Fuel Capability Demonstration Test Report 1
for the
JEA Large-Scale CFB Combustion Demonstration Project

100% Pittsburgh 8 Fuel

Submitted to
U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory (NETL)
Pittsburgh, Pennsylvania 15236
Cooperative Agreement No.
DE-FC21-90MC27403

September 3, 2004

DOE Issue, Rev. 1

Prepared by Black & Veatch for:

Building Community

TABLE OF CONTENTS

TABLES

FIGURES

1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels. Therefore, it was necessary for JEA to demonstrate this capability through a series of tests.

The purpose of the test program was to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility would be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin
    - Furan
- Stack opacity

This test report documents the results of JEA's Fuel Capability Demonstration Tests on 100% Pittsburgh 8 coal for the JEA Large-Scale CFB Combustion Demonstration Project. The tests were conducted in accordance with the Fuel Demonstration Test Protocol in Attachment A.

Throughout this report, unless otherwise indicated, the term "unit" refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF)

1.1 Test Schedule

Unit 2 of the JEA Northside plant site is a Circulating Fluidized Bed Steam Generator designed and constructed by Foster-Wheeler. The steam generator was designed to deliver main steam to a steam turbine at a flow rate of 1,993,591 lb/hr, at a throttle pressure of 2,500 psig, and at a throttle temperature of 1,000 deg F.

The fuel capability demonstration test for the unit firing 100% Pittsburgh 8 coal, was conducted over a four (4) day period beginning on January 13, 2004 and completed on January 16, 2004. During that four (4) day period, data were taken in accordance with the Test Protocol (Attachment A) while the unit was operating at 100% load, 80% load , 60% load, and 40% load.

The following log represents the sequence of testing:

- Day 1 January 13, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 1030 hours; completed at 2100 hours.
  - Boiler performance testing commenced at 1100 hours; completed at 1500 hours.

- Day 2 January 14, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 0751 hours; completed at 1752 hours.
  - Boiler performance testing commenced at 1000 hours; completed at 1400 hours.

- Day 3 January 15, 2004:
  - Unit at 80% load - turbine load set and maintained at approx. 240 MW.
  - Unit began 2-hour stabilization period at 240 MW at 1400 hours.
  - Boiler performance testing commenced at 1600 hours after stabilization period completed; test completed at 2000 hours.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 3 (cont'd) January 15, 2004:
  - Unit load 40% load after completion of testing at 80% load - turbine load set and maintained at approx. 120 MW.
  - Unit began 2-hour stabilization period at 120 MW at 2200 hours.
  - Boiler performance testing commenced at 0000 hours after stabilization period completed; test completed at 0400 hours, Jan. 16, 2004.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 4 January 16, 2004:
  - Unit load increased to 60% load - turbine load set and maintained at approx. 180 MW.
  - Unit began 2-hour stabilization period at 180 MW at 1230 hours.
  - Boiler performance testing commenced at 1430 hours after stabilization period completed; test completed at 1830 hours.
  - Flue gas emissions data taken and recorded by CEMS system.
  - This concluded the testing of JEA Northside Unit 2 firing 100% Pittsburgh 8 coal.

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of “as-fired” fuel
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Fahrenheit
FA	Flyash
FF	Fabric Filter
gpm	gallons per minute

Abbreviation	Definition
gr/acf	grains per actual cubic foot
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater
$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside

Abbreviation	Definition
Pb	Lead
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1

Abbreviation	Definition
W_{fe}	Fuel feed rate (lb/hr)
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number

2.0 SUMMARY OF TEST RESULTS

2.1 Test Requirements

The Protocol required that the following tests be performed and the results be reported at four (4) different unit loads:

- Unit Capacity, percent (all capacities in Megawatts are gross MW).
- Boiler Efficiency, percent (100 % load only).
- Main Steam and Reheat Steam Temperature, deg F.
- Emissions - NOx, SO2, CO, and Particulate (see Section 4.0 of this report).

The results of the test were compared against the design performance data of the boiler produced by Foster-Wheeler. The design performance data for the boiler established by Foster-Wheeler was (Note that the data are for 100% load only - no partial load data were presented):

Boiler efficiency (firing Pittsburgh 8 coal):	88.1 % HHV
Main steam flow at turbine inlet:	1,993,591 lb/hr
Main steam temperature at turbine inlet:	1,000 deg F
Main steam pressure at turbine inlet:	2,500 psig
Hot reheat steam temperature at turbine inlet:	1,000 deg F

The average steam temperatures during the Test shall be within the limits described in the following sections (The average of the readings recorded every minute shall be determined to be the Test average):

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

2.2 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the 'closed' position of certain main steam and feedwater system valves. A listing of these valves is included in Attachment F.

2.3 Test Results

The results of the 100% tests are summarized in Table 1. The results of the part-load tests are summarized in Table 3. The performance of the boiler met and/or exceeded all of the design values provided by Foster-Wheeler. No problems with the fuel feeding system were observed or recorded during the full- and part-load test periods.

TABLE 1 - TESTS RESULTS - 100% LOAD

	Design Maximum-Continuous Rating (MCR)	January 13, 2004 Test (**corrected to MCR)	January 14, 2004 Test (**corrected to MCR)
Boiler Efficiency (percent)	88.1	90.6** (Note 1)	90.6** (Note 1)
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,999,572**	2,000,369**
Pressure (psig)	2,500	2,400	2400
Temperature (°F)	1,000	997**	996.6**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,820,447	1,769,377
Pressure (psig)	547.7	570.9	568.7
Temperature (°F)	1,000	1008.1**	1008.25**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,819,973	1,768,905
Pressure (psig)	608.6	570.5	568.24
Enthalpy (Btu/lb)	1,304.5	1297.3	1,297.3
Feedwater to Economizer			
Temperature (°F)	487.5	484.5	484.1
Pittsburgh 8 Coal Constituents (As-Received)			
Carbon %	68.6	72.7	72.3
Hydrogen %	4.6	4.84	4.7
Sulfur %	3.3	4.84	4.56
Nitrogen %	1.3	1.37	1.35
Chlorine %	0.09	0.18	0.14
Oxygen %	4.11	2.11	2.54
Ash %	12.8	6.89	7.06
Moisture %	5.2	7.26	7.39
HHV (Btu/lb)	12,690	12,877	12,970
Limestone Composition (% By Weight)			
CaCO3	92.0	90.86	91.81
MgCO3	3.0	3.31	2.95
Inerts	4.0	5.34	4.9
Total Moisture	1.0	0.49	0.34

	Design Maximum-Continuous Rating (MCR)	**January 13, 2004 Test (**corrected to MCR)**	**January 14, 2004 Test (**corrected to MCR)**
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	45.15	46.02
MgO and inerts	15.0	54.85	53.98
AQCS Lime Slurry Density – % Solids	35	5.57	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	57,600	54,625
Flue Gas Emissions			
Nitrogen Oxides, NOx, lb/MMBtu (HHV)	0.09	0.074	0.081
Uncontrolled SO2, lb/MMBtu (HHV)	5.20	7.52	7.03
Boiler Outlet SO2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2371	.2902
Stack SO2 lb/MMBtu, (HHV)	0.15	0.102	0.106
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.004	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.026	0.027
Opacity, percent	10	1.1	1.0
Ammonia (NH3) Slip, ppmvd	2.0	1.17	
Ammonia feed rate, gal/hr	NA	7.16	8.38
Lead, lb/MMBtu	2.60×10^{-5} (max)	3.516×10^{-7}	
Mercury (fuel and limestone)	NA	8.24×10^{-6}	
Mercury, lb/MMBtu (at stack)	1.05×10^{-5} (max)	7.238×10^{-6} (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	14.0	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 3.09 \times 10^{-5}$	
Dioxins / Furans	No Limit	6.52×10^{-14}	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from Foster-Wheeler data).
NOTE 2: Refer to Section 4.3.4.1.
NOTE 3: Design boiler outlet SO2 emission rate based on 85% removal of SO2 in the boiler.

TABLE 2 - BOILER & SDA SO2 REMOVAL EFFICIENCY

	Design Basis	January 13, 2004 Test	January 14, 2004 Test
Percent of total SO2 removed by boiler	85.0 typical, with range of 75 - 90	96.8	95.8
Percent of total SO2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.8	2.7
Percent of Total SO2 Removed	97.1	98.6	98.5
Percent of SO2 entering SDA removed in SDA	81.0 typical with range 90 – 71	56.9	63.5
Boiler Calcium to Sulfur Ratio	< 2.88	1.77	1.86

TABLE 3 - TEST RESULTS - PARTIAL LOADS

	Day 3	Day 4	
Percent Load	80%	40%	60%
Unit Capacity (MW)	240	120	180
Total Main Steam Flow, lb/hr	1,435,543	1,070,747	738,397
Main Steam Temperature, deg F	1,003	998	999
Main Steam Pressure, psig	2,400.6	1,800.4	1,300.4
Cold Reheat Steam Temperature, deg F	576.6	572.7	565.9
Hot Reheat Steam Temperature, deg F	1,005	1,006	1,004
NOx, lb/MMBtu	0.080	0.072	0.082
CO, lb/MMBtu	0.044	0.118	0.053
SO2, lb/MMBtu	0.082	0.081	0.108
Opacity, percent	1.0	1.5	1.4

2.3.1 Unit Capacity - During the four (4) day testing period, the boiler was successfully operated at 100 % MCR (turbine load of approximately 300 MW), for day 1 and day 2, and at partial loads of 40% (turbine load of approximately 120 MW), 60% (turbine load of approximately 180 MW), and 80% (turbine load of approximately 240 MW), for day 3 and day 4. The unit operated steadily at each of the stated loads without any deviation in unit output. Prior to each of the testing periods, the unit was brought to load and allowed to stabilize for two (2) hours prior to the start of each test.

2.3.2 Boiler Efficiency - The steam generator operated at corrected efficiencies of 90.6 % and 90.6 % on Day 1 and Day 2, respectively, of the testing period. These efficiencies exceeded the design values by approximately 2.5 %.

2.3.3 Steam Temperature and Steam Pressure - During both days at 100% load operation, the average corrected main steam temperature measured at the turbine inlet was 997 deg F, which is below the design tolerances of the unit. The reduced temperature is due to the loss of superheat surface caused by tube failures attributed to a lack of solution annealing on the original tube bends during manufacture of the tubes. The corrected hot reheat steam temperature measured at the turbine inlet was 1008.2 deg F, which is within the design tolerances of the unit. During partial load operation, the main steam temperatures and the hot reheat temperatures were within the design tolerances previously listed in Section 2.1.

The throttle pressure of the unit was maintained at a value of 2400 psig during both days of the 100% load operation. As can be seen in the previous table, this value is less than the design value of 2500 psig. Although the unit is operated at the reduced pressure, the unit is able to achieve full load. JEA has chosen to operate at this reduced pressure because it provides an additional margin of safety for the turbine stop valves and the high pressure feedwater heaters.

2.3.4 Steam Production - The steam flows of the unit at the 100% load operation cases and partial load operation cases were each determined by adding the main steam desuperheating system flow rates to the feed water system flow rates, and subtracting the continuous blow down flow rates and the sootblowing steam flow rates. The data for each of these systems were retrieved from the plant information system database. The main steam flow rates were corrected to the MCR condition. The corrected main steam flow rates determined for the 100% load operation cases were greater than the design flow rates established by Foster-Wheeler. The main steam flow rates at the partial load operation cases were adequate enough to maintain the steam turbine at the required output.

2.3.5 Calcium to Sulfur Ratio (Ca:S) - The calcium to sulfur ratio represents the ability of the CFB boiler and limestone feed system to effectively remove the sulfur dioxide produced by the combustion process of the boiler. The maximum ratio established for firing Pittsburgh 8 coal was 2.88. The calculated calcium to sulfur ratios for Day 1 and Day 2 are approximately 1.77 and 1.86, respectively. These values represent SO2 removal efficiencies for the boiler of greater than 90 % which are acceptable values for a CFB. SO2 reductions of 90% are typically achieved in a CFB with Ca:S ratios of 2 to 2.5. These values are dependent on the sulfur content in the fuel and the reactivity of the limestone.

3.0 BOILER EFFICIENCY TESTS

The unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in Section 2 of the Attachment A Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency. Prior to beginning the Day 1 testing, it was noted that one of the eight (8) coal feeders was offline and operation of the unit was considered to be unstable. The testing was delayed until the coal feeder was returned to service and operation of the unit was stable. No further operational restrictions were observed during the 4 days of testing.

3.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcinations / sulfation. A complete description of the modified procedures is included in Section 4.2 of Attachment A. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the flyash, and the heat loss due to radiation and convection from the insulated boiler surfaces. A complete list of the heat losses can be found in Section 4.2.1 of Attachment A. The completed efficiency calculations are included in Attachment F to this report.

3.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. The data provided by the plant instrumentation is included in *Attachment D, PI Data Summary*. Additional data required for the boiler efficiency calculations were provided by two independent testing contractors, PGT/ESC, and Clean Air Engineering (CAE). A summary of this information is located in *Attachments G, H, I, J, and K, lab analyses provided by PGT/ESC for the fuel, limestone, bed ash, flyash, and environmental data,* and *Attachment C, CAE Test Report,* respectively. As directed in the test protocol (Attachment A), test data for days 1 and 2 were taken and labeled by CAE and PGT. No flue gas sampling was performed on the unit during operations at reduced loads. Data were, however, recorded by the CEMS system and are reported in this document.

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the plant information system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, flyash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis. (Refer to Figures 1 thru 6 for approximate locations).

<u>Lime (Figure 1):</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Flyash (Figures 2, 3, and 4):</u>

Flyash samples were taken by two different methods.

1) Flyash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Flyash was also taken by grab sample method in two different locations. One grab sample was taken every hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel (Figures 4, 5, and 6):</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

<u>Limestone (Figures 4 and 6):</u>

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

Bed Ash (Figure 6):

Bed Ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

As instructed by the Test Protocol, all of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation. The results of the lab analyses are included in Attachments G, H, I, and J.

4.0 AQCS INLET AND STACK TESTS

4.1 System Description

The Unit 2 AQCS consists of a single, lime-based spray dryer absorber (SDA) and a multi-compartment pulse jet fabric filter (PJFF). The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/flyash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 flyash silo or the Unit 2 AQCS recycle bin. Flyash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [Ca(OH)2] slurry, which is fed to the atomizers as a supplemental reagent.

4.2 Unit Emissions Design Points

The following sections describe the desired emissions design goals of the unit. The tests were conducted in accordance with standard emissions testing practices and test methods as listed in Section 4.2.7. It should be noted that not all tests conducted fit exactly the 4 hour performance test period that was the basis of the fuel capability demonstration test. Several of the tests (especially those not based on CEMS) had durations that were different than the 4 hour performance period due to the requirements of the testing method and good engineering/testing practice. All sampling tests were done at the 100% load case only. All data collected by the CEMS were done at the 100%, 80%, 60% and 40% performance load tests.

4.3 Emission Design Limits and Results

4.3.1 NOx / SO2 / Particulate Emission Design Limits / Results

The following gaseous emissions were measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NOx) values in the flue gas as measured in the stack were expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMBtu values reported by the Continuous Emissions Monitoring system (CEMS) were used as the measure of NOx in the flue gas over the course of each fuel test. The average NOx values for Day 1 and Day 2, based on HHV, were 0.074 lb/MMBtu and 0.081 lb/MMBtu, respectively. Both of these values were less than the expected maximum value.

b. **Sulfur dioxide** (SO2) The design operating condition of the unit is to remove 85 percent of the SO2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. Burning performance coal with a boiler SO2 removal efficiency of 85%, the SO2 concentration at the air heater outlet was expected to be 0.78 lb/MMBtu, with an uncontrolled SO2 emission rate (at 0% SO2 removal) calculated to be 5.20 lb/MMBtu. JEA has chosen to operate at a much higher boiler SO2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO2 emissions. Over time the operations group has learned that if limestone feed is higher than normally desired the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO2 removal and increased SDA removal.

The SO2 concentration at the SDA inlet was measured by an independent test contractor, Clean Air Engineering (CAE). These results are included in Attachment C. The average SO2 values for Day 1 and Day 2, based on HHV of the fuel, out of the air heaters and into the SDA, were 0.2445 lb/MMBtu and 0.2992 lb/MMBtu, respectively. Both of these values were below the expected outlet emission rate. In fact, the boiler removed 97% and 96% respectively, in comparison to the design removal rate of 85%. Uncontrolled SO2 emissions rates were calculated to be 7.52 lb/MMBtu and 7.03 lb/MMBtu, respectively, for an increased SO2 input of 44.6% and 35.2% above the design performance coal SO2 input of 5.20 lb/MMBtu.

The SO2 emissions from the stack during the execution of the tests were expected to be less than 0.15 lb/MMBtu. The hourly average lb/MMBtu values (based on HHV of the fuel) reported by CEMS were used as the measure of SO2 emissions from the stack for the test. The average SO2 values for Day 1 and Day 2, (based on HHV of the fuel) were 0.102 lb/MMBtu and 0.106 lb/MMBtu, respectively. These values were 32% and 29% lower than the 0.15 lb/MMBtu permitted emission rate.

b. **Solid particulate matter** in the flue gas at the fabric filter outlet was expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input. These values were measured at the stack by CAE. The average particulate matter value for the testing period was 0.004 lb/MMBtu which is below the expected maximum value.

4.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas was expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by the plant CEMS. The average values for Day 1 and Day 2 were 0.026 lb/MMBtu and 0.027 lb/MMBtu, respectively. The average values were less than the maximum expected value.

4.3.3 SO3 Emissions Design Point

Sulfur Trioxide (SO3) in the flue gas was assumed to be zero due to the high removal efficiency of the SDA. No testing was done for SO3 as explained in the Test Protocol located in Attachment A. See Section 4.2.3 of the Fuel Capability Test Protocol for the rationale.

4.3.4 NH3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH3, Lead, Mercury, and Fluorine gaseous emissions were measured during the Test (EPA Permit averaging period). Mercury sampling and analysis was performed at the inlet to the AQCS system in addition to the samples taken at the stack. Both samples were taken by CAE. Lead, ammonia and fluorine were sampled only at the stack by CAE. The average values are indicated in Table1.

4.3.4.1 Mercury Testing Anomaly

During the emissions tests, the reagent used in the fourth impinger of the Ontario Hydro sampling train was a 5% HNO3 (nitric acid) / 10% H2O2 (hydrogen peroxide) solution. Mercury levels in both the 5% / 10% reagent blank and the 5% / 10% portion of the field train blanks were elevated. The mercury concentration in the reagent field blanks of the other solutions (KCl, potassium chloride, and KMnO4, potassium permanganate) used in the Ontario Hydro sampling train was at the expected levels or below the detection limit. In accordance with the Ontario Hydro Method, the allowable blank adjustments have been made to the final results presented.

A review of the total mercury in the coal was completed for comparison to measured values. The coal analyses indicated a mercury content of approximately 0.105 µg/g, with a limestone mercury content of 0.09 µg/g. This is equivalent to a total mercury content of 0.22 lb/hr. This represents more mercury than what was measured by the independent test contractor at the inlet to the SDA. However due to the bias adjustment made by the independent test contractor, the removal efficiency was lower than expected. Subsequent tests should help determine the expected mercury removal efficiency of the unit.

4.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions were measured at the stack by CAE for the 4-hour interval during the Test (EPA Permit averaging period). Note this test is only being done for the 100% Pittsburgh 8 coal. The resulting average values are indicated in Table 1.

4.3.6 Opacity

The opacity was measured by the plant CEMS/COMS (Continuous Opacity Monitoring System) to determine the opacity of the unit over a six minute block average during the test period. The maximum expected opacity was 10%. The testing indicated that the maximum opacity of the unit during the two day test was 1.1 %, which is much less than the maximum opacity value.

4.3.7 Ammonia, NH3 Slip

Ammonia slip was guaranteed to be less than 2.0 ppmvd at 3 percent O_2 at Design Maximum Load. The resultant averages were around 1.17 ppmvd when measured using the CTM - 027 EPA method. This identifies that the SNCR was working within design parameters and meeting the boiler NOx removal efficiency as required. An ammonia slip level of less than 2.0 ppmvd is recognized as an industry standard acceptable value.

4.4 Flue Gas Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – CTM 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans – PCDD/F

Specific descriptions of the testing methods (non-CEMS) are included in the Clean Air Engineering Emissions Test Report located in Attachment D of this document.

4.5 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration and as listed in Section 4.2.7. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NOX, SO2, and CO2 analyzers. The data listed for CEMS in Section 4.2.7 originated from the certified Data Acquisition Handling System (DAHS).

Attachments

ATTACHMENT A

Fuel Capability Demonstration Test Protocol

This Document is located via the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

ATTACHMENT B

Boiler Efficiency Calculation

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED		
		Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	207,558	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7270	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0484	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0211	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0137	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0484	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0689	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0726	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	12,877	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	57,600	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9086	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0331	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0534	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0049	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.85496		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	398	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0008	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0008	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2102	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	34,171	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0276	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0276	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2252	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	36,608	lb/hr	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	109	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	45	lb/hr	
1.5.4	Fan Outlet Temperature, °F	109	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	755,011	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	101	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	35,970	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	164	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	44702	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	178	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	61.02	°F	ta
1.6.2	Ambient wet bulb temperature, °F	49.56	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.43	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0045	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	306.50	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	577.18	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0041	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, psig	2177.3	psig	pfw - Plant instrument.
1.8.2	Temperature, °F	484.5	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,882,591	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, psig (drum pressure)	2,564.6	psig	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.9	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, lb/hr	0.00	lb/hr	SB - Plant instrument
1.10.2	Pressure, psig	0.00	psig	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, psig	2,707.7	psig	pdsw - Plant instrument.
1.11.2	Temperature, °F	305.0	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	11,224	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, psig (superheater outlet)	2,400.4	psig	pms - Plant instrument.
1.12.2	Temperature, °F	1,003.3	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,893,814	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, psig	727.35	psig	pdswrh - Plant instrument.
1.13.2	Temperature, °F	186.59	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	474	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, psig	570.48	psig	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	607.52	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, psig	570.91	psig	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,000.03	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, lb/hr	1,819,973	lb/hr	RHin - From turbine heat.

Jacksonville Electric Authority			
Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 107.50

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1 ASSUMED FUEL FLOW RATE, lb/h	195,933	lb/h	
3.2 ASSUMED SULFUR EMISSIONS, fraction	0.0320	fraction	Can get reading from CEMS system
3.3 Sulfur Capture, fraction	0.9680		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory 0 lb/h

4.2 Corrected Ash Carbon Content

4.2.1	Bottom Ash, fraction	0.0008	lb/lb BA
4.2.2	Fly Ash, fraction	0.0276	lb/lb FA

4.3 Bottom Ash Flow Rate

4.3.1	Total bottom ash including bed change	34,171.3939550	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.7670	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.976495449	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	57600	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba)/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.766996783	mole Ca/mole S	
	LImestone Flow Rate from PI Data, lb/h	**57,600**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-1.03078E-05	percent	
4.4.6	Calculated Fly Ash Flow Rate	36,608	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000015)	percent	

4.5 Total Dry Refuse

4.5.1	Total Dry Refuse Hourly Flow Rate	70,780	lb/h
4.5.2	Total Dry Refuse Per Pound Fuel	0.3612	lb/lb AF fuel

4.6 Heating Value Of Total Dry Refuse

4.6.1	Average Carbon Content Of Ash	0.0147	fraction
4.6.2	Heating Value Of Dry Refuse	212.59	Btu/lb

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone

5.1.1	Carbon Burned	0.7217	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7503	lb/lb AF fuel

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	27.770	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3455	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.7905	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.7490	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6279	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	9.9539	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0137	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0726	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.4323	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.0586	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.3476	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6076	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	13.9126	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7629	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.3234	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0111	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	81.0533	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1121	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-0.000534978	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1432		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8118		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.2999	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6023	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.3625	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01032	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.1981	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.6158	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1046	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7086	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	13.8648	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7553	lb/lb mole	

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0471	fraction
5.2.19.2	Nitrogen, fraction weight	0.7470	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2059	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.304	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.7490	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4763	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.4502	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0137	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0726	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.4323	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.0556	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.6923	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.6975	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.2542	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8078	lb/lb AF fuel
		Volume Basis	
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	% Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.1073	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.1627	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1183	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-0.000863113	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1511	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8089	
5.3.12	Weight Dry FG At Air Heater INLET	12.7033	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8408	lb/lb mole

		Volume Basis	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	14.0474	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01085	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3475	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.4688	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1100	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	7.0154	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.2653	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9380	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0374	fraction
5.3.17.2	Nitrogen, fraction weight	0.7386	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2156	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0085	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0358	fraction
5.3.18.2	Nitrogen, fraction weight	0.7073	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2065	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0081	fraction
5.3.18.6	Moisture, fraction weight	0.0422	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.157	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.7490	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0031	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5198	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.5945	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0137	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0726	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.4323	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0014	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.0565	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	12.8801	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.6708	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	13.4429	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.7945	lb/lb mole
		Volume Basis	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	% Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	13.8441	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.5125	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1084	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.9243	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	14.8740	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8679	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.1302	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1165	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet l	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	-0.000868122	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	9.78568E-05	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

			Oxygen
		C0	-1.1891960E+02
		C1	4.2295190E-01
		C2	-1.6897910E-04
		C3	3.7071740E-07
		C4	-2.7439490E-10
		C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15		5.111496E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8		6.702388E+00
			Nitrogen
		C0	-1.3472300E+02
		C1	4.6872240E-01
		C2	-8.8993190E-05
		C3	1.1982390E-07
		C4	-3.7714980E-11
		C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15		5.6669989E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8		7.5168742E+00
			Carbon Dioxide
		C0	-8.5316190E+01
		C1	1.9512780E-01
		C2	3.5498060E-04
		C3	-1.7900110E-07
		C4	4.0682850E-11
		C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15		4.9592543E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8		6.2194310E+00
			Carbon Monoxide
		C0	-1.3574040E+02
		C1	4.7377220E-01
		C2	-1.0337790E-04
		C3	1.5716920E-07
		C4	-6.4869650E-11
		C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15		5.7274953E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8		7.5832565E+00

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.6109522E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	4.5733958E+00		

General equation for constituent enthalpy:
h = C0 + C1 * T + C2 * T² + C3 * T³ + C4 * T * T³ + C5 * T² * T³
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	54.95	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	7.21	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	634.93	Btu/lb AF fuel	
5.6 HHV Percent Loss, as tested		4.93	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1198.60	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)² + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	75.50	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	81.49	Btu/lb AF fuel	
6.4 HHV Percent Loss, as tested		0.63	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	485.57	Btu/lb AF fuel
7.2 HHV Percent Loss, as tested		3.77	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	76.80	Btu/lb AF fuel
8.2 HHV Percent Loss, as tested		0.60	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	12.67	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	7.44	Btu/lb AF fuel
9.2 Total Dry Refuse Heat Loss, as tested		20.11	Btu/lb AF fuel
9.3 HHV Percent Loss, as tested		0.16	percent

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.26	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	151.99	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	52.74	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	5.96	Btu/lb

10.3 HHV Percent Loss, as tested 0.05 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	180.35	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	1.60	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-315.59	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-133.64	Btu/lb AF Fuel

11.5 HHV Percent Loss -1.04 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.27 percent

12.1.1	Radiation & Convection Heat Loss	34.52	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	634.93
13.1.2	81.49
13.1.3	485.57
13.1.4	76.80
13.1.5	20.11
13.1.6	5.96
13.1.7	-133.64
13.1.8	34.52
	1,205.74

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 13, 2004		
Test Start Time:	11:00 AM		
Test End Time:	3:00 PM		
Test Duration, hours:	4		

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.93
13.1.10	Moisture In Fuel	0.63
13.1.11	H2O From H2 In Fuel	3.77
13.1.12	Unburned Combustibles In Refuse	0.60
13.1.13	Dry Refuse	0.16
13.1.14	Moisture In Combustion Air	0.05
13.1.15	Calcination/Sulfation	-1.04
13.1.16	Radiation & Convection	0.27
		9.36
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***90.64***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.73	Btu/lb
14.1.2	Blow Down, Btu/lb	738.78	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	279.65	Btu/lb
14.1.5	Main Steam, Btu/lb	1463.30	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	156.22	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1295.99	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1517.12	Btu/lb

14.2 Heat Output 2,286,862,656 Btu/h

2,288,632,676

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,523,107,338	Btu/h
15.1.2	Fuel Burned - CALCULATED	195,933	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	-9.18857E-06	percent

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency: 90.64**
Test Date:	JANUARY 14, 2004	
Test Start Time:	10:15 AM	
Test End Time:	2:15 PM	
Test Duration, hours:	4	

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	206,906	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.7235	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0472	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0254	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0135	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0456	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0706	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0739	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	12,970	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	54,625	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9181	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0295	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0490	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0034	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.88668		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	463	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0004	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0004	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.2099	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	30,240	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0276	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0276	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.2252	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	36,608	lb/hr	Wfam - Weight of fly ash from isokenetic sample colleciton.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,682,824	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	108	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	38	lb/hr	
1.5.4	Fan Outlet Temperature, °F	108	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	721,210	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	102	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	36,289	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	165	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	45477	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	179	°F	tspb

Boiler Efficiency: 90.64

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	62.78	°F	ta
1.6.2	Ambient wet bulb temperature, °F	51.26	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.24	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0051	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	305.82	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0450	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	578.26	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0041	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	2.90	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Meausred	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, psig	2030.0	psig	pfw - Plant instrument.
1.8.2	Temperature, °F	484.1	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,810,754	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, psig (drum pressure)	2,560.0	psig	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	673.6	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, lb/hr	0.00	lb/hr	SB - Plant instrument
1.10.2	Pressure, psig	0.00	psig	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, psig	2,697.7	psig	pdsw - Plant instrument.
1.11.2	Temperature, °F	308.1	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	30,013	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, psig (superheater outlet)	2,400.5	psig	pms - Plant instrument.
1.12.2	Temperature, °F	1,003.4	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,840,767	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, psig	725.58	psig	pdswrh - Plant instrument.
1.13.2	Temperature, °F	188.62	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	472	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, psig	568.24	psig	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	607.19	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, psig	568.76	psig	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,001.91	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, lb/hr	1,768,905	lb/hr	RHin - From turbine heat.

Jacksonville Electric Authority			
Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 107.36

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	189,635	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0322	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9678		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory 0 lb/h

4.2 Corrected Ash Carbon Content

4.2.1	Bottom Ash, fraction	0.0004	lb/lb BA
4.2.2	Fly Ash, fraction	0.0276	lb/lb FA

4.3 Bottom Ash Flow Rate

4.3.1	Total bottom ash including bed change	30,239.9610800	lb/h

4.4 Limestone Flow Rate

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	1.858457038	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.959955857	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	54625	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	1.858452254	mole Ca/mole S	
	Limestone Flow Rate from PI Data	**54,625**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-0.000257424	percent	
4.4.6	Calculated Fly Ash Flow Rate	36,608	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000017)	percent	

4.5 Total Dry Refuse

4.5.1	Total Dry Refuse Hourly Flow Rate	66,848	lb/h
4.5.2	Total Dry Refuse Per Pound Fuel	0.3525	lb/lb AF fuel

4.6 Heating Value Of Total Dry Refuse

4.6.1	Average Carbon Content Of Ash	0.0153	fraction
4.6.2	Heating Value Of Dry Refuse	221.79	Btu/lb

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone

5.1.1	Carbon Burned	0.7181	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.7473	lb/lb AF fuel

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	27.75	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.3184	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	7.7006	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	2.7382	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0029	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6213	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	9.8374	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0135	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0739	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.4214	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0010	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.0647	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	13.2134	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.6226	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	13.7743	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.7741	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.4191	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0106	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.5000	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.9584	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1119	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.5	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-2.97191E-06	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1442		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8108		
5.2.14	Weight Dry FG At Air Heater OUTLET	13.1631	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.6194	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.4486	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.00989	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.1971	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.5094	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1043	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7307	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	13.7241	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.7682	lb/lb mole	

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0470	fraction
5.2.19.2	Nitrogen, fraction weight	0.7457	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2073	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components - NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.28	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.7382	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0029	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4713	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	9.3390	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0135	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0739	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.4214	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0010	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.0614	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	12.5649	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.7133	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	13.1226	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.8201	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.2082	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0112	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.0627	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1180	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-1.6827E-05	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1521	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8078	
5.3.12	Weight Dry FG At Air Heater INLET	12.5771	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.8578	lb/lb mole

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

		Volume Basis	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	14.1384	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01040	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3468	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.3603	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1097	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	7.0345	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	13.1348	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.9514	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7372	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2169	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0085	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0357	fraction
5.3.18.2	Nitrogen, fraction weight	0.7059	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2077	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0082	fraction
5.3.18.6	Moisture, fraction weight	0.0423	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	18.12	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.7382	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0029	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.3982	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	9.0962	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0135	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0739	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.4214	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0010	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.0598	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	12.2489	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7612	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	12.8050	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.8443	lb/lb mole
		Volume Basis	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	% Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	14.5007	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	2.9000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.2819	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1125	percent volume
5.4.7.6 a	Moisture in flue gas, voluem percent	7.1942	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.6248	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.1248	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.1177	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1212	percent volume
5.4.7.6 b	Moisture in flue gas, voluem percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet l	2.9	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	8.00226E-06	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-0.00034795	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

			Oxygen
		C0	-1.1891960E+02
		C1	4.2295190E-01
		C2	-1.6897910E-04
		C3	3.7071740E-07
		C4	-2.7439490E-10
		C5	7.384742E-14
5.5.2 a	Flue Gas Constituent Enthalpy At tG15		5.096182E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8		6.670957E+00
			Nitrogen
		C0	-1.3472300E+02
		C1	4.6872240E-01
		C2	-8.8993190E-05
		C3	1.1982390E-07
		C4	-3.7714980E-11
		C5	-3.5026400E-16
5.5.2 b	Flue Gas Constituent Enthalpy At tG15		5.6502462E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8		7.4816825E+00
			Carbon Dioxide
		C0	-8.5316190E+01
		C1	1.9512780E-01
		C2	3.5498060E-04
		C3	-1.7900110E-07
		C4	4.0682850E-11
		C5	1.0285430E-17
5.5.2 c	Flue Gas Constituent Enthalpy At tG15		4.9437727E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8		6.1900302E+00
			Carbon Monoxide
		C0	-1.3574040E+02
		C1	4.7377220E-01
		C2	-1.0337790E-04
		C3	1.5716920E-07
		C4	-6.4869650E-11
		C5	6.1175980E-15
5.5.2 d	Flue Gas Constituent Enthalpy At tG15		5.7105255E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8		7.5477452E+00

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	**Boiler Efficiency:**	**90.64**
Test Date:	JANUARY 14, 2004		
Test Start Time:	10:15 AM		
Test End Time:	2:15 PM		
Test Duration, hours:	4		

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.5997781E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	4.5518156E+00		

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	54.78	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	7.18	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	626.59	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	4.83	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1198.29	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * $(tG15)^2$ + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	75.36	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	82.96	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	0.64	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	473.25	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	3.65	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	78.18	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	0.60	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	14.17	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	7.66	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	21.83	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.17	percent

Boiler Efficiency: 90.64

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	13.10	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	151.65	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	52.67	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	6.55	Btu/lb

10.3 HHV Percent Loss, as tested 0.05 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	184.53	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	1.09	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-297.01	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-111.39	Btu/lb AF Fuel

11.5 HHV Percent Loss -0.86 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.27 percent

12.1.1	Radiation & Convection Heat Loss	35.62	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	626.59
13.1.2	82.96
13.1.3	473.25
13.1.4	78.18
13.1.5	21.83
13.1.6	6.55
13.1.7	-111.39
13.1.8	35.62
	1,213.60

Jacksonville Electric Authority	
Unit Tested:	Northside Unit 2
Test Date:	JANUARY 14, 2004
Test Start Time:	10:15 AM
Test End Time:	2:15 PM
Test Duration, hours:	4

Boiler Efficiency: 90.64

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.83
13.1.10	Moisture In Fuel	0.64
13.1.11	H2O From H2 In Fuel	3.65
13.1.12	Unburned Combustibles In Refuse	0.60
13.1.13	Dry Refuse	0.17
13.1.14	Moisture In Combustion Air	0.05
13.1.15	Calcination/Sulfation	-0.86
13.1.16	Radiation & Convection	0.27
		9.36
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***90.64***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	469.20	Btu/lb
14.1.2	Blow Down, Btu/lb	738.25	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	282.79	Btu/lb
14.1.5	Main Steam, Btu/lb	1463.41	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	158.25	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1295.99	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1518.20	Btu/lb
14.2 Heat Output		2,229,406,364	Btu/h
		2,231,155,818	

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,459,546,374	Btu/h
15.1.2	Fuel Burned - CALCULATED	189,633	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	0.000711725	percent

ATTACHMENT C

CAE Test Report

Tony Compaan
Black & Veatch Corporation
10751 Deerwood Park Boulevard, Suite 130
Jacksonville, FL 32256

REPORT ON
LARGE SCALE CFB COMBUSTION DEMONSTRATION PROJECT
100% PITTSBURGH NO. 8 COAL

Performed for:
BLACK & VEATCH CORPORATION
UNIT 2, SDA INLET AND STACK
JEA - NORTHSIDE GENERATING STATION

Client Reference No: 137064.96.1400
CleanAir Project No: 9475-1
Revision 0: DRAFT (February 23, 2004)

To the best of our knowledge, the data presented in this report are accurate and complete and error free, legible and representative of the actual emissions during the test program.

Submitted by,

Reviewed by,

Robert A. Preksta
Project Manager
(412) 787-9130
bpreksta@cleanair.com

Timothy D. Rodak
Manager, Pittsburgh Regional Office

CONTENTS

PROJECT OVERVIEW

The Northside Generating Station Repowering project provided JEA (formerly the Jacksonville Electric Authority) with the two largest circulating fluidized bed (CFB) boilers in the world. The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Black and Veatch Corporation (B&V) contracted Clean Air Engineering, Inc. (CleanAir) to perform the air emission measurements required as part of the demonstration test program. This report covers air emission measurements obtained during the firing of 100% Pittsburgh No. 8 coal to the unit.

The test program included the measurement of the following parameters:

- particulate matter (PM), [SDA Inlet and Stack];
- sulfur dioxide (SO_2), [SDA Inlet];
- fluoride (F), [Stack];
- dibenzo-p-dioxins and dibenzofurans (PCDD/F), [Stack];
- lead (Pb), [Stack];
- speciation of mercury (Hg^0, Hg^{2+}, Hg^{tp}), [SDA Inlet and Stack];
- ammonia (NH_3).

The field portion of the test program took place at the Unit 2 SDA Inlet and Stack locations on January 13 and 14, 2004. Coordinating the field portion of the testing were:

T. Compaan – Black And Veatch
R. Huggins – Black And Veatch
W. Goodrich - JEA
K. Davis - JEA
J. Martin - RMB
J. Stroud - Clean Air Engineering

Table 1-1 contains a summary of the specific test locations, various reference methods and sampling periods for each of the sources sampled during the program.

The results of the test program are summarized in Table 1-2. A more detailed presentation of the test data is contained in Tables 2-1 through 2-11. Process data collected during the test program is contained in Appendix H.

PROJECT OVERVIEW

Table 1-1:
Summary of Air Emission Field Test Program

Run Number	Location	Method	Analyte	Date	Start Time	End Time	Notes
1	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/13/04	11:26	12:36	
2	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/13/04	13:26	15:01	
3	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/13/04	16:50	18:38	
1	Unit 2 SDA Inlet	Method 6C	SO2	1/13/04	11:26	12:26	
2	Unit 2 SDA Inlet	Method 6C	SO2	1/13/04	13:28	14:28	
3	Unit 2 SDA Inlet	Method 6C	SO2	1/13/04	16:52	17:52	
1	Unit 2 SDA Inlet	Ontario Hydro	Mercury	1/13/04	11:19	14:44	
2	Unit 2 SDA Inlet	Ontario Hydro	Mercury	1/13/04	15:50	18:08	
3	Unit 2 SDA Inlet	Ontario Hydro	Mercury	1/13/04	18:40	20:47	
1	Unit 2 Stack	Ontario Hydro	Mercury	1/13/04	11:19	14:42	
2	Unit 2 Stack	Ontario Hydro	Mercury	1/13/04	15:50	18:00	
3	Unit 2 Stack	Ontario Hydro	Mercury	1/13/04	18:40	20:45	
1	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/13/04	10:42	12:51	
2	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/13/04	13:26	15:34	
3	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	1/13/04	16:50	19:04	
4	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/14/04	10:10	11:15	
5	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/14/04	11:58	13:40	
6	Unit 2 SDA Inlet	USEPA Method 17	Particulate	1/14/04	14:31	15:50	
4	Unit 2 SDA Inlet	Method 6C	SO2	1/14/04	10:11	11:11	
5	Unit 2 SDA Inlet	Method 6C	SO2	1/14/04	12:00	13:00	
6	Unit 2 SDA Inlet	Method 6C	SO2	1/14/04	14:32	15:32	
1	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/14/04	13:06	14:15	
2	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/14/04	14:24	15:33	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	1/14/04	16:11	17:22	
1	Unit 2 Stack	USEPA Method 23	PCDD/F	1/14/04	07:51	11:02	
2	Unit 2 Stack	USEPA Method 23	PCDD/F	1/14/04	11:14	14:28	
3	Unit 2 Stack	USEPA Method 23	PCDD/F	1/14/04	14:42	17:52	
1	Unit 2 Stack	CTM-027	Ammonia	1/14/04	08:02	09:14	
2	Unit 2 Stack	CTM-027	Ammonia	1/14/04	09:42	11:28	
3	Unit 2 Stack	CTM-027	Ammonia	1/14/04	11:41	12:47	

Notes:

Sulfur dioxide concentrations (ppmdv) were converted into the mass emission rate (lb/hr) using the volumetric flow rate from concurrently conducted EPA Method 17 test runs.

022304 115802

Table 1-2:
Summary of Test Results

Source / Constituent	Sampling Method	Average Emission
Unit 2 SDA Inlet		
Sulfur Dioxide (ppmdv), Runs 1-3	EPA M6C	115.8
Sulfur Dioxide (lb/MMBtu), Runs 1-3	EPA M6C/19	0.2405
Sulfur Dioxide (ppmdv), Runs 4-6	EPA M6C	140.7
Sulfur Dioxide (lb/MMBtu), Runs 4-6	EPA M6C/19	0.2929
Particulate (gr/dscf), Runs 1-3	EPA M17	8.08
Particulate (lb/MMBtu), Runs 1-3	EPA M17/19	14.472
Particulate (gr/dscf), Runs 4-6	EPA M17	7.34
Particulate (lb/MMBtu), Runs 4-6	EPA M17/19	13.374
Mercury (lb/hr)	Ontario Hydro	4.902E-02
Mercury (lb/MMBtu)	Ontario Hydro/19	1.777E-05
Unit 2 Stack		
Particulate (gr/dscf)	EPA M5	0.0021
Particulate (lb/hr)	EPA M5	10.80
Particulate (lb/MMBtu)	EPA M5/19	0.0040
Particulate (% Removal)	EPA M5/19	99.97
Fluoride (lb/hr)	EPA M13B/19	<0.0881
Fluoride (lb/MMBtu)	EPA M13B/19	<3.0962E-05
PCDD/PCDF (lb/hr), TEQ	EPA M23	1.803E-10
PCDD/PCDF (lb/MMBtu), TEQ	EPA M23B/19	6.520E-14
Lead (lb/hr)	EPA M29	9.567E-04
Lead (lb/MMBtu)	EPA M29/19	3.516E-07
Mercury (lb/hr)	Ontario Hydro	2.011E-02
Mercury (lb/MMBtu)	Ontario Hydro/19	7.238-06
Mercury (% Removal)	Ontario Hydro/19	58.2
Ammonia (ppmdv)	CTM-027	1.17
Ammonia (lb/hr)	CTM-027	2.047
Ammonia (lb/MMBtu)	CTM-027/19	0.0007

Notes:
1. The mass emission rate (lb/MMBtu) presented in the above table for all test parameters was calculated using a dry fuel factor (F_d) of 9,780 dscf/MMBtu.
2. The mercury results shown are for total mercury emissions. A speciated breakdown of the mercury emissions is contained in Section 2 of the report.
3. Percent removal efficiency was calculated based on the units of lb/MMBtu.
4. USEPA/International toxicity equivalency factors (TEF) were used to calculate the toxicity equivalent (TEQ) of thePCDD/PCDF isomers of concern. Results are expressed as 2,3,7,8-TCDD (tetrachlorodibenzo-p-dioxin).

PROJECT MANAGER'S COMMENTS

Mass Emission Rate (lb/MMBtu)

The mass emission rate of lb/MMBtu has been calculated using both the dry fuel factor (F_d) of 9,780 dscf/MMBtu and the carbon based fuel factor (F_c) of 1,856 scf/MMBtu.

Ontario Hydro Test Results

The reagent used in the fourth impinger of the Ontario Hydro sampling train is a 5% HNO_3 (nitric acid)/10% H_2O_2 (hydrogen peroxide) solution. Mercury levels in both the 5%/10% Reagent Blank and the 5%/10% portion of the Field Train Blanks were elevated. The Mercury concentration in the Reagent and Field Blanks of the other solutions (KCl, potassium chloride and KMnO4, potassium permanganate) used in the Ontario Hydro sampling train is at expected levels or below the detection limit.

In accordance with the Ontario Hydro Method the allowable blank adjustments (10% of the measured regent blank value or ten (10) times the detection limit whichever is less) have been made to the final results presented.

The elevated elemental mercury present in the 5%/10% sample fraction can be attributed to the corresponding elevated mercury levels present in both the 5%/10% Reagent Blank and the 5%/10% portion of the Field Train Blanks and not to actual mercury emissions. It is recommended that the blank subtraction to the 5%/10% fraction of the sampling trains be based on the mercury level present in the respective location field blanks. All of the remaining fractions would be blank corrected in accordance with the Ontario hydro procedures outlined above. The average emission rate based on the modified blank correction would be SDA Inlet 3.918E-02 lb/hr (1.420 E-05 lb/MMBtu) and Stack 6.328E-03 lb/hr (2.278E-06 lb/MMBtu) with a removal efficiency of 83.0%.

RESULTS

Table 2-1:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 1 through 3

Run No.	**1**	**2**	**3**	**Average**
Date (2004)	January 13	January 13	January 13	
Start Time	11:26	13:28	16:52	
End Time	12:26	14:28	17:52	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
F_c - Unit 2 (dscf/MMBtu)	1,856	1,856	1,856	**1,856**
F_d - Unit 2 (dscf/MMBtu)	9,780	9,780	9,780	**9,780**
Capacity - Unit 2 (Hours per Year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Actual Gas Flow Rate - SDA Inlet (acfm)	985,668	964,818	964,834	**971,773**
Standard Gas Flow Rate - SDA Inlet (scfm)	638,778	628,239	624,168	**630,395**
Dry Standard Gas Flow Rate - SDA Inlet (dscfm)	590,543	579,370	573,670	**581,194**
H_2O - SDA Inlet (%)	7.6	7.8	8.1	**7.8**
Oxygen (O_2) - SDA Inlet (%dv)	4.5	4.5	4.5	**4.5**
Carbon Dioxide (CO_2) - SDA Inlet (%dv)	14.6	14.7	14.6	**14.6**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	130.5	87.7	129.3	**115.8**
Mass Rate (lb/hr)	769	507	740	**672**
Mass Rate (Ton/yr)	3,368	2,220	3,242	**2,943**
Mass Rate (lb/MMBtu) - F_c	0.2762	0.1840	0.2733	**0.2445**
Mass Rate (lb/MMBtu) - F_d	0.2711	0.1819	0.2684	**0.2405**

RESULTS

Table 2-2:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 4 through 6

Run No.	**4**	**5**	**6**	**Average**
Date (2004)	January 14	January 14	January 14	
Start Time	10:11	12:00	14:32	
End Time	11:11	13:00	15:32	
Elapsed Time	1:00	1:00	1:00	
Operating Conditions				
F_c - Unit 2 (dscf/MMBtu)	1,856	1,856	1,856	**1,856**
F_d - Unit 2 (dscf/MMBtu)	9,780	9,780	9,780	**9,780**
Capacity - Unit 2 (Hours per Year)	8,760	8,760	8,760	**8,760**
Gas Parameters				
Actual Gas Flow Rate - SDA Inlet (acfm)	964,351	952,995	973,682	**963,676**
Standard Gas Flow Rate - SDA Inlet (scfm)	629,277	619,489	630,999	**626,588**
Dry Standard Gas Flow Rate - SDA Inlet (dscfm)	585,264	572,328	586,497	**581,363**
H_2O - SDA Inlet (%)	7.0	7.6	7.1	**7.2**
Oxygen (O_2) - SDA Inlet (%dv)	4.6	4.6	4.5	**4.6**
Carbon Dioxide (CO_2) - SDA Inlet (%dv)	14.6	14.6	14.2	**14.5**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	152.6	159.5	110.1	**140.7**
Mass Rate (lb/hr)	891	911	644	**815**
Mass Rate (Ton/yr)	3,902	3,988	2,821	**3,570**
Mass Rate (lb/MMBtu) - F_c	0.3222	0.3369	0.2384	**0.2992**
Mass Rate (lb/MMBtu) - F_d	0.3190	0.3323	0.2275	**0.2929**

RESULTS

Table 2-3:
Unit 2 – SDA Inlet – Particulate Matter, Runs 1 through 3

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:26	13:26	16:50	
Stop Time (approx.)		12:36	15:01	18:38	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.5	4.7	4.6	**4.6**
CO_2	Carbon dioxide (dry volume %)	14.6	14.6	14.6	**14.6**
T_s	Sample temperature (°F)	315	311	316	**314**
B_w	Actual water vapor in gas (% by volume)	7.55	7.78	8.09	**7.81**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	985,668	964,818	964,834	**971,773**
Q_s	Volumetric flow rate, standard (scfm)	638,778	628,239	624,168	**630,395**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	590,543	579,370	573,670	**581,194**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	10.3713	5.9869	7.8949	**8.0844**
$E_{lb/hr}$	Particulate Rate (lb/hr)	52,515	29,741	38,833	**40,363**
$E_{kg/hr}$	Particulate Rate (kg/hr)	23,816	13,488	17,611	**18,305**
$E_{T/yr}$	Particulate Rate (Ton/yr)	230,014	130,266	170,090	**176,790**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	18.4722	10.7949	14.1478	**14.4716**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	18.8409	10.8761	14.3422	**14.6864**

022304 115819

RESULTS

Table 2-4:
Unit 2 – SDA Inlet – Particulate Matter, Runs 4 through 6

Run No.		4	5	6	Average
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		10:10	11:58	14:31	
Stop Time (approx.)		11:15	13:40	15:50	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	4.8	4.8	**4.9**
CO_2	Carbon dioxide (dry volume %)	14.3	14.2	14.2	**14.2**
T_s	Sample temperature (°F)	311	314	316	**313**
B_w	Actual water vapor in gas (% by volume)	6.99	7.61	7.05	**7.22**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	964,351	952,995	973,682	**963,676**
Q_s	Volumetric flow rate, standard (scfm)	629,277	619,489	630,999	**626,588**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	585,264	572,328	586,497	**581,363**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	7.7634	6.6914	7.5628	**7.3392**
$E_{lb/hr}$	Particulate Rate (lb/hr)	38,958	32,836	38,031	**36,608**
$E_{kg/hr}$	Particulate Rate (kg/hr)	17,668	14,892	17,248	**16,602**
$E_{T/yr}$	Particulate Rate (Ton/yr)	170,635	143,823	166,577	**160,345**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	14.2620	12.1399	13.7209	**13.3743**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	14.3990	12.4982	14.1258	**13.6743**

022304 115823

RESULTS

Table 2-5:
Unit 2 – SDA Inlet – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.8	4.6	4.8	**4.7**
CO_2	Carbon dioxide (dry volume %)	14.1	14.3	14.1	**14.2**
T_s	Sample temperature (°F)	318	319	318	**318**
B_w	Actual water vapor in gas (% by volume)	8.37	7.91	7.47	**7.92**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	976,004	971,461	988,368	**978,611**
Q_s	Volumetric flow rate, standard (scfm)	630,041	625,639	637,925	**631,202**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	577,282	576,172	590,245	**581,233**
Total Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.217E-09	8.806E-10	1.270E-09	**1.122E-09**
$E_{lb/hr}$	Rate (lb/hr)	4.214E-02	3.044E-02	4.497E-02	**3.918E-02**
$E_{T/yr}$	Rate (Ton/yr)	1.846E-01	1.333E-01	1.970E-01	**1.716E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.545E-05	1.104E-05	1.612E-05	**1.420E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.602E-05	1.143E-05	1.671E-05	**1.472E-05**
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	9.609E-10	6.872E-10	1.011E-09	**8.864E-10**
$E_{lb/hr}$	Rate (lb/hr)	3.328E-02	2.376E-02	3.581E-02	**3.095E-02**
$E_{T/yr}$	Rate (Ton/yr)	1.458E-01	1.041E-01	1.569E-01	**1.356E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.220E-05	8.618E-06	1.284E-05	**1.122E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.265E-05	8.919E-06	1.331E-05	**1.163E-05**
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.418E-11	4.377E-11	1.196E-11	**2.331E-11**
$E_{lb/hr}$	Rate (lb/hr)	4.912E-04	1.513E-03	4.237E-04	**8.094E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.151E-03	6.628E-03	1.856E-03	**3.545E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.800E-07	5.489E-07	1.519E-07	**2.936E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.867E-07	5.681E-07	1.575E-07	**3.041E-07**
Elemental Mercury Results [1]					
C_{sd}	Concentration (lb/dscf)	2.416E-10	1.496E-10	2.466E-10	**2.126E-10**
$E_{lb/hr}$	Rate (lb/hr)	8.369E-03	5.172E-03	8.732E-03	**7.424E-03**
$E_{T/yr}$	Rate (Ton/yr)	3.666E-02	2.265E-02	3.825E-02	**3.252E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	3.068E-06	1.876E-06	3.130E-06	**2.691E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	3.181E-06	1.942E-06	3.245E-06	**2.789E-06**

[1] Allowable HNO_3-H_2O_2 blank (0.02 ug) calculated at ten (10) times detection limit of 0.002 ug.

RESULTS

Table 2-6:
Unit 2 – Stack – Particulate Matter

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		10:42	13:26	16:50	
Stop Time (approx.)		12:51	15:34	19:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.4	5.4	**5.4**
CO_2	Carbon dioxide (dry volume %)	13.4	13.4	13.4	**13.4**
T_s	Sample temperature (°F)	228	240	231	**233**
B_w	Actual water vapor in gas (% by volume)	11.37	9.96	10.64	**10.66**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	881,383	871,051	883,573	**878,669**
Q_s	Volumetric flow rate, standard (scfm)	678,033	658,683	677,463	**671,393**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	600,934	593,062	605,414	**599,803**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	0.0026	0.0016	0.0021	**0.0021**
$E_{lb/hr}$	Particulate Rate (lb/hr)	13.38	8.20	10.83	**10.80**
$E_{T/yr}$	Particulate Rate (Ton/yr)	58.59	35.92	47.44	**47.32**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	0.0049	0.0030	0.0039	**0.0040**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	0.0051	0.0032	0.0041	**0.0042**
RE	Reduction Efficiency (% Removal)[1]	99.97%	99.97%	99.97%	**99.97%**

[1] Removal efficiency calculated using the F_d-based (lb/MMBtu).

022304 115829

RESULTS

Table 2-7:
Unit 2 – Stack - Fluoride

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		13:06	14:24	16:11	
Stop Time (approx.)		14:15	15:33	17:22	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.7	5.2	5.1	**5.3**
CO_2	Carbon dioxide (dry volume %)	13.4	13.8	13.7	**13.6**
T_s	Sample temperature (°F)	218	220	218	**219**
B_w	Actual water vapor in gas (% by volume)	12.07	11.81	11.32	**11.73**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	909,374	905,251	895,703	**903,443**
Q_s	Volumetric flow rate, standard (scfm)	711,366	706,404	700,672	**706,147**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	625,514	623,006	621,339	**623,287**
Hydrogen Fluoride (HF) Results					
C_{sd}	HF Concentration (ppmdv)	<0.0498	<0.0435	<0.0428	**<0.0454**
$E_{lb/hr}$	HF Rate (lb/hr)	<0.0970	<0.0844	<0.0828	**<0.0881**
$E_{kg/hr}$	HF Rate (kg/hr)	<0.0440	<0.0383	<0.0376	**<0.0399**
$E_{T/yr}$	HF Rate (Ton/yr)	<0.4249	<0.3696	<0.3628	**<0.3857**
E_{Fd}	HF Rate - Fd-based (lb/MMBtu)	<3.4758E-05	<2.9387E-05	<2.8740E-05	**<3.0962E-05**
E_{Fc}	HF Rate - Fc-based (lb/MMBtu)	<3.5800E-05	<3.0358E-05	<3.0097E-05	**<3.2085E-05**

022304 115833

RESULTS

Table 2-8: Unit 2 – Stack – PCDD/PCDF

Run No.		1	2	3	Average
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		07:51	11:14	14:42	
Stop Time (approx.)		11:02	14:28	17:52	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.3	5.2	**5.3**
CO_2	Carbon dioxide (dry volume %)	13.6	13.5	13.6	**13.6**
T_s	Sample temperature (°F)	216	213	218	**216**
B_w	Actual water vapor in gas (% by volume)	10.94	11.11	10.92	**10.99**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	868,040	865,842	874,649	**869,510**
Q_s	Volumetric flow rate, standard (scfm)	681,348	682,343	684,230	**682,640**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	606,818	606,531	609,514	**607,621**
Total PCDD/F Results (TEF=1)					
C_{sd}	PCDD/F Concentration (ng/dscm)	2.122E-02	1.714E-02	1.481E-02	**1.772E-02**
$E_{lb/hr}$	PCDD/F Rate (lb/hr)	4.825E-08	3.895E-08	3.382E-08	**4.034E-08**
$E_{g/s}$	PCDD/F Rate (g/s)	6.078E-09	4.906E-09	4.261E-09	**5.082E-09**
$E_{T/yr}$	PCDD/F Rate (Ton/yr)	2.113E-07	1.706E-07	1.481E-07	**1.767E-07**
E_{Fd}	PCDD/F Rate - F_d-based (lb/MMBtu)	1.747E-11	1.402E-11	1.204E-11	**1.451E-11**
E_{Fc}	PCDD/F Rate - F_c-based (lb/MMBtu)	1.808E-11	1.471E-11	1.262E-11	**1.514E-11**
Total PCDD/F TEQ Results (using USEPA/INTL 1989 TEFs)					
C_{sdTEQ}	TEQ Concentration (ng/dscm)	2.141E-04	3.608E-06	2.012E-05	**7.927E-05**
$E_{lb/hrTE}$	TEQ Rate (lb/hr)	4.867E-10	8.198E-12	4.596E-11	**1.803E-10**
$E_{g/sTEQ}$	TEQ Rate (g/sec)	6.131E-11	1.033E-12	5.790E-12	**2.271E-11**
$E_{T/yrTE}$	TEQ Rate (Ton/yr)	2.132E-09	3.591E-11	2.013E-10	**7.897E-10**
E_{FdTEQ}	TEQ Rate - F_d-based (lb/MMBtu)	1.763E-13	2.952E-15	1.636E-14	**6.520E-14**
E_{FcTEQ}	TEQ Rate - F_c-based (lb/MMBtu)	1.824E-13	3.097E-15	1.715E-14	**6.756E-14**

RESULTS

Table 2-9:
Unit 2 – Stack – Lead

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		10:42	13:26	16:50	
Stop Time (approx.)		12:51	15:34	19:04	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.4	5.4	5.4	**5.4**
CO_2	Carbon dioxide (dry volume %)	13.4	13.4	13.4	**13.4**
T_s	Sample temperature (°F)	228	240	231	**233**
B_w	Actual water vapor in gas (% by volume)	11.37	9.96	10.64	**10.66**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	881,383	871,051	883,573	**878,669**
Q_s	Volumetric flow rate, standard (scfm)	678,033	658,683	677,463	**671,393**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	600,934	593,062	605,414	**599,803**
Lead Results - Total					
C_{sd}	Concentration (lb/dscf)	1.570E-11	4.207E-11	2.222E-11	**2.666E-11**
$E_{lb/hr}$	Rate (lb/hr)	5.659E-04	1.497E-03	8.072E-04	**9.567E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.479E-03	6.556E-03	3.535E-03	**4.190E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	2.070E-07	5.547E-07	2.930E-07	**3.516E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.174E-07	5.826E-07	3.078E-07	**3.693E-07**

Table 2-10:
Unit 2 – Stack – Mercury (Ontario Hydro)

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.2	5.4	5.8	**5.5**
CO_2	Carbon dioxide (dry volume %)	13.4	13.5	13.2	**13.4**
T_s	Sample temperature (°F)	241	250	234	**242**
B_w	Actual water vapor in gas (% by volume)	10.53	10.69	9.98	**10.40**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	907,511	913,697	899,844	**907,017**
Q_s	Volumetric flow rate, standard (scfm)	685,928	681,365	686,707	**684,667**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	613,694	608,500	618,165	**613,453**
Total Mercury Results [1]					
C_{sd}	Concentration (lb/dscf)	5.337E-10	5.867E-10	<5.191E-10	**<5.465E-10**
$E_{lb/hr}$	Rate (lb/hr)	1.965E-02	2.142E-02	<1.925E-02	**<2.011E-02**
$E_{T/yr}$	Rate (Ton/yr)	8.608E-02	9.383E-02	<8.434E-02	**<8.808E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	6.949E-06	7.737E-06	<7.027E-06	**<7.238E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.393E-06	8.066E-06	<7.299E-06	**<7.586E-06**
RE	Reduction Efficiency (% Removal)[2]	63.6%	46.7%	64.3%	**58.2%**
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	5.693E-13	5.666E-13	5.686E-13	**5.682E-13**
$E_{lb/hr}$	Rate (lb/hr)	2.096E-05	2.069E-05	2.109E-05	**2.091E-05**
$E_{T/yr}$	Rate (Ton/yr)	9.182E-05	9.061E-05	9.237E-05	**9.160E-05**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.412E-09	7.472E-09	7.697E-09	**7.527E-09**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.885E-09	7.790E-09	7.995E-09	**7.890E-09**
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	2.562E-12	2.266E-12	<1.706E-12	**<2.178E-12**
$E_{lb/hr}$	Rate (lb/hr)	9.433E-05	8.275E-05	<6.327E-05	**<8.012E-05**
$E_{T/yr}$	Rate (Ton/yr)	4.132E-04	3.624E-04	<2.771E-04	**<3.509E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	3.335E-08	2.989E-08	<2.309E-08	**<2.878E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	3.548E-08	3.116E-08	<2.398E-08	**<3.021E-08**
Elemental Mercury Results [3]					
C_{sd}	Concentration (lb/dscf)	5.306E-10	5.839E-10	5.177E-10	**5.441E-10**
$E_{lb/hr}$	Rate (lb/hr)	1.954E-02	2.132E-02	1.920E-02	**2.002E-02**
$E_{T/yr}$	Rate (Ton/yr)	8.558E-02	9.337E-02	8.410E-02	**8.768E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	6.908E-06	7.700E-06	7.008E-06	**7.205E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.349E-06	8.027E-06	7.279E-06	**7.552E-06**

[1] Allowable HNO_3-H_2O_2 blank (0.02 ug) calculated at ten (10) times detection limit of 0.002 ug.

[2] Removal efficiency calculate using F_d-based (lb/MMBtu)

[3] Non-detect values entered in Total Mercury as 0.5 x ND value

RESULTS

Table 2-11:
Unit 2 – Stack - Ammonia

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 14	Jan 14	Jan 14	
Start Time (approx.)		08:02	09:42	11:41	
Stop Time (approx.)		09:14	11:28	12:47	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,856	1,856	1,856	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.6	5.4	5.4	**5.5**
CO_2	Carbon dioxide (dry volume %)	13.5	13.6	13.6	**13.6**
T_s	Sample temperature (°F)	220	215	216	**217**
B_w	Actual water vapor in gas (% by volume)	10.81	11.79	11.55	**11.39**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	948,401	971,199	980,558	**966,719**
Q_s	Volumetric flow rate, standard (scfm)	740,076	762,917	769,697	**757,563**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	660,041	672,960	680,798	**671,266**
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (ppmdv)	3.17	0.18	0.15	**1.17**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	5.550	0.326	0.265	**2.047**
$E_{T/yr}$	Ammonia Rate (Ton/yr)	24.31	1.43	1.16	**8.97**
E_{Fd}	Ammonia Rate - Fd-based (lb/MMBtu)	0.0019	0.0001	0.0001	**0.0007**
E_{Fc}	Ammonia Rate - Fc-based (lb/MMBtu)	0.0019	0.0001	0.0001	**0.0007**

022304 115849

DESCRIPTION OF INSTALLATION

PROCESS DESCRIPTION

The Jacksonville Electric Northside Generating Station Unit 2 consists of a 300 MW circulating fluidized bed (CFB) boiler a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The control system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

The testing reported in this document was performed at the Unit 2 SDA Inlet and Stack locations.

A schematic of the process indicating sampling locations is shown in Figure 3-1.

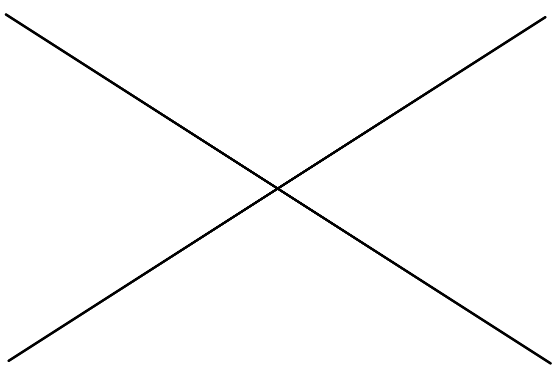


Figure 3-1: Process Schematic

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION(S)

Sampling point locations were determined according to EPA Method 1.

Table 3-1 outlines the sampling point configurations. Figure 3-3 and 3-3 illustrate the sampling points and orientation of sampling ports for each of the sources tested in the program.

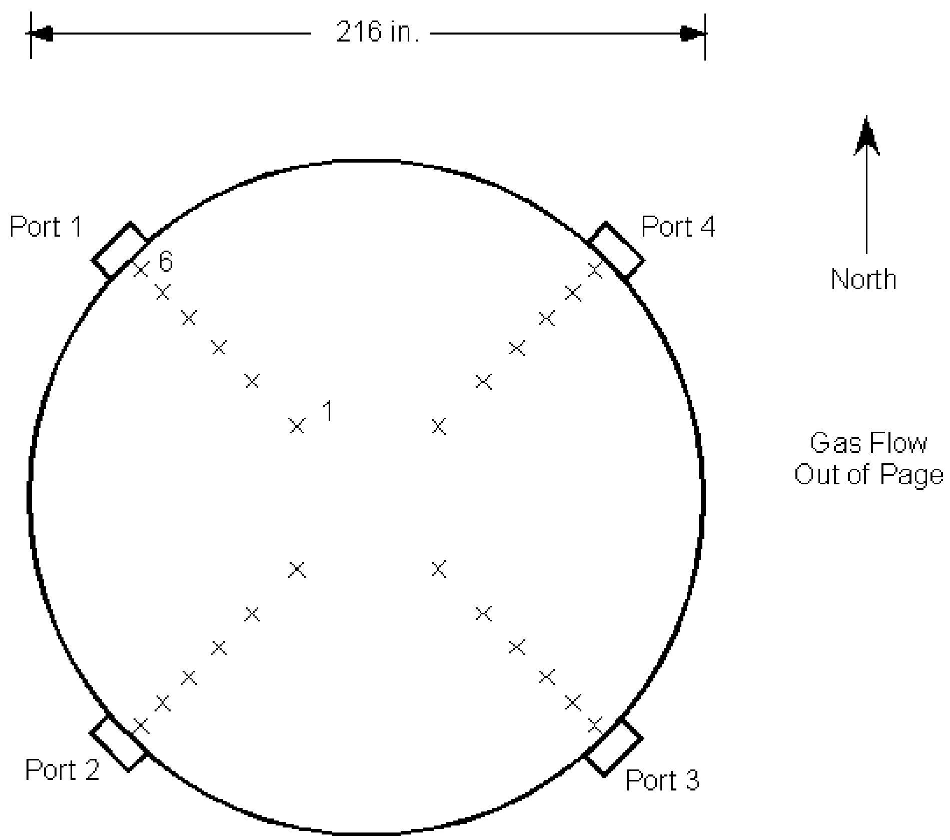
Table 3-1:
Sampling Points

Location	Constituent	Method	Run No.	Ports	Points per Port	Minutes per Point	Total Minutes	Figure
Unit 2 SDA Inlet	SO2	6C	1-6	1	1	60[1]	60	N/A
Unit 2 SDA Inlet	Particulate	17	1-6	4	6	2.5	60	3-1
Unit 2 SDA Inlet	Mercury	OH[2]	1-6	4	6	5	120	3-1
Unit 2 Stack	Particulate	5	1-3	4	3	10	120	3-2
Unit 2 Stack	Fluoride	13B	1-3	4	3	5	60	3-2
Unit 2 Stack	PCDD/PCDF	23	1-3	4	3	15	180	3-2
Unit 2 Stack	Lead	29	1-3	4	3	10	120	3-2
Unit 2 Stack	Mercury	OH[2]	1-6	4	3	10	120	3-2
Unit 2 Stack	Ammonia	CTM-027	1-3	4	3	5	60	3-2

[1] Sulfur Dioxide was sampled from a single point in the duct. Readings were collected at one-second intervals by the computer based data acquisition system and reported as one-minute averages.
[2] Mercury was determined using the Ontario Hydro method.

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



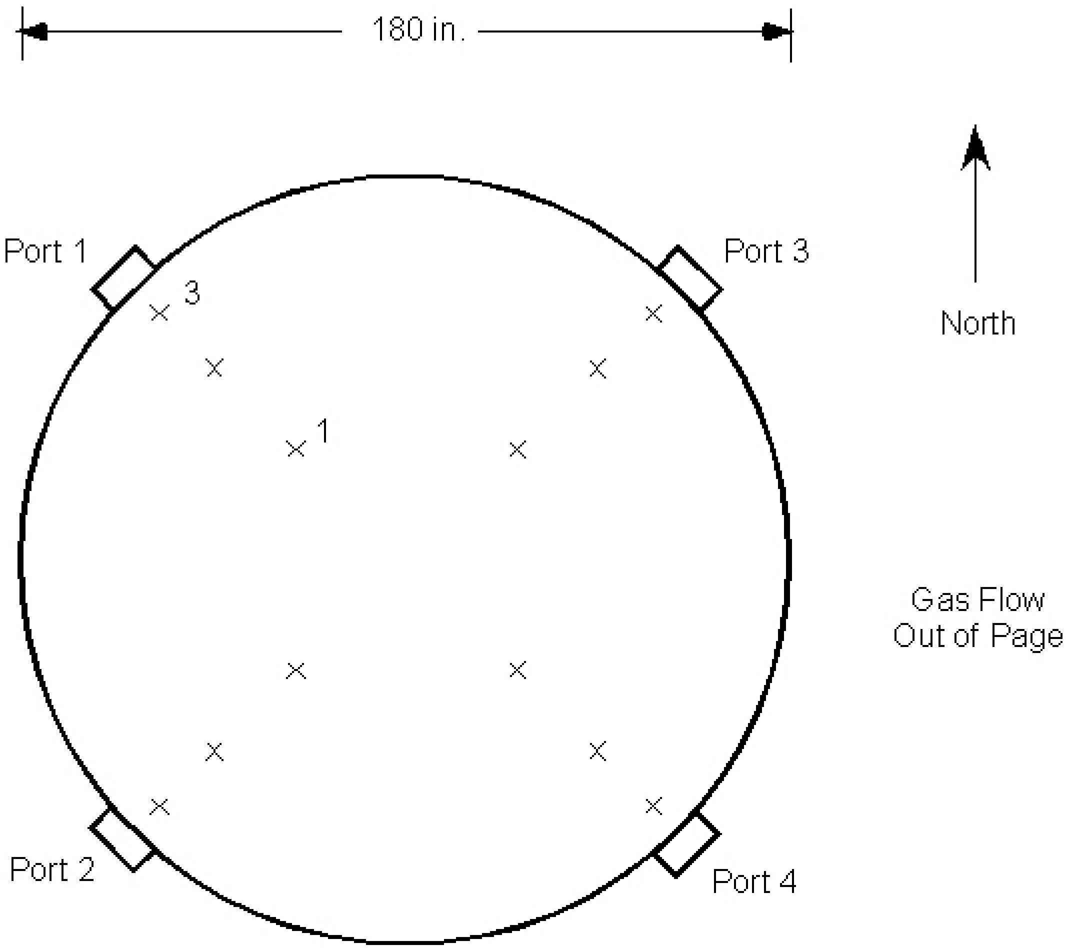
Sampling Point	Port to Point Distance (in.)
1	76.9
2	54.0
3	38.2
4	25.5
5	14.5
6	4.5

Diameters to upstream disturbance: >2.0 — Limit: 2.0 (minimum)
Diameters to downstream disturbance: >0.5 — Limit: 0.5 (minimum)

Figure 3-2: SDA Inlet Sampling Point Determination (EPA Method 1)

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



Sampling Point	Port to Point Distance (in.)
1	53.3
2	26.3
3	7.9

Diameters to upstream disturbance: >8.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >2.0 Limit: 0.5 (minimum)

Figure 3-3: Stack Sampling Point Determination (EPA Method 1)

METHODOLOGY

Clean Air Engineering followed procedures as detailed in U.S. Environmental Protection Agency (EPA) Methods 1, 2, 3A, 4, 5, 6C, 13B, 23, 29, Conditional Test Method CTM-027 and the Ontario Hydro Method. The following table summarizes the methods and their respective sources.

Table 4-1:
Summary of Sampling Procedures

Title 40 CFR Part 60 Appendix A	
Method 1	"Sample and Velocity Traverses for Stationary Sources"
Method 2	"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)"
Method 3A	"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 4	"Determination of Moisture Content in Stack Gases"
Method 5	"Determination of Particulate Emissions from Stationary Sources"
Method 6C	"Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 13B	"Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)"
Method 23	"Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources"
Method 29	"Determination of Metals Emissions from Stationary Sources"
Conditional Test Method	
CTM-027	"Procedure for the Collection and Analysis of Ammonia in Stationary Sources."
Draft Methods	
Ontario Hydro	"Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources."

The EPA Methods (1 through 29) appear in detail in Title 40 of the Code of Federal Regulations (CFR). The Conditional Test Method and the Hydro Ontario Method appear in detail on the US EPA Emissions Measurement Center web page. All methods may be found on the World Wide Web at http://www.cleanair.com.

Diagrams of the sampling apparatus and major specifications of the sampling, recovery and analytical procedures are summarized for each method in Appendix A.

Clean Air Engineering followed specific quality assurance and quality control (QA/QC) procedures as outlined in the individual methods and in USEPA "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III Stationary Source-Specific Methods", EPA/600/R-94/038C. Additional QA/QC methods as prescribed in Clean Air's internal Quality Manual were also followed. Results of all QA/QC activities performed by Clean Air Engineering are summarized in Appendix D.

APPENDIX

ATTACHMENT D

PI Data Summary

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

		Date:	**January 13, 2004**	**January 14, 2004**
		Start:	**1100 hours**	**1000 hours**
		End:	**1500 hours**	**1400 hours**
Substance	**Characteristic Being Measured**		**Values Used in Efficiency Calculation**	
Primary Air	Avg. Out A and B, Deg F		104.3	102.8
	Average, deg F		109.0	108.3
	Count		480	480
	Standard Deviation		4.3537	3.4784
Secondary Air	Total SA flow, klb/hr		0.8300	0.8215
	Average, Total SA Flow, klb/hr		0.8170	0.8222
	Count		240	240
	Standard Deviation		0.0110	0.0090
	Avg. Out A and B, Deg F		97.2	95.4
	Average, deg F		101.3	102.3
	Count		480	480
	Standard Deviation		2.3087	3.7724
Fuel	Total Flow, klb/hr		207.8	206.5
	Average, deg F		207.6	206.9
	Count		240	240
	Standard Deviation		0.1874	0.2361
PAHTR Gas Out	Gas Out, deg F, A train		308.3	302.3
	Gas Out, deg F, B train		326.2	320.6
	Average, deg F		314.5	313.6
	Count		480	480
	Standard Deviation		8.6833	9.1275
SAHTR Gas Out	Gas Out, deg F, A train		279.1	274.1
	Gas Out, deg F, B train		290.2	287.1
	Average, deg F		287.8	287.7
	Count		480	480
	Standard Deviation		10.9188	11.1038
PAH Gas In	Gas In, deg F, A & B train		587.0	579.7
	Average, deg F		575.7	576.6
	Count		240	240
	Standard Deviation		6.3042	4.1497
SAH Gas In	Gas In, deg F A & B train		590.2	583.0
	Average, deg F		578.6	579.9
	Count		240	240
	Standard Deviation		6.3563	4.3556
PAH Air Out	Air Out, deg F A & B train		482.4	474.8
	Average, deg F		475.0	473.5
	Count		240	240
	Standard Deviation		4.6017	3.1539
SA Airheater Air Out	Air Out, deg F A & B train		429.9	424.5
	Average, deg F		424.0	424.7
	Count		240	240
	Standard Deviation		3.9809	2.8573

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

		Date:	January 13, 2004	January 14, 2004
		Start:	1100 hours	1000 hours
		End:	1500 hours	1400 hours

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Stripper/ Coolers - A, B, C, D	Ash leaving temperature, deg F, A	0	423.8745
	Ash leaving temperature, deg F, B	0	0
	Ash leaving temperature, deg F, C	0	0
	Ash leaving temperature, deg F, D	382.1	376.1
	Average, deg F	398.1	462.8
	Count	480	254
	Standard Deviation	6.8019	25.3686
SDA Hopper	Temperature, deg F		
	Average, deg F	215.1	184.3
	Count	240	240
	Standard Deviation	7.8791	5.8660
Limestone Feed Rate 1	Feedrate, feeders 1, 2, 3, klb/hr	59.9	53.2
	Average, klb/hr	57.6	54.6
	Count	240	240
	Standard Deviation	4.1078	4.4497
SO2, in flue Gas	AH inlet, ppm		
	Average, ppm mv	40.7	41.1
	Count	240	240
	Standard Deviation	12.7747	11.0049
Intrex Blower Air Flow	Flow to A, B, C, klb/hr	36043.7	36367.3
	Average, klb/hr	35970.0	36289.4
	Count	1440	1440
	Standard Deviation	135.2805	84.9352
Intrex Seal Pot Blower	PA Flow to Intrex A, B, C, klb/hr	44614.8	44838.0
	Average, klb/hr	44702.2	45476.7
	Count	240	240
	Standard Deviation	211.5243	191.6591
Intrex Blower Exit Air Temp	Average, deg F	164.2	164.8
	Count	240	240
	Standard Deviation	3.1128	3.8639
Seal Pot Blower Exit Air Temp	Average, deg F	177.6	179.0
	Count	240	240
	Standard Deviation	2.3340	3.2261
Feedwater Temperature to Econ	Average, deg F	484.5	484.1
	Count	240	240
	Standard Deviation	0.5612	0.5413
Feedwater Pressure to Econ	Average, psiG	2177.3	2030.0
	Count	240	240
	Standard Deviation	6.1670	5.8581
(DSH)SH-1 Spray Flow	Average, klb/hr	11.2	30.0
	Count	240	240
	Standard Deviation	2.2235	4.3873

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

	Date:	**January 13, 2004**	**January 14, 2004**
	Start:	**1100 hours**	**1000 hours**
	End:	**1500 hours**	**1400 hours**

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
SH-1 Spray Temperature	Average, deg F	305.0	308.1
	Count	240	240
	Standard Deviation	0.9412	1.2058
SH-1 Spray Pressure	Average, psiG	2707.7	2697.7
	Count	240	240
	Standard Deviation	5.0183	4.3845
Drum Pressure	Average of three pressure values	2565.5	2558.0
	Average, psiG	2564.6	2560.0
	Count	720	720
	Standard Deviation	4.4214	3.3911
Main Steam Temperature	Average, deg F	1003.3	1003.4
	Count	240	240
	Standard Deviation	0.7794	0.8207
Main Steam Pressure	Average of two pressure values	2400.6	2400.5
	Average, psiG	2400.4	2400.5
	Count	480	480
	Standard Deviation	3.1311	2.7904
Reheater Outlet Temperature	Average of three temp values	1001.3	1003.9
	Average, deg F	1000.0	1001.9
	Count	720	720
	Standard Deviation	1.0939	1.3519
Reheater Outlet Pressure	Average of two pressure values	571.7	568.7
	Average, psiG	570.9	568.8
	Count	480	480
	Standard Deviation	25.2664	25.2064
CRH Ent Attemp Temp	Average, deg F	607.5	607.2
	Count	240	240
	Standard Deviation	0.8773	1.1088
CRH Ent Attemp Press	Average, psiG	570.5	568.2
	Count	240	240
	Standard Deviation	3.5904	3.4197
RH Spray Flow	Average, klb/hr	0.5	0.5
	Count	240	240
	Standard Deviation	0.0750	0.0780
RH Spray Temp	Average, deg F	186.6	188.6
	Count	240	240
	Standard Deviation	1.0044	0.8165
RH Spray Pressure	Average, psiG	727.4	725.6
	Count	240	240
	Standard Deviation	1.2194	1.1281

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

		Date:	January 13, 2004	January 14, 2004
		Start:	1100 hours	1000 hours
		End:	1500 hours	1400 hours
Substance	**Characteristic Being Measured**		**Values Used in Efficiency Calculation**	
Htr 1 FW Entering Temp	Data		417.8	417.3
	Data		484.7	483.8
	Average, deg F		451.1	450.7
	Count		480	480
	Standard Deviation		33.4367	33.3596
Htr 1 FW Entering Pressure	Data		2186.7	2039.6
	Data		2186.7	2039.6
	Average, psiG		2177.3	2030.0
	Count		480	480
	Standard Deviation		6.1606	5.8520
Htr 1 FW Leaving Temp	Average, deg F		484.5	484.1
	Count		240	240
	Standard Deviation		0.5612	0.5413
Htr 1 FW Leaving Pressure	Average, psiG		2177.3	2030.0
	Count		240	240
	Standard Deviation		6.1670	5.8581
Htr 1 Extraction Stm Temp	Average, deg F		632.1	631.9
	Count		240	240
	Standard Deviation		0.8084	1.0135
Htr 1 Extraction Stm Pressure	Average, psiG		573.8	571.5
	Count		240	240
	Standard Deviation		3.4706	3.3074
Htr 1 Drain Temp	Average, deg F		423.1	422.8
	Count		240	240
	Standard Deviation		0.4722	0.4885
Htr 1 Drain Pressure	Average, psiG		573.8	571.5
	Count		240	240
	Standard Deviation		3.4706	3.3074
Feedwater to Econ	Pressure, psiG		2201.6	2039.6
	Temperature, deg F		484.7	483.8
	Density, lb / cu. ft.		0.01980	0.01981
Primary Air to SC A	Total of three flow values		40.3	27.7
	Average, k lb/hr		39.5	27.5
	Count		240	240
	Standard Deviation		2.2858	0.1828
Primary Air to SC B	Total of three flow values		10.3	10.4
	Average, k lb/hr		10.3	10.4
	Count		240	240
	Standard Deviation		0.0680	0.0573
Primary Air to SC C	Total of three flow values		18.3	18.0
	Average, k lb/hr		17.8	18.2
	Count		240	240
	Standard Deviation		2.5480	0.1116

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY PI DATA

		Date:	January 13, 2004	January 14, 2004
		Start:	1100 hours	1000 hours
		End:	1500 hours	1400 hours
Substance	**Characteristic Being Measured**		**Values Used in Efficiency Calculation**	
Primary Air to SC D	Total of three flow values		31.7	31.3
	Average, k lb/hr		31.3	31.7
	Count		240	240
	Standard Deviation		0.2770	0.2094
Combustion Air Flow into PAH (hot), lb/hr	Total of fourteen flow values		13865.3	13984.3
	Average, k lb/hr		13733.0	13872.9
	Count		240	240
	Standard Deviation		85.3431	90.1078
Combustion Air Flow bypassing PAH (cold), lb/hr	Total of four flow values		47.5	37.7
	Average, k lb/hr		45.0	38.0
	Count		240	240
	Standard Deviation		3.9395	0.2002
Total air Flow, klb/hr	Average, k lb/hr		2435.7	2436.0
	Count		240	240
	Standard Deviation		9.3840	8.1778

ATTACHMENT E

Abbreviation List - Refer to Section 1.2

ATTACHMENT F

Isolation Valve List

Hole #	Description	Approximate Location	Closed (Yes / No)			
			13-Jan-04	14-Jan-04	15-Jan-04	16-Jan-04
37	RHA to CRH	Next to Heat 1	closed	closed	closed	closed
Use Digital Readout	MS Bypass to CRH (Upstream)	Next to Heater 1	closed	closed	closed	closed
38	Desup Wtr from BFP Disch to MS Bypass		closed	closed	closed	closed
Bare Pipe	Heater 1 ~~Running~~ Vent	On Side of Heater 1	closed	closed	closed	closed
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	closed	closed	closed	closed
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	closed	closed	closed	closed
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	closed	closed	closed	closed
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	closed	closed	closed	closed
33	Aux Steam Header (GRAY Valve) 337	Platform Overhead	closed	closed	closed	closed
55	CRH Line Drains - common line	Below Turbine	closed	closed	~~open~~ closed	closed
56	CRH Line Drains - common line	Below Turbine	closed	closed	closed	closed
57	CRH Line Drains - North	Below Turbine	closed	closed	closed	closed
58	CRH Line Drains - South	Below Turbine	closed	closed	closed	closed
60	MS Line Drain	Below Turbine	closed	closed	closed	closed
61	MS Line Drain	Below Turbine	closed	closed	closed	closed
#1	Extraction Drain	Below Turbine	closed	closed	closed	closed
	Heat Soak Valve SA330	Below Turbine	closed	closed	closed	closed

#1 Heater Shell Drain leaking small amount

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
Mezzanine Level			
35	DA Pegging Steam (Upstream)	Next to Heater 1	
36	DA Pegging Steam (Downstream)	Next to Heater 1	
34	DA Pegging Steam Line Drain	Next to Heater 1	
37	RHA to CRH	Next to Heater 1	
39	MS Bypass to CRH (Upstream)	Over railing by Heater 1	
Use Digital Readout	MS Bypass to CRH (Downstream)	Next to Heater 1	
38	Desup Wtr from BFP Disch to MS Bypass	Near railing by Heater 1	
Bare Pipe	Heater 1 Running Vent	On Side of Heater 1	
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	
Visual	Heater 1 FW Bypass	Directly above Heater 1	
Bare Pipe	Heater 2 Running Vent	On Side of Heater 2	
Bare Pipe	Heater 2 Relief Vent	Top of Heater 2	
Visual	Heater 2 FW Bypass	Directly above Heater 2	
41	Aux Steam to Unit 3 CRH	Against wall - stairs near Htr 5	
40	Aux Steam from Unit 3 CRH	Against wall - stairs near Htr 5	
42	MS to SSH	Platform (overhead)	
43	SSR Bypass Line	Platform (overhead)	
44	Aux Steam Supply Line to SSR	Vertical Pipe near Platform	
Gauge	SSH Pressure	Board on Platform	
45	Heater 4 Running Vent	Side of Heater 4	
Bare Pipe	Heater 4 Relief Vent	Top of Heater 4	
Visual	Heater 4 FW Bypass	Directly above Heater 4	
46	Heater 5 Vent	Side of Heater 5	
47	Heater 5 Vent	Side of Heater 5	
Bare Pipe	Heater 5 Relief Vent	Top of Heater 5	
Visual	Heater 5 FW Bypass	Directly above Heater 5	
48	CBP Disch to BFP Suction	To the side of Heater 5	
Visual	Heater 6 FW Bypass	Near Condenser Wall	
19	BDV to Cond	Near Condenser Wall (right side)	
20	RFDV (Ventilator Valve) to Cond	Bare Pipe near Cond Wall (R/S)	
21	Equalizer Valve to Cond (CRV-1)	Bare Pipe near Cond Wall (R/S)	
22	Equalizer Valve to Cond (CRV-2)	Bare Pipe near Cond Wall (R/S)	
12	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
14	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
52	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
53	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
13	Stm Lead Drains	Near Condenser Wall (R/S)	
16	Stm Lead Drains	Near Condenser Wall (R/S)	
17	Stm Lead Drains	Near Condenser Wall (R/S)	
18	Stm Lead Drains	Near Condenser Wall (R/S)	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
15	CRV Drain Lines	Near HRH Line	
23	CRV Drain Lines	Hear HRH Line	
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	
DCS	HRH Bypass to Condenser (Downstream)	Control Room	
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	
Visual	SDBFP Recirc to DA	Near HRH Bypass Line	
Visual	MDBFP Recirc to DA	Near HRH Bypass Line	
	Condenser Vacuum		

Ground Floor

Hole #	Description	Approximate Location	Temp Check
24	TDV to Cond (SS Dump)	Into Condenser (use platform)	
7	CRH Drain Hdr 1	Hdr into Cond on Left Side	
8	MS Drain Hdr 2	Hdr into Cond on Left Side	
6	Extraction Drain Hdr 3	Hdr into Cond on Left Side	
10	Drain Hdr 4	Hdr into Cond on Right Side	
9	Drain Hdr 5	Hdr into Cond on Right Side	
11	Steam Lead Drains	Bare Pipe - Side of Condenser	
51	BAC Return to Condenser (CV-4)	U/S of CV-4	
Double Isolate	Hotwell Makeup		
	Polisher Drains	Near Condensate Polishing Sys	
	Bitter Water Pump Off	Near Condensate Polishing Sys	Yes / No
	Unit 2 Fill Pump Off	Near Condensate Polishing Sys	Yes / No
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	/
2	Htr 6 Dump to Cond	Upstream of Valve	
3 / 26	Htr 2 Dump to Cond	Up/Downstream of Valve	/
4 / 27	Htr 4 Dump to Cond	Up/Downstream of Valve	/
5 / 28	Htr 5 Dump to Cond	Up/Downstream of Valve	/
29	Aux Stm to CRH Warm. (U/S of Check Vlv)	Platform Overhead	
30	Aux Stm to CRH Warm. (D/S of Check Vlv)	Platform Overhead	
31	Aux Steam to/from Unit 3 CRH	Platform Overhead	
32	Aux Steam to SSH	Platform Overhead	
33	Aux Steam Header Gray Valve	Platform Overhead	
54	HRH Line Drains	Below Turbine	
59	HRH Line Drains	Below Turbine	
55	CRH Line Drains - common line	Below Turbine	
56	CRH Line Drains - common line	Below Turbine	
57	CRH Line Drains - North	Below Turbine	
58	CRH Line Drains - South	Below Turbine	
60	MS Line Drain	Below Turbine	
61	MS Line Drain	Below Turbine	
	#1 Extr Drain	Below Turbine	
	Heat Soak Valve		

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
	Hotwell Make-Up Valves		
	Boiler Blow Down Valve		
	Valve SA 328 (turbine soak line)		
	Auxiliary Steam Supply to Seal Steam System		
	Valve 331 Auxiliary Steam from Cold RH		
	Reheat Attemperator		
	Heater #1 Continuous Vent		
	Heater #2 Continuous Vent		
	Heater #4 Continuous Vent		
	Heater #5 Continuous Vent		

ATTACHMENT G

Fuel Analyses - Pittsburgh 8 Coal

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY FUEL ANALYSES

Fuel	Unit #2 Jan. 13, 2004					
Lab Number	32006-01A	32006-02B	32006-03C	32006-04D	32006-05E	Average Values
Date	1/13/2004	1/13/2004	1/13/2004	1/13/2002	1/13/2004	
Time	11:00 - 11:20	12:00 - 12:20	13:00 - 13:20	14:00 - 14:20	15:00 - 15:20	
Proximate Analysis						
Moisture, wt% (±0.25)	6.59	7.47	7.17	7.23	7.82	7.256
Ash, wt% (±0.49)	7.48	6.76	7.67	6.02	6.51	6.89
Volatile, wt% (±1.0)	49.4	54.29	57.06	55.77	55.78	54.46
Fixed Carbon, wt% (±1.0)	36.53	30.48	28.10	30.98	29.89	31.20
Ultimate Analysis						
Carbon, wt% (±2.51)	73.1	73.36	70.17	73.77	73.08	72.70
Hydrogen, wt% (±0.30)	4.97	4.87	4.62	5.01	4.72	4.84
Nitrogen, wt% (±0.17)	1.28	1.35	1.33	1.49	1.4	1.37
Sulfur, wt% (±0.009)	4.89	4.86	4.82	4.84	4.8	4.84
Moisture, wt% (±0.25)	6.59	7.47	7.17	7.23	7.82	7.26
Ash, wt% (±0.49)	7.48	6.76	7.67	6.02	6.51	6.89
Oxygen, wt% (±2.51)	1.69	1.33	4.22	1.64	1.67	2.11
Higher Heating, Btu/lb (±107 Btu/lb)	12,874	12,972	12,770	12,886	12,885	12,877
Total Chlorine, wt% (±200 ug/g)	0.18	0.23	0.12	0.25	0.10	0.18
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Moisture (oven), wt% (±1.0)	6.59	7.47	7.17	7.23	7.82	7.26
Ash elemental analysis						
SiO_2, wt% (±0.65)	0.42	0.33	0.30	0.30	1.22	0.51
Al_2O_3, wt% (±0.98)	48.75	49.90	47.57	65.98	53.51	53.14
Fe_2O_3, wt% (±1.44)	19.55	18.62	17.19	12.18	18.15	17.14
CaO, wt% (±4.74)	18.96	19.67	23.92	8.86	16.86	17.65
MgO, wt% (±1.25)	3.84	3.59	3.70	3.00	3.02	3.43
Na_2O, wt% (±3.70)	4.27	3.58	2.84	2.52	2.75	3.19
K_2O, wt% (±4.25)	3.42	3.53	3.63	6.99	3.47	4.21
Ti_2O, wt% (±1.52)	0.78	0.78	0.85	0.17	1.02	0.72
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	25.63	9.29	7.96	11.35	15.88	14.02
Particulate Left Mesh, 1/4", wt%	14.27	18.77	14.81	20.37	29.10	19.46
Particulate Left Mesh, #4, wt%	30.06	10.97	10.88	10.52	9.95	14.48
Particulate Left Mesh, #8, wt%	9.44	22.40	19.67	21.82	17.72	18.21
Particulate Left Mesh, #14, wt%	6.43	13.84	17.19	13.66	11.13	12.45
Particulate Left Mesh, #28, wt%	6.78	12.61	16.76	12.48	9.22	11.57
Particulate Left Mesh, #50, wt%	3.84	5.82	7.44	5.84	4.11	5.41
Particulate Left Mesh, #100, wt%	1.94	4.04	3.69	2.43	1.41	2.70
Bottom, wt%	0.56	1.38	0.57	0.33	0.41	0.65

JEA Northside Unit 2
Test #1 - Pittsburgh 8 Coal
SUMMARY - FUEL ANALYSES

Fuel	Unit #2 Jan. 14, 2004					
Lab Number / Date / Time	31991-01A 1/14/2004 10:00 - 10:15	31991-02B 1/14/2004 11:00 - 11:15	31991-03C 1/14/2004 12:00 - 12:15	31991-04D 1/14/2004 13:00 - 13:15	31991-05E 1/14/2004 14:00 - 14:15	Average Values
Proximate Analysis						
Moisture, wt% (±0.25)	7.28	7.25	7.80	7.32	7.29	7.388
Ash, wt% (±0.49)	6.16	7.17	7.30	6.93	7.74	7.06
Volatile, wt% (±1.0)	54.91	55.69	54.14	54.31	56.63	55.14
Fixed Carbon, wt% (±1.0)	31.65	29.89	30.76	31.44	28.34	30.42
Ultimate Analysis						
Carbon, wt% (±2.51)	72.15	70.10	73.51	73.49	72.49	72.35
Hydrogen, wt% (±0.30)	4.50	4.65	4.93	4.84	4.66	4.72
Nitrogen, wt% (±0.17)	1.32	1.32	1.39	1.45	1.28	1.35
Sulfur, wt% (±0.009)	4.60	4.70	3.82	4.83	4.84	4.56
Moisture, wt% (±0.25)	7.28	7.25	7.80	7.32	7.29	7.39
Ash, wt% (±0.49)	6.16	7.17	7.30	6.93	7.74	7.06
Oxygen, wt% (±2.51)	3.81	4.81	1.25	1.14	1.71	2.54
Higher Heating, Btu/lb (±107 Btu/lb)	13,044	12,864	12,930	12,952	13,060	12,970
Total Chlorine, wt% (±200 ug/g)	0.13	0.15	0.13	0.15	0.13	0.14
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.000	0.000	0.000	0.001	0.001	0.00
Total Lead, ug/g (±9 ug/g)	0.002	0.002	0.002	0.006	0.000	0.00
Moisture (oven), wt% (±1.0)	7.28	7.25	7.80	7.32	7.29	7.39
Ash elemental analysis						
SiO_2, wt% (±0.65)	0.60	0.21	0.37	0.56	0.37	0.42
Al_2O_3, wt% (±0.98)	53.66	40.91	50.60	54.99	53.45	50.72
Fe_2O_3, wt% (±1.44)	15.10	17.31	19.78	17.42	15.83	17.09
CaO, wt% (±4.74)	19.32	32.35	18.25	14.84	18.49	20.65
MgO, wt% (±1.25)	3.08	3.14	3.29	3.23	3.48	3.24
Na_2O, wt% (±3.70)	3.29	2.50	3.28	3.77	3.55	3.28
K_2O, wt% (±4.25)	3.84	2.74	3.42	3.98	3.95	3.59
Ti_2O, wt% (±1.52)	1.11	0.84	1.01	1.21	0.88	1.01
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	1.21	2.61	7.96	11.35	15.88	7.80
Particulate Left Mesh, 1/4", wt%	16.27	18.30	14.81	20.37	29.10	19.77
Particulate Left Mesh, #4, wt%	13.68	5.89	10.88	10.52	9.95	10.18
Particulate Left Mesh, #8, wt%	24.28	27.90	19.67	21.82	17.72	22.28
Particulate Left Mesh, #14, wt%	18.25	17.53	17.19	13.66	11.13	15.55
Particulate Left Mesh, #28, wt%	13.95	17.60	16.76	12.48	9.22	14.00
Particulate Left Mesh, #50, wt%	6.94	6.36	7.44	5.84	4.11	6.14
Particulate Left Mesh, #100, wt%	3.73	1.93	3.69	2.43	1.41	2.64
Bottom, wt%	0.69	0.41	0.57	0.33	0.41	0.48

ATTACHMENT H

Limestone Analyses

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Unit #2 Jan. 13, 2004					
Lab number	**31987-01A**	**31987-02B**	**31987-03C**	**31987-04D**	**31987-05E**	**Average Values**
Date	**1/13/2004**	**1/13/2004**	**1/13/2004**	**1/13/2004**	**1/13/2004**	
Time	**11:45**	**12:45**	**13:45**	**14:45**	**15:45**	
Compound analysis						
$CaCO_3$, wt% (±0.41)	90.67	85.50	92.38	94.05	91.70	90.86
$MgCO_3$, wt% (±0.41)	3.66	3.04	2.99	3.09	3.77	3.31
Moisture (oven), wt% (±1.0)	0.27	1.26	0.31	0.30	0.29	0.49
Inerts (subtraction), wt% (±1.0)	5.40	10.20	4.32	2.56	4.24	5.34
Total Chlorine, wt% (±200 ug/g)	0.13	0.16	0.15	0.20	0.19	0.17
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.020	0.008	0.005	0.005	0.004	0.01
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.07	0.07	0.08	0.06	0.07	0.07
K, wt% (±0.5 ug/g)	0.02	0.02	0.02	0.02	0.03	0.02
Particulate size distribution						
Particulate Left Mesh, #8, wt%	37.87	38.30	39.66	26.06	34.11	35.20
Particulate Left Mesh, #14, wt%	21.01	18.70	18.01	18.58	18.51	18.96
Particulate Left Mesh, #28, wt%	19.90	16.11	14.49	17.51	18.51	17.30
Particulate Left Mesh, #50, wt%	7.52	7.35	7.22	9.87	9.23	8.24
Particulate Left Mesh, #100, wt%	4.70	6.46	6.46	13.69	6.51	7.56
Particulate Left Mesh, #200, wt%	5.32	6.73	6.73	9.75	9.61	7.63
Particulate Left Mesh, #270, wt%	3.69	4.60	4.60	2.33	2.37	3.52
Bottom, wt%	1.78	0.98	0.99	1.16	1.15	1.21
Conversion Fraction	85.16	84.48	85.41	85.55	86.88	85.50

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Unit #2 Jan. 14, 2004					
Lab number	31989-01A	31989-02B	31989-03C	31989-04D	31989-05E	Average Values
Date	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	
Time	10:15	11:15	12:15	13:15	14:15	
Compound analysis						
$CaCO_3$, wt% (±0.41)	89.46	90.57	94.91	93.06	91.04	91.81
$MgCO_3$, wt% (±0.41)	2.93	3.03	2.97	3.07	2.74	2.95
Moisture (oven), wt% (±1.0)	0.30	0.30	0.32	0.36	0.41	0.34
Inerts (subtraction), wt% (±1.0)	7.31	6.09	1.80	3.51	5.81	4.90
Total Chlorine, wt% (±200 ug/g)	0.02	0.02	0.02	0.03	0.03	0.02
Total Fluorine, wt% (±15 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Total Mercury, ug/g (±0.031 ug/g)	0.006	0.004	0.005	0.004	0.005	0.00
Total Lead, ug/g (±9 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
K, wt% (±0.5 ug/g)	0.000	0.000	0.000	0.000	0.000	0.00
Particulate size distribution						
Particulate Left Mesh, #8, wt%	22.25	24.39	28.52	26.41	31.21	26.56
Particulate Left Mesh, #14, wt%	16.33	14.29	16.26	17.45	16.59	16.18
Particulate Left Mesh, #28, wt%	18.58	18.40	18.37	19.57	13.93	17.77
Particulate Left Mesh, #50, wt%	11.77	12.15	10.94	9.24	13.29	11.48
Particulate Left Mesh, #100, wt%	7.54	6.80	6.44	6.56	5.07	6.48
Particulate Left Mesh, #200, wt%	7.11	5.77	4.70	5.40	4.07	5.41
Particulate Left Mesh, #270, wt%	11.70	11.50	8.87	9.32	9.59	10.20
Bottom, wt%	3.87	5.60	4.37	4.56	4.99	4.68
Conversion Fraction	89.10	89.30	89.54	85.34	90.06	88.67

ATTACHMENT I

Bed Ash Analyses

JEA Northside Unit 2
Test #1 - Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Unit #2 Jan. 13, 2004					
Lab Number / Date / Time	31986-04 1/13/2004 11:00	31986-05 1/13/2004 12:00	31986-08 1/13/2004 13:00	31986-09 1/13/2004 14:00	31986-11 1/13/2004 15:00	Average Values
Unburned carbon, wt%	0.12	0.03	0.04	0.10	0.10	0.08
Compound analysis						
CaSO4, wt% (±0.2)	12.91	14.07	13.38	13.45	14.29	13.62
Sulfur, wt% (±0.09)	0.44	0.48	0.46	0.48	0.49	0.47
Ash compound analysis						
SiO2, wt% (±0.65)	2.03	1.84	1.75	2.83	1.91	2.07
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	54.22	60.21	58.42	54.49	61.18	57.71
CaO, wt% (±4.74) (Not Part of Normalization)	20.87	20.96	20.84	21.30	21.14	21.02
MgO, wt% (±1.25)	38.42	30.59	30.30	33.34	31.27	32.78
Na2O, wt% (±3.70)	3.05	4.85	7.15	7.17	3.88	5.22
K2O, wt% (±4.25)	2.04	1.99	1.74	1.63	1.43	1.77
Vanadium, wt% (±1.0)	0.21	0.48	0.57	0.46	0.30	0.41
Nickel, wt% (±1.0)	0.02	0.05	0.07	0.06	0.03	0.05
Elemental analysis, AA						
Na, wt% (±0.5 ug/g)	0.01	0.02	0.03	0.03	0.01	0.02
K, wt% (±0.5 ug/g)	0.01	0.01	0.01	0.01	0.01	0.01
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	0.41	0.00	0.41	0.41	0.69	0.39
Particulate Left Mesh, #4, wt%	0.41	0.41	0.39	0.40	0.88	0.50
Particulate Left Mesh, #8, wt%	5.73	8.20	5.02	5.95	11.09	7.20
Particulate Left Mesh, #14, wt%	8.30	11.18	7.77	8.85	13.96	10.01
Particulate Left Mesh, #28, wt%	20.95	21.64	21.96	22.53	27.25	22.87
Particulate Left Mesh, #48, wt%	22.49	20.58	23.74	23.53	20.28	22.12
Particulate Left Mesh, #100, wt%	23.21	21.43	23.52	22.66	15.89	21.34
Particulate Left Mesh, #200, wt%	17.73	16.19	16.30	14.82	8.89	14.79
Bottom, wt%	0.10	0.05	0.11	0.09	0.05	0.08

JEA Northside Unit 2
Test #1 - Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

Bed Ash	Unit #2 Jan. 14, 2004						
Lab Number	31986-01	31986-02	31986-03	31986-06	31986-07	31986-10	Average Values
Date	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	1/14/2004	
Time	10:00	10:20	11:00	12:15	13:00	14:15	
Unburned carbon, wt%	0.04	0.04	0.02	0.02	0.09	0.06	0.05
Compound analysis							
CaSO4, wt% (±0.2)	14.66	14.43	14.60	12.03	14.07	14.20	14.00
Sulfur, wt% (±0.09)	0.50	0.50	0.51	0.42	0.49	0.48	0.48
Ash compound analysis							
SiO2, wt% (±0.65)	2.92	2.95	2.51	2.94	2.17	2.16	2.61
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	45.30	53.12	56.62	61.31	62.04	46.07	54.08
CaO, wt% (±4.74) (Not Part of Normalization)	21.17	21.49	20.80	20.55	20.96	21.35	21.05
MgO, wt% (±1.25)	43.13	38.29	33.92	29.50	26.30	43.44	35.76
Na2O, wt% (±3.70)	5.66	3.93	4.93	4.52	6.26	5.56	5.14
K2O, wt% (±4.25)	2.58	1.34	1.51	1.30	2.69	2.30	1.95
Vanadium, wt% (±1.0)	0.37	0.33	0.45	0.38	0.48	0.43	0.41
Nickel, wt% (±1.0)	0.04	0.03	0.06	0.05	0.06	0.03	0.04
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.01	0.01	0.02	0.02	0.03	0.02	0.02
K, wt% (±0.5 ug/g)	0.01	0.00	0.01	0.01	0.01	0.01	0.01
Particulate size distribution							
Particulate Left Mesh, 1/2", wt%	0.00	0.41	1.37	0.14	0.00	0.27	0.37
Particulate Left Mesh, #4, wt%	0.34	0.47	0.34	0.41	0.38	0.30	0.37
Particulate Left Mesh, #8, wt%	4.68	6.21	3.49	5.96	3.58	4.44	4.73
Particulate Left Mesh, #14, wt%	8.55	9.10	6.02	8.81	5.78	7.22	7.58
Particulate Left Mesh, #28, wt%	26.65	22.44	17.91	22.70	18.77	20.83	21.55
Particulate Left Mesh, #48, wt%	26.81	21.94	20.42	23.77	21.63	23.80	23.06
Particulate Left Mesh, #100, wt%	22.94	22.22	25.12	22.78	25.71	24.62	23.90
Particulate Left Mesh, #200, wt%	9.04	16.35	24.00	14.74	23.61	17.76	17.58
Bottom, wt%	0.07	0.09	0.13	0.09	0.13	0.11	0.10

ATTACHMENT J

Flyash (Air Heater and PJFF) Analyses

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY FLYASH ANALYSES

Flyash	Unit #2 Jan. 13, 2004						
Lab Number / Time	31990-05 (Bag House) 11:52	31990-07 (Bag House) 12:12	31990-10 (Bag House) 13:20	31990-14 (Bag House) 14:29	31990-16 (Bag House) 15:30	32065-01A (Isokinetic)	Average Values
Unburned carbon, wt%	6.88	6.90	7.17	7.68	8.27	7.86	7.38
Compound analysis							
CaSO4, wt% (±0.2)	34.83	38.80	34.04	35.16	37.35	19.80	36.04
Sulfur, wt% (±0.09)	1.25	1.38	1.22	1.26	1.33	0.73	1.29
Ash compound analysis							
SiO2, wt% (±0.65)	0.22	0.25	0.18	0.15	0.12	0.13	0.18
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	60.64	60.59	62.56	63.68	63.19	56.68	62.13
CaO, wt% (±4.74) (Not Part of Norma	20.80	20.77	20.87	20.81	20.77	21.04	20.80
MgO, wt% (±1.25)	4.49	4.15	3.68	3.25	3.34	3.94	3.78
Na2O, wt% (±3.70)	7.10	7.28	6.52	6.09	6.34	9.63	6.67
K2O, wt% (±4.25)	6.57	6.79	6.14	5.92	6.08	8.67	6.30
Vanadium, wt% (±1.0)	0.14	0.12	0.11	0.10	0.11	0.12	0.12
Nickel, wt% (±1.0)	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	100.00	99.96	100.07	100.01	99.96	100.24	100.00
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.21	0.23	0.22	0.24	0.23	0.23	0.22
K, wt% (±0.5 ug/g)	0.22	0.24	0.24	0.26	0.24	0.23	0.24
Particulate size distribution							
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #28, wt%	0.05	0.04	0.04	0.03	0.04	0.00	0.04
Particulate Left Mesh, #48, wt%	0.05	0.04	0.04	0.03	0.04	0.00	0.04
Particulate Left Mesh, #100, wt%	1.25	3.57	2.88	1.45	0.17	0.31	1.86
Particulate Left Mesh, #270, wt%	23.45	24.02	24.85	25.55	26.05	21.38	24.78
Particulate Left Mesh, #325, wt%	14.22	11.76	13.45	14.33	15.38	26.10	13.83
Bottom, wt%	59.78	60.04	57.54	57.41	58.11	50.10	58.58

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY FLYASH ANALYSES

Flyash	Unit #2 Jan. 14, 2004						
Lab Number / Time	31990-02 (Bag House) 10:06	31990-04 (Bag House) 11:35	31990-08 (Bag House) 12:23	31990-11 (Bag House) 13:46	31990-13 (Bag House) 14:20	31990-15 (Bag House) 15:15	Average Values
Unburned carbon, wt%	7.73	7.30	7.34	7.38	7.44	2.96	7.44
Compound analysis							
CaSO4, wt% (±0.2)	38.83	35.02	23.47	27.29	31.14	38.37	31.15
Sulfur, wt% (±0.09)	1.38	1.25	0.85	0.98	0.17	0.20	0.93
Ash compound analysis							
SiO2, wt% (±0.65)	0.30	0.23	0.13	0.15	0.16	0.29	0.19
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	61.65	61.59	61.80	62.46	62.64	52.16	62.03
CaO, wt% (±4.74) (Not Part of Norma	20.80	20.90	20.86	20.91	20.90	22.33	20.88
MgO, wt% (±1.25)	4.56	4.14	4.24	4.02	3.90	8.18	4.17
Na2O, wt% (±3.70)	6.19	6.32	6.27	5.95	5.98	12.28	6.14
K2O, wt% (±4.25)	6.35	6.77	6.61	6.48	6.38	4.91	6.52
Vanadium, wt% (±1.0)	0.13	0.12	0.12	0.12	0.11	0.14	0.12
Nickel, wt% (±1.0)	0.02	0.02	0.02	0.02	0.02	1.23	0.02
	100.00	100.10	100.06	100.11	100.10	101.53	100.07
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.17	0.17	0.17	0.18	0.18	0.17	0.17
K, wt% (±0.5 ug/g)	0.20	0.21	0.20	0.22	0.21	0.07	0.21
Particulate size distribution							
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #28, wt%	0.03	0.04	0.05	0.05	0.04	0.03	0.04
Particulate Left Mesh, #48, wt%	0.05	0.08	0.07	0.08	0.04	0.06	0.06
Particulate Left Mesh, #100, wt%	0.18	0.20	0.19	0.15	0.17	0.16	0.18
Particulate Left Mesh, #270, wt%	33.34	46.68	41.56	30.45	23.61	29.52	35.13
Particulate Left Mesh, #325, wt%	24.35	30.78	20.19	25.87	20.31	30.33	24.30
Bottom, wt%	40.75	22.18	36.64	42.10	55.54	38.60	39.44

JEA Northside Unit 2
Test #1-PITTSBURGH 8 Coal
SUMMARY FLYASH ANALYSES

Flyash	Unit #2 Jan. 14, 2004						
Lab Number / Time	31990-01 (Air heater) 10:00	31990-03 (Air heater) 11:05	31990-06 (Air heater) 12:03	31990-09 (Air heater) 13:06	31990-12 (Air heater) 14:00	32065-02B (Isokinetic)	Average Values
Unburned carbon, wt%	2.80	2.34	2.49	3.35	2.80	7.29	2.76
Compound analysis							
CaSO4, wt% (±0.2)	23.47	21.05	29.86	30.95	34.43	24.90	27.95
Sulfur, wt% (±0.09)	0.83	0.75	1.05	1.08	0.18	0.90	0.78
Ash compound analysis							
SiO2, wt% (±0.65)	0.20	0.17	0.30	0.25	0.33	0.15	0.25
SO3, wt% (±0.98)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fe2O3, wt% (±1.44)	68.80	69.29	69.12	68.08	69.17	58.73	68.89
CaO, wt% (±4.74) (Not Part of Norma	22.50	22.57	22.56	22.36	22.60	21.16	22.52
MgO, wt% (±1.25)	5.76	5.88	5.84	5.50	5.78	4.05	5.75
Na2O, wt% (±3.70)	2.48	2.19	2.21	3.01	2.20	7.87	2.42
K2O, wt% (±4.25)	1.63	1.37	1.45	2.06	1.45	8.25	1.59
Vanadium, wt% (±1.0)	0.30	0.27	0.26	0.26	0.24	0.12	0.27
Nickel, wt% (±1.0)	0.04	0.03	0.03	0.03	0.03	0.02	0.03
	101.70	101.77	101.76	101.56	101.80	100.35	101.71
Elemental analysis, AA							
Na, wt% (±0.5 ug/g)	0.06	0.05	0.05	0.07	0.05	0.18	0.05
K, wt% (±0.5 ug/g)	0.04	0.03	0.04	0.05	0.04	0.21	0.04
Particulate size distribution							
Particulate Left Mesh, #4, wt%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulate Left Mesh, #14, wt%	0.04	0.08	0.12	0.08	0.10	0.00	0.08
Particulate Left Mesh, #28, wt%	0.12	0.10	0.08	0.12	0.10	0.00	0.10
Particulate Left Mesh, #48, wt%	0.16	0.14	0.12	0.16	0.14	0.00	0.14
Particulate Left Mesh, #100, wt%	0.56	0.55	0.53	0.29	0.41	0.00	0.47
Particulate Left Mesh, #270, wt%	68.96	69.63	70.30	59.58	64.94	26.77	66.68
Particulate Left Mesh, #325, wt%	8.95	8.46	7.96	10.30	9.13	25.81	8.96
Bottom, wt%	21.13	20.97	20.81	29.30	25.06	41.61	23.45

ATTACHMENT K

Ambient Data, Jan. 13, 2004 & Jan. 14, 2004

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY MET DATA

Date:	**January 13, 2004**	**January 14, 2004**
Start:	**1100 hours**	**1000 hours**
End:	**1500 hours**	**1400 hours**

Characteristic Being Measured	Values Used in Efficiency Calculation	
Dry Bulb Temperature, North / South, deg F	61.0	62.78
Count	478	482
Standard Deviation	2.9707	4.8577
Wet Bulb Temperature, North / South, deg F	49.6	51.26
Count	478	482
Standard Deviation	1.7038	1.8616
Atmospheric Pressure, in Hg	30.43	30.24
Atmospheric Pressure, psia	14.9	14.8
Count	5	5
Standard Deviation	0.01207	0.02918

ATTACHMENT L

Ambient Data, Jan. 15, 2004 & Jan. 16, 2004

JEA Northside Unit 2
Test #1-Pittsburgh 8 Coal
SUMMARY MET DATA - PARTIAL LOADS

DATE	WET BULB, DEG F	DRY BULB, DEG F	PRESSURE, PSIA	RELATIVE HUMIDITY, %
JAN. 16, 2004	48	54	14.696	64.77
40% LOAD	47	53	14.696	64.12
	45	50	14.696	68.08
	44	50	14.696	62.03
	43	49	14.696	61.28
JAN. 16, 2004	54	60	14.696	68.21
60% LOAD	54	61	14.696	63.84
	53	59	14.696	67.68
	52	57	14.696	71.89
	52	57	14.696	71.89
JAN. 15, 2004	55	61	14.696	68.71
80% LOAD	56	62	14.696	69.20
	54	63	14.696	55.80
	54	62	14.696	59.71
	54	62	14.696	59.71

ATTACHMENT M

Ontario Hydro Mercury Emission Summary

Black & Veatch
Clean Air Project No. 9475-1
100% Pittsburgh No. 8 Coal

Ontario Hydro Mercury Emission Summary

JEA Northside Generating Station - Unit 2

Run No.	Particulate Bound Hg^{tp} (lb/hr)	Separate Oxidized Hg^{2+} (lb/hr)	Separate Elemental Hg^{0} (lb/hr)	Total Mercury Hg^{Total} (lb/hr)
SDA Inlet Run 1	0.033263	0.000361	0.008258	0.041882
SDA Inlet Run 2	0.023739	0.001389	0.005065	0.030193
SDA Inlet Run 3	0.035793	0.000295	0.008621	0.044709
Average	**0.030932**	**0.000682**	**0.007315**	**0.038928**
Stack Run 1	0.000021	0.000021	0.005545	0.005566
Stack Run 2	0.000021	0.000021	0.007509	0.007530
Stack Run 3	0.000021	0.000063	0.005125	0.005146
Average	**0.000021**	**0.000035**	**0.006060**	**0.006081**
Removal Efficiency (%)	**99.93%**	**94.87%**	**17.16%**	**84.38%**

Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters
Total Mercury (Hg^{Total}) Results

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.8000	4.6000	4.8000	**4.7333**
CO_2	Carbon dioxide (dry volume %)	14.1000	14.3000	14.1000	**14.1667**
T_s	Sample temperature (°F)	317.6250	319.2500	317.5417	**318.1389**
B_w	Actual water vapor in gas (% by volume)	8.3739	7.9066	7.4743	**7.9183**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	976,004	971,461	988,368	**978,611**
Q_s	Volumetric flow rate, standard (scfm)	630,041	625,639	637,925	**631,202**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	577,282	576,172	590,245	**581,233**
Q_a	Volumetric flow rate, actual (acf/hr)	58,560,246	58,287,688	59,302,059	**58,716,664**
Q_s	Volumetric flow rate, standard (scf/hr)	37,802,449	37,538,334	38,275,518	**37,872,100**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	34,636,927	34,570,337	35,414,675	**34,873,980**
Q_a	Volumetric flow rate, actual (m^3/hr)	1,658,461	1,650,742	1,679,469	**1,662,891**
Q_s	Volumetric flow rate, standard (m^3/hr)	1,070,588	1,063,108	1,083,985	**1,072,560**
Q_{std}	Volumetric flow rate, dry standard (dry m^3/hr)	980,938	979,052	1,002,964	**987,652**
Q_s	Volumetric flow rate, normal (Nm^3/hr)	997,593	990,623	1,010,077	**999,431**
Q_{std}	Volumetric flow rate, dry normal (Nm^3/hr)	914,056	912,299	934,581	**920,312**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	82.4059	85.6378	84.7806	**84.2748**
%I	Isokinetic sampling (%)	100.5579	104.7030	101.1837	**102.1482**
Laboratory Data					
$Hg_{particle}$	Total Particulate Bound Mercury (µg)	35.8900	26.6700	38.8600	**33.8067**
Hg_O	Total Oxidized Mercury (µg)	0.3900	1.5600	0.3200	**0.7567**
Hg_E	Total Elemental Mercury (µg)	8.9100	5.6900	9.3600	**7.9867**
m_n	Total Mercury (µg)	45.1900	33.9200	48.5400	**42.5500**
Total Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.2092E-09	8.7337E-10	1.2624E-09	**1.1150E-09**
C_a	Concentration (lb/acf)	7.1520E-10	5.1800E-10	7.5392E-10	**6.6237E-10**
C_{sd}	Concentration (µg/dscm)	1.9363E+01	1.3986E+01	2.0216E+01	**1.7855E+01**
C_{sd}	Concentration (mg/dscm)	1.9363E-02	1.3986E-02	2.0216E-02	**1.7855E-02**
C_a	Concentration (µg/m^3 (actual,wet))	1.1453E+01	8.2950E+00	1.2073E+01	**1.0607E+01**
C_{sd}	Concentration (µg/Nm^3 dry)	2.0780E+01	1.5009E+01	2.1696E+01	**1.9162E+01**
$E_{lb/hr}$	Rate (lb/hr)	4.1882E-02	3.0193E-02	4.4709E-02	**3.8928E-02**
$E_{g/s}$	Rate (g/s)	5.2762E-03	3.8036E-03	5.6323E-03	**4.9040E-03**
$E_{T/yr}$	Rate (Ton/yr)	1.8345E-01	1.3224E-01	1.9583E-01	**1.7050E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.5352E-05	1.0952E-05	1.6028E-05	**1.4110E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.5436E-05	1.0993E-05	1.6116E-05	**1.4182E-05**

020604 131326

N K Q @_O

Prepared by Clean Air Engineering Proprietary Software
SS OntHydro-1 Version 12-2003a

QA/QC _________
Date _________

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Particulate Bound (Hg^{tp}) Results

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	9.6034E-10	6.8670E-10	1.0107E-09	**8.8591E-10**
C_a	Concentration (lb/acf)	5.6802E-10	4.0728E-10	6.0357E-10	**5.2629E-10**
C_{sd}	Concentration (µg/dscm)	1.5378E+01	1.0997E+01	1.6185E+01	**1.4187E+01**
C_{sd}	Concentration (mg/dscm)	1.5378E-02	1.0997E-02	1.6185E-02	**1.4187E-02**
C_a	Concentration (µg/m^3 (actual,wet))	9.0960E+00	6.5220E+00	9.6653E+00	**8.4278E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	1.6504E+01	1.1801E+01	1.7369E+01	**1.5225E+01**
$E_{lb/hr}$	Rate (lb/hr)	3.3263E-02	2.3739E-02	3.5793E-02	**3.0932E-02**
$E_{g/s}$	Rate (g/s)	4.1904E-03	2.9906E-03	4.5091E-03	**3.8967E-03**
$E_{T/yr}$	Rate (Ton/yr)	1.4569E-01	1.0398E-01	1.5677E-01	**1.3548E-01**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.2192E-05	8.6112E-06	1.2831E-05	**1.1212E-05**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.2260E-05	8.6438E-06	1.2902E-05	**1.1269E-05**

020604 131326
N K Q @_O

QA/QC _________
Date _________

Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Oxidized (Hg^{2+}) Results

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.0436E-11	4.0167E-11	8.3227E-12	**1.9642E-11**
C_a	Concentration (lb/acf)	6.1724E-12	2.3823E-11	4.9702E-12	**1.1655E-11**
C_{sd}	Concentration (µg/dscm)	1.6711E-01	6.4322E-01	1.3328E-01	**3.1453E-01**
C_{sd}	Concentration (mg/dscm)	1.6711E-04	6.4322E-04	1.3328E-04	**3.1453E-04**
C_a	Concentration (µg/m^3 (actual,wet))	9.8842E-02	3.8149E-01	7.9591E-02	**1.8664E-01**
C_{sd}	Concentration (µg/Nm^3 dry)	1.7934E-01	6.9028E-01	1.4303E-01	**3.3755E-01**
$E_{lb/hr}$	Rate (lb/hr)	3.6146E-04	1.3886E-03	2.9474E-04	**6.8159E-04**
$E_{g/s}$	Rate (g/s)	4.5535E-05	1.7493E-04	3.7131E-05	**8.5865E-05**
$E_{T/yr}$	Rate (Ton/yr)	1.5832E-03	6.0820E-03	1.2910E-03	**2.9854E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.3249E-07	5.0369E-07	1.0566E-07	**2.4728E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.3322E-07	5.0560E-07	1.0625E-07	**2.4835E-07**

020604 131326
N K Q @_O

QA/QC _________
Date _________

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Elemental (Hg^0) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:44	18:08	20:47	
Elemental Mercury Results					
C_{sd}	Concentration (lb/dscf)	2.3841E-10	1.4651E-10	2.4344E-10	**2.0945E-10**
C_a	Concentration (lb/acf)	1.4101E-10	8.6892E-11	1.4538E-10	**1.2443E-10**
C_{sd}	Concentration (µg/dscm)	3.8178E+00	2.3461E+00	3.8983E+00	**3.3541E+00**
C_{sd}	Concentration (mg/dscm)	3.8178E-03	2.3461E-03	3.8983E-03	**3.3541E-03**
C_a	Concentration (µg/m^3 (actual,wet))	2.2582E+00	1.3915E+00	2.3280E+00	**1.9926E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	4.0972E+00	2.5178E+00	4.1836E+00	**3.5995E+00**
$E_{lb/hr}$	Rate (lb/hr)	8.2579E-03	5.0648E-03	8.6213E-03	**7.3146E-03**
$E_{g/s}$	Rate (g/s)	1.0403E-03	6.3804E-04	1.0861E-03	**9.2147E-04**
$E_{T/yr}$	Rate (Ton/yr)	3.6169E-02	2.2184E-02	3.7761E-02	**3.2038E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	3.0268E-06	1.8372E-06	3.0906E-06	**2.6515E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	3.0436E-06	1.8441E-06	3.1077E-06	**2.6651E-06**

020604 131326
N K Q @_O

QA/QC _________
Date _________

Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters
Total Mercury (Hg^{Total}) Results

Run No.		1	2	3	Average
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.2000	5.4000	5.8000	**5.4667**
CO_2	Carbon dioxide (dry volume %)	13.4000	13.5000	13.2000	**13.3667**
T_s	Sample temperature (°F)	240.7083	250.2083	234.0000	**241.6389**
B_w	Actual water vapor in gas (% by volume)	10.5308	10.6940	9.9813	**10.4020**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	907,511	913,697	899,844	**907,017**
Q_s	Volumetric flow rate, standard (scfm)	685,928	681,365	686,707	**684,667**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	613,694	608,500	618,165	**613,453**
Q_a	Volumetric flow rate, actual (acf/hr)	54,450,670	54,821,797	53,990,630	**54,421,032**
Q_s	Volumetric flow rate, standard (scf/hr)	41,155,683	40,881,928	41,202,426	**41,080,012**
Q_{std}	Volumetric flow rate, dry standard (dscf/hr)	36,821,650	36,510,025	37,089,874	**36,807,183**
Q_a	Volumetric flow rate, actual (m^3/hr)	1,542,075	1,552,586	1,529,046	**1,541,236**
Q_s	Volumetric flow rate, standard (m^3/hr)	1,165,553	1,157,800	1,166,877	**1,163,410**
Q_{std}	Volumetric flow rate, dry standard (dry m^3/hr)	1,042,811	1,033,985	1,050,407	**1,042,401**
Q_s	Volumetric flow rate, normal (Nm^3/hr)	1,086,084	1,078,859	1,087,317	**1,084,087**
Q_{std}	Volumetric flow rate, dry normal (Nm^3/hr)	971,710	963,486	978,788	**971,328**
Sampling Data					
V_{mstd}	Volume metered, standard (dscf)	77.4613	77.8307	77.5580	**77.6167**
%I	Isokinetic sampling (%)	99.6342	100.9638	99.0372	**99.8784**
Laboratory Data					
$Hg_{particle}$	Total Particulate Bound Mercury (µg)	0.0200	0.0200	0.0200	**0.0200**
Hg_O	Total Oxidized Mercury (µg)	<0.0200	<0.0200	<0.0600	**<0.0333**
Hg_E	Total Elemental Mercury (µg)	5.2900	7.2600	4.8600	**5.8033**
m_n	Total Mercury (µg)	5.3100	7.2800	4.8800	**5.8233**
Total Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.5115E-10	2.0625E-10	1.3874E-10	**1.6538E-10**
C_a	Concentration (lb/acf)	1.0222E-10	1.3736E-10	9.5310E-11	**1.1163E-10**
C_{sd}	Concentration (µg/dscm)	2.4205E+00	3.3028E+00	2.2217E+00	**2.6483E+00**
C_{sd}	Concentration (mg/dscm)	2.4205E-03	3.3028E-03	2.2217E-03	**2.6483E-03**
C_a	Concentration (µg/m^3 (actual,wet))	1.6368E+00	2.1996E+00	1.5263E+00	**1.7876E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	2.5976E+00	3.5444E+00	2.3843E+00	**2.8421E+00**
$E_{lb/hr}$	Rate (lb/hr)	5.5657E-03	7.5301E-03	5.1458E-03	**6.0806E-03**
$E_{g/s}$	Rate (g/s)	7.0115E-04	9.4862E-04	6.4826E-04	**7.6601E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.4378E-02	3.2982E-02	2.2539E-02	**2.6633E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.9679E-06	2.7198E-06	1.8781E-06	**2.1886E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.0304E-06	2.7500E-06	1.8919E-06	**2.2241E-06**

020604 131326

N P K @_O

Prepared by Clean Air Engineering Proprietary Software
SS OntHydro-1 Version 12-2003a

QA/QC _________
Date _________

Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Particulate Bound (Hg^{tp}) Results

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Particulate Bound Mercury Results					
C_{sd}	Concentration (lb/dscf)	5.6932E-13	5.6661E-13	5.6861E-13	**5.6818E-13**
C_a	Concentration (lb/acf)	3.8499E-13	3.7735E-13	3.9061E-13	**3.8432E-13**
C_{sd}	Concentration (µg/dscm)	9.1168E-03	9.0735E-03	9.1054E-03	**9.0986E-03**
C_{sd}	Concentration (mg/dscm)	9.1168E-06	9.0735E-06	9.1054E-06	**9.0986E-06**
C_a	Concentration (µg/m^3 (actual,wet))	6.1651E-03	6.0428E-03	6.2552E-03	**6.1544E-03**
C_{sd}	Concentration (µg/Nm^3 dry)	9.7839E-03	9.7375E-03	9.7717E-03	**9.7643E-03**
$E_{lb/hr}$	Rate (lb/hr)	2.0963E-05	2.0687E-05	2.1090E-05	**2.0913E-05**
$E_{g/s}$	Rate (g/s)	2.6409E-06	2.6061E-06	2.6568E-06	**2.6346E-06**
$E_{T/yr}$	Rate (Ton/yr)	9.1819E-05	9.0610E-05	9.2372E-05	**9.1600E-05**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	7.4121E-09	7.4721E-09	7.6970E-09	**7.5270E-09**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	7.6475E-09	7.5549E-09	7.7537E-09	**7.6520E-09**

020604 131326

N P K @_O

QA/QC _________
Date _________

Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Oxidized (Hg^{2+}) Results

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Oxidized Mercury Results					
C_{sd}	Concentration (lb/dscf)	<5.6932E-13	<5.6661E-13	<1.7058E-12	**<9.4725E-13**
C_a	Concentration (lb/acf)	<3.8499E-13	<3.7735E-13	<1.1718E-12	**<6.4473E-13**
C_{sd}	Concentration (µg/dscm)	<9.1168E-03	<9.0735E-03	<2.7316E-02	**<1.5169E-02**
C_{sd}	Concentration (mg/dscm)	<9.1168E-06	<9.0735E-06	<2.7316E-05	**<1.5169E-05**
C_a	Concentration (µg/m^3 (actual,wet))	<6.1651E-03	<6.0428E-03	<1.8765E-02	**<1.0324E-02**
C_{sd}	Concentration (µg/Nm^3 dry)	<9.7839E-03	<9.7375E-03	<2.9315E-02	**<1.6279E-02**
$E_{lb/hr}$	Rate (lb/hr)	<2.0963E-05	<2.0687E-05	<6.3269E-05	**<3.4973E-05**
$E_{g/s}$	Rate (g/s)	<2.6409E-06	<2.6061E-06	<7.9703E-06	**<4.4058E-06**
$E_{T/yr}$	Rate (Ton/yr)	<9.1819E-05	<9.0610E-05	<2.7712E-04	**<1.5318E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.4121E-09	<7.4721E-09	<2.3091E-08	**<1.2658E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.6475E-09	<7.5549E-09	<2.3261E-08	**<1.2821E-08**

020604 131326
N P K @_O

QA/QC _________
Date _________

Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Ontario Hydro
Mercury (Hg) Emission Parameters (continued)
Separate Elemental (Hg^0) Results

Run No.		**1**	**2**	**3**	**Average**
Date (2004)		Jan 13	Jan 13	Jan 13	
Start Time (approx.)		11:19	15:50	18:40	
Stop Time (approx.)		14:42	18:00	20:45	
Elemental Mercury Results					
C_{sd}	Concentration (lb/dscf)	1.5058E-10	2.0568E-10	1.3817E-10	**1.6481E-10**
C_a	Concentration (lb/acf)	1.0183E-10	1.3698E-10	9.4919E-11	**1.1124E-10**
C_{sd}	Concentration (µg/dscm)	2.4114E+00	3.2937E+00	2.2126E+00	**2.6392E+00**
C_{sd}	Concentration (mg/dscm)	2.4114E-03	3.2937E-03	2.2126E-03	**2.6392E-03**
C_a	Concentration (µg/m^3 (actual,wet))	1.6307E+00	2.1935E+00	1.5200E+00	**1.7814E+00**
C_{sd}	Concentration (µg/Nm^3 dry)	2.5878E+00	3.5347E+00	2.3745E+00	**2.8324E+00**
$E_{lb/hr}$	Rate (lb/hr)	5.5448E-03	7.5094E-03	5.1248E-03	**6.0596E-03**
$E_{g/s}$	Rate (g/s)	6.9851E-04	9.4601E-04	6.4560E-04	**7.6337E-04**
$E_{T/yr}$	Rate (Ton/yr)	2.4286E-02	3.2891E-02	2.2446E-02	**2.6541E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.9605E-06	2.7124E-06	1.8704E-06	**2.1811E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.0228E-06	2.7424E-06	1.8842E-06	**2.2164E-06**

020604 131326
N P K @_O

QA/QC _________
Date _________

Black and Veatch
Clean Air Project No: 9475-1
SDA Inlet - 100% Pittsburgh 8

Mercury Laboratory Data - Data Entry Sheet

☐ DRAFT LAB DATA

Mercury	Units	Detection Limit	Blank (as-rcvd)	Run 1	Run 2	Run 3
Hg_{ash}-Filter Fraction	**µg**	0.0100		34.0000	24.9000	36.0000
Hg_{pr}-Probe Rinse Fraction	**µg**	0.0100		1.9100	1.7900	2.8800
Hg_{KCl}-KCl Fraction	**µg**	0.0200		0.5300	1.7000	0.4600
Hg_{H2O2}-HNO3-H2O2 Fraction	**µg**	0.0200		18.3000	15.5000	19.7000
Hg_{KMnO4}-KMnO4 Fraction	**µg**	0.0300		1.5300	1.1100	0.5800
V_{3a}-As-received Volume of KCl Blank	**ml**		300.0			
V_{5a}-As-received volume of HNO3-H2O2 Blank	**ml**		100.0			
V_{7a}-As-received volume of H2SO4-KMnO4 Blank	**ml**		300.0			
V_3-Volume of KCl charged to impingers	**ml**			300.0	300.0	300.0
V_5-Volume of HNO3-H2O2 charged to impingers	**ml**			100.0	100.0	100.0
V_7-Volume of H2SO4-KMnO4 charged to impingers	**ml**			300.0	300.0	300.0
Hg_{fb}-Filter Blank	**µg**		0.0200	0.0200	0.0200	0.0200
Hg_{Ob}-KCl Solution Blank	**µg**		0.1400	0.1400	0.1400	0.1400
Hg_{Eb1}-HNO3-H2O2 Blank	**µg**		**10.8000**	10.8000	10.8000	10.8000
Hg_{Eb2}-KMnO4 Blank	**µg**		0.1200	0.1200	0.1200	0.1200

Notes:
"<" indicates result below reported minimum detection limit.

Solution blank values are derived by multiplying the as-received blank value by the ratio of the impinger charge volume to the as-received volume.

020604 134833
O

Black and Veatch
Clean Air Project No: 9475-1
Stack - 100% Pittsburgh 8

Mercury Laboratory Data - Data Entry Sheet

☐ DRAFT LAB DATA

Mercury	Units	Detection Limit	Blank (as-rcvd)	Run 1	Run 2	Run 3
Hg_{ash}-Filter Fraction	µg	0.0100		0.0200	0.0200	0.0200
Hg_{pr}-Probe Rinse Fraction	µg	0.0100		<0.0100	<0.0100	<0.0100
Hg_{KCl}-KCl Fraction	µg	0.0200		0.0900	0.0800	<0.0600
Hg_{H2O2}-HNO3-H2O2 Fraction	µg	0.0200		17.9000	20.4000	17.9000
Hg_{KMnO4}-KMnO4 Fraction	µg	0.0300		0.7600	0.2300	0.3300
V_{3a}-As-received Volume of KCl Blank	ml		300.0			
V_{5a}-As-received volume of HNO3-H2O2 Blank	ml		100.0			
V_{7a}-As-received volume of H2SO4-KMnO4 Blank	ml		300.0			
V_3-Volume of KCl charged to impingers	ml			300.0	300.0	300.0
V_5-Volume of HNO3-H2O2 charged to impingers	ml			100.0	100.0	100.0
V_7-Volume of H2SO4-KMnO4 charged to impingers	ml			300.0	300.0	300.0
Hg_{fb}-Filter Blank	µg		<0.0100	<0.0100	<0.0100	<0.0100
Hg_{Ob}-KCl Solution Blank	µg		0.9800	0.9800	0.9800	0.9800
Hg_{Eb1}-HNO3-H2O2 Blank	µg		**13.2000**	13.2000	13.2000	13.2000
Hg_{Eb2}-KMnO4 Blank	µg		0.1700	0.1700	0.1700	0.1700

Notes:
"<" indicates result below reported minimum detection limit.

Solution blank values are derived by multiplying the as-received blank value by the ratio of the impinger charge volume to the as-received volume.

020604 134833
O

FIGURES

DWG40998 03-MAR-2004 14:48:45

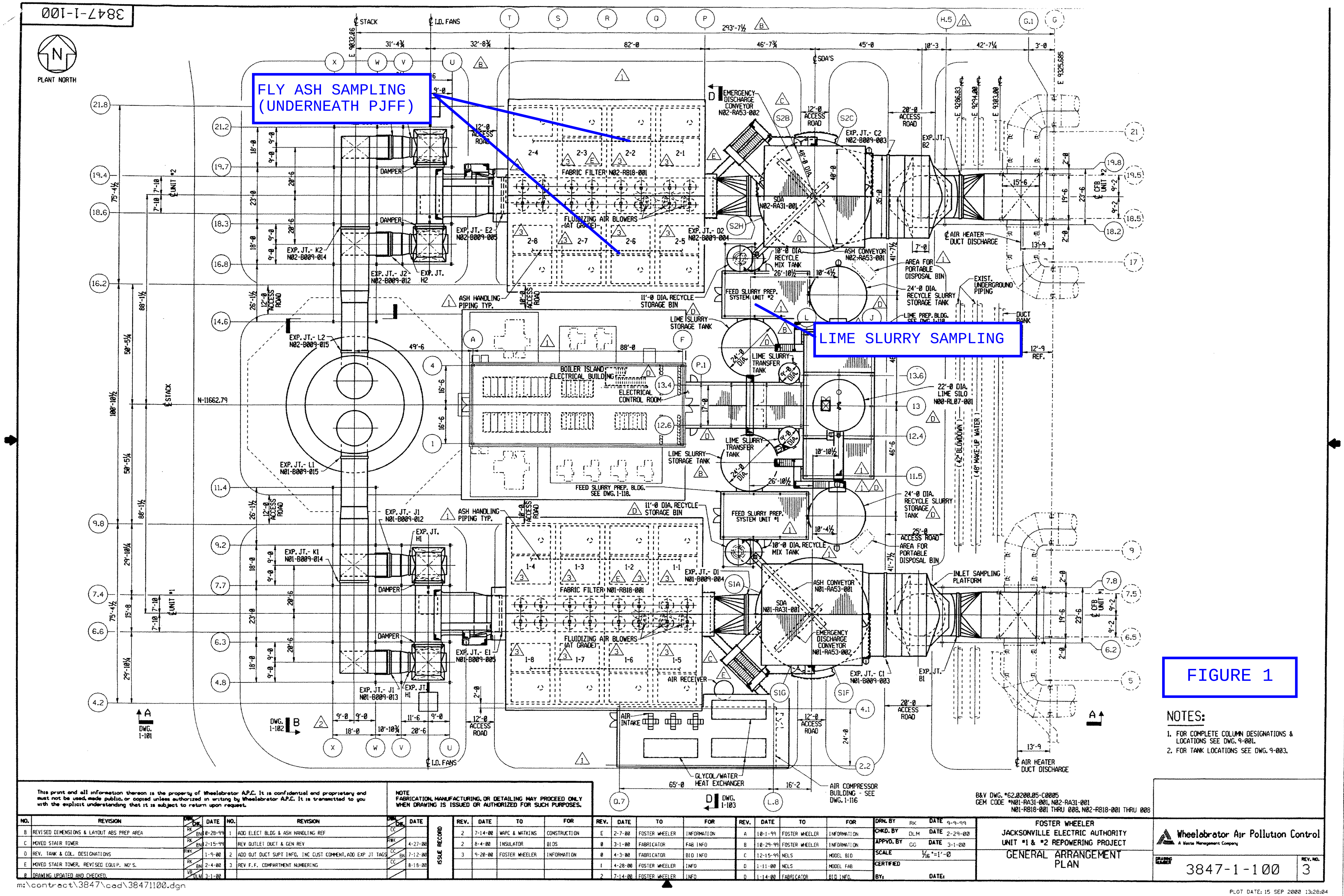
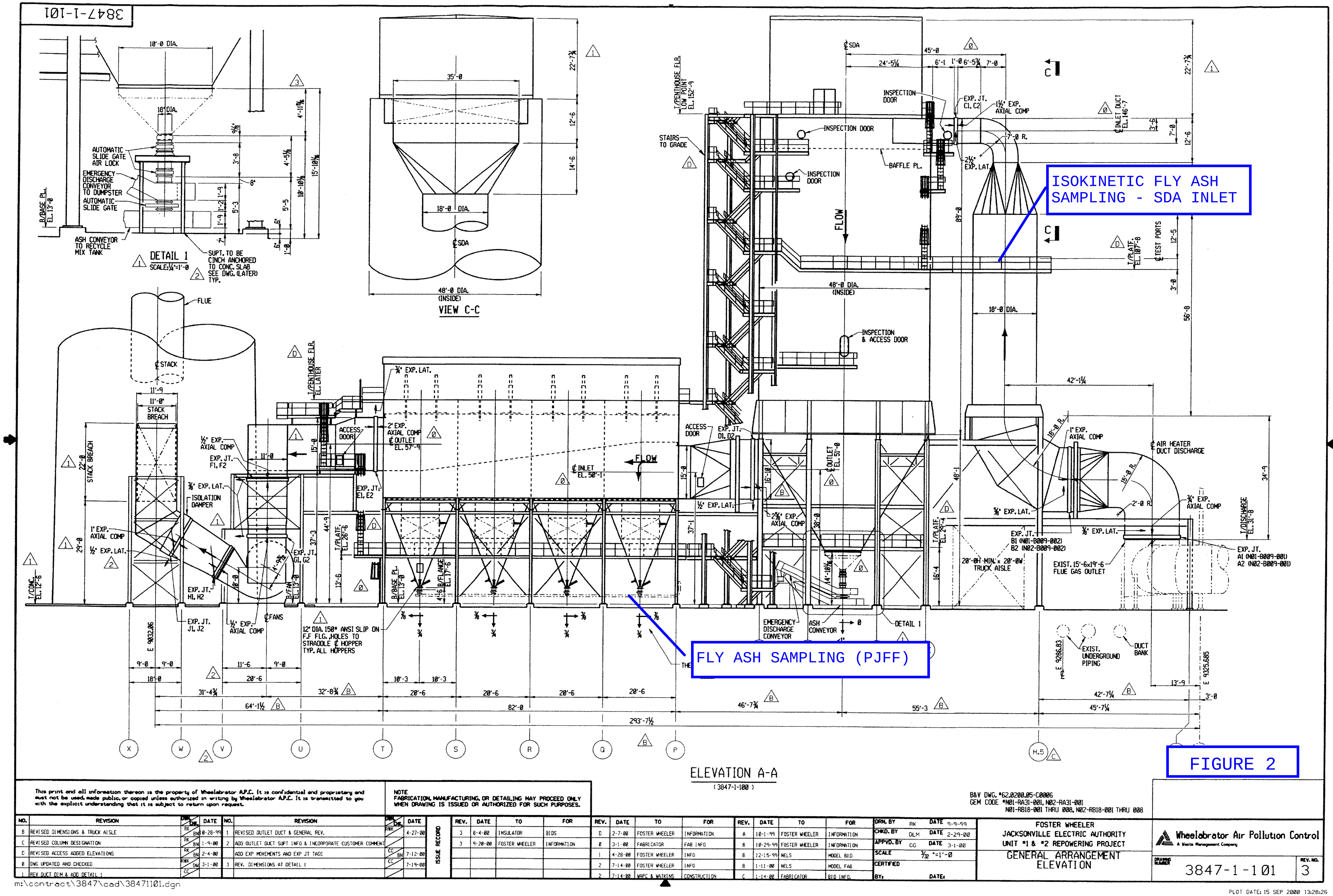


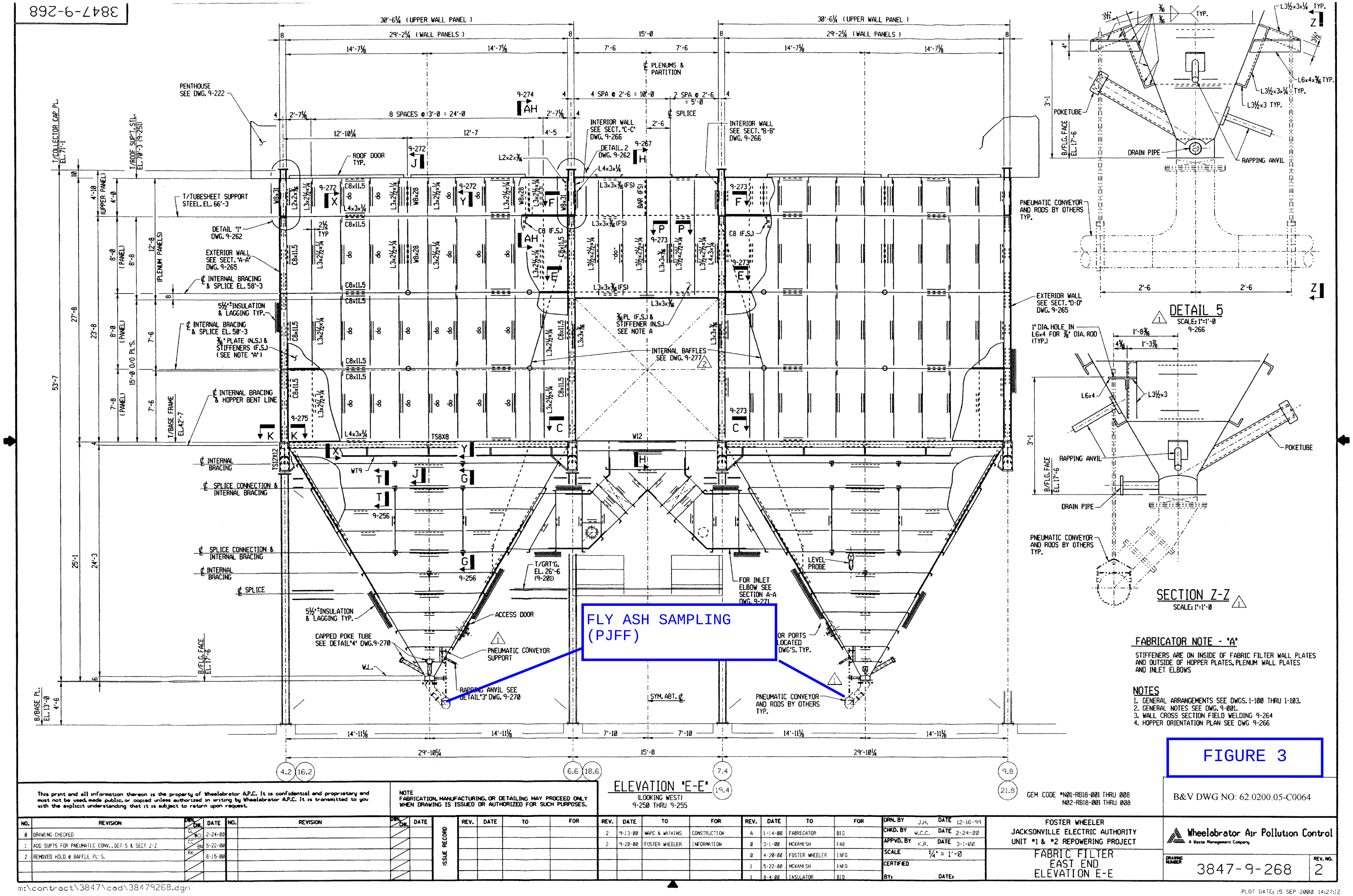
FIGURE 1

DWG40998 03-MAR-2004 14:47:11



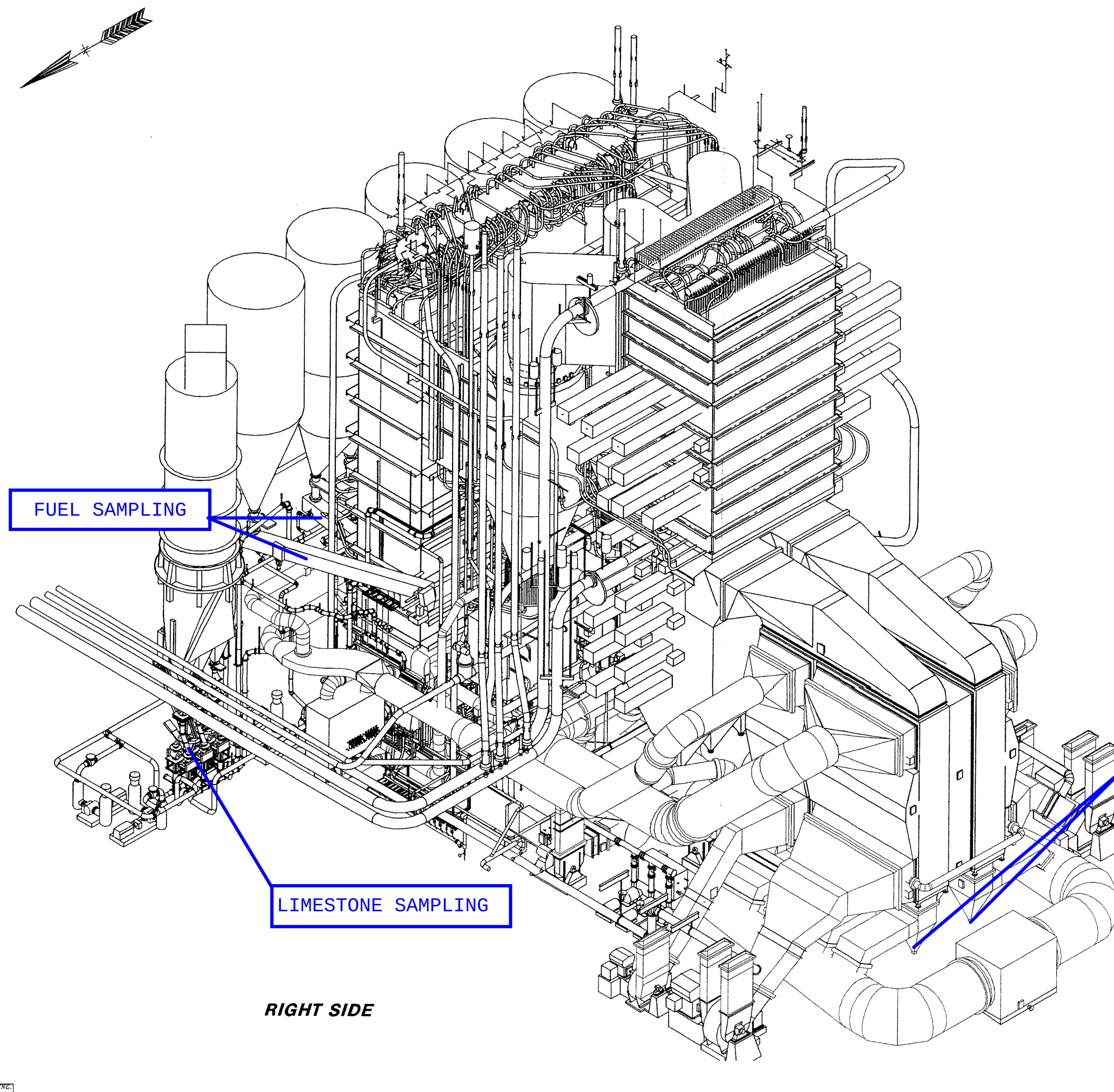
P062713.62.0200.05-C0006 St:NE 11/21/00 MM-01186

DWG40998 03-MAR-2004 14:42:45



P062713.62.0200.05-C0064 St:NE 11/21/00 MM-01179

DWG40998 03-MAR-2004 14:21:50



NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. FOR ADDITIONAL NOTES & REFERENCE DRAWINGS SEE DRAWING 43-7587-5-50

B&V Dwg No: 62.3401.05-C0012

REV.	DATE	DR.	DESCRIPTION
C	6-23-00	JHM	UPDATED DRAWING
B	5-26-99	JHM	DESIGN UPDATE
A	3-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
ISO VIEW (RIGHT SIDE)

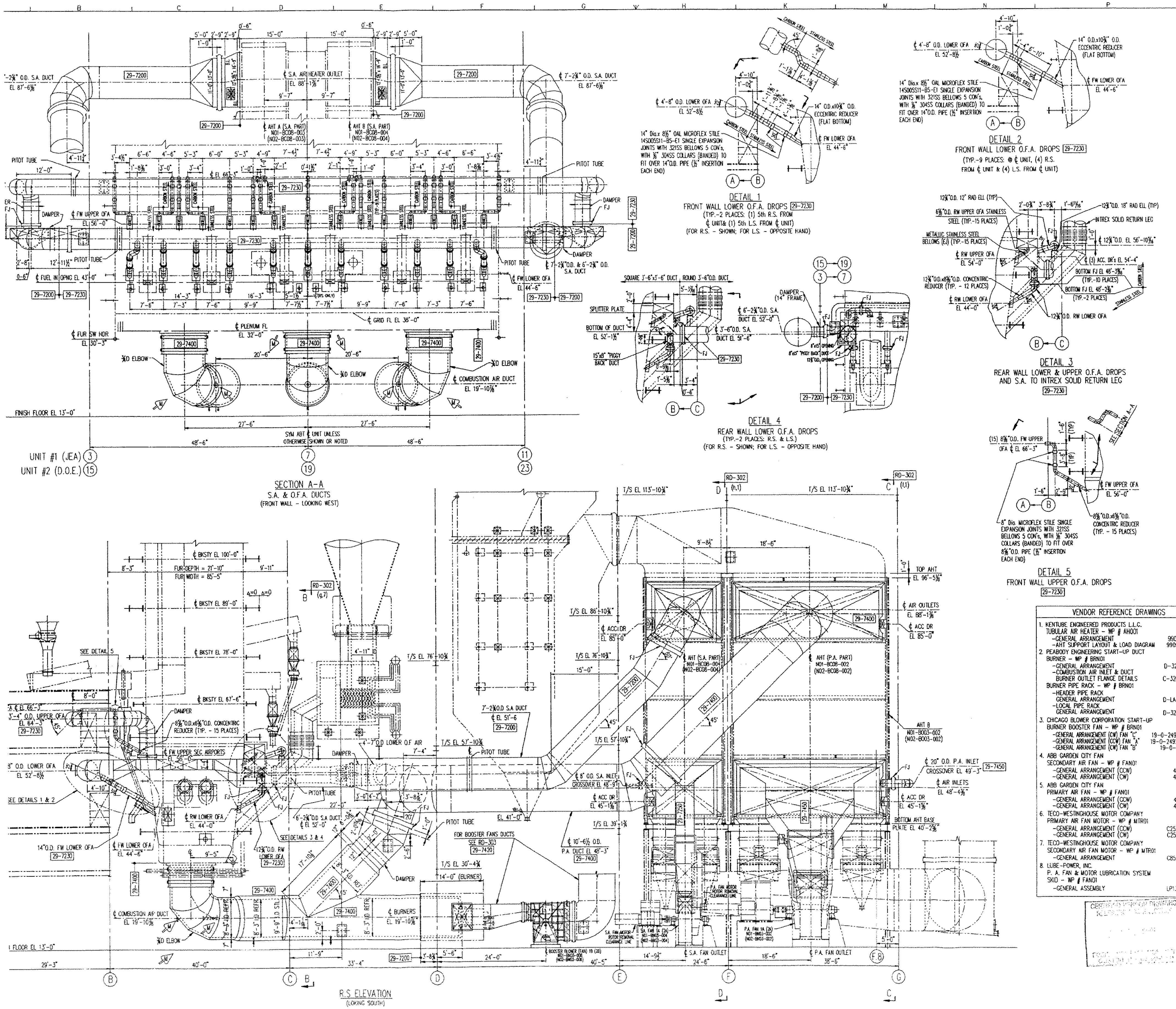
NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.:
B&V Drawing No.: 62.3401.05-C0012

FIGURE 4

DRAWING NUMBER 43-7587-5-53 REVISION C

DRAWN BY JHM 3-16-99 200758700 UNIT 2 DOE
CHECKED BY 200761000 UNIT 1 JEA
APPROVED BY

FOSTER WHEELER ENERGY CORPORATION



NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. UNLESS OTHERWISE SPECIFIED, ALL CLEARANCE LINES FOR DUCTS AND FLUES SHALL BE AS FOLLOWS:
   a) DUCTS & FLUES – 18", UNLESS NOTED;
   b) AIR HEATERS, FANS & DUST COLLECTORS – 18";
   c) EXP. JOINTS & DAMPERS – 30" FOR A LENGTH OF 24" EITHER SIDE OF JOINT OR DAMPER.
4. FWEC DENOTES FOSTER WHEELER ENERGY CORPORATION WORK TERMINATES; VD– DENOTES VENDOR REF. DWG.
5. ALL DIMENSIONS ARE TO INSIDE OF PLATE UNLESS OTHERWISE NOTED.
6. ALL ROUND MITERED DUCT ELBOWS RADIUS EQUAL ONE DIAMETR OF DUCT OR FLUE (R=1D) UNLESS OTHERWISE NOTED.
7. FOR PLATE THICKNESS, PLATE MATERIAL & EXPANSION JOINT INFORMATION REFER TO FLUE & DUCT ASSEMBLY DRAWINGS BEGINNING WITH DRAWING 43-7587-5-310, WHEN ISSUED.
8. ALL ACCESS DOORS ARE 18"x24"(H).

FWEC REFERENCE DRAWINGS

1. GENERAL ARRANGEMENT CROSS SECTION — 43-7587-5-20
2. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS A-A & B-B — 43-7587-5-21
3. GENERAL ARRANGEMENT LONGITUDINAL SECTIONS C-C & D-D — 43-7587-5-22
4. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS PLAN VIEW — 43-7587-5-301
5. ARRANGEMENT AUXILLIARY EQUIPMENT SECONDARY AIR, PRIMARY AIR DUCTS SECTIONS B-B, C-C, D-D AND VIEWS — 43-7587-5-302
6. ARRANGEMENT AUXILLIARY EQUIPMENT BURNER BOOSTER BLOWERS (FANS) LAYOUT. PLAN VIEW & SECTIONS — 43-7587-5-303
7. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEW @ AHT TOP, R.S. ELEVATION AND VIEWS A-A & B-B — 43-7587-5-304
8. ARRANGEMENT AUXILLIARY EQUIPMENT BOILER EXIT/AHT & AHT/FWEC TERMINAL FLUE PLAN VIEWS C-C & @ AHT SUPPORT LEVEL AND DETAILS — 43-7587-5-305
9. INSTRUMENT LOCATION PLANS — 43-7587-5-6400 THRU 6404, 6406, 6408, 6411, 6413 THRU 6419

VENDOR REFERENCE DRAWINGS

1. KENTUBE ENGINEERED PRODUCTS L.L.C.
   TUBULAR AIR HEATER – WP # AH001
   - GENERAL ARRANGEMENT — 99091-1
   - AHT SUPPORT LAYOUT & LOAD DIAGRAM — 99091-2
2. PEABODY ENGINEERING START-UP DUCT
   BURNER – WP # BRN01
   - GENERAL ARRANGEMENT — D-326001
   - COMBUSTION AIR INLET & DUCT BURNER OUTLET FLANGE DETAILS — C-326004
   BURNER PIPE RACK – WP # BRN01
   - HEADER PIPE RACK GENERAL ARRANGEMENT — D-LATER
   - LOCAL PIPE RACK GENERAL ARRANGEMENT — D-326036
3. CHICAGO BLOWER CORPORATION START-UP
   BURNER BOOSTER FAN – WP # BRN01
   - GENERAL ARRANGEMENT (CW) FAN "C" — 19-0-2492-01
   - GENERAL ARRANGEMENT (CCW) FAN "A" — 19-0-2492-02
   - GENERAL ARRANGEMENT (CW) FAN "B" — 19-0-2493
4. ABB GARDEN CITY FAN
   SECONDARY AIR FAN – WP # FAN01
   - GENERAL ARRANGEMENT (CCW) — 43092
   - GENERAL ARRANGEMENT (CW) — 43093
5. ABB GARDEN CITY FAN
   PRIMARY AIR FAN – WP # FAN01
   - GENERAL ARRANGEMENT (CCW) — 43104
   - GENERAL ARRANGEMENT (CW) — 43105
6. TECO-WESTINGHOUSE MOTOR COMPANY
   PRIMARY AIR FAN MOTOR – WP # MTR01
   - GENERAL ARRANGEMENT (CCW) — C2534AA
   - GENERAL ARRANGEMENT (CW) — C2534AB
7. TECO-WESTINGHOUSE MOTOR COMPANY
   SECONDARY AIR FAN MOTOR – WP # MTR01
   - GENERAL ARRANGEMENT — C8550AA
8. LUBE-POWER, INC.
   P. A. FAN & MOTOR LUBRICATION SYSTEM SKID – WP # FAN01
   - GENERAL ASSEMBLY — LP1354-A

REVISIONS

REV.	DATE	DR.	DESCRIPTION
M	03-20-01	AGS	REVISED LOCATION OF RIGHT AND LEFT SIGHT GLASS PORTS AT COMBUSTION AIR DUCTS @ SECTION A-A AND RIGHT SIDE ELEVATION.
L	02-28-01	AGS	DELETED "HOLD!" FROM COMBUSTION AIR DUCT AND ADDED (2) ACCESS DOOR AND DIMENSIONS TO IT AS SHOWN AT RIGHT SIDE ELEVATION.
K	07-12-00	AGS	ADDED VENDOR REFERENCE DRAWINGS VRD-8.
J	06-22-00	AGS	REVISED TAG NUMBER FOR BURNER BOOSTER FAN "B", S.A. & P.A. FANS @ R.S. ELEVATION. ADDED FWEC REFERENCE DRAWINGS RD-9. REVISED VENDOR REFERENCE DRAWINGS VRD-3. ADDED VENDOR REFERENCE DRAWINGS: PEABODY BURNER PIPE RACKS DRAWINGS. UPDATED BOOSTER BLOWER INLET & OUTLET DUCTING AND BOOSTER BLOWERS PICTURES ACCORDING TO ACTUAL PURCHASED FANS. PURCHASED FANS @ R.S. ELEVATION. REVISED DIMENSION 24'-0" (WAS 24'-6") FOR BOOSTER BLOWER "B" FROM ℄ TO COLUMN "D" @ R.S. ELEVATION.
H	03-08-00	AGS	REVISED SOME (8 of 15) FRONT WALL UPPER O.F.A. DROPS (8⅝" O.D. PIPE) AT R.S. ELEVATION, SECTION A-A & DETAIL 5.
G	02-08-00	AGS	CORRECTED FWUSA TAG No's FOR Pri. & Sec. AHT PARTS.
F	02-04-00	AGS	ADDED P.A. FAN MOTOR VENDOR REFERENCE DRAWINGS. REVISED START-UP BURNER BOOSTER FAN VENDOR REFERENCE DRAWING NUMBERS. DELETED "HOLD" @ P.A. & S.A. FAN MOTORS & REVISED P.A. & S.A. FAN MOTORS PICTURES AT RIGHT SIDE ELEVATION. ADDED PART No.'s FOR DUCTS.
E	11-24-99	AGS	ADDED NOTE 8. REVISED DIMENSION BETWEEN COLUMNS "F.8" & "G": 5'-0" (WAS 6'-0") @ R.S. ELEVATION. ADDED P.A. FAN VENDOR REFERENCE DRAWING NUMBERS. REVISED P.A. FAN PICTURE TO INCLUDE ACTUAL PURCHASED FAN @ R.S. ELEVATION. ADDED DETAIL 5. REVISED SIZE OF FW UPPER OFA DROPS EXPANSION JOINTS: TOGGLE SECTION WITH (2) TWO METALLIC BELLOWS (WAS (1) ONE FABRIC EJ) @ R.S. ELEVATION & SECTION A-A.
D	11-08-99	AGS	ADDED VENDOR REFERENCE DRAWINGS. ADDED FWEC REFERENCE DRAWINGS No.'s 6, 7 & 8. ADDED S.A. DUCTS TO INTREX SOLID RETURN LEG. ADDED P.A. & S.A. AHT INLET DUCT CROSSOVERS. REVISED SIZE OF FW LOWER OFA DROPS: 14" O.D. (WAS 16" O.D.). ADDED DETAILS 1 THRU 4. REVISED DIMENSIONS AND ADDED DETAILS INFO WHERE INDICATED IN FIELD OF DRAWING.
C	08-20-99	AGS	REVISED IN RESPONSE TO FWUSA COMMENTS (ADDED GRADE INFO, NOTES & DWG No.s INFO). REVISED S.A. & P.A. DUCTS AS SHOWN.
B	6/7/99	AP	ADDED PRI. AND SEC. AIR FANS AND DUCTS TO AIR HEATER. ADDED PRIMARY AIR FLOW MEASUREMENT DEVICES AT SEC. AND O.F. AIR DUCTS. REVISED O.F. AIR DUCTS AT BOILER FRONT AND REAR WALLS. DRAWING ISSUED FOR STAFF AND PERFORMANCE REVIEW.
A	5/10/99	AP	ISSUED FOR PRI.AIR AND SEC.AIR DUCT LOAD CALCULATIONS ONLY.

FOSTER WHEELER ENERGY CORPORATION
STEAM GENERATOR
ARRANGEMENT OF AUXILIARY EQUIPMENT SECONDARY & PRIMARY AIR DUCTS R.S. ELEVATION, SECTION A-A AND DETAILS 1 THRU 4

JEA
JACKSONVILLE, FLORIDA

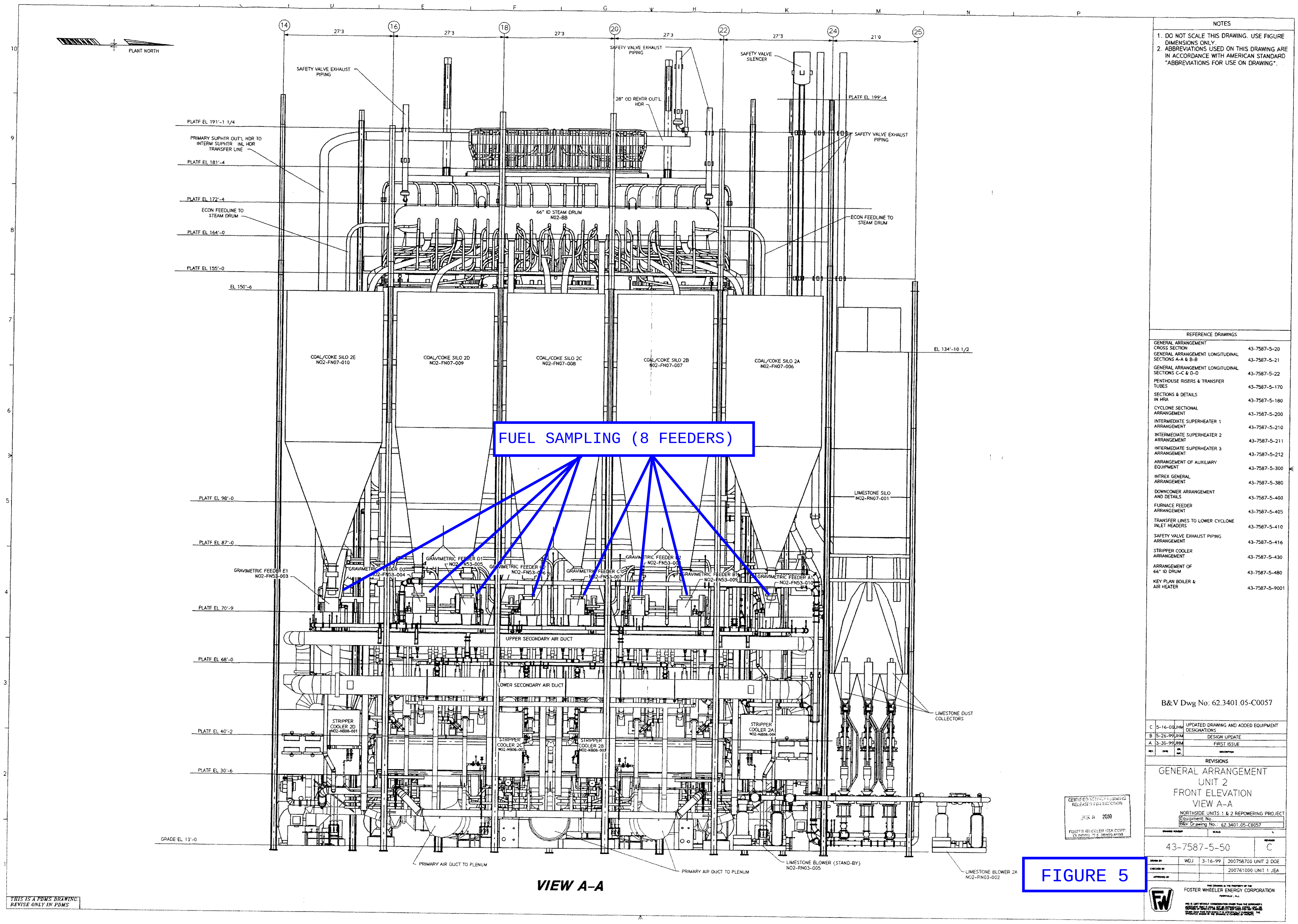
NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT

Equipment No.:	N01-BN, N02-BN
B&V Drawing No.:	62.3401.05-C0046

DRAWING NUMBER	SCALE: ⅛" = 1'-0"	REVISION
43-7587-5-300		M

DRAWN BY	AP	4/8/99	200758700 UNIT 2 DOE
CHECKED BY			200761000 UNIT 1 JEA
APPROVED BY			

DWG40998 03-MAR-2004 14:30:16



DWG40998 03-MAR-2004 14:18:59