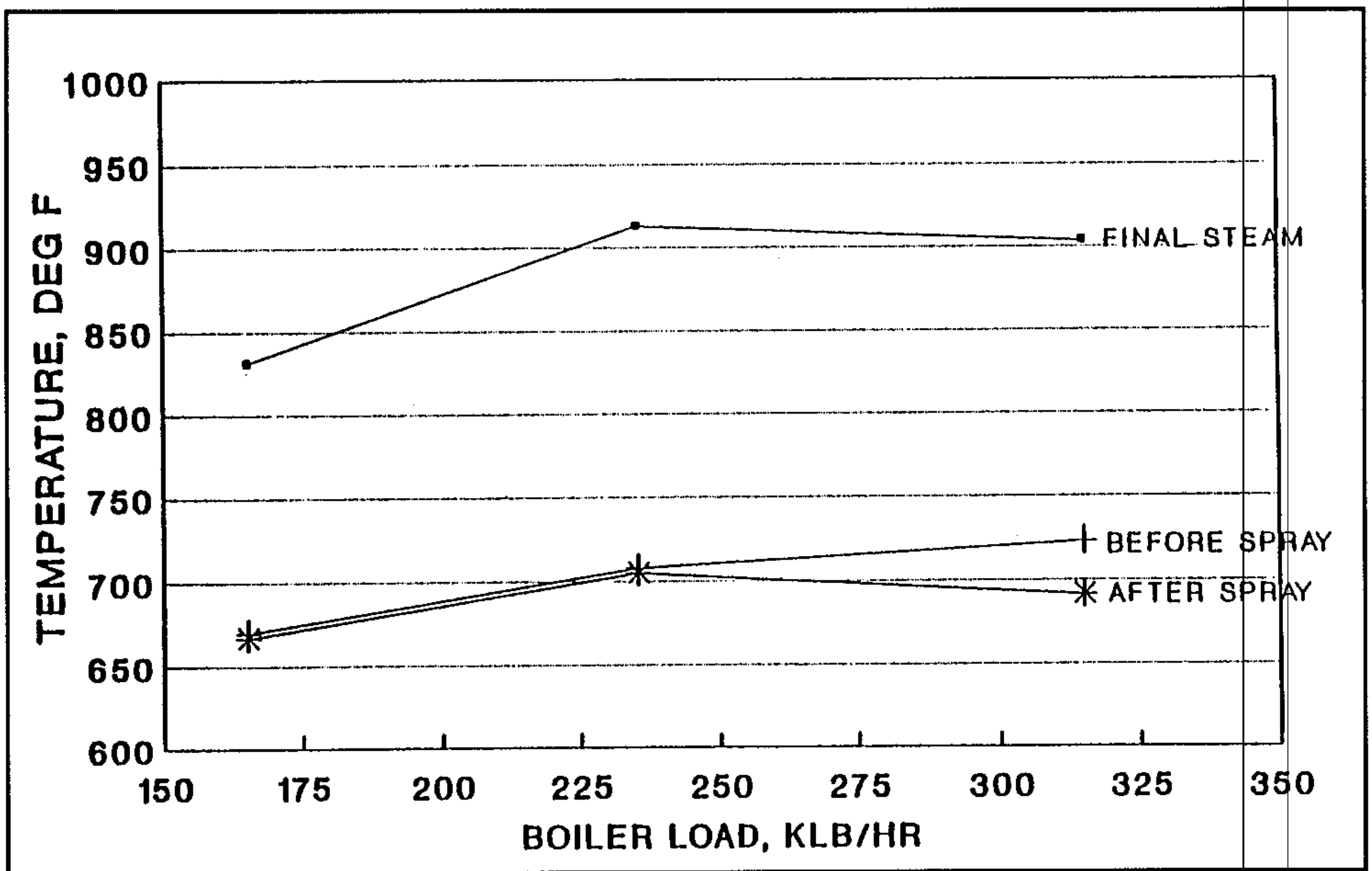

Figure 1. Steam Temperatures versus Load

Source: Riley Boiler Performance Test Report.

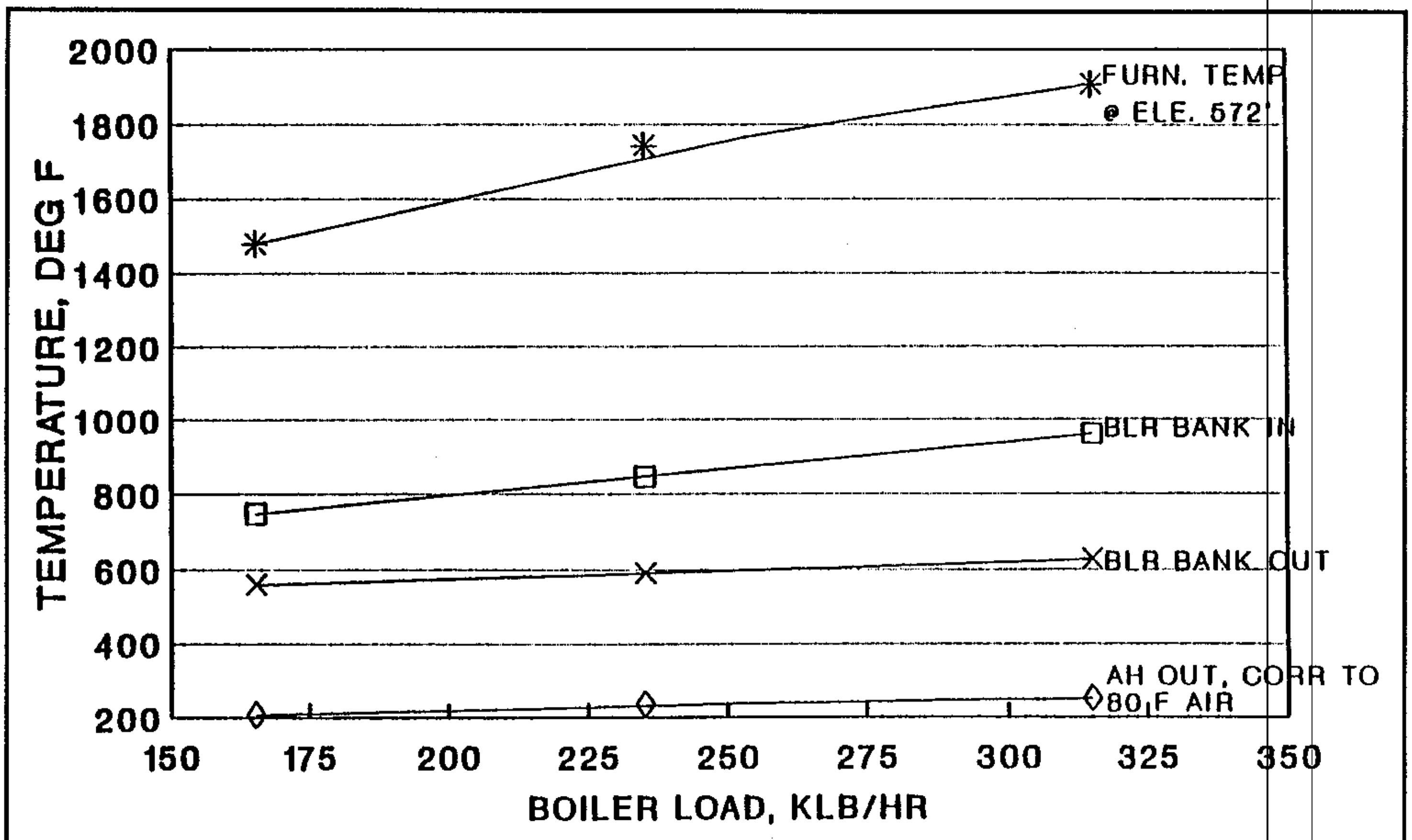

Figure 2. Flue Gas Temperatures versus Load

Source: Riley Boiler Performance Test Report.

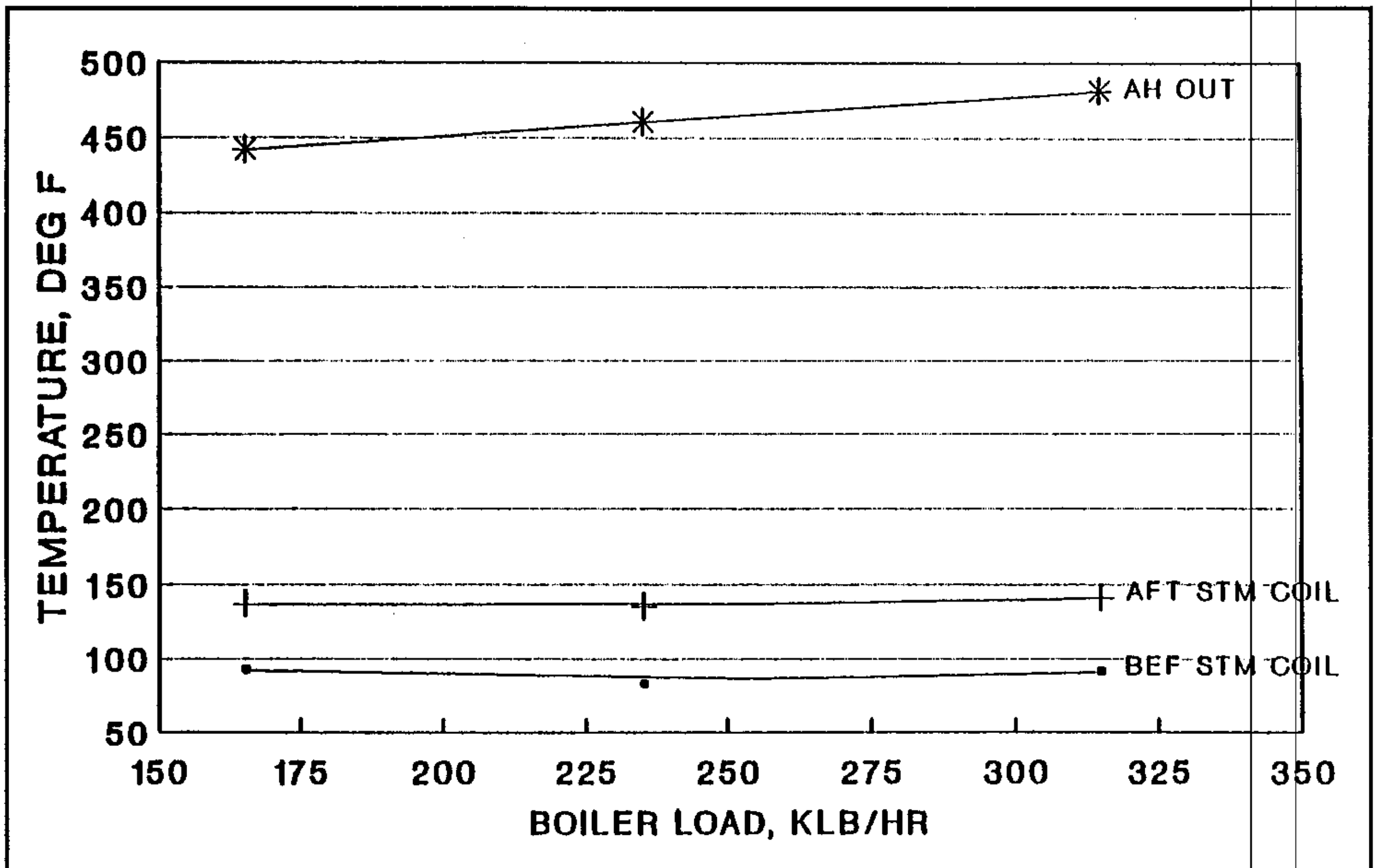

Figure 3. Air Temperature versus Load

Source: Riley Boiler Performance Test Report.

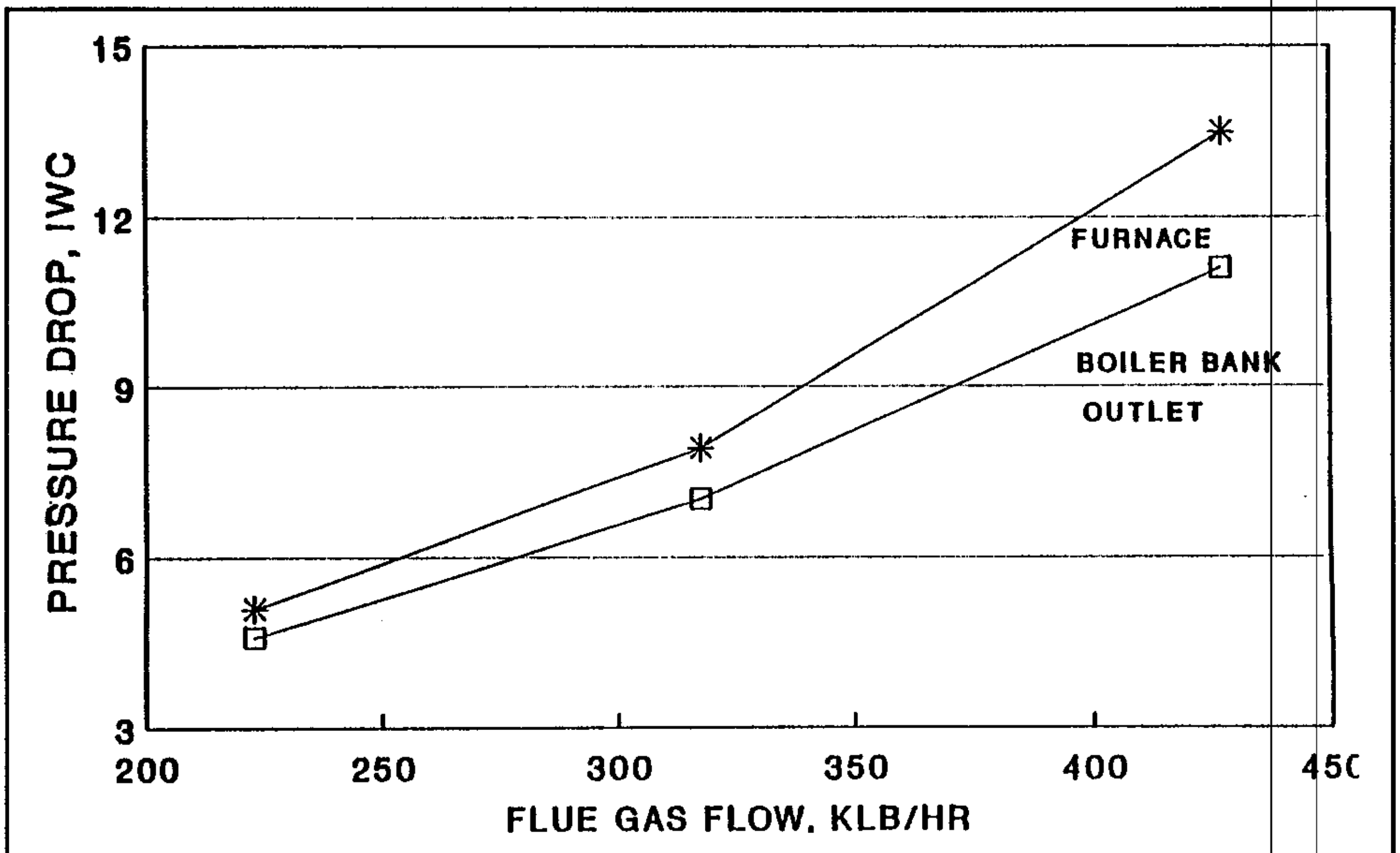

Figure 4. Gas Draft Loss versus Flue Gas Flow

Source: Riley Boiler Performance Test Report.

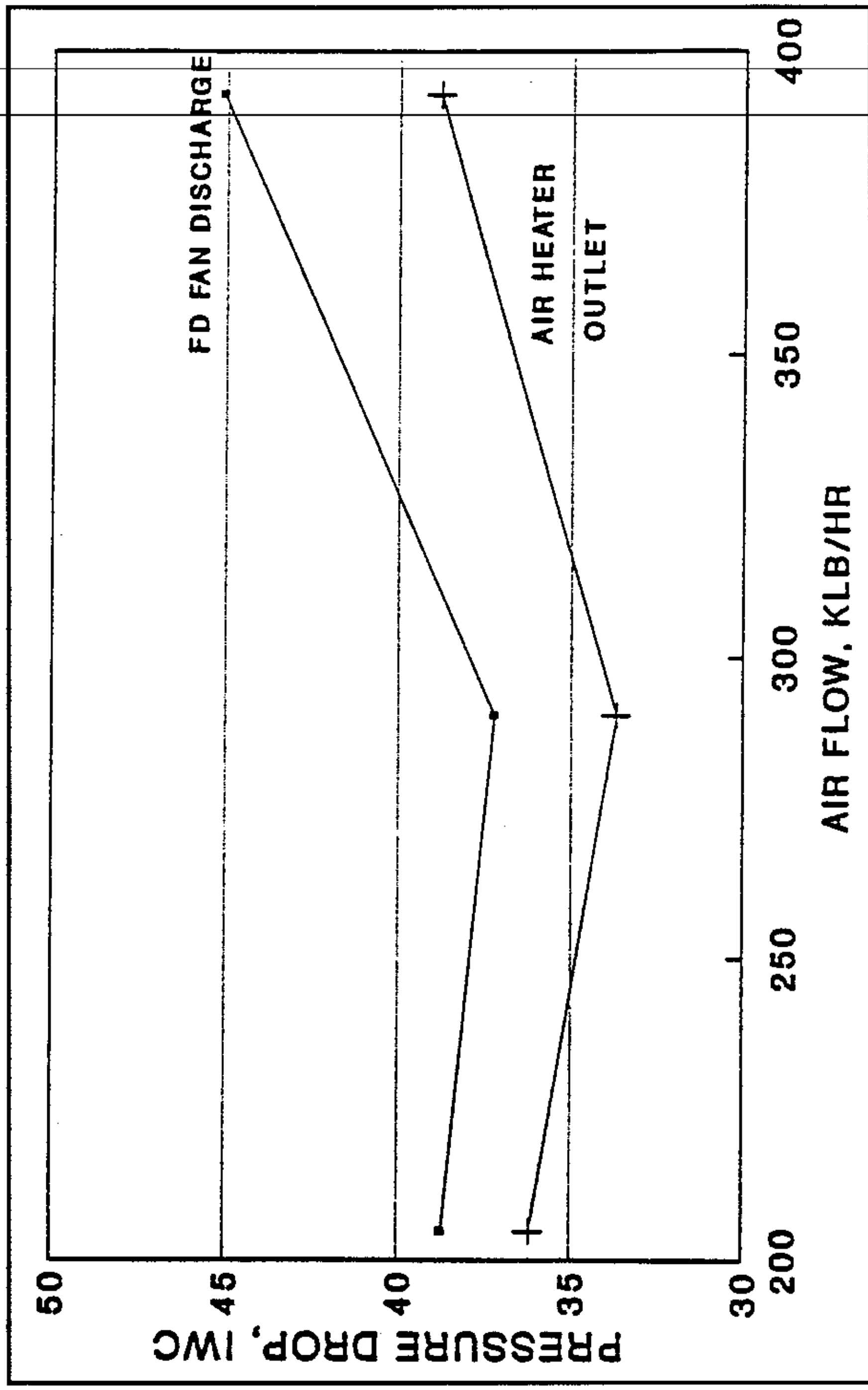

Figure 5. Air Draft Loss versus Air Flow

Source: Riley Boiler Performance Test Report.

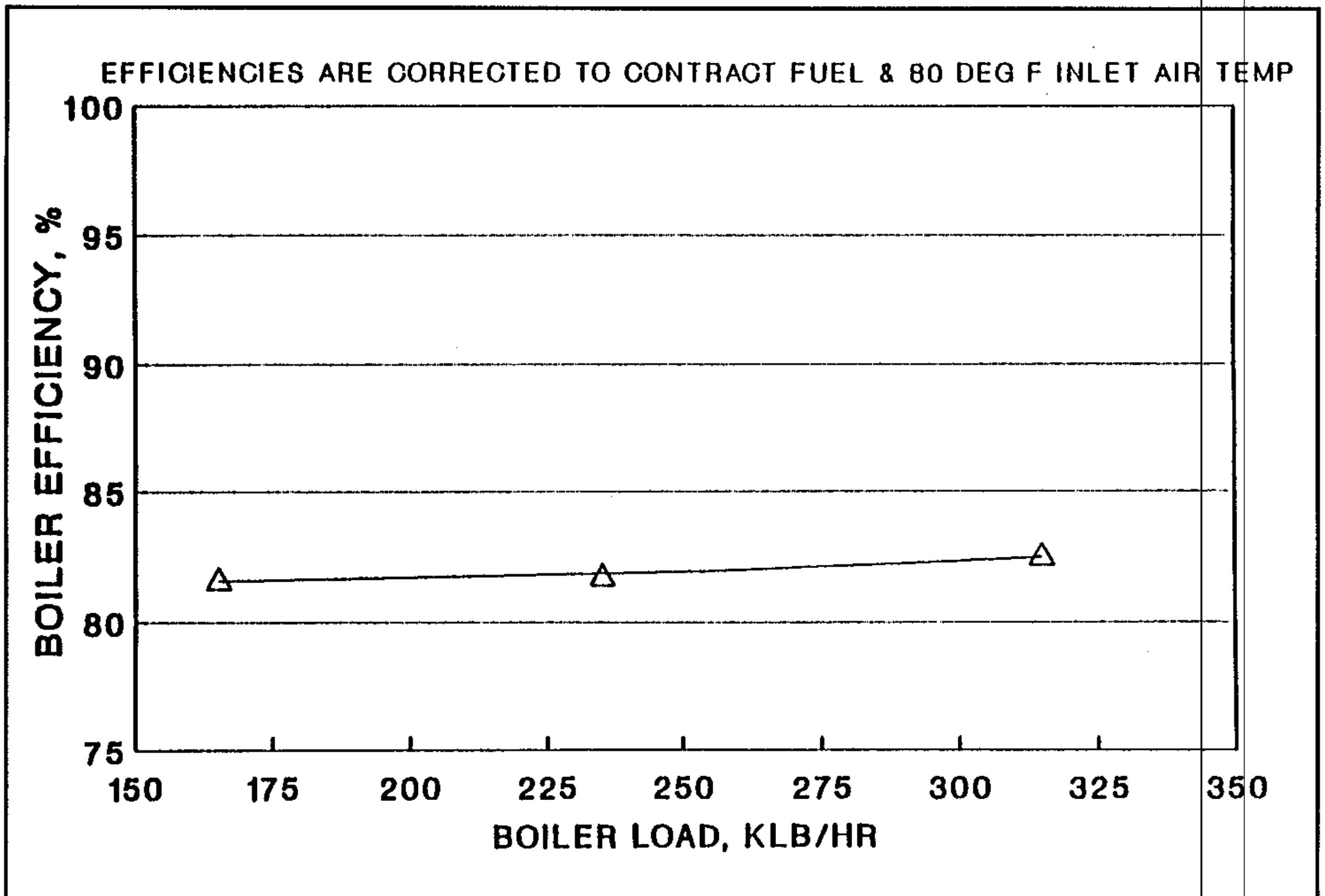

Figure 6. Boiler Efficiency versus Load

Source: Riley Boiler Performance Test Report.

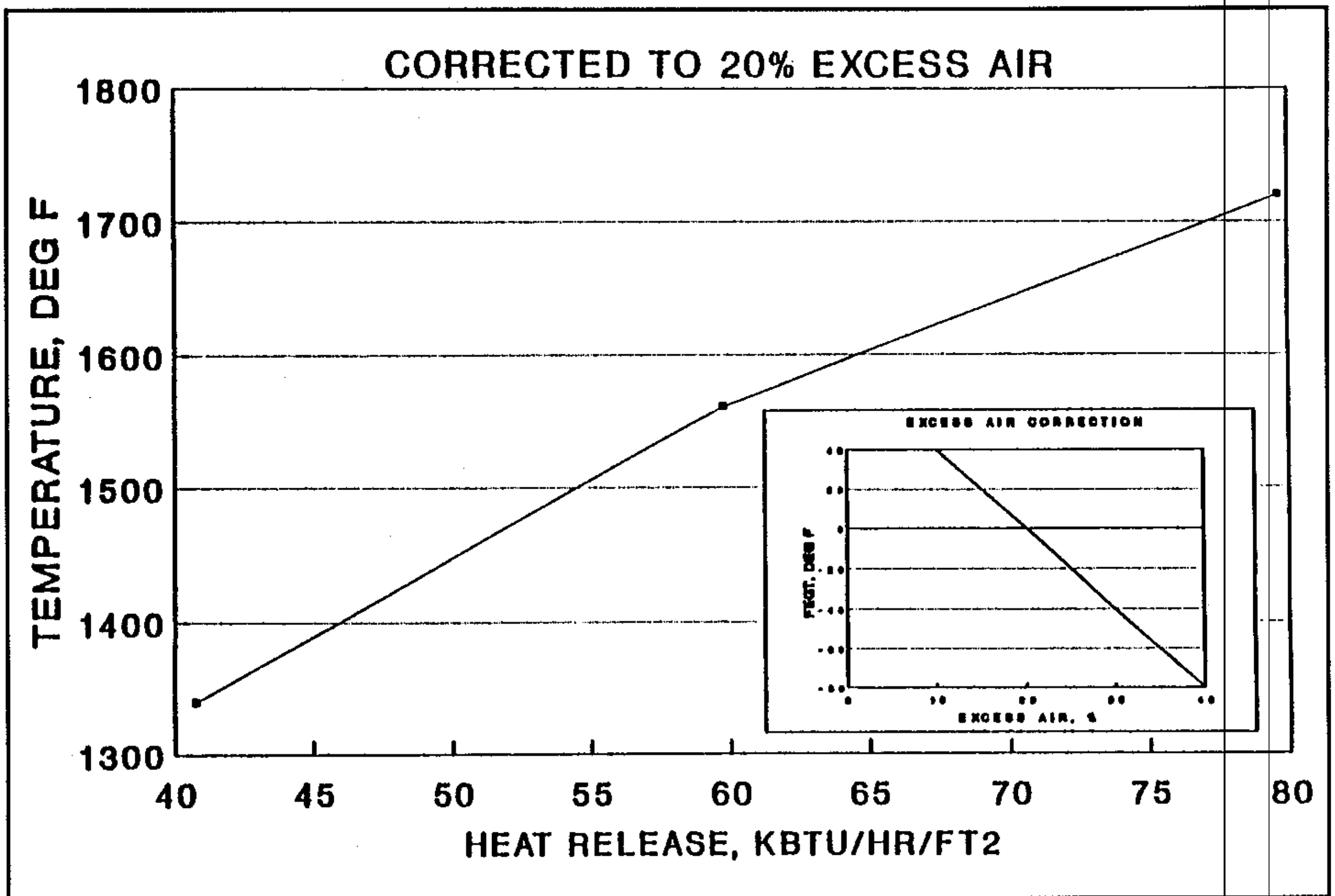

Figure 7. Furnace Exit Gas Temperature versus Heat Release

Source: Riley Boiler Performance Test Report.

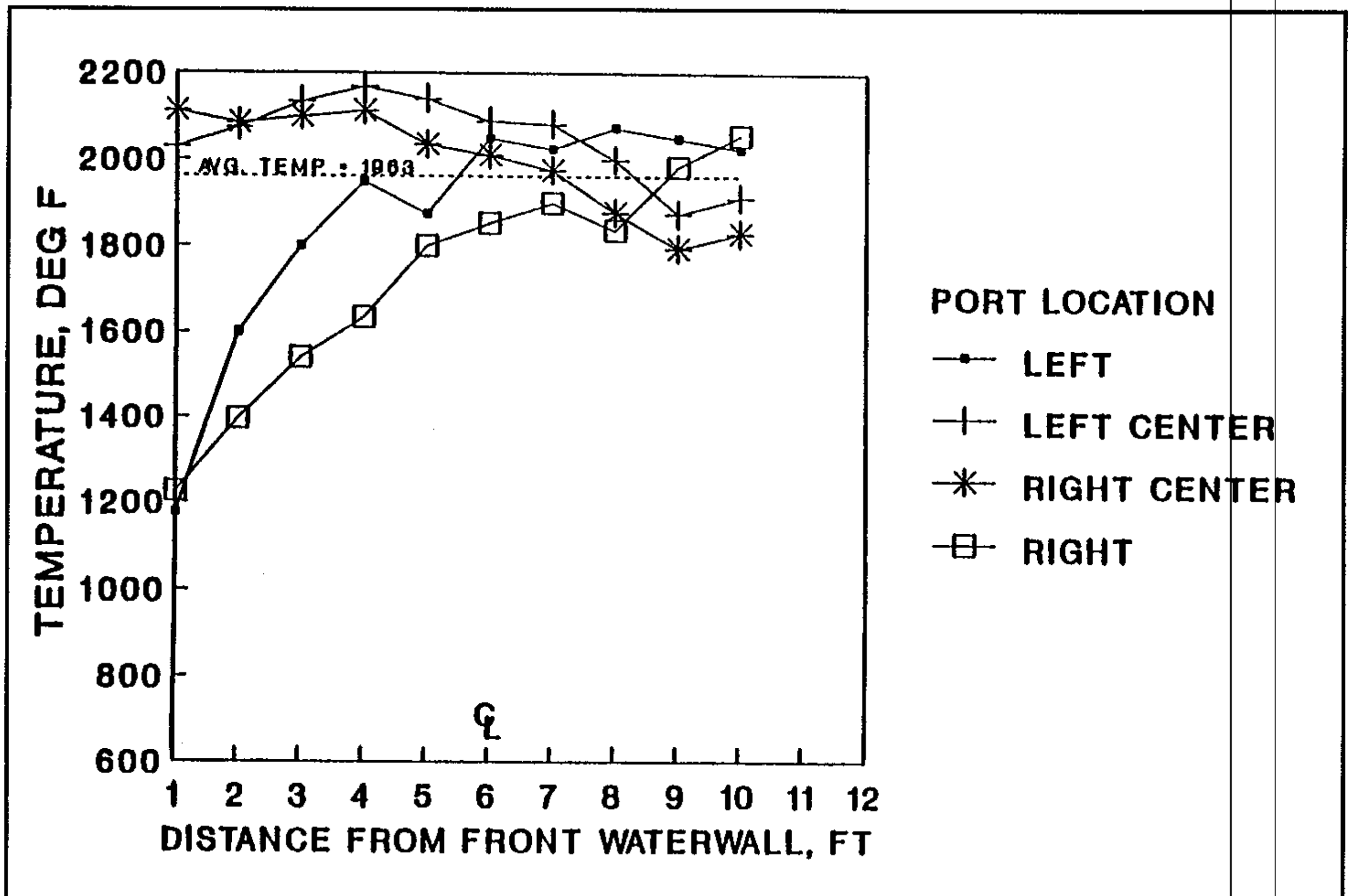

Figure 8. Furnace Gas at Elevation 572 ft Temperature Profile Test 1 at 100% MCR

Source: Riley Boiler Performance Test Report.

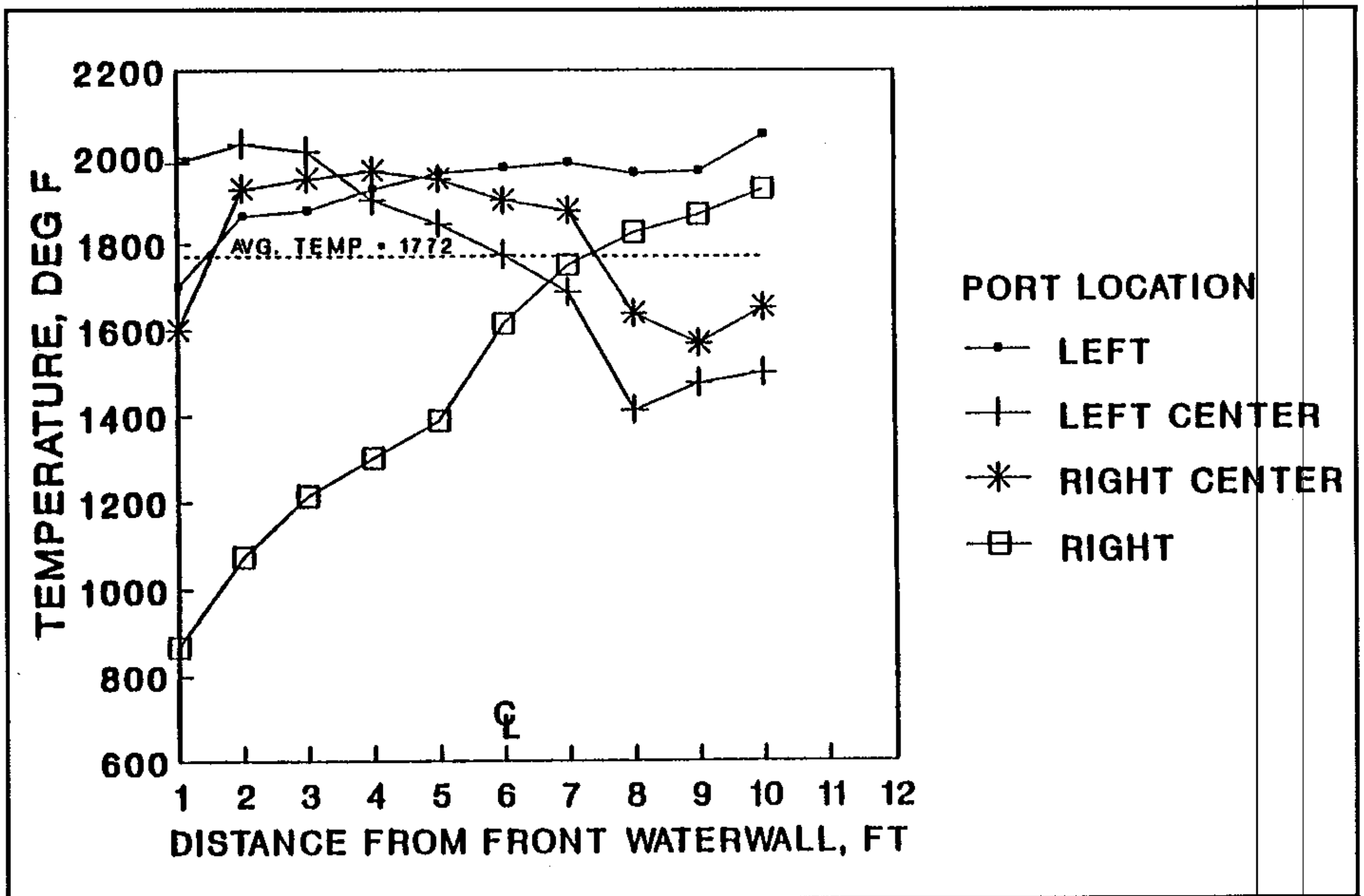

Figure 9. Furnace Gas at Elevation 572 ft Temperature Profile Test 2 at 50 % MCR

Source: Riley Boiler Performance Test Report.

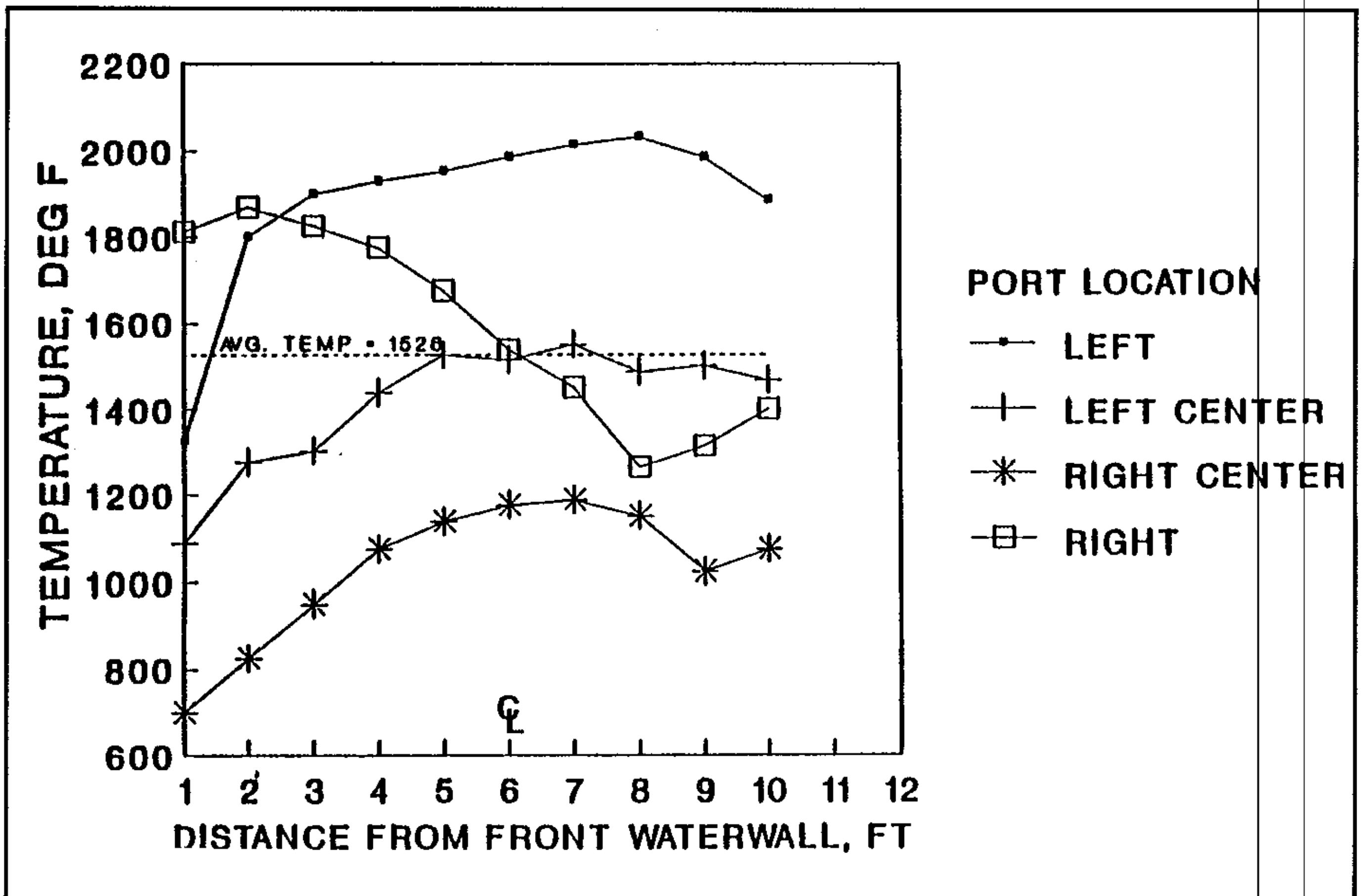

Figure 10. Furnace Gas at Elevation 572 ft Temperature Profile Test 3 at 75% MCR

Source: Riley Boiler Performance Test Report.

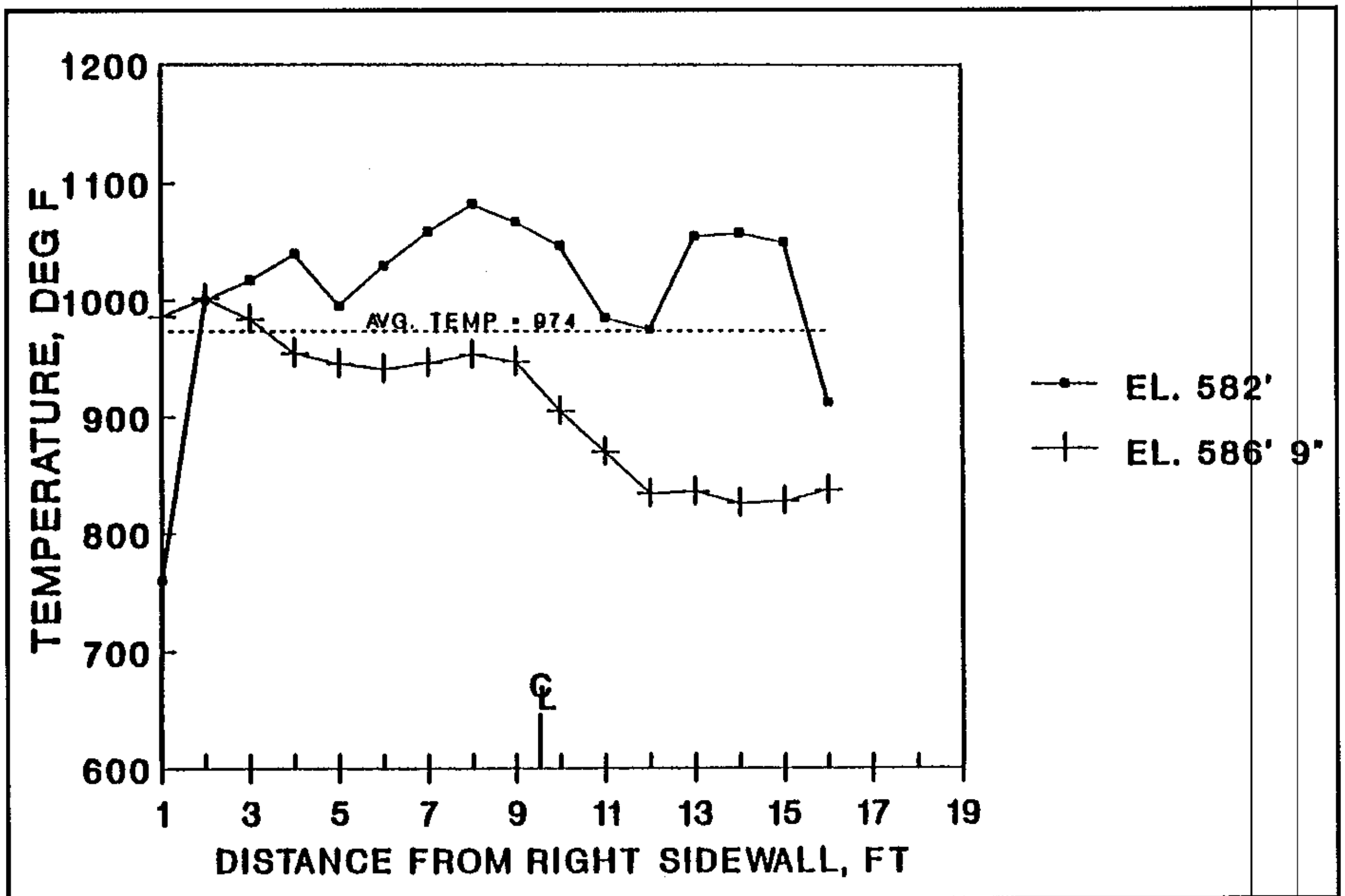

Figure 11. Boiler Bank Inlet Gas Temperature Profile Test 1 at 100% MCR

Source: Riley Boiler Performance Test Report.

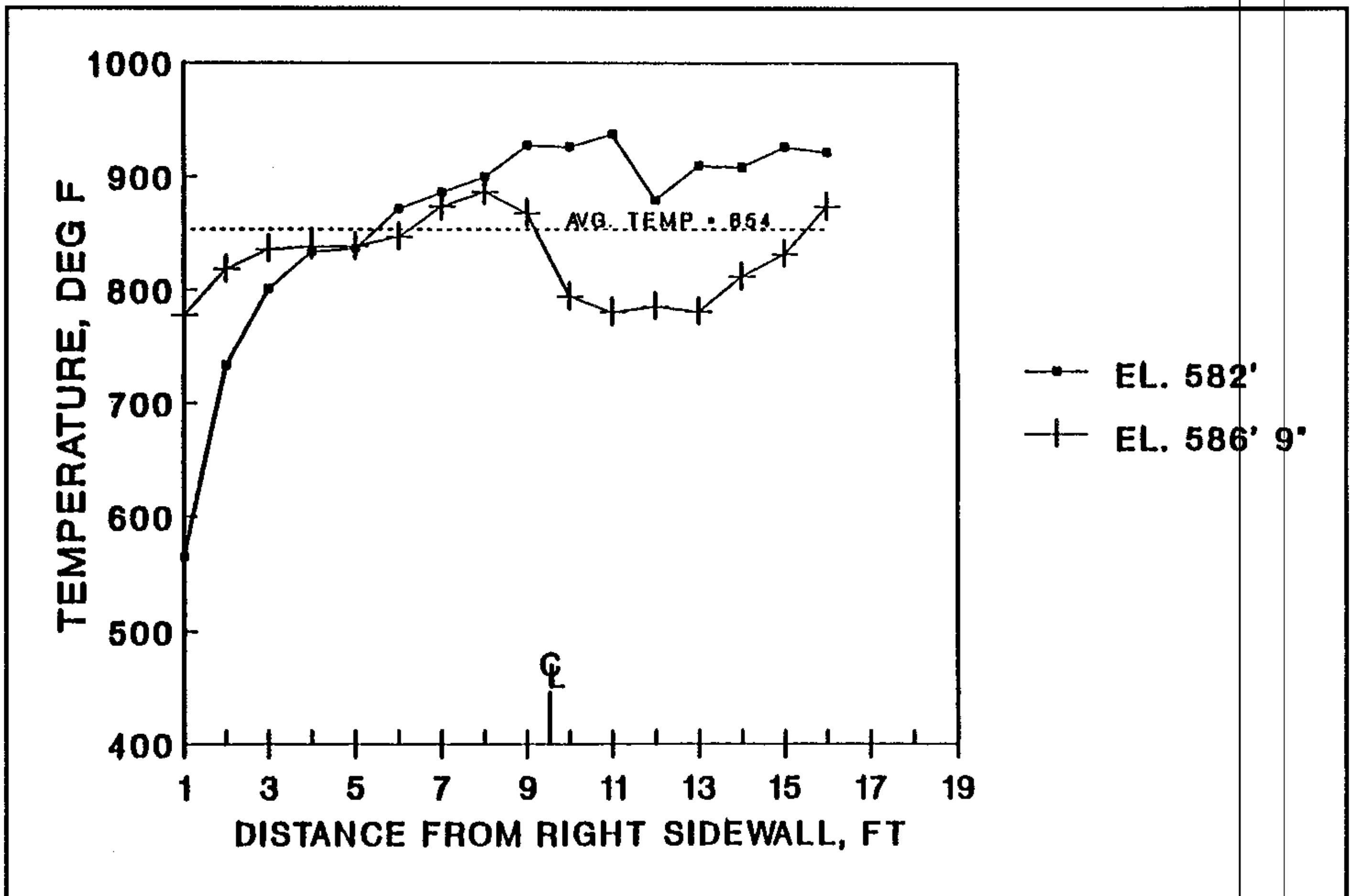

Figure 12. Boiler Bank Inlet Gas Temperature Profile Test 2 at 50% MCR

Source: Riley Boiler Performance Test Report.

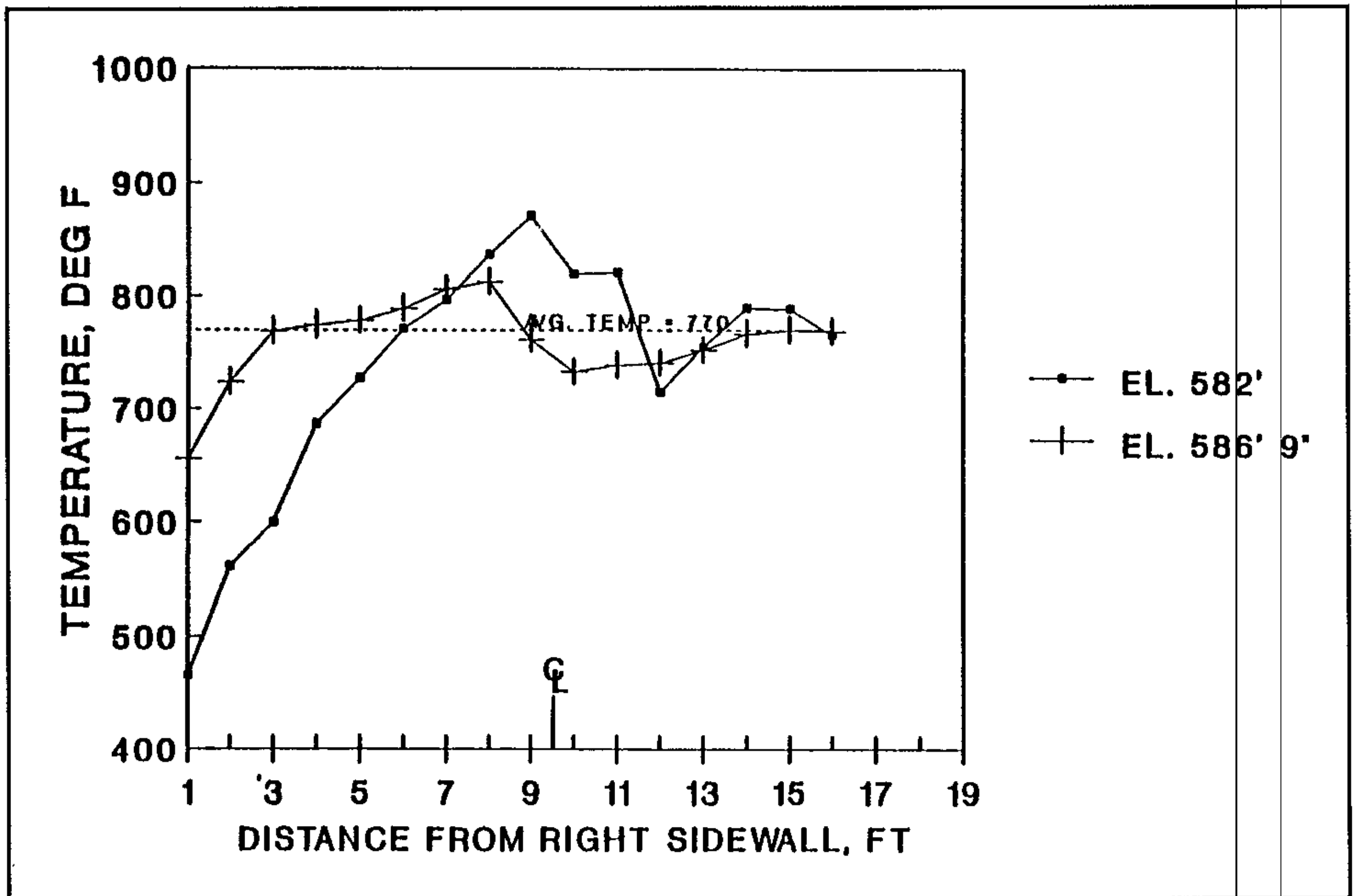

Figure 13. Boiler Bank Inlet Gas Temperature Profile Test 3 at 75% MCR

Source: Riley Boiler Performance Test Report.

3. ENVIRONMENTAL MONITORING

The environmental monitoring activity addressed the atmospheric emissions, wastewater effluent, and solid waste products resulting from the unit 1 operation during baseline tests.

3.1 FLUE GAS MONITORING

Flue gas monitoring was performed simultaneously with boiler performance testing at steady-state operating conditions of minimum, intermediate, and rated load. Flue gas emissions were also recorded at increased oxygen levels for each load condition.

Baseline testing included continuous monitoring of NO_X, SO_2, CO_2, O_2, and opacity. These measurements were performed in the stack downstream from the ESP. Grain loading at the inlet and outlet of the ESP was measured to determine ESP efficiency. Unburned hydrocarbon emissions were measured downstream from the ESP during full-load tests only.

The test locations and emissions sampled are listed in Table 11. The test measurements drawing M74-BA01-1 and -2 also show the specific location of the sample points.

TABLE 11. TEST LOCATIONS AND POLLUTANTS SAMPLED

Location	Pollutant(s)
Air heater inlet	Particulate, CO
ESP inlet	Particulate, SO_2, SO_3
Stack	Particulate, O_2, CO_2, SO_2, total hydrocarbons

3.2 SAMPLING PROGRAM

Table 12 describes the actual sampling program conducted during tests 1, 2, and 3.

Marion unit 1 shares a common stack with unit 2. Unit 2 was down and isolated from the common stack with dampers. An in-leakage traverse was performed at the unit 2 stack breaching with a six-point traverse for a total sampling time of 15 min. No in-leakage was found.

TABLE 12. SAMPLING PROGRAM: TESTS 1, 2, AND 3

Test/Activity	Data Gathered
Pretest (22 Oct 90)	Relative accuracy audit performed on stack CEM's (CO_2, oxygen, SO_2, NO_X)
Test 1 (23 Oct 90)	100% load baseline characterization:
Ash resistivity	Determinations made on ESP hopper composite samples.
Particle size distribution	Determinations made on samples from multicyclone and ESP hopper composite samples separately.
Ash morphology	SEM examination of isokinetically obtained sample from air heater inlet duct.
SO_3	Concentration determined at ESP inlet.
Particulate loading/ gas velocity	Determination made at the Air Heater inlet duct, ESP inlet duct and stack. Also, velocity traverse at unit 2 breaching to check for dilution air entering stack.
Continuous monitoring	O_2, CO_2, NO_X, and UHC monitored at the stack.
Additional sampling	Samples obtained from multicyclone and ESP hoppers were composited for elemental analysis. The individual samples were also analyzed for percent total carbon before composition. Slag samples obtained from the slag pond sluice were also analyzed for elemental composition. Water samples from the slag pond and ash pond sluices and the raw sluice water were also analyzed.
Test No. 2 (10/24/90)	50% load baseline characterization:
Continuous monitoring	As per 100% load
Additional sampling	Multicyclone and ESP hopper samples obtained and composited, analyzed for unburned carbon only. Slag samples also obtained and analyzed for unburned carbon only.
Test No. 3 (10/25/90)	75% load baseline characterization:
Continuous monitoring	As per 100% load
Additional sampling	As per 50% load

Fly ash samples were gathered from all hoppers at the multicyclone and ESP. A composite fly ash sample was made in the following manner before elemental analysis:

1) ESP hopper samples were blended in the proportion of 76% inlet hopper and 24% outlet hopper, by weight.

2) The above sample was then blended with the multicyclone ash in the proportion of 50% ESP and 50% multicyclone hopper, by weight.

The particulate removal efficiency of the multicyclone could not be determined from the data. There are several explanations for this problem:

1) The compact ductwork layout which resulted in very poor sample port locations. Flow and particulate concentrations are much more difficult to determine in ducts with turbulent or stratified flow.

2) An obstructed sample port at the air heater inlet was not sampled, possibly resulting in erroneous test results.

3) The hoppers were full, even though the test procedure planned that they be flushed at the start of the run. This would allow material to reenter the gas stream.

The air heater inlet has five ports. For the particulate sampling, only four ports were sampled because port 3 was blocked by a structure inside the duct. Six points were sampled per port. The sampling time per point was 2.5 min, for a total sampling time of 60 min.

The ESP inlet has four ports. For the particulate sampling, six points were sampled per port. The sampling time per point was 2.5 min, for a total sampling time of 60 min. Also at the ESP inlet, a single point was sampled for SO_2 and SO_3 for a total sampling time of 30 min.

Unit 1 and 2 stack has four sampling ports. Six points were sampled per port for particulate sampling. The sampling time per point was 2.5 min, for a total sampling time of 60 min. For the oxygen, CO_2, SO_2, NO_X, and total hydrocarbons sampling, a single point was sampled for 4 h continuously. Additionally, velocity traverses and relative accuracy determinations were performed at the stack breaching. At the air heater inlet and at the unit 2 stack breaching, one port was inaccessible for sampling.

During the continuous emission monitor certification test runs, three points located at 16, 48, and 80 in. across the stack were sampled for 7 min each for a total sampling time of 21 min. At the end of each load test, an additional excess air test was recorded with the continuous emissions monitoring equipment.

3.3 EMISSION TEST RESULTS

The test conditions and summary results of the emissions testing are presented in the tables listed in Table 13.

TABLE 13. TABLES PRESENTING TEST CONDITIONS AND SUMMARY RESULTS

Emissions	Table No.
Particulate results	14
SO_3 results	15
CEM results	16
O_2 relative accuracy	17
CO_2 relative accuracy	18
SO_2 relative accuracy	19
NO_X relative accuracy	20

3.4 BASELINE FLY ASH CHARACTERISTICS

Inlet and outlet precipitator hopper samples were collected as well as hopper samples from the mechanical collector. Proportionately blended test samples were prepared from the individual precipitator hopper samples. The baseline fly ash was characterized with respect to density, particle size distribution, particle morphology, and resistivity.

Resistivity was determined as a function of ascending and descending test temperature in an air environment containing 7.5% moisture. Resistivity was also determined isothermally as a function of electric field intensity in an air environment containing 7.5% moisture and 6 ppm of sulfuric acid vapor.

3.4.1 Particle Size Analysis

Hopper samples from the mechanical collector were evaluated using a screening technique. The two samples gave similar results with about 99% coarser than 43 μm. Bahco particle size distributions and helium pycnometer densities were determined for two samples. Because the ash was unusually coarse, the +60 mesh fraction of each sample was removed before the Bahco test. These fractions amounted to 16.1% and 37.1% of samples 1 and 2, respectively. The data indicate that the size distributions are coarse and somewhat bimodal. One would not anticipate particle size to be a limiting factor with respect to electrostatic collection.

3.4.2 Ash Morphology

A sample from the method 17 test at the air heater inlet was examined for particle morphology using scanning electron microscopy. Using the x-ray mode of the instrument, it was confirmed that the spherical particles are fly ash, and the majority of the irregular shapes are unburned carbon. It was obvious from the photomicrographs and in agreement with the weight loss data that a large percentage of the ash is a combustible material.

The fly ash analyzed has an exceptionally high level of combustibles. The ash from the precipitator hoppers is also coarse from a material that had passed a mechanical collector. The aforementioned combustibles dominate the electrical conduction process. Consequently, the resistivity is extraordinarily low, and poor precipitator performance would be expected due to reentrainment problems. If combustion were improved so that unburned carbon did not control resistivity, the prevailing flue gas composition and inherent ash characteristics should provide desirable precipitator performance.

3.4.3 Resistivity without Acid Vapor

Resistivity of two test samples was determined in accordance with IEEE Standard 548-1984. Resistivity in the ascending mode was extremely low due to the excessive concentration of combustibles present in the fly ash. As temperature was increased when testing this type of ash, resistivity decreased until a sufficient amount of carbon had been oxidized. At this point, resistivity started to increase. In the case of sample 1, resistivity continued to decrease up to the highest test temperature because of the unusually large amount of unburned carbon. Sample 2 had much lower resistivity than sample 1 and produced somewhat erratic data. Again, this is believed to be due to the residual unburned carbon.

The data for sample 1 produced a smooth curve with a maximum value of about 3×10^{11} Ω•cm at 160°C (320°F). This is a typical value for ash produced from eastern coal. Samples 1 and 2 lost 21.5% and 27.5% of this weight, respectively. This loss occurred due to a 14-h thermal equilibration in dry air at 450°C (842°F) that is part of IEEE Standard 548-1984 and takes place between the ascending and descending temperature tests. These weight loss values are usually equal to 50% to 90% of the loss on ignition values for fly ash. Therefore, one would expect these ashes to contain 30% to 45% combustibles. Well burned ash produced from eastern coal usually contains only 2% to 5% combustibles. Depending on the nature of the combustibles and the particle size distribution, the possibility of combustibles affecting resistivity commences when the concentration reaches 8% to 12%. In the present case, the unburned carbon controls the conduction through the collected dust layer on the precipitator plates, and resistivity is extremely low. Therefore, the high carbon content of the fly ash would explain the measured emissions from the measured emissions from the ESP.

3.4.4 Resistivity with Acid Vapor

Resistivity was determined at 148°C (298°F) as a function of electric field intensity in an air environment containing 7.5% water vapor and 6.0 ppm sulfuric acid vapor. This procedure is defined in EPA-600/7-78-035. An annealed sample is one that has experienced the high-temperature equilibration used in the IEEE 548 resistivity test. Both samples in the as-received condition and the sample in the annealed condition were also included in the test using acid vapor. However, these samples produced excessive current levels at low voltages and were unusable.

The data indicate that the fly ash produced from the subject coal, if adequately burned to a low combustible level, will respond to acid conditioning. The annealed sample 1 had a resistivity of 2.6×10^{11} Ω•cm at 148°C (298°F). At this temperature in an environment with 6.0 ppm of sulfuric acid vapor, the resistivity was 1.0×10^{8} Ω•cm at electrical breakdown of 8 kV/cm. In the field, the sulfuric acid vapor level was 9 to 10 ppm. The difference between the amount of acid vapor found in the field and that used in the laboratory would produce only a minor additional attenuation of resistivity.

3.5 SOLID WASTE MONITORING

Solid waste monitoring during the baseline tests concentrated on slag and fly ash from unit 1. The test did not assess any other solid waste stream from the plant. No waste monitoring is currently conducted by the plant. Slag from all four units is fed through a common discharge pipe to the bottom ash disposal ponds. The two bottom ash ponds are alternately emptied and sold to a buyer who uses the slag for a variety of commercial applications. The fly ash from units 1, 2, and 3 is collected in the multicyclone and ESP hoppers and sluiced to a fly ash pond, where it is presently being stored.

The material balance requirement to quantify all the slag that is produced by the test presented a unique situation. Samples were collected at the same time that slag sluice water samples were collected. A large "bin" container of the type typically used by refuse trucks was adapted to collect the slag sluice water before it entered the ash ponds. Screened drains were added to the bin, and the bin was weighed empty. The bin was then moved to the pond and positioned. As the slag was sluiced, the water and slag entered the bin. The water was allowed to drain and the bin reweighed. Slag samples were also gathered. The slag and fly ash samples were split, and one sample was stored in a sealed container for archive. Residual moisture remaining on the slag was determined by drying a sample overnight in an oven.

Slag and fly ash samples were collected during other load tests. Results of the slag and fly ash sample wet leachate analysis are reported in Tables 22 and 23.

The sluice water was quickly decanted from the slag samples, and the solids were allowed to air dry. A composite fly ash sample was prepared from the different collection points in the dust collection system before the operation of the fly ash sluice water system. Collection in this manner assured that the sluice water samples and the ash samples were representative of the same operating conditions. The slag and fly ash samples were split, and one sample was stored in a sealed container for archive.

Slag and fly ash samples were collected during other load tests. Results were used in determining boiler efficiency as part of the boiler performance testing.

3.6 WASTEWATER MONITORING

Wastewater monitoring conducted during the demonstration project is limited to slag and fly ash sluice water effluent from unit 1. The demonstration project does not assess other water flows from the plant.

The fly ash and bottom ash sluice water systems for each unit feed a common header (one header for each system). The sluice water systems are manually controlled. During the full load baseline test, two sluice water samples were collected and analyzed. Samples of the raw sluice water as well as from the slag and fly ash handling systems were collected each time.

Before obtaining the sample, the slag and fly ash hoppers for units 2, 3, and 4 were checked to ensure that they did not need to be emptied while the unit 1 sample was being taken. After the unit 1 sluice water systems started, the technician waited at least 15 min before collecting the sample to ensure that the sluice water system had been flushed.

The sluice water samples from all three of the sampling points (raw sluice water, fly ash pond, and bottom ash pond) were tested and characterized. Also, a sample of the sluice water from the upstream side of the system was collected and analyzed, since TSS, TDS, and pH can vary substantially during the year. Test results are contained in Table 21.

4. MATERIAL MONITORING PROGRAM

The existing boiler, air heater, and dust collection system component materials (as well as the retrofitted burner support system components and materials) have been inspected to evaluate their behavior in the LNS Burner combustion process.

The unit 1 boiler is nearly 30 years old. As required by the Demonstration Plan, materials monitoring consists of material inspection and the accumulation of baseline data concerning the as-found condition of boiler pressure parts, refractory, ductwork, support, dust collection system, and air heater. The as-found material condition and data will be compared with inspection data accumulated from the same areas, at the completion of the project demonstration phase. The new components and materials specific to the LNS Burner, including new boiler tubing, will also be inspected and evaluated for corrosion.

Performance and physical condition of the equipment in the material monitoring program noted during operational readiness inspections and maintenance inspections completed before the baseline performance test indicated that major maintenance items should be completed to assure plant reliability during the demonstration phase of the project. This maintenance includes replacement of boiler tubing in the lower furnace and general repair of other items that are related to the program. This work is scheduled to be completed during the retrofit of the LNS Burner, but before start-up of the retrofitted plant. The material monitoring inspection will be accomplished after this work has been completed. This will assure that program objectives will be met in documenting the effect of the LNS Burner on plant components. Any comparison with existing components that require replacement or extensive maintenance would not fulfill program objectives.

4.1 GENERAL BOILER CONDITION

The following boiler casing breaching and ductwork leaks were noted during baseline testing and were taken into consideration in validating data and test results:

- Failures in the refractory seal between the furnace and penthouse existed, which was evident by a deposit of ash that could be seen and the velocity with which it was being carried from the penthouse access door and from beneath the penthouse lagging in many areas.

- Gas leakage from the upper section of the convection pass was apparent from the concentration of noxious fumes in general areas.

- The breaching in the area of the regenerative air preheater hot gas inlet had several leaks.

- The southeast corner of the mechanical fly ash separator was a minor source of gas and ash leakage.

- One convection pass manhole door leaked badly around its circumference.

- One third of the steam coil air heater was not in service.

- The inlet expansion joint on the east secondary metering venturi failed and leaked.

- The boiler insulation and lagging was deteriorated in some areas.

4.2 OPERATIONAL READINESS

Before baseline testing, Marion unit 1 was inspected for operational readiness to assess plant operability for the baseline test and to assess availability and reliability for the demonstration testing program. Extensive major repair and betterment work was begun on the unit 1 boiler during a November-December 1988 outage. A plant betterment program had been conducted earlier for Marion units 1, 2, and 3. The work now under way would bring the units up to utility industry standards of availability a plant of this age and size.

The major work completed, in progress, or scheduled for the plant retrofit is summarized below.

4.3 BOILER AND AUXILIARIES

- Boiler casing leak repair–Extensive work is in progress or planned to repair boiler casing leaks.

- Asbestos removal–SIPC has completed removal and replacement of all asbestos insulation in the plant.

- Chelate cleaning–The boiler was acid (chelate) cleaned in December 1988. This was the first time the boiler had been acid cleaned since 1973. A few tube leaks occurred as a result of the acid cleaning, which indicates that some degree of waterside corrosion existed. All leaks were repaired.

- Boiler tubes–During the November-December 1988 overhaul outage, the boiler furnace floor tubes were ultrasonically tested to determine wall thickness. As a result of this activity and a visual inspection throughout the boiler, 31 furnace floor and 28 boiler roof tubes were repaired to improve boiler reliability. It was not determined if the tube wastage was due to fire side abrasion/erosion/corrosion or water side corrosion or both.

- The vibration of a tube alignment bar (which was welded to every fifth roof tube) against the adjacent roof tubes resulted in excessive tube material wastage on 28 tubes and necessitated that repairs be made. SIPC felt this was the cumulative result of vibration impact over a long period of time. Measures were taken to eliminate the vibration problem.

- Under the design cyclone combustion conditions, the major fire side tube wastage is assumed to have essentially been concentrated in the lower furnace (floor) area. This is attributable to the fact that the refractory had not been installed. All boiler tubes in the lower furnace area will be replaced in addition to select tubes.

- Air preheater–In November 1988, an inspection of the regenerative air heater was completed, outlining maintenance that should be performed to assure reliability. Corrective action had been taken by SIPC for major deficiencies. The air heater will be reinspected as part of the material monitoring program.

- Electrostatic precipitator–SIPC performed maintenance on the precipitator and it had been operating satisfactorily. The equipment will be re-inspected for subsequent deficiencies as part of the material monitoring program.

- Instrumentation–A survey conducted of the unit's instrumentation determined that all instrumentation required for the baseline test was available for performance data collection. The equipment will require calibration and preventative maintenance work to ensure reliability for the demonstration program.

- Ductwork and furnace access for isokinetic dust sampling and gas temperature traverses–All flue gas dust sample points required for the baseline test were available; however, sampling piping connections to the boiler casing found to be in poor condition were repaired and/or replaced.

- Furnace access–Access to the boiler furnace for furnace temperature probe(s) traverses to obtain temperature profiles during the demonstration program can be gained at two furnace elevations. One penetration, which was included in the original boiler design, is located in a side wall in the area of the cyclones was capped. One or both existing furnace inspection ports, which are located approximately 3/4 of the way up the front wall, could be utilized. Additional penetrations were installed before the baseline test.

- Stack emissions monitoring–Unit 1 was not equipped with emissions monitoring instrumentation. This equipment was installed before baseline testing.

- Slag and ash sampling–The bottom ash system is common to all four Marion units. Operation is manual with ash sluiced sequentially from all operating units. Each slag tank is emptied approximately once per shift. There is no reliable method to measure slag quantity at the slag tank. Therefore, slag was captured at the ash pond during the baseline tests to determine the quantity produced.

- Turbine-generator and unit auxiliary systems and equipment–Turbine-generator unit 1, which underwent a major overhaul during March-April 1986, has been highly reliable throughout the life of the plant.

- Electrical–The electrical system generally was found operable providing all services required for baseline testing. Major modifications and additions to both the 2400 V and 480 V system are required for the retrofit plan.

5. TEST METHODS AND ANALYTICAL PROCEDURES

5.1 BOILER PERFORMANCE TEST METHOD

The boiler performance test was conducted in accordance with ASME PTC 4.1 (abbreviated form) by Riley Stoker at steady state operating conditions of minimum, intermediate, and rated load. The heat loss method was used to determine the boiler efficiency considering the following losses:

- Heat loss due to dry gas.
- Heat loss due to moisture in the fuel.
- Heat loss due to H_2O from combination of H_2.
- Heat loss due to combustibles in the refuse (unburned carbon).
- Heat loss due to radiation. (The manufacturer's predicted value was to be used if the boiler insulation condition was acceptable and/or the value determined from the ABMA radiation loss chart.
- Heat loss due to sensible heat in slag.
- Heat loss due to moisture in air.
- Unaccounted-for losses.

Allowances for measurement and sampling errors for the full-load test were determined in accordance with paragraph 3.03.1 of ASME PTC 4.1 and the table of tolerances given on page 27 of the code for the heat loss method. In calculating the boiler efficiency by the heat loss method, the flue gas temperature leaving the air preheater, corrected for leakage, was utilized. Approximately 1 hr was allowed to stabilize the unit at steady-state load conditions before obtaining test data. During the stabilization period and for the duration of the load tests, the boiler continuous blow down was valved out of service. Sootblowers were operated just before the stabilization and test period and then remained idle until the completion of the tests.

During the load tests, coal samples were taken at the coal feeder inlet in accordance with PTC 3.2, Test Code for Solid Fuels, and the analysis was performed in accordance with ASTM D271. The samples taken for ultimate analysis were composited and divided into two equal composite samples. One sample was analyzed by the testing laboratory, and the other was retained as a duplicate until the final results of the test have been reviewed and found acceptable. Separate samples were obtained for fuel moisture.

Temperature data throughout the boiler were gathered at the operating loads. Temperatures of the boiler wall tubes were measured by thermocouples welded to water tubes. The furnace outlet and superheater outlet were measured with high velocity temperature probes. Gas temperatures at the air heater inlet and outlet were determined from an installed thermocouple grid.

5.2 BOILER EFFICIENCY CORRECTION

For direct comparison of efficiencies before and after the modification, it is necessary to correct the as-fired efficiencies to the reference fuel and air temperature of 80°F. These corrections were performed according to ASME PTC 4.1.

The corrections calculated per ASME PTC 4.1 are summarized below:

- Dry flue gas loss based on the calculated pounds of dry flue gas per pound of design fuel.
- Fuel moisture loss based on the design fuel moisture content.
- Fuel hydrogen loss based on the design fuel hydrogen content.
- Design fuel higher heating value per 1969 Addendum.
- Air temperature correction.
- Corrected air heater gas outlet temperature.

5.3 PARTICULATE EMISSIONS

The particulate emission rate was determined following procedures detailed in EPA methods 5 and 17. Particulate samples collected on Whatman 934 AH glass fiber filters were analyzed gravimetrically. The probe and nozzles were washed with acetone. The wash was transferred to tared beakers and evaporated to dryness. These weight differentials were combined to determine total particulate matter.

5.3.1 SO_3 Emissions

The SO_3, ammonia concentrations and the acid dewpoint were determined using the controlled condensation method. Flue gas was sampled in accordance with TRW document 2805516005-RU-00.

The flue gas containing SO_3 vapor was sampled through a quartz fiber filter at 700°F then through a condenser controlled by a water jacket to maintain a temperature between 160 and 180°F. As the flue gas was cooled below 200°F, the SO_3 condensed on the walls of the condenser and reacted with the water vapor present in the gas stream to form sulfuric acid vapor. After sampling, the condenser was purged and washed, and the sample was titrated with the barium-thorium method to determine the concentration of sulfuric acid, which is reported as SO_3. SO_2 passed through the condenser and was captured in a 3% hydrogen peroxide solution.

5.4 CONTINUOUS EMISSIONS MONITORING EQUIPMENT

5.4.1 Oxygen and CO_2

The oxygen and CO_2 emission rates were determined following procedures detailed in EPA method 3A. A sample was extracted continuously from each flue gas stream, and a portion was conveyed to a Teledyne oxygen analyzer and to a Horiba CO_2 analyzer.

5.4.2 SO_2

The SO_2 emission rate was determined following procedures detailed in EPA method 6C. A sample was extracted continuously from each flue gas stream, and a portion was conveyed to a Western Research UV photometric analyzer.

5.4.3 NO_X

The NO_X emission rate was determined following procedures detailed in EPA method 7E. A sample was extracted continuously from each flue gas stream, and a portion was conveyed to a TECO chemiluminescent nitrogen oxides analyzer.

5.4.4 Total Hydrocarbons

The total hydrocarbons emission rate was determined following procedures detailed in EPA method 25A. A gas sampple was extracted continuously from each flue gas stream, and a portion was conveyed to a J.U.M. Research flame ionization analyzer. Before and after each test run, each monitor was zeroed and calibrated with calibration gas. These calibrations were used to correct the raw data for zero and calibration draft occurring during the test runs.

5.4.5 Fly Ash Resistivity

The resistivity was performed in the laboratory according to IEEE Standard 548-1984 *Resistivity Ascending or Descending Temperature*. Gas composition data (moisture and sulfuric acid content) were obtained from the particulate testing and the SO_3 testing performed at the ESP inlet.

5.4.6 Fly Ash Morphology

The fly ash morphology was determined using scanning electron microscopy at 500x, 1,000x, 3,500x, and 10,000x magnifications.

TABLE 14. PARTICULATE RESULTS

EPA Method 17
Unit 1
October 23, 1990

	Average
Process Data	
Load (percent)	100
AIR HEATER INLET[1]	
Gas Conditions	
Temperature (°F)	621
Moisture (volume %)	9.3
O_2 (dry volume %)	3.9
CO_2 (dry volume %)	15.2
Volumetric Flow Rate	
acfm	185,667
dscfm	84,137
ELECTROSTATIC PRECIPITATOR INLET	
Gas Conditions	
Temperature	299
Moisture (volume %)	6.6
O_2 (dry volume %)	7.0
CO_2 (dry volume %)	12.1
Volumetric Flow Rate	
acfm	159,433
dscfm	102,670
Particulate	
gr/dscf	5.0803
lb/hr	4,476
lb/MBtu[2]	10.7612
STACK	
Gas Conditions	
Temperature (°F)	272
Moisture (volume %)	6.1
O_2 (dry volume %)	8.5
CO_2 (dry volume %)	10.3
Volumetric Flow Rate	
acfm	151,967
dscfm	101,323
Particulate	
gr/dscf	0.1349
lb/hr	118
lb/MBtu[2]	0.3209
Particulate Removal Efficiency	
percent	97.36

[1]See comments
[2]As calculated with an Fd factor of 9844

Source: CAE Report dated 27 March 1991.

TABLE 15. SO_3 RESULTS

Electrostatic Precipitator Inlet 23 October 1990	Average
Process Data	
Load (percent)	100
Gas Conditions[1]	
O_2 (dry volume %)	7.0
CO_2 (dry volume %)	12.1
Volumetric Flow Rate[1]	
acfm	158,500
dscfm	102,670
Sulfur Trioxide	
ppm	11.41
lb/hr	14.59
lb/MBtu[2]	0.035
Sulfur Dioxide to Sulfur Trioxide Conversion	
ppm	0.46
Acid Dewpoint	
°F	274

[1]Data obtained from the particulate testing
[2]As calculated with an Fd factor of 9844 based on coal analysis

Source: CAE Report dated 27 March 1991.

TABLE 16. CONTINUOUS EMISSIONS MONITORING RESULTS AT THREE LOAD CONDITIONS

EPA Methods 3A 6C, 7E and 10
Unit 1 and 2 Common Stack

Process Data			
Load (percent)	100	50	75
Volumetric Flow Rate[1]			
acfm	153,500	N/A	N/A
dscfm	102,700	N/A	N/A
Oxygen			
(dry volume %)	7.8	10.7	3.0
Carbon Dioxide			
(dry volume %)	11.3	8.9	7.0
Sulfur Dioxide			
ppm	2,273	1,869	1,540
lb/hr	2,326	N/A	N/A[4]
lb/MBtu[2]	5.93	6.26	
Nitrogen Oxides			
ppm	443	358	288
lb/hr	270	208	178
lb/MBtu[2]	0.831	0.862	0.395
Total Hydrocarbons[3]			
ppm			
lb/hr			
lb/MBtu			

[1]As calculated with an Fd factor of 9844
[2]As calculated with an Fd factor of 9844
[3]See Comments
[4]Data invalid due to boiler upset
N/A - Not applicable

Source: CAE Report dated 27 March 1991.

TABLE 17. OXYGEN RELATIVE ACCURACY RESULTS

EPA Method 3A
Unit 1 and 2 Common Stack
22 October 1990

	RM percent	CEM percent	difference
Average	7.9	9.2	-1.29

Standard Deviation	0.1983
Confidence Coefficient	0.1525
Relative Accuracy	18.17%

RM–Reference method
CEM–Continuous emissions monitoring

Source: CAE Report dated 27 March 1991.

TABLE 18. CO_2 RELATIVE ACCURACY RESULTS

EPA Method 3A
Unit 1 and 2 Common Stack
22 October 1990

	RM percent	CEM percent	difference
Average	10.0	8.9	1.11

Standard Deviation	0.2750
Confidence Coefficient	0.2114
Relative Accuracy	13.24%

RM–Reference method
CEM–Continuous emissions monitoring

Source: CAE Report dated 27 March 1991.

TABLE 19. SO_2 RELATIVE ACCURACY RESULTS

EPA Method 6C
Unit 1 and 2 Common Stack
22 October 1990

	Oxygen	RM ppm	CEM ppm	difference
Average	7.9	1973	1692	281.56

Standard Deviation	30.8671
Confidence Coefficient	23.7265
Relative Accuracy	15.47%

RM–Reference method
CEM–Continuous emissions monitoring

Source: CAE Report dated 27 March 1991.

TABLE 20. NO_X RELATIVE ACCURACY RESULTS

EPA Method 7C
Unit 1 and 2 Common Stack
22 October 1990

	Oxygen	RM ppm	CEM ppm	difference
Average	7.9	473	414	58.67

Standard Deviation	23.4627
Confidence Coefficient	18.0350
Relative Accuracy	16.22%

RM–Reference method
CEM–Continuous emissions monitoring

Source: CAE Report dated 27 March 1991.

TABLE 21. WATER ANALYSIS

	100% LOAD October 23, 1990					
	SLAG POND SLUICE		ASH POND SLUICE		RAW SLUICE	
Compound	Sample No. (25436-35) Concentration (mg/l)	Sample No. (25436-36) Concentration (mg/l)	Sample No. (25436-49) Concentration (mg/l)	Sample No. (25436-50) Concentration (mg/l)	Sample No. (25436-45) Concentration (mg/l)	Sample No. (25436-46) Concentration (mg/l)
Aluminum*	BDL	BDL	1.80E+01	4.15E+00	BDL	3.15E+00
Antimony*	BLD	BDL	BDL	BDL	BDL	BDL
Arsenic	BDL	BDL	2.70E-02	7.75E-03	BDL	BDL
Barium	BDL	BDL	BDL	BDL	BDL	BDL
Beryllium*	BDL	BDL	BDL	BDL	BDL	BDL
Boron	2.00E-02	2.00E-02	1.30E-01	6.00E-02	3.00E-02	2.50E-02
Cadmium	BDL	BDL	BDL	BDL	1.59E-01	1.95E-01
Calcium	2.93E+01	5.93E+01	3.93E+01	2.45E+01	9.50E+00	4.43E+01
Chloride	2.20E-01	4.98E+00	4.04E+00	4.05E+00	3.48E+00	3.45E+00
Chromium	BDL	BDL	5.65E-02	BDL	BDL	BDL
Copper	4.70E-02	5.75E-02	6.50E-02	1.24E-01	1.14E-01	1.23E-01
Fluoride	2.20E-01	1.90E-01	2.50E-01	2.50E-01	6.00E-01	2.10E-01
Iron	1.61E+00	2.66E+00	3.95E+01	4.34E+00	2.36E+00	6.49E+00
Lead	BDL	BDL	2.43E-01	BDL	BDL	BDL
Magnesium*	4.84E+00	4.64E+00	7.06E+00	4.79E+00	4.08E+00	4.53E+00
Manganese*	3.59E-01	3.72E-01	4.15E-01	3.34E-01	1.90E+00	2.23E+00
Mercury	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel*	BDL	BDL	1.22E-01	BDL	BDL	BDL
Nitrate	4.20E-01	7.80E-01	4.70E-01	4.70E-01	2.33E+01	1.18E+00
Potassium	2.18E+00	3.94E+00	4.62E+00	5.44E-01	4.35E-01	2.32E+00
Selenium	BDL	BDL	BDL	BDL	BDL	BDL
Silicon	2.00E+00	2.50E+00	2.00E+00	2.00E+00	2.00E+00	2.00E+00
Silver	BDL	BDL	BDL	BDL	BDL	BDL
Sodium	4.08E+00	5.35E+00	0.00E+00	4.45E+00	4.25E+00	5.00E+00
Strontium	2.50E-02	6.00E-02	3.50E-02	3.00E-02	3.00E-02	3.00E-02
Titanium*	BDL	BDL	3.22E+00	1.72E+00	BDL	BDL
Vanadium*	BDL	BDL	BDL	BDL	BDL	BDL
Zinc	2.64E-01	3.37E-01	6.35E-01	2.94E-01	3.22E-01	3.05E-01
Total Dissolved Solids	7.15	6.70	57.80	10.40	14.55	6.05
Total Suspended Solids	0.70	1.80	62.10	8.60	1.50	4.50

*Not required by test specification

Source: CAE Report dated 27 March 1991.

TABLE 22. WET LEACHATE ANALYSIS FOR SLAG–COMMON IONS

Compound	Sample No. (25436-33) Concentration (mg/kg)	Sample No. (25436-34) Concentration (mg/kg)
Alumina	2.21E+04	6.42E+04
Antimony	BDL	BDL
Inorganic Arsenic	1.92E-01	1.90E-01
Barium	2.12E+01	BDL
Beryllium	BDL	BDL
Boron	6.00E+01	5.00E+01
Cadmium	BDL	3.20E+00
Calcium Oxide (Lime)	4.37E+03	1.36E+04
Chromium	1.00E+01	1.79E+01
Copper	6.57E+00	8.18E+00
Ferric Oxide	3.06E+04	6.26E+04
Lead	2.41E+00	4.59E+00
Magnesium Oxide	2.70E+03	7.59E+03
Manganese Oxide	1.25E+02	3.59E+02
Mercury	0.00E+00	0.00E+00
Nickel	1.69E+01	2.72E+01
Potassium Oxide	1.76E+03	6.24E+03
Selenium	1.03E-01	1.70E-01
Silicon	BDL	BDL
Silver	BDL	BDL
Sodium Oxide	5.29E+02	1.01E+03
Strontium	8.00E+01	8.00E+01
Titanium Dioxide	BDL	5,85E+2
Vanadium	5.29E+01	BDL
Zinc	5.81E+00	1.84E+01
Vibrated Bulk Density (lb/ft3, wet method)	76.49	84.86
Vibrated Bulk Density (lb/ft3, dry method)	83.36	90.63
Total Unburned Carbon (%, dry basis)	0.35	0.6
Fluorine (mg/kg, dry basis)	34	32
Total Sulfites (%, as received)	1.25	4.92
Phosphorus Pentoxide (mg/kg, dry basis)	2600	2700
Btu/lb (dry basis)	120	94

Source: CAE Report dated 27 March 1991.

TABLE 23. WET LEACHATE ANALYSIS FOR FLY ASH–COMMON IONS

Compound	Sample No. (25436-113) Concentration (mg/kg)	Sample No. (25436-114) Concentration (mg/kg)
Alumina	BDL	BDL
Antimony	BDL	BDL
Inorganic Arsenic	3.66E+01	2.85E+01
Barium	2.75E+02	1.93E02
Beryllium	BDL	BDL
Boron	1.10E+02	8.50E+01
Cadmium	BDL	BDL
Calcium Oxide (Lime)	6.24E+03	6.26E+03
Chromium	4.17E+01	5.07E+01
Copper	3.38E+01	4.01E+01
Ferric Oxide	9.61E+04	1.11E+05
Lead	2.12E+02	2.88E+02
Magnesium Oxide	3.78E+03	3.38E+03
Manganese Oxide	1.96E+02	2.06E+02
Mercury	0.00E+00	0.00E+00
Nickel	4.35E+01	5.60E+01
Potassium Oxide	5.25E+03	1.39E+04
Selenium	2.02E+00	3.57E+00
Silicon	BDL	BDL
Silver	BDL	BDL
Sodium Oxide	1.60E+03	1.28E+03
Strontium	8.00E+01	8.00E+01
Titanium Dioxide	BDL	BDL
Vanadium	BDL	BDL
Zinc	2.20E+02	5.70E+02
Vibrated Bulk Density (lb/ft3, wet method)	35.97	33.35
Vibrated Bulk Density (lb/ft3, dry method)	36.12	33.46
Total Unburned Carbon (%, dry basis)	52.44	57.25
Fluorine (mg/kg, dry basis)	84	84
Total Sulfites (%, as received)	4.72	1.03
Phosphorus Pentoxide (mg/kg, dry basis)	780	650
Btu/lb (dry basis)	7360	7377

Source: CAE Report dated 27 March 1991.

TABLE 24. PREMODIFICATION BASELINE TESTING DETERMINATION OF FLY ASH TO SLAG RATIO

TEST NO.		1		
BOILER LOAD	% OF MCR	100		
DATE OF TEST		10/23/90		
TIME OF TEST	HOURS	1030-1615		
FUEL FIRED		COAL		
1. % CARBON IN FLYASH	%	54.85	(a)	FROM ASH ANALYSIS BY CAE
2. % CARBON IN SLAG	%	0.48		FROM SLAG ANALYSIS BY CAE
3. % ASH IN FUEL	%	17.28		FROM FUEL ANALYSIS BY RSC
4. GRAIN LOADING, AVERAGE	GR/DSCF	5.138		FROM ISOKINETIC PARTICULATE SAMPLING BY CAE
5. MEASURED OXYGEN LEVEL, DRY BASIS	%	3.1		FROM FLUE GAS SAMPLING BY RSC
6. LOADING PER EPA METHOD 19	LB/MBTU	8.43		ITEM 4 ÷ 7000 x 9780 x (20.9 ÷ (20.9 − ITEM 5))
7. HIGHER HEATING VALUE OF FUEL	BTU/LB	10,526		FROM FUEL ANALYSIS BY RSC
8. LB DRY REFUSE(FLYASH)/LB FUEL	LB/LB	0.0887		(ITEM 6 x ITEM 7) ÷ 1,000,000
9. LB ASH(FLYASH)/LB FUEL	LB/LB	0.0401		(100 − ITEM 1) ÷ 100 x ITEM 8
10. LB ASH(SLAG)/LB FUEL	LB/LB	0.1327		(ITEM 3 ÷ 100) − ITEM 9
11. LB DRY REFUSE(SLAG)/LB FUEL	LB/LB	0.1334		ITEM 10 ÷ ((100 − ITEM 2) ÷ 100)
12. LB TOTAL DRY REFUSE/LB FUEL	LB/LB	0.2221		ITEM 11 + ITEM 8
13. % OF REFUSE TO FLYASH	%	39.95		ITEM 8 ÷ ITEM 12 x 100
14. % OF REFUSE TO SLAG	%	60.05		ITEM 11 ÷ ITEM 12 x 100

NOTES:

(a) THE PERCENT CARBON IN FLYASH WAS DETERMINED FROM THE HOPPER SAMPLES COLLECTED AND COMPOSITED BY CLEAN AIR ENGINEERING.

Source: Riley Boiler Performance Test Report.

TABLE 25. PREMODIFICATION BASELINE TESTING TEST NO. 1 EFFICIENCY BY ISOKINETIC SAMPLES UNBURNED CARBON ANALYSIS

TEST NO.		1	1
BOILER LOAD	% OF MCR	100	100
~~DATE OF TEST~~		~~10/23/90~~	~~10/23/90~~
TIME OF TEST	HOURS	1030-1615	1030-1615
~~FUEL FIRED~~		~~COAL~~	~~COAL~~
CYCLONES IN SERVICE		A+B	A+B
EFFICIENCY UNBURNED CARBON SAMPLES		ISOKINETIC	HOPPER
1. ASH ANALYSIS			
CARBON IN FLYASH	%	45.77	54.85
CARBON IN SLAG	%	0.48	0.48
% TOTAL DRY REFUSE AS FLYASH	%	41.46	39.95
% TOTAL DRY REFUSE AS SLAG	%	58.54	60.05
2. FUEL ANALYSIS, AS FIRED (AVERAGE)			
CARBON	%	58.65	58.65
HYDROGEN	%	3.97	3.97
NITROGEN	%	1.16	1.16
OXYGEN	%	5.24	5.24
SULFUR	%	2.95	2.95
ASH	%	17.28	17.28
MOISTURE	%	10.75	10.75
HIGHER HEATING VALUE	BTU/LB	10,526	10,526
3. BOILER EFFICIENCY, AS FIRED BY HEAT LOSS METHOD			
REFERENCE TEMPERATURE	°F	141	141
LOSSES:			
DRY FLUE GAS	%	4.32	4.26
MOISTURE IN FUEL	%	1.11	1.11
WATER FROM COMBUSTION OF H2	%	3.65	3.65
COMBUSTIBLE IN REFUSE	%	5.68	6.79
RADIATION (ABMA CURVE)	%	0.35	0.35
UNMEASURED			
- AIR MOISTURE	%	0.06	0.05
- SENSIBLE HEAT IN SLAG	%	0.64	0.64
- UNACCOUNTABLE	%	0.50	0.50
TOTAL LOSSES	%	16.31	17.35
EFFICIENCY	%	83.69	82.65

Source: Riley Boiler Performance Test Report.

TABLE 26. PREMODIFICATION BASELINE TESTING DETERMINATION OF FLY ASH TO SLAG RATIO FROM ISOKINETIC FLY ASH SAMPLES

TEST NO.		1	
BOILER LOAD	% OF MCR	100	
DATE OF TEST		10/23/90	
TIME OF TEST	HOURS	030-1615	
FUEL FIRED		COAL	
1. % CARBON IN FLYASH	%	45.77 (a)	FROM ASH ANALYSIS BY CAE
2. % CARBON IN SLAG	%	0.48	FROM SLAG ANALYSIS BY CAE
3. % ASH IN FUEL	%	17.28	FROM FUEL ANALYSIS BY RSC
4. GRAIN LOADING, AVERAGE	GR/DSCF	5.138	FROM ISOKINETIC PARTICULATE SAMPLING BY CAE
5. MEASURED OXYGEN LEVEL, DRY BASIS	%	3.1	FROM FLUE GAS SAMPLING BY RSC
6. LOADING PER EPA METHOD 19	LB/MBTU	8.43	ITEM 4 ÷ 7000 x 9780 x (20.9 ÷ (20.9 - ITEM 5))
7. HIGHER HEATING VALUE OF FUEL	BTU/LB	10,526	FROM FUEL ANALYSIS BY RSC
8. LB DRY REFUSE(FLYASH)/LB FUEL	LB/LB	0.0887	(ITEM 6 x ITEM 7) ÷ 1,000,000
9. LB ASH(FLYASH)/LB FUEL	LB/LB	0.0481	(100 - ITEM 1) ÷ 100 x ITEM 8
10. LB ASH(SLAG)/LB FUEL	LB/LB	0.1247	(ITEM 3 ÷ 100) - ITEM 9
11. LB DRY REFUSE(SLAG)/LB FUEL	LB/LB	0.1253	ITEM 10 ÷ ((100 - ITEM 2) ÷ 100)
12. LB TOTAL DRY REFUSE/LB FUEL	LB/LB	0.2140	ITEM 11 + ITEM 8
13. % OF REFUSE TO FLYASH	%	41.46	ITEM 8 ÷ ITEM 12 x 100
14. % OF REFUSE TO SLAG	%	58.54	ITEM 11 ÷ ITEM 12 x 100

NOTES:

(a) THE PERCENT CARBON IN FLYASH WAS DETERMINED FROM THE ISOKINETIC SAMPLES COLLECTED BY CLEAN AIR ENGINEERING FOR TEST NO. 1.

Source: Riley Boiler Performance Test Report.

TABLE 27. PREMODIFICATION BASELINE TESTING BOILER EFFICIENCY, CORRECTED TO CONTRACT CONDITIONS

EST NO.		1	2	3
OILER LOAD	% OF MCR	100	75	50
ATE OF TEST		10/23/90	10/25/90	10/24/90
IME OF TEST	HOURS	1030-1615	1030-1230	1300-1700
UEL FIRED		COAL	COAL	COAL
1. ASH ANALYSIS				
CARBON IN FLYASH	%	54.85	50.25	54.10
CARBON IN SLAG	%	0.48	0.35	0.87
% TOTAL DRY REFUSE AS FLYASH	%	39.95	39.95	39.95
% TOTAL DRY REFUSE AS SLAG	%	60.05	60.05	60.05
2. CONTRACT FUEL ANALYSIS, FOR EFFICIENCY				
CARBON	%	60.20	60.20	60.20
HYDROGEN	%	3.81	3.81	3.81
NITROGEN	%	0.99	0.99	0.99
OXYGEN	%	5.47	5.47	5.47
SULFUR	%	3.18	3.18	3.18
ASH	%	17.00	17.00	17.00
MOISTURE	%	9.20	9.20	9.20
HIGHER HEATING VALUE	BTU/LB	10,864	10,864	10,864
3. BOILER EFFICIENCY, BY HEAT LOSS METHOD, CORRECTED TO CONTRACT FUEL				
REFERENCE TEMPERATURE	°F	80	80	80
LOSSES:				
DRY FLUE GAS	%	4.71	4.23	4.02
MOISTURE IN FUEL	%	0.94	0.93	0.92
WATER FROM COMBUSTION OF H2	%	3.47	3.46	3.41
COMBUSTIBLE IN REFUSE	%	6.79	7.85	8.13
RADIATION (ABMA CURVE)	%	0.35	0.40	0.58
UNMEASURED				
- AIR MOISTURE	%	0.10	0.08	0.08
- SENSIBLE HEAT IN SLAG	%	0.64	0.82	0.77
- UNACCOUNTABLE	%	0.50	0.50	0.50
TOTAL LOSSES	%	17.50	18.27	18.41
EFFICIENCY	%	**82.50**	**81.73**	**81.59**

Source: Riley Boiler Performance Test Report.

TABLE 28. PREMODIFICATION BASELINE TESTING FURNACE EXIT GAS TEMPERATURE CALCULATION

TEST NO.		1	2	3
BOILER LOAD	% OF MCR	100	75	50
DATE OF TEST		10/23/90	10/25/90	10/24/90
TIME OF TEST	HOURS	1030-1615	1030-1230	1300-1700
FUEL FIRED		COAL	COAL	COAL
CYCLONES IN SERVICE		A+B	A+B	A
1. STEAM AND WATER FLOWS				
HIGH TEMP. SUPERHEATER (Mht)	LB/HR	314,936	235,222	165,168
LOW TEMP. SUPERHEATER (Mlt)	LB/HR	309,434	234,817	164,954
SUPERHEAT SPRAY WATER (Ms)	LB/HR	5,502	404 (a)	214 (a)
2. STEAM AND WATER TEMPERATURES				
FINAL SUPERHEAT OUTLET	°F	904	913	831
LTSH OUT AFTER ATTEMPORATOR	°F	692	705	667
LTSH OUT BEFORE ATTEMPORATOR	°F	723	708	670
DRUM SATURATION	°F	536	533	532
SUPERHEAT SPRAY WATER	°F	240	172 (b)	154 (b)
3. STEAM AND WATER PRESSURES				
SUPERHEAT OUTLET	PSIG	844	845	860
DRUM	PSIG	918	890	882
FEEDWATER	PSIG	1163	1239 (c)	1136
4. GAS FLOW, CALCULATED BY HEAT BALANCE				
FLUE GAS PRODUCED (Mfg)	LB/HR	427,220	317,468	223,158
5. STEAM AND WATER ENTHALPY				
LTSH INLET (Hlt1)	BTU/LB	1197.7	1199.3	1199.6
LTSH OUTLET (Hlt2)	BTU/LB	1347.8	1339.1	1313.4
ATTEMPORATOR INLET (Hs1)	BTU/LB	210.4	142.5	124.2
HTSH INLET (Hht1, Hs2)	BTU/LB	1327.9	1337.0	1311.8
FINAL HTSH OUTLET (Hht2)	BTU/LB	1456.5	1461.5	1414.3
6. GAS ENTHALPY				
GAS LEAVING FURNACE EXIT PLANE (Hfg1)	BTU/LB	454.7	400.2	341.2
GAS ENTERING BOILER BANK (Hfg2)	BTU/LB	236.8	203.2	179.7
7. GAS TEMPERATURE				
GAS ENTERING BOILER BANK	°F	974	854	770
FURNACE EXIT GAS TEMPERATURE, ACTUAL	°F	1715 (d)	1535 (d)	1335 (d)
FEGT, CORRECTED TO 20% EXCESS AIR	°F	1720	1561	1340
8. FURNACE HEAT RELEASE	BTU/HR/FT2	79,648	59,733	40,792

NOTES:

(a) THIS FLOW REPRESENTS LEAKAGE ACROSS THE CLOSED SPRAY VALVE.
(b) SPRAY VALVE WAS CLOSED.
(c) THIS DATA POINT IS QUESTIONABLE.
(d) OBTAINED FROM RILEY GAS ENTHALPY TABLES.

Source: Riley Boiler Performance Test Report.

REFERENCES

1. *Preliminary Report on the Evaluation of the Low NO_X/SO_X Burner, Phase 1-Baseline Testing*. CAE, 27 March 1991.

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3. *Demonstration Test Plan*, CDOE30101N, Issue A.

4. *Environmental Monitoring Plan*, CDOE30110N, Issue A.

5. *Materials Monitoring Plan*, CDOE30111N, Issue A.

6. *EPRI Test Requirements*, CDOE30401N, Issue A.

7. *Demonstration Program Data Acquisition Measurements*, M74-BA01, Sheets 1 and 2.

8. *Summary of Significant Activities and Raw Data*, TTI-90-0057, Bechtel, 8 November 1990.