# HEALY CLEAN COAL PROJECT

## QUARTERLY TECHNICAL PROGRESS REPORT NO. 33-36

FOR THE PERIOD OF

JANUARY 1 TO DECEMBER 31, 1999

PREPARED BY

ALASKA INDUSTRIAL DEVELOPMENT AND EXPORT AUTHORITY

FOR THE

US DEPARTMENT OF ENERGY

UNDER

COOPERATIVE AGREEMENT NO DE-FC22-91PC90544

October 2000

Patents Cleared by Chicago on July 10, 2000

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## DISCLAIMER

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## 1.0 ABSTRACT


### BACKGROUND

The Healy Clean Coal Project (HCCP) was one of thirteen projects selected out of forty-eight proposals submitted in 1989 to receive funding under Round III of the U.S. Department of Energy (DOE) Clean Coal Technology Program.

Project participants were Alaska Industrial Development and Export Authority (AIDEA) as Owner; the Golden Valley Electric Association, Inc. (GVEA), a Fairbanks utility, as Operator (who was to pay for the power generated under the terms of the power sales agreement); the Usibelli Coal Mine, Inc. (who furnished coal to GVEA), TRW Space and Technology Division (the combustor technology supplier), Babcock and Wilcox (the flue gas desulfurization technology supplier) and the DOE (who provided supplemental funding for the new technologies). The draft documents for the environmental permitting process were completed in November of 1992, but the permit process took an additional two years to complete because of the close proximity of HCCP (in Healy, Alaska) to the Denali National Park. The architect/engineer for the project was Stone and Webster Engineering Corporation and H.C. Price Company was the general construction contractor. HCCP is located adjacent to GVEA's existing Healy No. 1 power plant, which was constructed in 1967.

### PROJECT OBJECTIVES

The objectives of HCCP were to demonstrate an environmentally sound technology for burning coal, create additional energy generation to serve the Alaskan interior and to show the attractiveness of Alaskan coal in combination with developing modern combustion technology.

General construction began in May 1995 and was completed by November 1997. Demonstration testing of the completed plant, required under the provisions of the DOE Cooperative Agreement with AIDEA, started in 1998 and extended into 1999 and included the ninety-day commercial operation test completed in November 1999.

### REGIONAL COAL SIGNIFICANCE

The project will enhance export potential of all Alaskan coal and reduce dependence on imported oil by 30 million gallons per year or save four billion cubic feet per year of natural gas. It will also provide stabilization for coal mining and power plant operation, augment or replace aging coal powered generation, and lock in known base-load power via a long-term coal sales agreement.

The primary fuel fired in HCCP is a blend of run-of-mine (ROM) and waste coals. ROM coal has a higher heating value range of 7,500 to 8,200 Btu/lb, a low average sulfur content of 0.2 percent, and an average ash content of eight percent. The waste coal is either a lower grade seam coal or ROM coal contaminated with overburden and interburden material having a lower higher heating value range of approximately 5,000 - 7,500 Btu/lb, average sulfur content of 0.15 percent, and average ash content of twenty percent. The project is to demonstrate the ability of slagging combustors and downstream flue gas desulfurization (FGD) equipment to utilize a lower grade coal than could otherwise be used effectively in an environmentally acceptable manner.

Coal is provided by the Usibelli Coal Mine located near the project site.

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## TECHNOLOGY DESCRIPTION

HCCP slagging combustors burn coal in a fuel-rich, high temperature atmosphere to minimize formation of nitrogen and sulfur oxides ($NO_x$ and $SO_2$) and to remove most of the coal ash as slag (molten ash). The resulting low concentration of fly ash in the flue gas allows pulverized limestone to be added effectively (i.e., with little dilution by fly ash) near the combustor/furnace interface and to be converted by heat in the flue gas to lime (CaO). A baghouse catches the unreacted lime and other fly ash constituents downstream of a spray dryer absorber (SDA). A slipstream of these solids is recycled and slurried with plant waste water to remove sulfur dioxide by spraying the resulting slurry into the SDA. The process uses a conventional boiler that produces steam for a conventional turbine to provide up to 62 megawatts (gross) of electricity.

The slagging combustor is designed to operate under fuel-rich conditions and utilizes staged combustion to minimize $NO_x$ formation. These conditions are obtained using a precombustor as an integral preheater for firing additional coal in the second stage fuel-rich slagging combustor. Then combustion is completed with excess air in the furnace. The first and second stages of combustion produce a temperature high enough (approximately 3,000° F) to melt the coal ash, while reducing the fuel-bound nitrogen to molecular nitrogen ($N_2$). The third and final stage of combustion in the radiant portion of the furnace occurs at lower combustion temperature (approximately 2000° F) to minimize thermal $NO_x$ formation in an oxidizing atmosphere.

The slagging combustor reduces $SO_2$ emissions using ash constituents and injection of pulverized limestone into the hot gases as they leave the combustor and enter the furnace. Calcium carbonate ($CaCO_3$) in the limestone flash calcines to calcium oxide (CaO), which is mixed with water to create calcium hydroxide slurry to react with the sulfur compounds in the exhaust gas to form calcium sulfate and calcium sulfite. The flue gas leaving the furnace contains the remaining unreacted gaseous sulfur compounds (primarily $SO_2$), particles of calcium oxide, and other fly ash particles. The flue gas leaves the boiler and passes through the SDA and a baghouse for further $SO_2$ and particulate removal prior to exiting through the stack.

The innovative aspect of the concept being demonstrated is a lower level of $NO_x$ and $SO_2$ emissions (while maintaining low carbon monoxide (CO) emissions) by the combustion and reuse of the unreacted lime, which contains minimal fly ash in the second stage $SO_2$ removal. A portion of the solids collected from the SDA vessel and the bag filter are slurried with water, chemically and physically activated, and then atomized in the SDA vessel for second stage $SO_2$ removal. Third stage $SO_2$ and particulate removal occurs in the fabric filters in the baghouse as the flue gas passes through the reactive filter and cakes on the external surface of the fabric filters.

## TECHNOLOGY AND PROCESS SUMMARY

The use of limestone in the combustor, combined with the recycle system, replaces the more expensive lime required by commercial spray dryer absorbers, reduces plant $NO_x$ and $SO_2$ emissions, while maintaining low CO emission, and increases $SO_2$ removal efficiency.

The integrated process is capable of achieving $SO_2$ removal greater than ninety percent and $NO_x$ emissions down to 0.2 pounds per million Btu. The integrated process is suited for new facilities or for re-powering or retrofitting existing facilities. The technology is an alternative to conventional pulverized coal fired boiler flue gas desulfurization (FGD) and $NO_x$ reduction processes, while lowering overall operating costs and reducing the overall quantity of $SO_2$, CO, and $NO_X$ emissions.

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## 2.0 INTRODUCTION

This report encompasses the Demonstration Test Program Technical Progress Report for 1999.

During 1999, HCCP progressed from firing activities focused primarily on the sequence of actions needed to achieve demonstration testing, which included sustained firing of blended coal without accumulating excessive slag in the precombustors, to identifying the problems preventing reliable operation and performing the modifications or installing new equipment to overcome these problems, completing the remaining performance tests, and improving operations and maintenance procedures.

Section 3 (Summary) of this report briefly discusses the problems that most hampered reliable operation and their solutions. It also summarizes results of the performance tests and the ninety-day commercial operation test. Section 4 (Operation) gives detailed reports of operation in a chronological format, with supporting graphs, figures, and tables followed by Section 5 (Equipment and System Problems), which describes solutions to equipment and system problems encountered during operation in detail.

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## 3.0 SUMMARY

The following are totals for coal and energy generation for 1999:

| | |
|---|---|
| Coal: | 196,000 tons |
| Energy generation: | 264,500 MW hrs (gross) |
| Maximum load: | 64 MW (gross) |

Gross and net generation, along with oil and coal consumption, for 1999 are shown on a monthly basis in Figures 3.0.1 and 3.0.2, respectively. Figure 3.02 shows that more oil was fired during March than any other month in 1999. This was caused by multiple startups and extended operation to operate the boiler on oil only while blowing down contaminants from boiler water. The contaminants in the boiler water resulted from the failure of a dipper skirt drain line. Ash water was introduced into the boiler water via the dipper skirt condensate cooling system. Oil attributed to the decontamination effort accounted for slightly more than three percent of the total oil and coal heat content consumed in the boiler in March. The following major accomplishments are listed and then described briefly below:

1) Continuous operation, using blended coal without objectionable precombustor slag accumulation, was demonstrated.
2) A boiler test was conducted to determine whether the boiler manufacturer satisfied all performance guarantees. Data indicated all guaranteed values with the slagging combustors were satisfied.
3) Spray Dryer Absorber (SDA) and baghouse tests were conducted and indicated that all guaranteed emissions were satisfied.
4) Furnace pressure excursion trips were a major hindrance to continuous operation. The source of the trips was identified as slag falling from the sloped bottom ash hopper of the furnace into the slag drag chain conveyor reservoir. Two high pressure water lances, one each on the north and south walls of the furnace were designed and installed to minimize and remove slag accumulation on the sloped bottom ash hopper in a controlled manner, rather than allowing excessive slag to accumulate, fall, and trip the unit.
5) A ninety-day commercial operation test was conducted from September 15 to November 15 with blended coal. A capacity factor of approximately ninety-five percent was achieved compared to a contractual requirement of eighty-five percent. The average heating value of the coal burned over the test period was 7,214 Btu/lb, approximately three percent higher than the target value of 6,960 Btu/lb. The average percentage of waste coal (including screening fines) used during the test period was approximately 83% and at times during the test, the inferred heating value of the coal fell below 6,000 Btu/lb.
6) A modified ASME (not a full ASME turbine test) turbine performance test was conducted, by the turbine manufacturer (Fuji), in December 1999. The test was performed at valves-wide-open and over three loads: 100% load – 62MW; 80% Load – 58MW and 70% Load – 43MW (values are approximate). Test results indicated that the turbine/generator met its performance guarantee.

Slag accumulation in the precombustors (PC) was problematic during 1998 and the early part of 1999, but the problem was solved by the elimination of the secondary air from the mixed annulus. During the first quarter, the modifications to more effectively eliminate secondary air from the precombustor mix annulus to prevent precombustor slag accumulation were accomplished by adding closure plates to the secondary air piping. This proved to be effective and the precombustor mix annulus was permanently blocked with refractory. The resulting configuration allowed continuous operation burning blended coal. Section 4.0 of this report contains plots (for April, May and June) of the coal HHV, PC windbox pressure(chamber pressure), and burner air flow rates (values are not normalized). The plots were made to evaluate if observed changes in the PC windbox pressure were due to changes in the PC coal flow rate, PC airburners or changes in the slagging conditions. As the coal HVV drops, the coal flow increases to maintain the same thermal input, and the burner air flowrate increases proportionally to the coal flowrate increase (ratio of klb/hr of air-to-klb/hr of coal is held constant). Therefore, as the coal HHV drops, the PC windbox pressure will increase due to the increase in mass flow. In addition, as the HVV drops very low( below 6500 Btu/lb), the coal T250 typically drops, and the PC gas temperature drops slightly. These changes will result in a slightly thicker slag layer within the PC and, hence an increase in PC windbox pressure. The slag layer will typically equilibrate to the new conditions within 30 minutes. If there is an observed increase in PC windbox pressure without a corresponding increase in burner air flow and, or decrease in coal HHV, then the change in the PC windbox pressure may be indicative of a change in slagging conditions within the PC.

A boiler performance test was conducted, in March, to determine whether the boiler manufacturer satisfied all performance guarantees. The critical boiler guarantees were:

- Maximum steam flow 490,000 lb/hr.
- Pulverizer and forced draft fan power consumption of 330 kW and 3150 kW respectively.
- Steam pressure 1300 psig.
- Steam temperature 955 $^{o}$F.
- Boiler efficiency was predicted to be 79.15% (this was not a guarantee).

All data taken indicated all guaranteed values associated with the slagging combustors were satisfied as indicated in Table 3.1. The tests were witnessed by Stone & Webster – the project design Engineer.

During the second quarter, spray dryer absorber (SDA) and baghouse tests were conducted. The testing started on June 8 and was completed on June 11. Although only three tests separated by 24 hours were required by the Contract, a total of nine tests were conducted over a period of four days of testing. The tests demonstrated that all guaranteed emissions and other performance guarantees were satisfied as shown in Table 3.2. A detailed discussion can be found in the SDA Performance Test Report (see Reference 6).

The modifications to the mix annulus air resulted in increased continuous operational time while firing blended coal without excessive slag accumulation in the precombustors. This allowed the previously unexplained problem of tripping on high furnace pressure to be attributed to slag falls from the slag buildup on the sloped bottom ash hopper at the bottom of the furnace.

The buildup accumulated until it fell back down through the two rectangular slagging combustor discharge openings into the sloped furnace hopper. This slag ash fell into the slag ash drag chain reservoir and is believed to have caused the rapid vaporization of sufficient water to upset the furnace pressure beyond the ability of the induced draft fan inlet dampers to react and control it, resulting in a main fuel trip (MFT). Since the potential problem of buildup on the sloped hopper had been foreseen during the design of the unit, sufficient clearance for retractable water lances had been allowed and such lances were designed and installed.

One lance was located on the north (or front) waterwall and the other on the south (or rear) waterwall. The lances insert and retract as a sootblower and operate using a high pressure (250 psig) condensate stream provided from the condensate pumps as the water-washing medium. Use of these lances eliminated large slag falls and the associated sudden boiler pressure excursions.

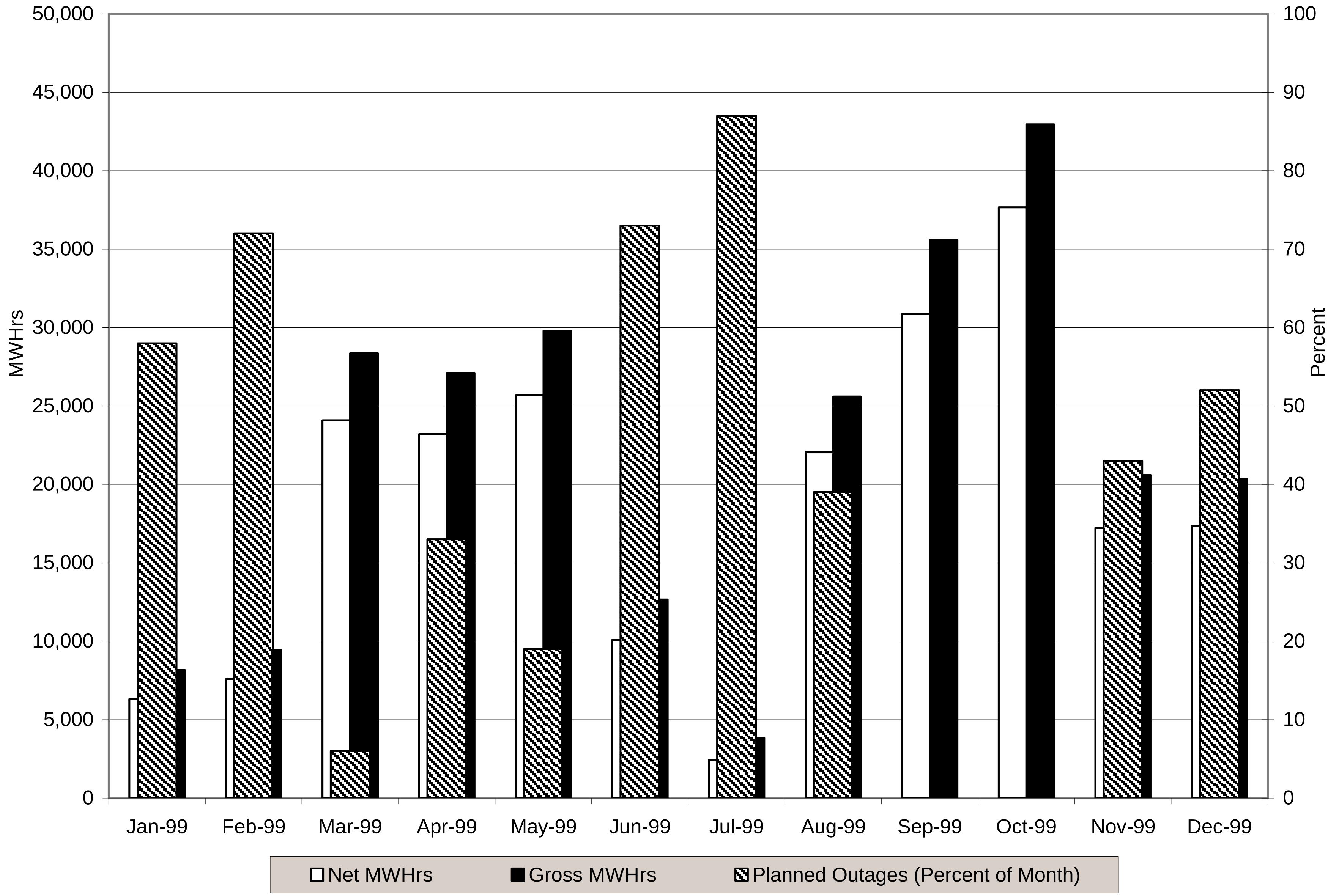
The ninety-day commercial operation test was to prove that the unit could run reliably by achieving ninety days of operation at a minimum capacity factor of eighty-five percent while firing performance coal as defined in contract documents. The test conducted from August 15 to November 15 resulted in a capacity factor of ninety-five percent and, according to data taken, met or exceeded all specified guarantee requirements associated with the slagging combustors. Coal properties during the ninety-day test, including the higher heating value, moisture content, ash content, and sulfur content, are provided in Figures 3.0.4 through 3.0.7. The highest daily three-hour average sulfur dioxide emissions are provided in Figure 3.0.8 and $NO_X$ emissions are provided in Figure 3.0.9.

A turbine performance test was conducted, in December, to determine whether the manufacturer's turbine guarantee heat rate was satisfied. Test data indicated that the turbine/generator heat rate was between 8,200 an 8,400 Btu/KWh compared to the corresponding guaranteed value of 8,420 Btu/KWh. The unit was considered by AIDEA to have met its contract performance requirements.

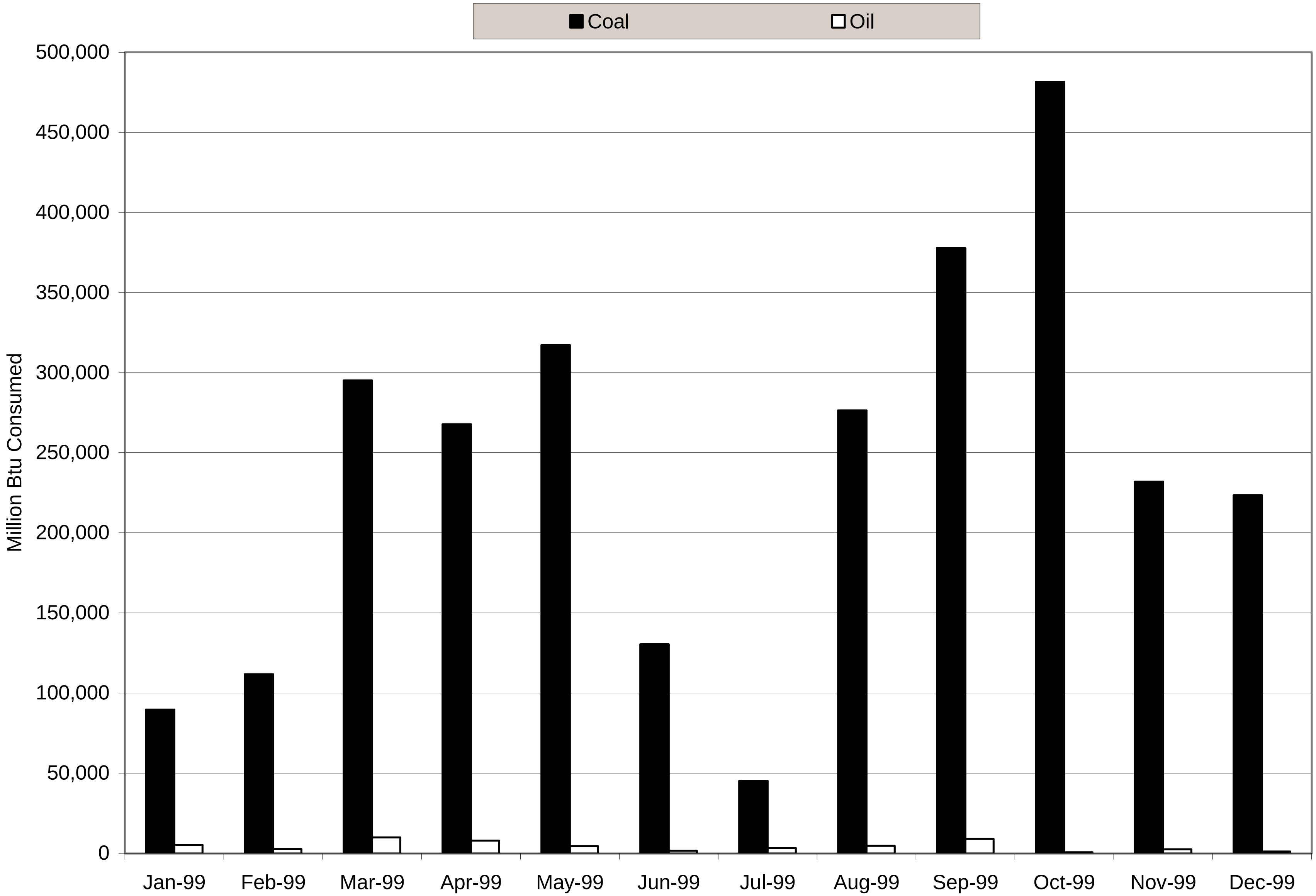
Throughout the year the unit continued to improve with respect to reliability, performance and environmental (addressed in section 6.0 of this report and in the TRW reports). $NO_X$ levels averaged approximately 0.27 lb/MBtu/lb for the year, however, the unit is expected to perform at lower $NO_x$ emission once fine-tuning of the unit and tuning for $NO_x$ has been carried out. Tuning of the unit for $NO_X$ and performance has not been carried out to any great extent, it was planned to carryout such tuning during the year 2000. The SDA and slurry systems continued to improve throughout the year and by the end of the year were very reliable and produced low levels of $SO_2$ emissions at the stack - levels of 0.07 lb/MBtu and lower were consistently achieved, refer section 6.0 the SDA reports for more details. The results were obtained, for the most part, using relatively low sulfur coal, more testing would be adventageous using higher sulfur coals when they become available from the mine. CO permitting is set at 200ppm for HCCP and the unit easily bettered this value, with CO levels below 60 ppm and typically ranged between 20 and 40 ppm. Opacity levels were lower than 5% on average, which was well below the 20% allowable limit.

Emissions are addressed in Section 4.0 as relevant to a particular month's operation, for more detail refer to section 6.0. The Healy Clean Coal Plant does run environmentally clean and is capable of performing within the environmental permit levels over a wide range of coals.

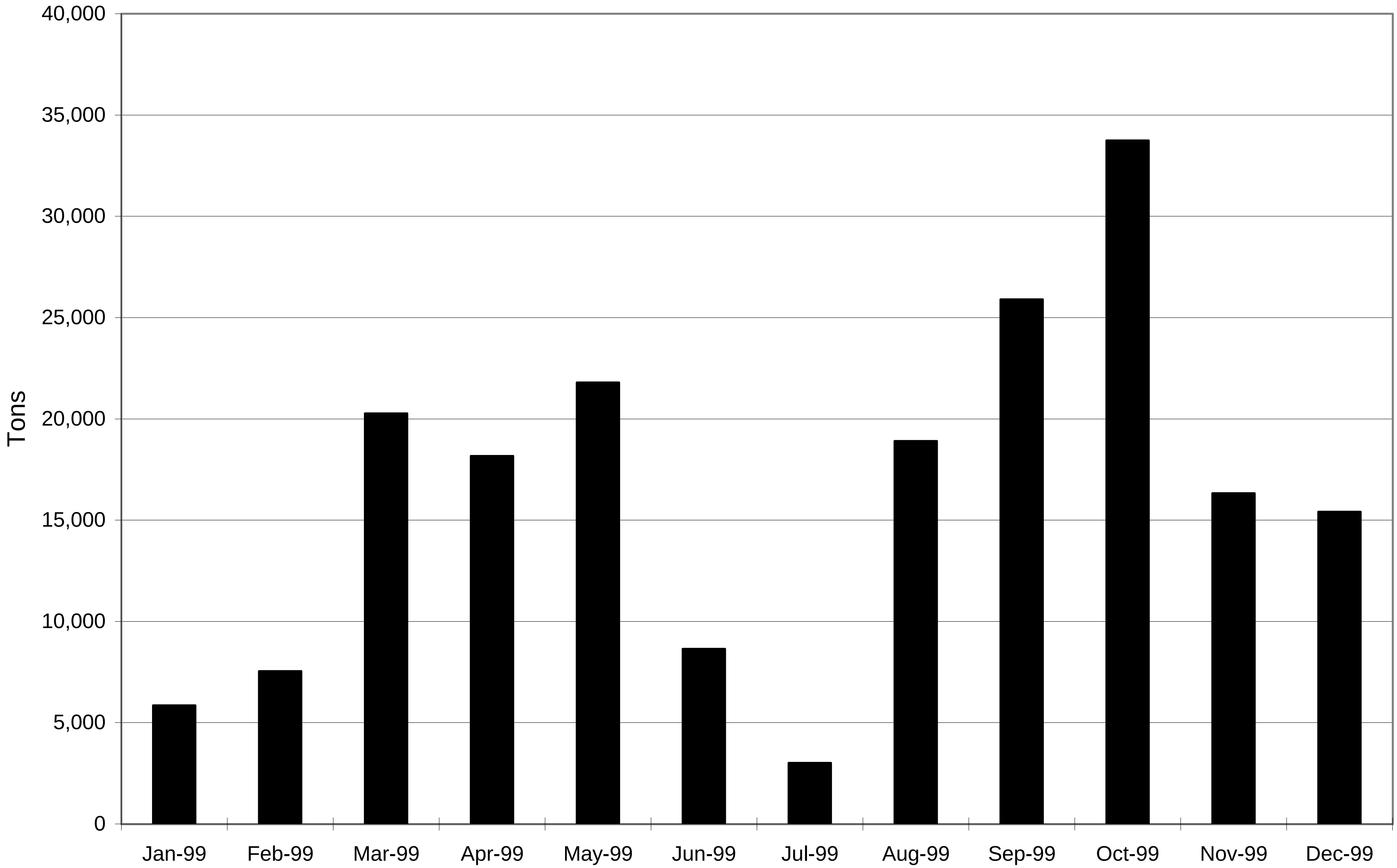
# Figure 3.0.1 - Electrical Generation for 1999



# Figure 3.0.2 - Oil and Coal Consumption for 1999



# Figure 3.0.3 - Coal Consumption for 1999



# Table 3.1 – Boiler Performance Guarantee Versus Test Results

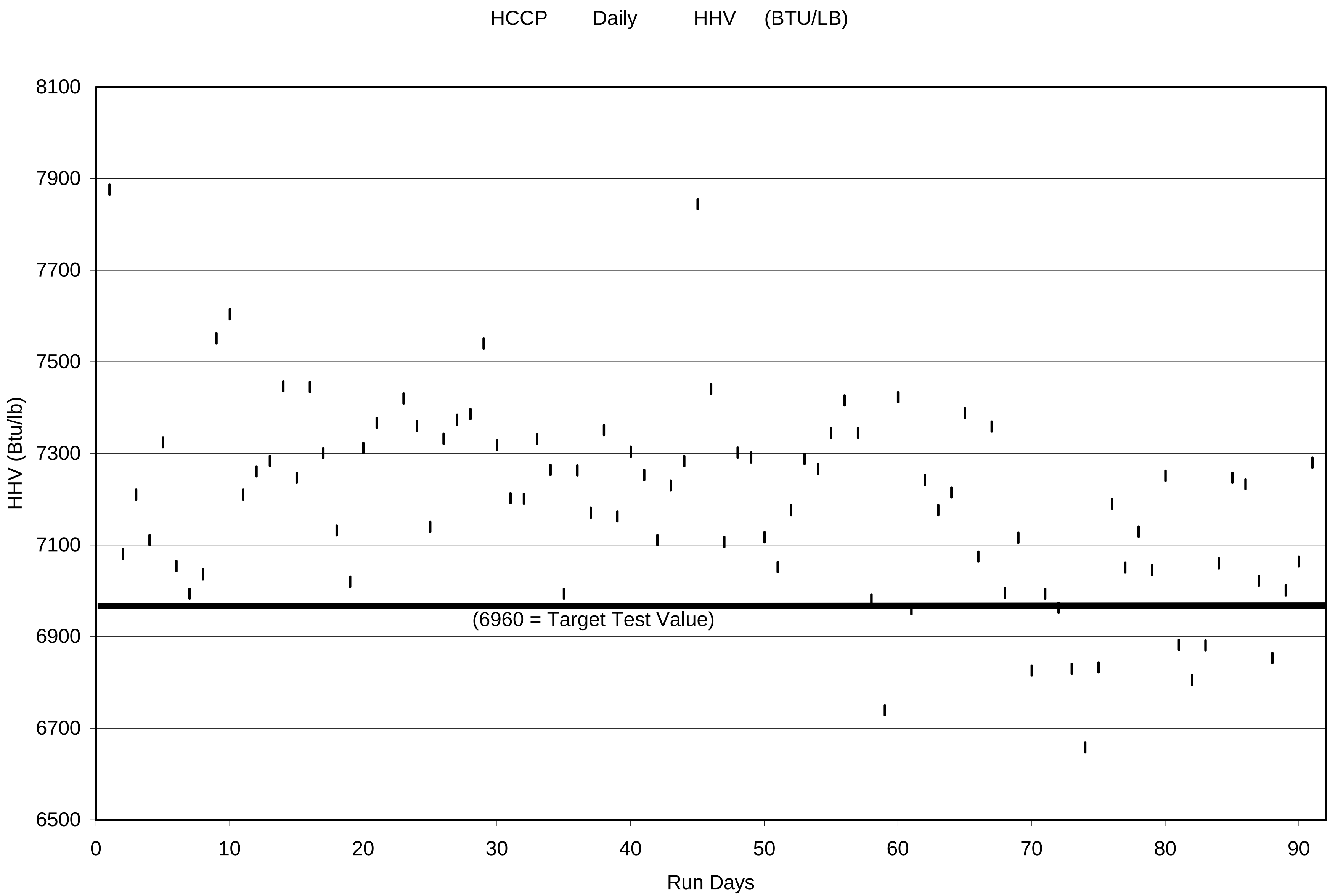
| | Guarantee | Test |
|---|---|---|
| Steam Flow, lbs/H | 490,000 @ 1300 psig | 494,865 |
| Steam Temperature Control Range | 955 +/- 10°F | 957/953°F |
| Maximum Steam Side Pressure Losses, psid | 126 | 84.4 |
| Maximum Water Side Pressure Losses, psid | 50 | 39.3 |
| Maximum Flue Gas Draft Loss, inwg | 19 | 15.9 |
| Maximum Pulverizer A shaft input power, kW | 330 | 213.6 |
| Maximum Pulverizer B shaft input power, kW | 330 | 204.4 |

# Table 3.2 – SDA System Performance Guarantee Versus Test Results

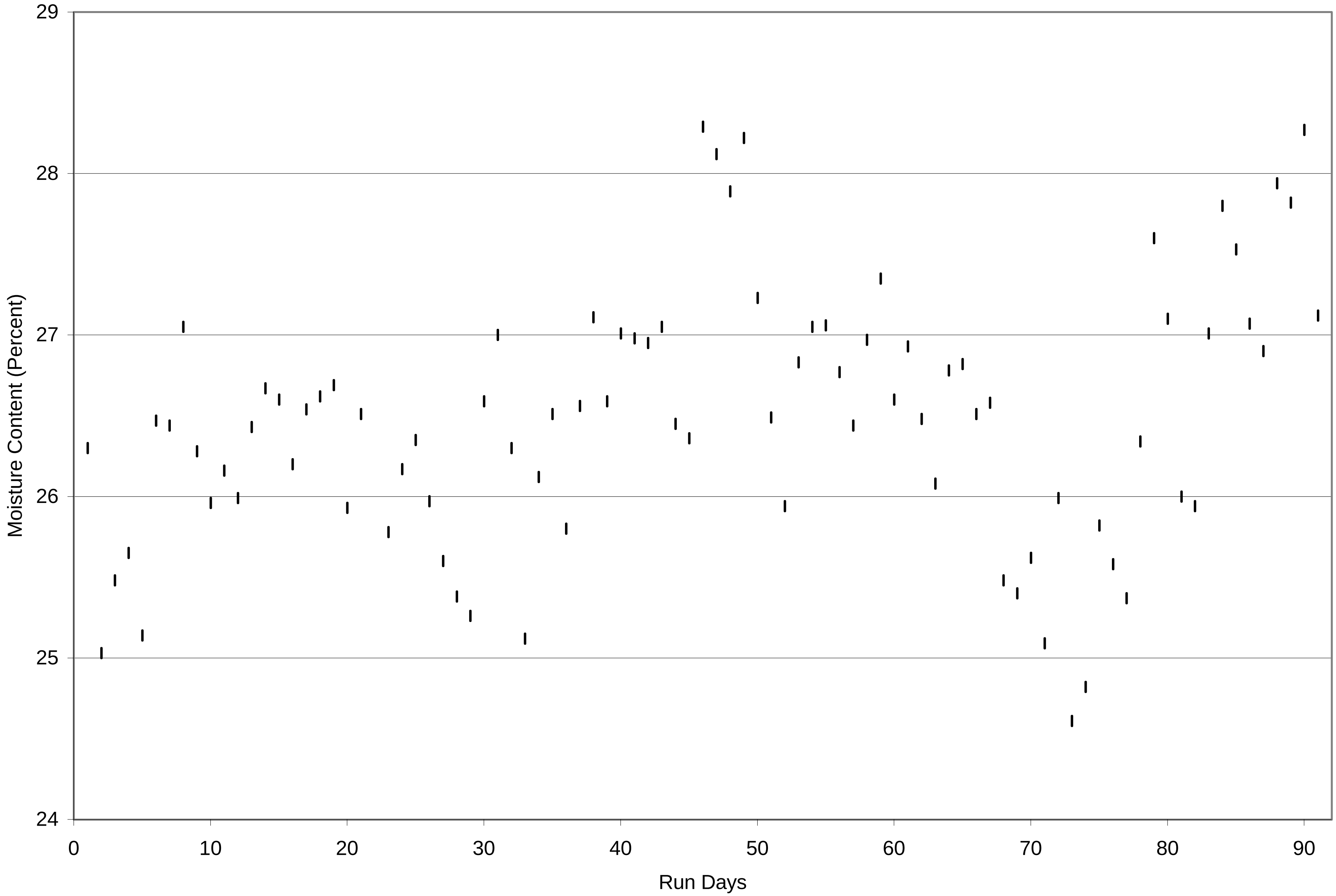
| | | | Parameter Values | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| No. | Operating Parameter | Guarantee | Test 1 | Test 3 | Test 4 | Test 5 | Test 6 | Test 7 | Test 8 | Test 9 |
| 1 | $SO_2$ Emissions | 79.6 lb/hr (Max.) | <2.01 | <2.07 | <2.13 | <2.15 | <2.10 | <2.13 | <2.13 | <2.15 |
| 2 | Particulate Loading | 0.015 lb/MBtu (Max.) | 0.0023 | 0.0042 | 0.0052 | 0.0040 | 0.0027 | 0.0030 | 0.0014 | 0.0034 |
| 3 | Opacity | Max. of 20% for a max. of three minutes in an hour and during the three minutes a max. of 27% | Range: 1.3 – 1.5<br>Max.: 1.5 | 1.3 –1.7<br>1.7 | 1.5 - 1.7<br>1.7 | 1.5 - 1.7<br>1.7 | 1.1 - 1.4<br>1.4 | 1.0 - 2.0<br>2.0 | 1.3 – 1.5<br>1.5 | 1.3 – 1.5<br>1.5 |
| 4 | System Pressure Drop | 13 in. WG | 10.0 | 10.5 | 9.6 | 9.7 | 9.8 | 9.9 | 9.8 | 9.9 |
| 6 | System Power Consumption | 550.5 kW | 334 | 330 | 324 | 331 | 333 | 333 | 328 | 340 |

Note: Test 2 has not been included because equipment problems resulted unusable test data.

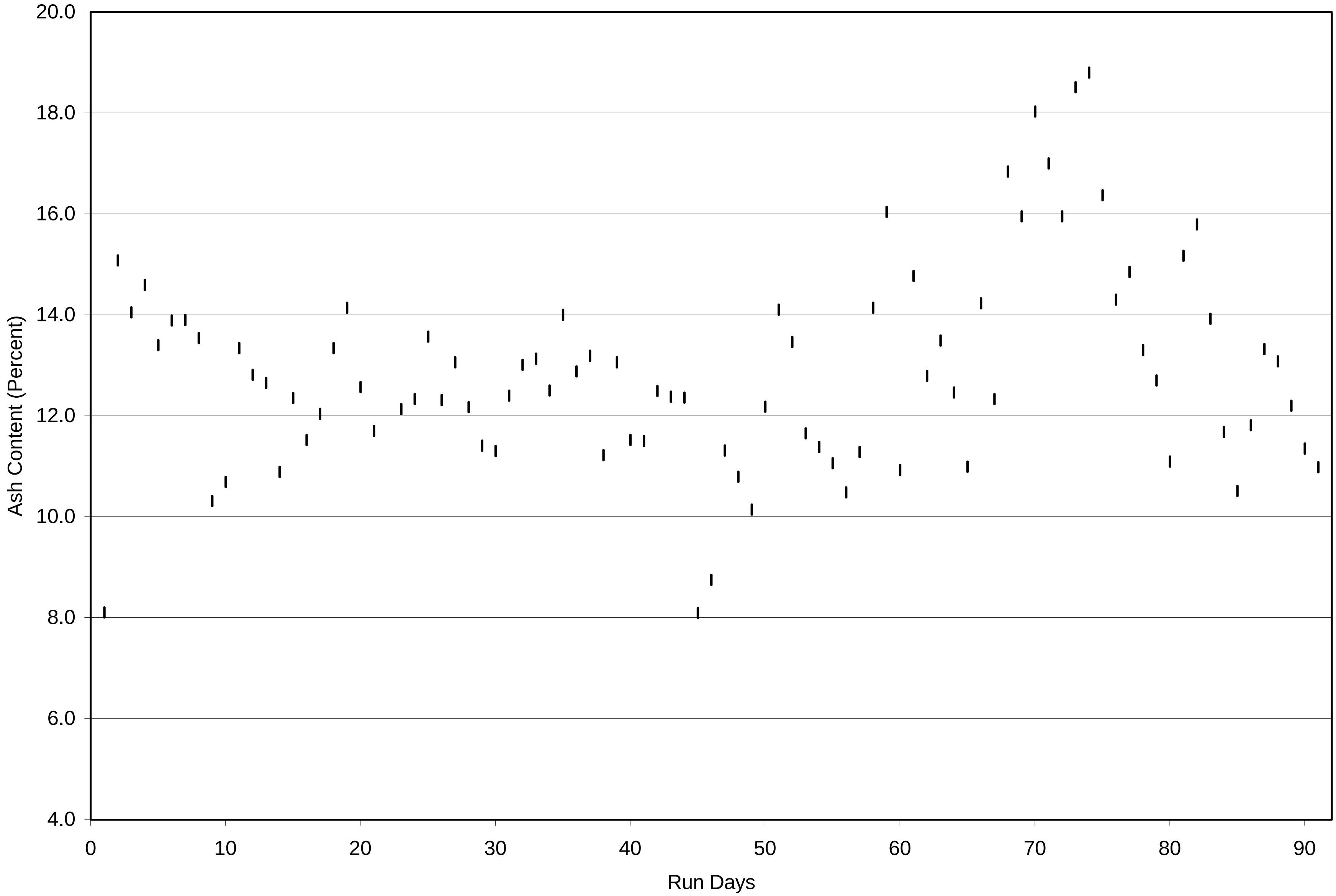
# Figure 3.0.4 - Coal Higher Heating Value for the Ninety-Day Test



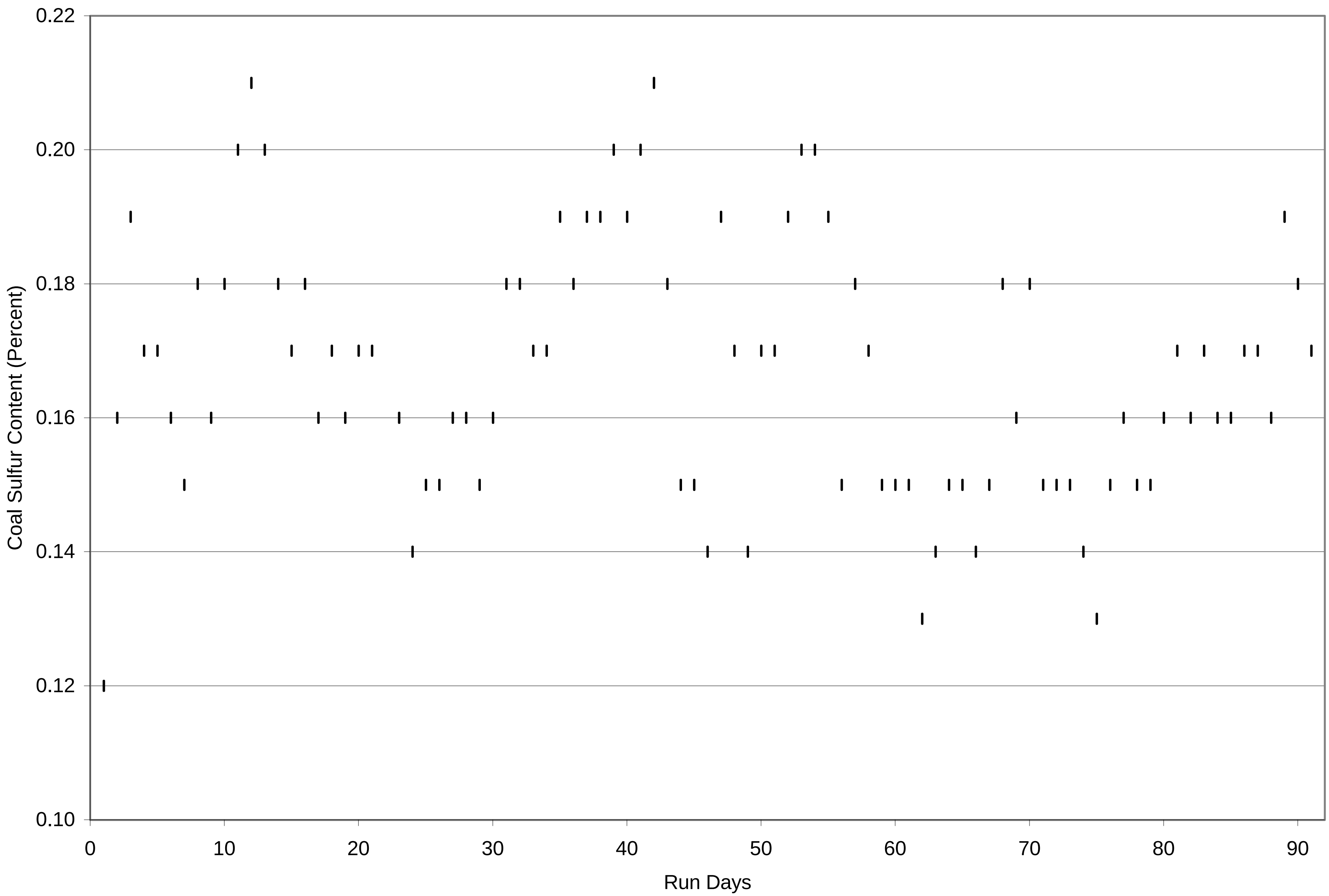
# Figure 3.0.5 - Coal Moisture Content for the Ninety-Day Test



# Figure 3.0.6 - Coal Ash Range for the Ninety-Day Test

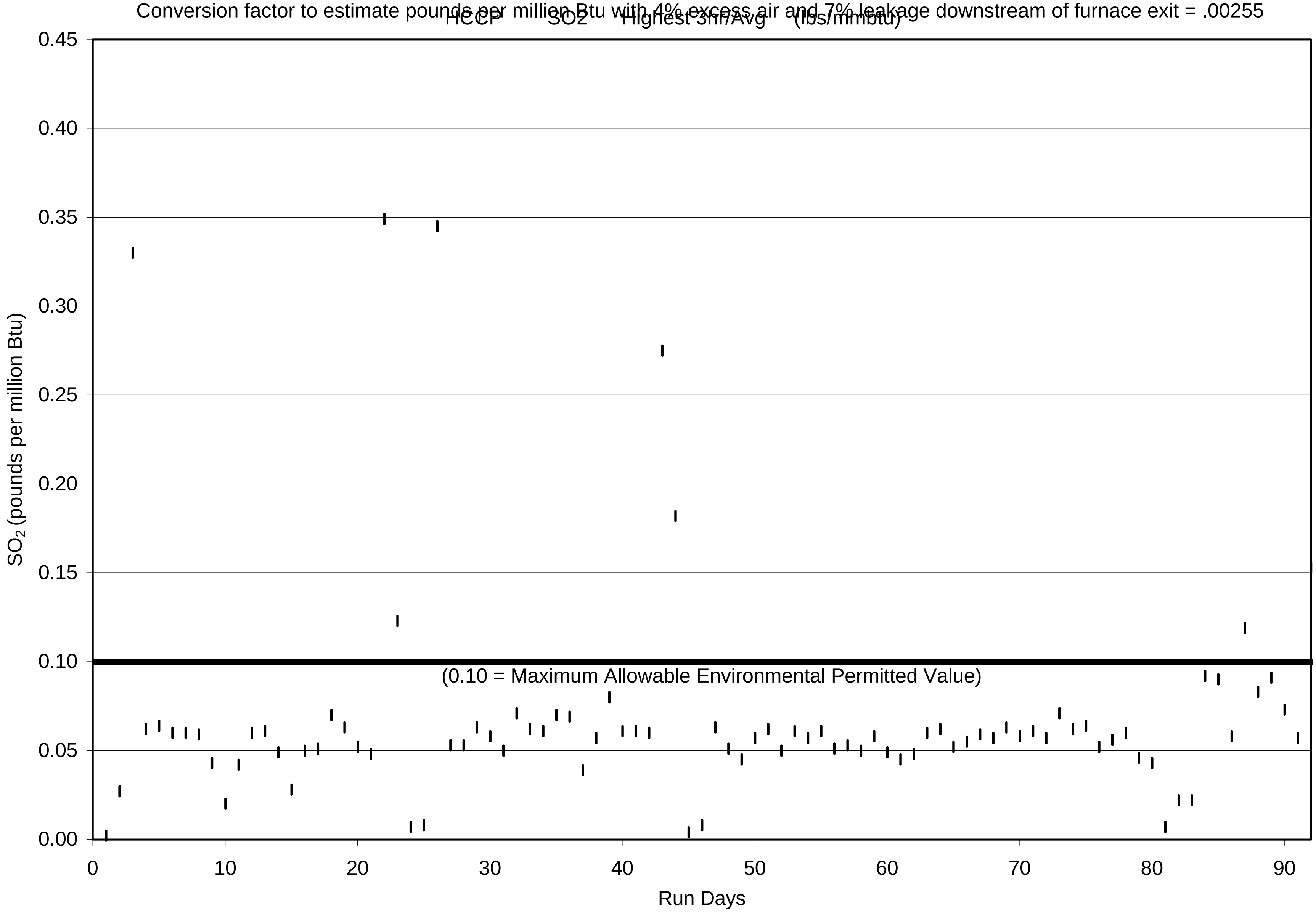


# Figure 3.0.7 - Coal Sulfur Range for the Ninety-Day Test

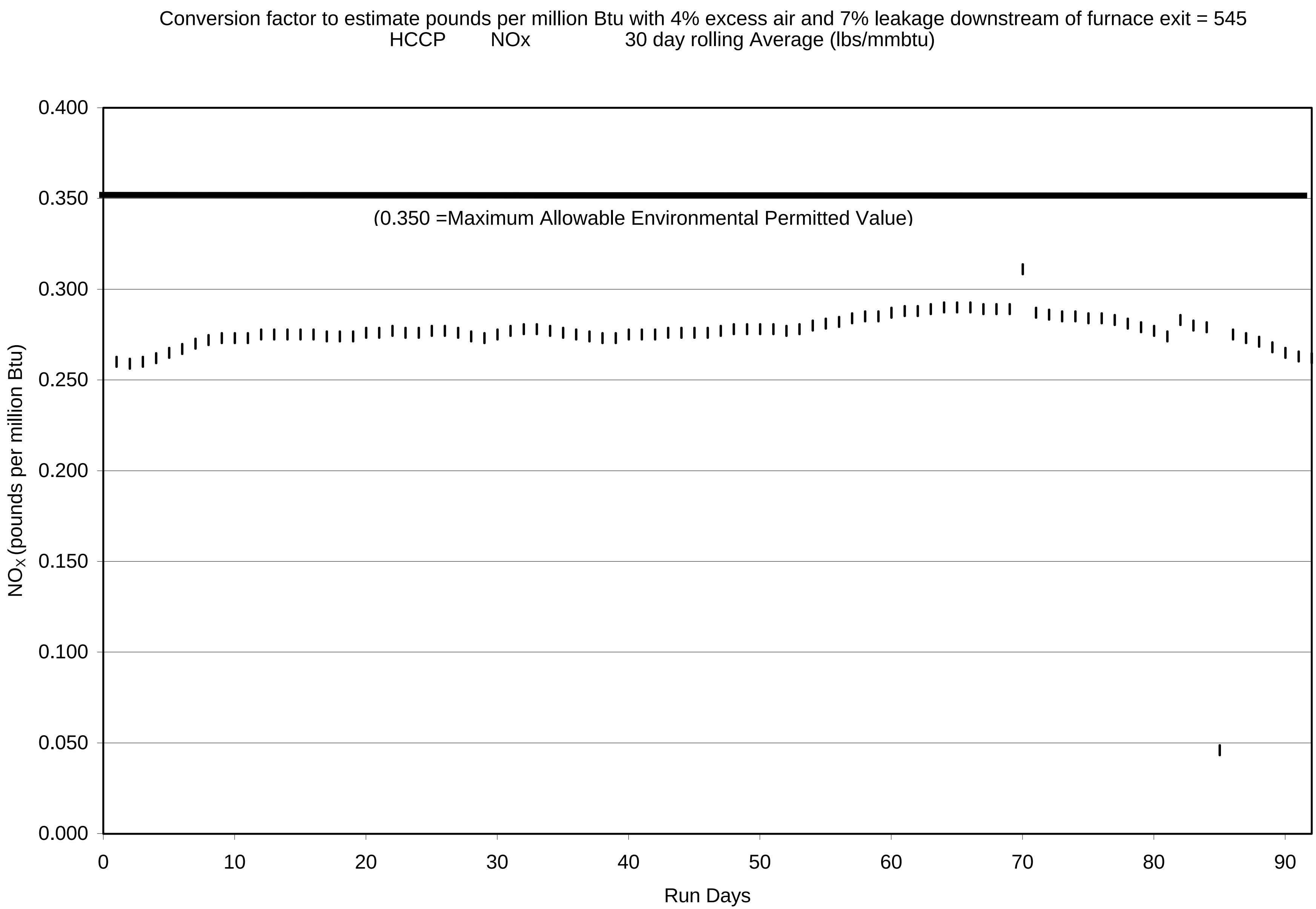


# Figure 3.0.8 - Highest Daily Three-Hour Average for Stack $SO_2$ Emissions for the Ninety-Day Test

Conversion factor to estimate pounds per million Btu with 4% excess air and 7% leakage downstream of furnace exit = .00255



# Figure 3.0.9 - $NO_X$ Emissions for the Ninety-Day Test



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## 4.0 OPERATION

Operational history for 1999 is summarized in Appendix C. HCCP generated 264,500 megawatt hours (gross) in 1999. There were nine planned shutdowns for maintenance and modifications. Operating time and down time associated with planned and unplanned outages is shown in Figure 4.0.1. The coal quality for the year averaged 7,345 Btu/lb, approximately 5.5 percent over the long-term economic target average of 6,960 Btu/lb.

The plant tripped twenty-eight times throughout the year. Twenty-three trips, or eighty-two percent of all trips, occurred prior to May 29, during thirty-nine percent of the total run time. The plant was very reliable after May 29, after which water lances were installed to prevent large furnace pressure excursions resulting from falling slag.

The plant trips are summarized below and are grouped into three categories, showing the total number of trips for that category and the root cause of each trip.

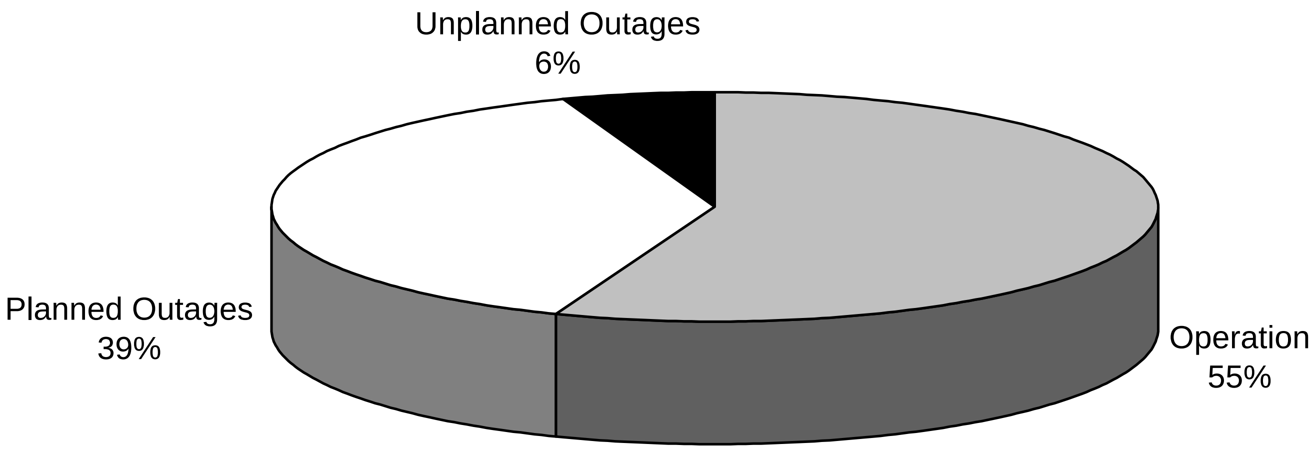
1. Turbine/generator at full load (13 total):
   - Falling slag – 6
   - Frozen/wet coal plugging the pulverizer feeder inlet – 1
   - Coal cyclone vent low transmitter failure – 1
   - Turbine throttle control cable failure – 1
   - Downloading DCS changes – 1
   - Loss of flame signals, poor quality coal – 1
   - Low cooling water flow to swirl dampers – 1
   - Pulverizer motor bearing thermocouple failure – 1

2. Coal fires in service, unit ramping up or down, less than or equal to fifty percent load (7 total):
   - Pulverizer/coal feed system fire or explosion – 2
   - Low condenser vacuum, low air ejector steam pressure – 2
   - Low condenser level caused by an open condenser draw-off manual bypass valve – 1
   - Running out of fuel oil, tanks not switched – 1
   - FD/ID fan retuning logic problems – 1

3. Oil fires only, unit ramping up or down, less than or equal to twenty-five percent load (8 total):
   - Oil torch strainers/tip plugged or fuel oil temperature too low – 2
   - Turbine throttle control cable failure – 1
   - Furnace pressure excursions when starting/stopping pulverizer equipment – 1
   - Inadequate condenser vacuum or faulty vacuum switch – 1
   - Loss of flame signals, air flow too high during startup/shutdown of pulverizers – 1
   - Low cooling water flow to swirl dampers – 1
   - Pulverizer/coal feed system fire or explosion - 1

A more detailed chronological discussion of operations is provided in the following sections on a monthly basis.

# Figure 4.0.1 - Operational and Outage Time Distribution



## 4.1 JANUARY OPERATIONS

Most of January was devoted to installing an acoustic silencer into the duct between the induced draft (ID) fan outlet and the stack, and on installing baffles to improve inlet flue gas distribution into the baghouse. These modifications are described in more detail in Section 5 (Equipment and Systems Problems).

Plant operation resumed on January 17. A total of 136 hours of operation was accumulated on Combustor B and 108 hours on Combustor A. Operation was intermittent because of a variety of facility and instrumentation problems. On January 25, turbine throttle valve positioning became erratic and eventually caused load swings and a unit trip as a result of the drum level. The turbine manufacturer addressed these problems during a site visit. A short test, accumulating fifty hours of coal-fired operation, was performed from January 30 to February 1 to check out the turbine while the turbine manufacturer's representatives were on site. This test was to ensure that the corrective measures for throttle valve control were successful. At the end of the test, the turbine manufacturer's representatives were satisfied with the test results.

## 4.2 FEBRUARY OPERATIONS

Test operations were shut down from February 1 through February 17, because of an onsite limestone shortage (caused by an unanticipated failure of the local limestone supplier's equipment) and the lengthy delivery lead times needed to obtain limestone from another source.

There were two test periods during February. The first test period started on February 18 and ended on February 23, following 116 hours of coal firing. It ended because of a condensate leak from the Combustor B dipper skirt shield drain valves. There were two drain valves installed in series on the bottom of the dipper skirt shield located within the slag drag chain reservoir. Post-test inspection revealed that both drain valves were partially open and the cap on the outlet of the drain line had not been installed. It has been postulated that a piece of slag had knocked the handles of both drain valves open. To mitigate this type of problem in the future, the handles were removed from both drain valves and a cap was installed on the outlet of the drain.

During the post-test inspection, several pinhole sized water leaks in the east swirl damper of Precombustor A were found. There appeared to be localized abrasion/erosion of the vertical tube surface on the downstream end of the blade. Weld overlay repair was performed on the last one and a half inches of the upstream side of the blade on both precombustors.

The second test period was initiated on February 25. Extremely high silica levels (greater than 2,000 ppb, which is off the instrumentation range), high pH (greater than ten), and high conductivity (approximately seventy micromhos) were present in the boiler water. Thermal load was reduced by shutting off Combustor A. The condenser was examined for a source of the poor quality water. After confirming that there were no circulating water leaks in the condenser, the test was terminated on February 27, following approximately thirty-eight hours of coal firing. It was subsequently determined, after a lengthy analysis of the events and the boiler water circuitry, that the boiler water was contaminated as a result of ash water being introduced into the dipper skirt cooling system. A review of the shutdown data indicated that operational procedure errors occurred during the shutdown of this test that may have contributed to coal pluggage in the coal feed system on the subsequent startup, to heat damage to gaskets on several couplings in the limestone feed line and to the loss of some of the abrasion resistant liner in the limestone injector.

The entire combustor/boiler water system was drained, flushed and refilled with clean water. From February 28 through March 3, the oil ignitors were activated periodically in order to increase the steam drum pressure and temperature, and the combustor/boiler system blowdown valves were opened repeatedly to rid the system of contaminants. As pressure and temperature increased, the silica levels continued to increase until sufficient blowdown of the contaminated water and replacement with treated water occurred.

## 4.3 MARCH OPERATIONS

Blowdown of contaminated boiler water, which occurred in the latter part of February, continued into March. On March 3, at 3:00 AM, when the silica levels had stabilized, an unsuccessful attempt was made to restart coal firing. Data review indicated that operational procedures had not been followed. Prior to starting the coal feeder, coal feed system pressure drops appeared to indicate plugging of coal upstream of the Slagging Combustor B cyclone. Approximately ten minutes after initiating coal firing, there was a furnace pressure excursion and temperature indications on the coal feed system identified high temperatures (approximately 600° F) within the cyclone vent, slagging combustor six-way splitter, and precombustor coal line. Operators shut off the coal, but maintained the mill air flow through the coal feed system. The system was inerted with steam and ten minutes later the coal feed was restarted. Temperature measurements indicated that the boiler $NO_X$ port temperature was gradually increasing at that time. Soon after restarting coal feed, there was a detonation in the coal feed system that damaged the primary air duct and the slagging combustor cyclone inlet roof damper gear drive mechanism on the coal feed system to Slagging Combustor B.

An inspection of the coal feed system performed on March 4 revealed the following:

- There was no coal accumulation within either of the precombustor or slagging combustor splitter drum outlet legs. The ceramic tiles were not damaged. Excessive heat caused paint to peel off of the splitter drum doors.
- There was no coal accumulation or obvious major fire damage within the cyclone vent manifold. The external paint on the vent was discolored (heat stained).
- The bottoms of the Slagging Combustor B and the Precombustor B cyclones didn't have excessive coal accumulation. There was approximately five gallons of water accumulated in the base of the slagging combustor cyclone (probably from the steam inerting). The water was removed from the bottom of the slagging combustor cyclone.
- Limited access prevented an inspection of the blowdown damper and flow annubars, including the flow straightening devices.

The objective in March was to continue to establish a broader operating envelope, while burning coal with low-grade coal (i.e., less than 6,800 Btu/lb). There were five test periods, accumulating a total of 518 hours of coal-fired operation. The longest continuous operating time was 283 hours. Shutdowns were caused by a digital control system (DCS) module failure, high furnace pressure spikes (two trips), a hot gas leak from a combustor rodding port, and unstable precombustor flame scanner indications during startup.

The first test period, initiated on March 5, provided less than thirty-six hours of coal firing and was terminated as a result of a DCS module failure. The plant was back online on March 6 at full load within five hours of the trip. The second test period tripped on a high furnace pressure spike on March 8, after fifty-five hours of coal firing. The third test period was initiated on March 9 and was terminated on March 14, following 125 hours of coal firing, because of an observed hot gas leak from a rodding port door on the precombustor. Post-test investigation revealed that the hot gas leak was the result of a lack of purge air flow to the rodding port door, caused by a closed purge air shutoff valve, and affected two rodding ports on each precombustor and six rodding ports on each slag recovery section. All four of the precombustor ports were plugged with molten slag, as a result of the lack of purge air flow. One of the four ports was damaged. The slag recovery ports were not damaged. Prior to the fourth test period startup, swirl vanes were installed in the annular opening between the coal burner and the nearest outer sleeve containing flow from the inner register. The fourth test period was initiated on March 18. There were several trips on Coal Feeder B caused by wet clay material packed into the feeder.

Boiler performance guarantee tests were performed at the maximum capacity rating (MCR) of 490,000 lb/hr (corresponding to approximately 62 megawatts) and at approximately sixty percent of MCR, during this fourth test period. The test was terminated by a trip on high furnace pressure on March 30, following 283 hours of continuous coal firing operation. The fifth test period began on March 31. It was terminated after less than twenty hours of coal firing, because of an inconsistent precombustor flame scanner signal. The performance guarantee test results achieved the target values, refer to section 3.0, table 3.1 for details. The tests also provided some useful information:

- Efficiency losses due to the combustor slag tap opening are less than anticipated by TRW and FW.
- FD fan power was considerably less than anticipated due to reduced requirements for combustion air and pressure losses in the duckwork.
- All MCR guarantees were met with 46% waste coal.
- Boiler efficiency was determined to be 82.2% (predicted was 79.15%).

Post-test inspection revealed a thick slag layer within the precombustor combustion chamber, which obscured the flame scanner view.

During March, a correlation was noticed between the unit tripping as a result of furnace pressure excursions and a severe impulse (as in a water hammer) in the slag drag chain reservoir. The cause of these events was attributed to large masses of slag disengaging and falling from the sloped hopper down into the slag drag chain reservoir. It is postulated that such an impulsive force is caused by a very rapid vaporization (as in an explosion) of slag reservoir water when the slag falls into it and/or the sudden collapse (or implosion) of a large steam void (or bubble) because of its submersion in subcooled reservoir water. This was also confirmed to some extent when hot slag fell into the slag drag chain reservoir after the unit was off between March 15 and March 18 and the impulsive water hammer phenomenon was noted. Engineering and design efforts to eliminate this problem began in March.

The coal supply for the tests performed during March came from the blended coal pile which was comprised of waste coal fines from Seams 3 and 6, ROM coal from Seam 3 and Two Bull Ridge (TBR) ROM coal. Waste coal fines contain a significant amount of sandstone, which lowers the overall heating value. The resulting coal heating value, determined from boiler performance calculations in the DCS, was typically 6,820 to 7,184 Btu/lb on a daily average. Properties between the two ROM coals differed significantly. Seam 3 coal is typically seven percent ash, 7,900 Btu/lb HHV and 0.18 percent sulfur; while TBR coal is typically nine percent ash, 7,500 Btu/lb HHV and 0.31 percent sulfur. TBR coal might be more accurately described as waste coal, even though it is not mixed with overburden or interburden.

$NO_X$ emissions during this series of tests averaged from 0.21 to 0.30 pounds per million Btu with 4.5 percent $O_2$ and less than 30 ppm CO at the furnace exit. Slag was, in general, small and granular, with occasional clinkers.

The precombustor coal split (percentage of coal injected into the precombustor) was held relatively constant at thirty-eight percent and precombustor stoichiometry was 1.20 for this series of tests. The inner sleeve setting and tertiary air flow rate adjusted precombustor burner flame shape and flame anchoring. Prior to the second test attempt, the coal burner inner sleeve on Precombustor A was retracted one inch. Online adjustments to the tertiary air flow rate were then made based on visual observations through the precombustor head end inner sight glass port. Adjustment to the inner sleeve setting and tertiary air flow rate did not appear to have a major impact on the precombustor flame and/or precombustor slagging behavior.

The objective in March was to continue to establish a broader operating envelope, while burning coal with low-grade coal (i.e., less than 6,800 Btu/lb). During March, there were five test periods, accumulating a total of 518 hours of coal-fired operation. The longest continuous operating time was 283 hours. Shutdowns were caused by a DCS module failure, high furnace pressure spikes (two trips), a hot gas leak from a combustor rodding port, and unstable precombustor flame scanner indications during startup.

## 4.4 APRIL OPERATIONS

The open area for secondary air flow through the spare coal ports at the head end of the slagging combustor was less than the previous open flow area provided by the precombustor mix annulus. Therefore, the mix annulus damper would occasionally open fully, especially during operation at full load with decreased precombustor stoichiometry. The coal pipe intended to feed coal to the slagging combustor coal injection port at the 11:00 position on Combustor A and its mirror image, the 1:00 coal pipe on Combustor B had been noted to plug with coal. Consequently, these coal injection ports were converted to a seventh secondary air injection port on each combustor to increase available secondary air flow area to the head end of the slagging combustors.

Based on observations of slag formations in the precombustor and the increase over time in windbox pressure, secondary air had been leaking through the mix annulus temporary blockades. Closure plates were welded into all four secondary air pant leg supply ducts to the precombustors to ensure elimination of this cold air source. Also, swirl vanes were installed in the annular area fed by the inner low-$NO_X$ burner register to improve flame stability.

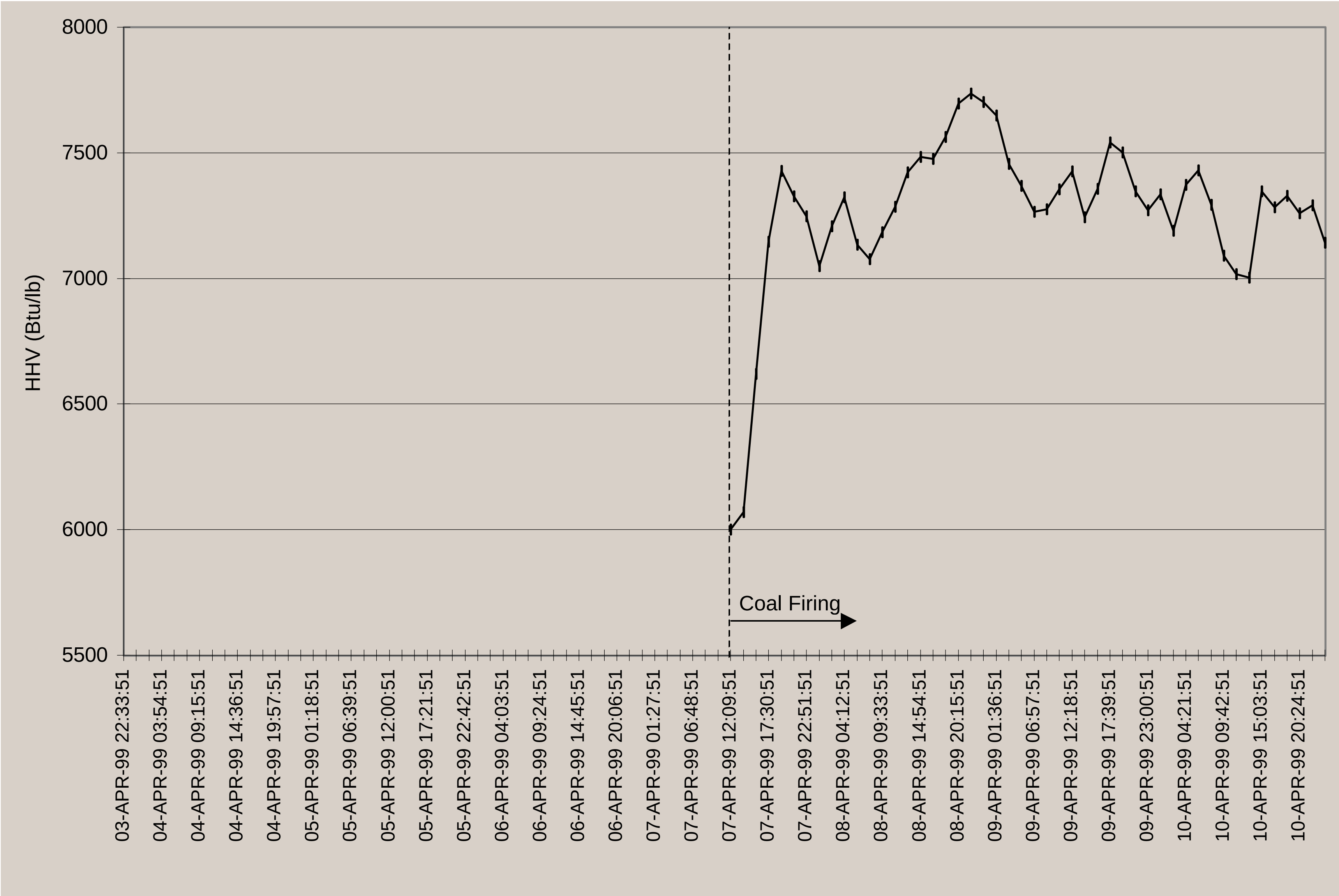
Precombustor operating conditions, in particular, coal split, and precombustor stoichiometry, were varied in April. The precombustor coal split was reduced from thirty-eight percent to thirty percent and the precombustor stoichiometry was increased from 1.20 to 1.40. The burner inner register opening was increased from twenty-five percent open to sixty percent open to increase the inner flame zone air flow. Tuning of the precombustor burner to improve the flame shape and flame anchoring was performed by adjusting the burner inner sleeve setting and tertiary air flow rate. During this series of tests, the coal burner inner sleeve on Precombustor A was varied between minus one inch (retracted one inch) to plus one inch (inserted one inch). Online adjustments to the tertiary air flow rate were then made based on visual observations through the precombustor head end inner sight glass port. The final position of the coal burner inner sleeve at the end of this series of tests was minus one inch on both of the precombustor burners. Online observations indicated that the adjustment to the inner sleeve setting did not appear to have a major impact on the precombustor flame and/or precombustor slagging behavior. Adjustments to the tertiary air setting appeared to have a significant effect on flame shaping. The flame holding devices appeared to provide some additional flame anchoring and broadened the tertiary air operating range.

Figures 4.4.1 through 4.4.4 show weekly inferred coal heating values (as defined in Appendix B) and Figures 4.4.5 through 4.4.12, which show the precombustor windbox pressures, indicate that the air flow configuration modifications from November, 1998 and the installation of the mix annulus supply piping blanking plates in April were effective at reducing or eliminating excessive precombustor slag accumulation. Increasing precombustor windbox pressure, as coal-firing time progresses, is a good indicator of precombustor slag accumulation and no such increase occurred. The unit tripped on April 17 because of a furnace pressure excursion caused by a slag fall.

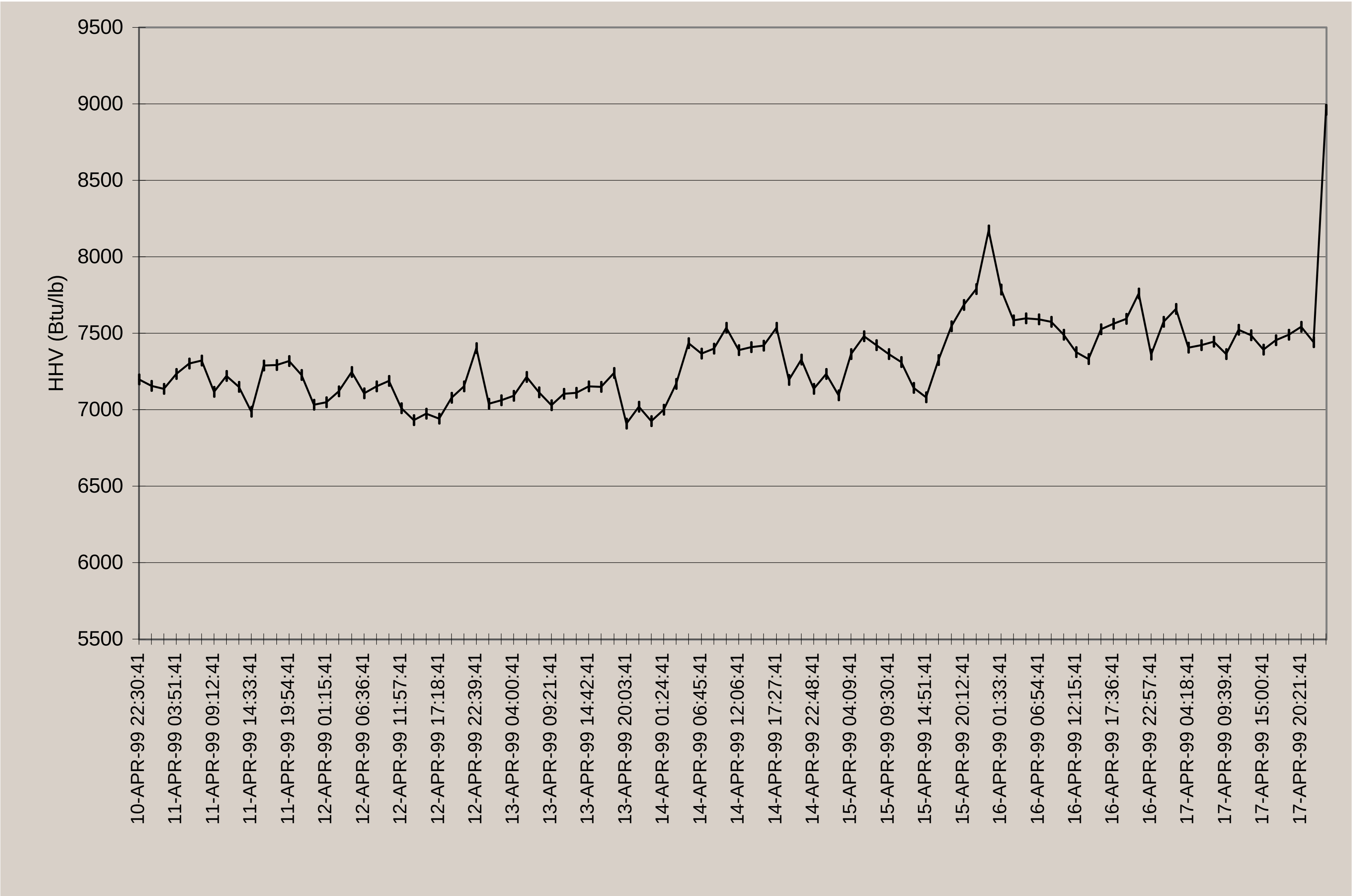
The unit was online for most of April 18 through April 24, except for three trips, two of which were caused by slag falling from the furnace hopper. Total downtime was sixteen hours for this six-day period. The slag falls caused the slag drag chain reservoir to bow outward slightly and column grout was sprawled out where the support columns were anchored to the ground floor.

The grout was repaired and the slag ash drag chain reservoir support columns were reinforced with triangular bracing to a parallel line of support columns. The manufacturer's engineers were involved in the evaluation of the hopper damage and the resulting remedial work. Design of the water lances was completed and the lances were ordered to resolve the falling slag problem.

# Figure 4.4.1 - Inferred Coal Heating Value April 3 - 10



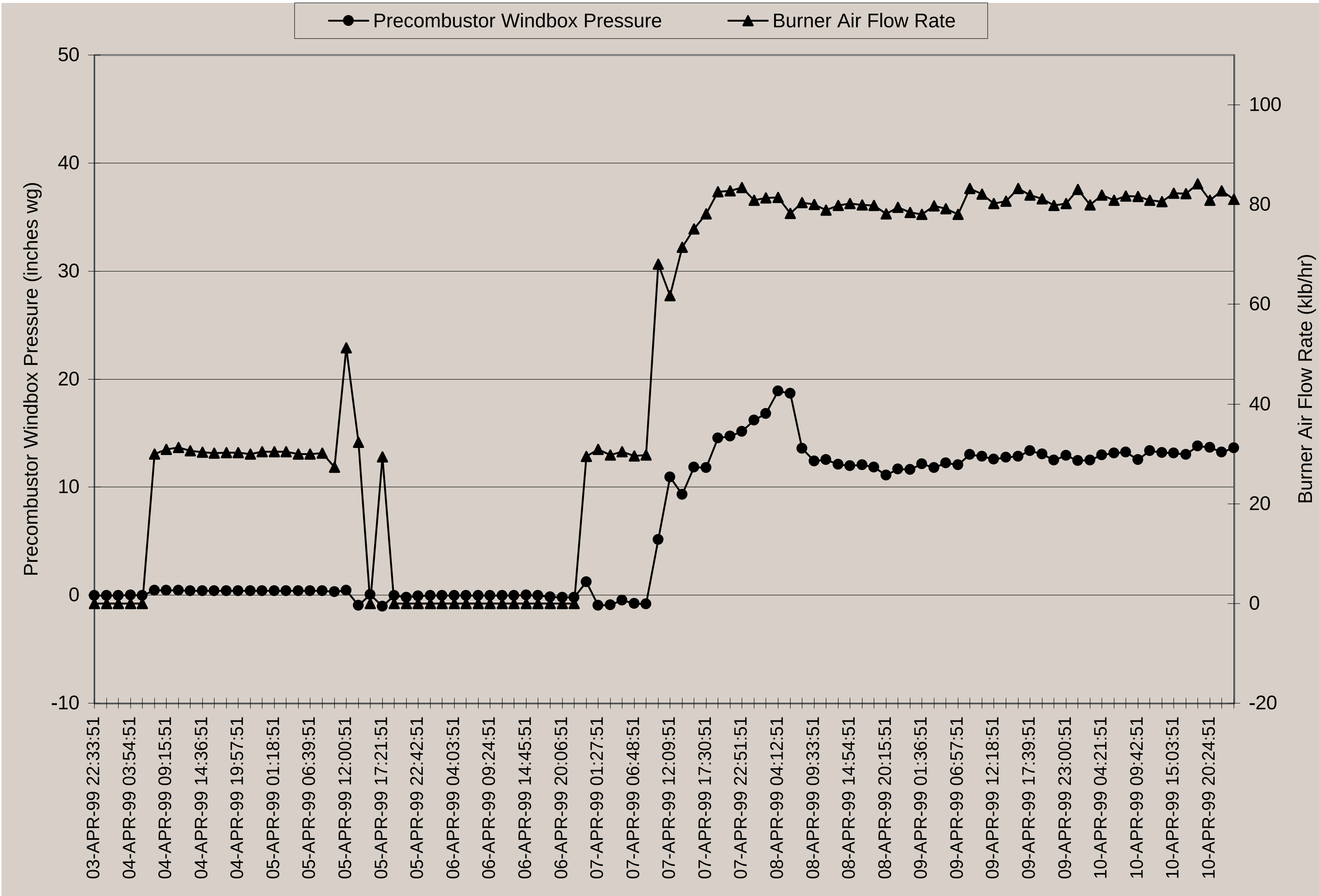
# Figure 4.4.2 - Inferred Coal Heating Value April 10 - 17



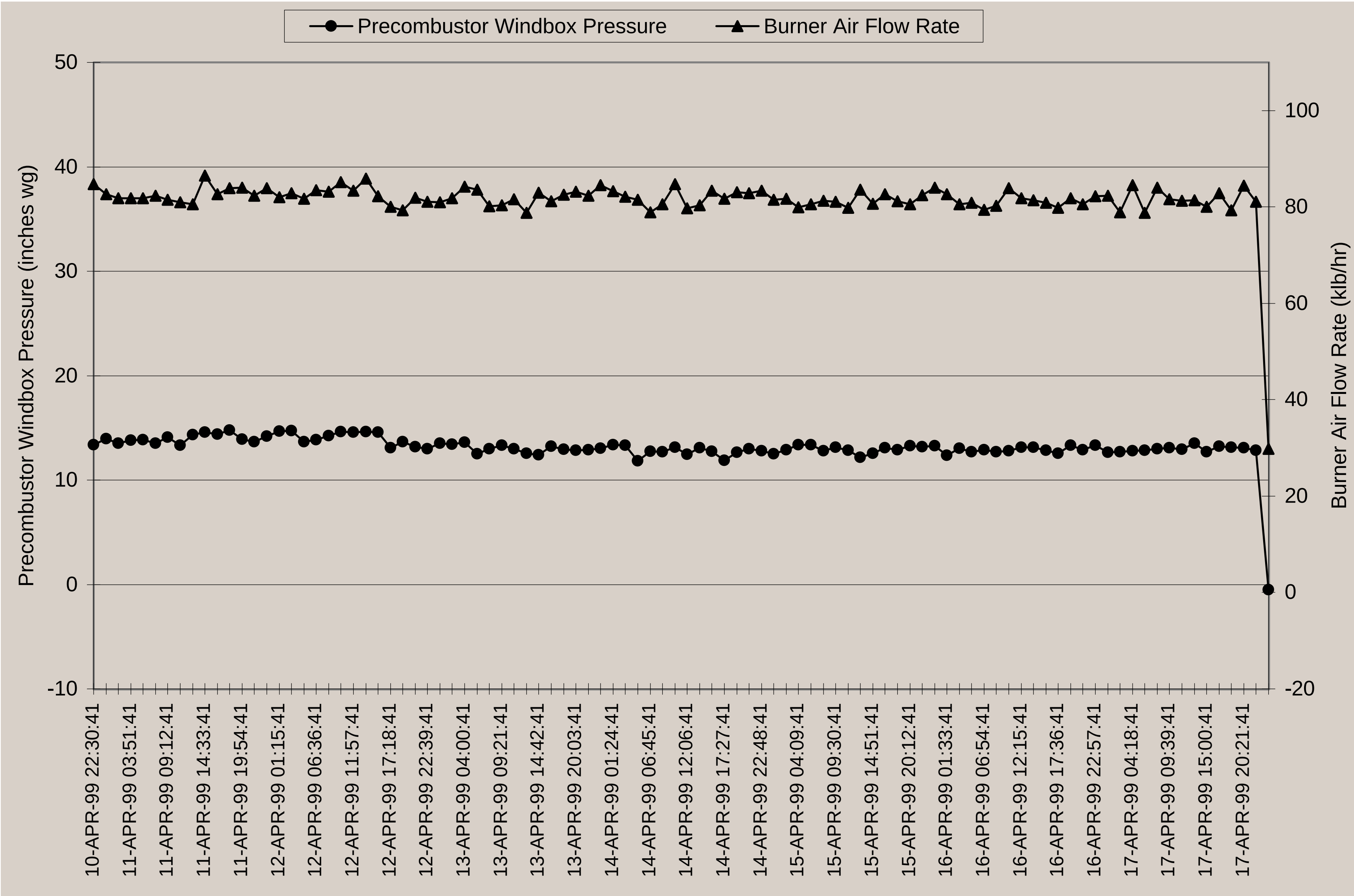
# Figure 4.4.3 - Inferred Coal Heating Value April 17 - 24

# Figure 4.4.4 - Inferred Coal Heating Value April 24 - May 1

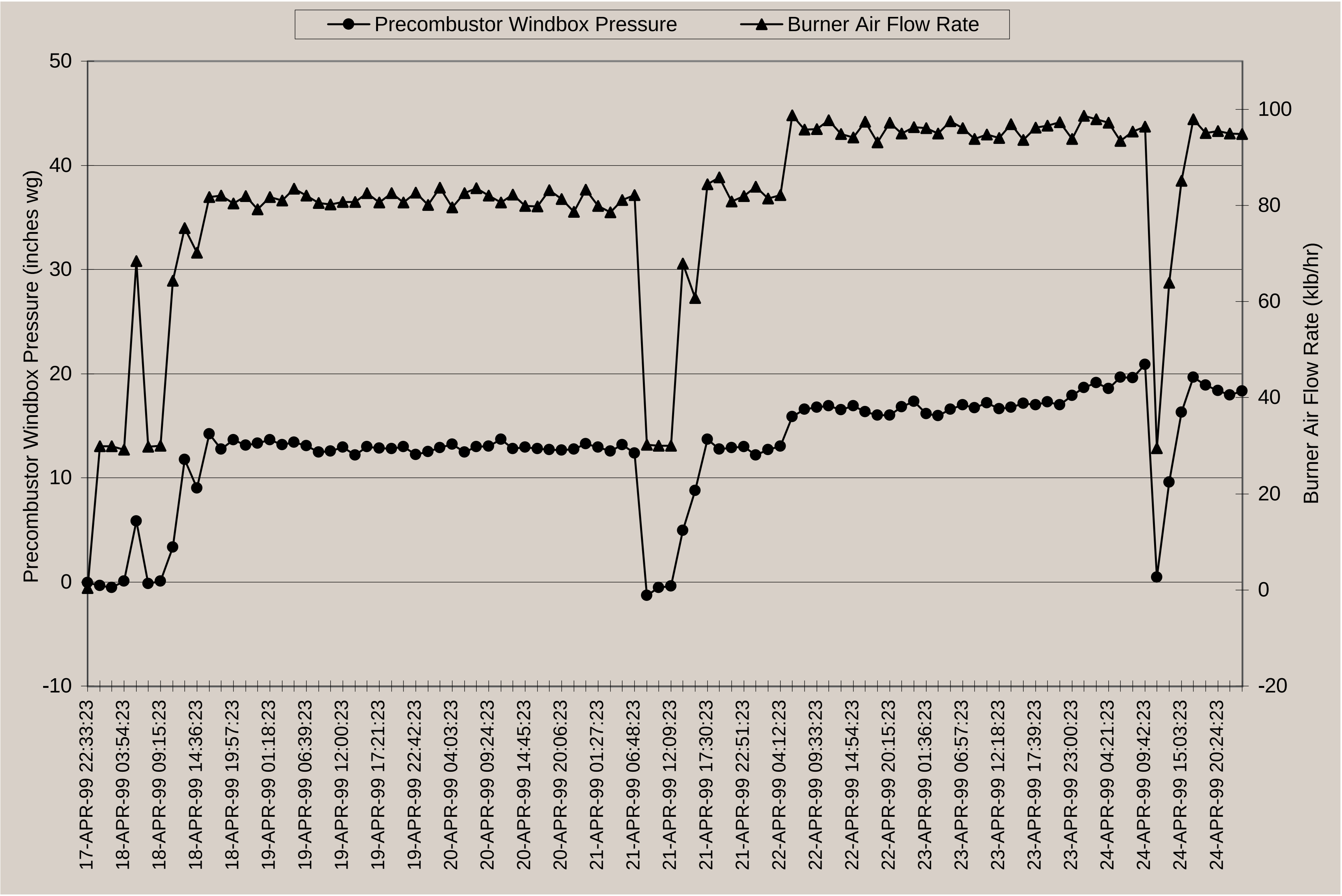
# Figure 4.4.5 - Precombustor A Windbox Pressure and Burner Flow Rate April 3 - 10



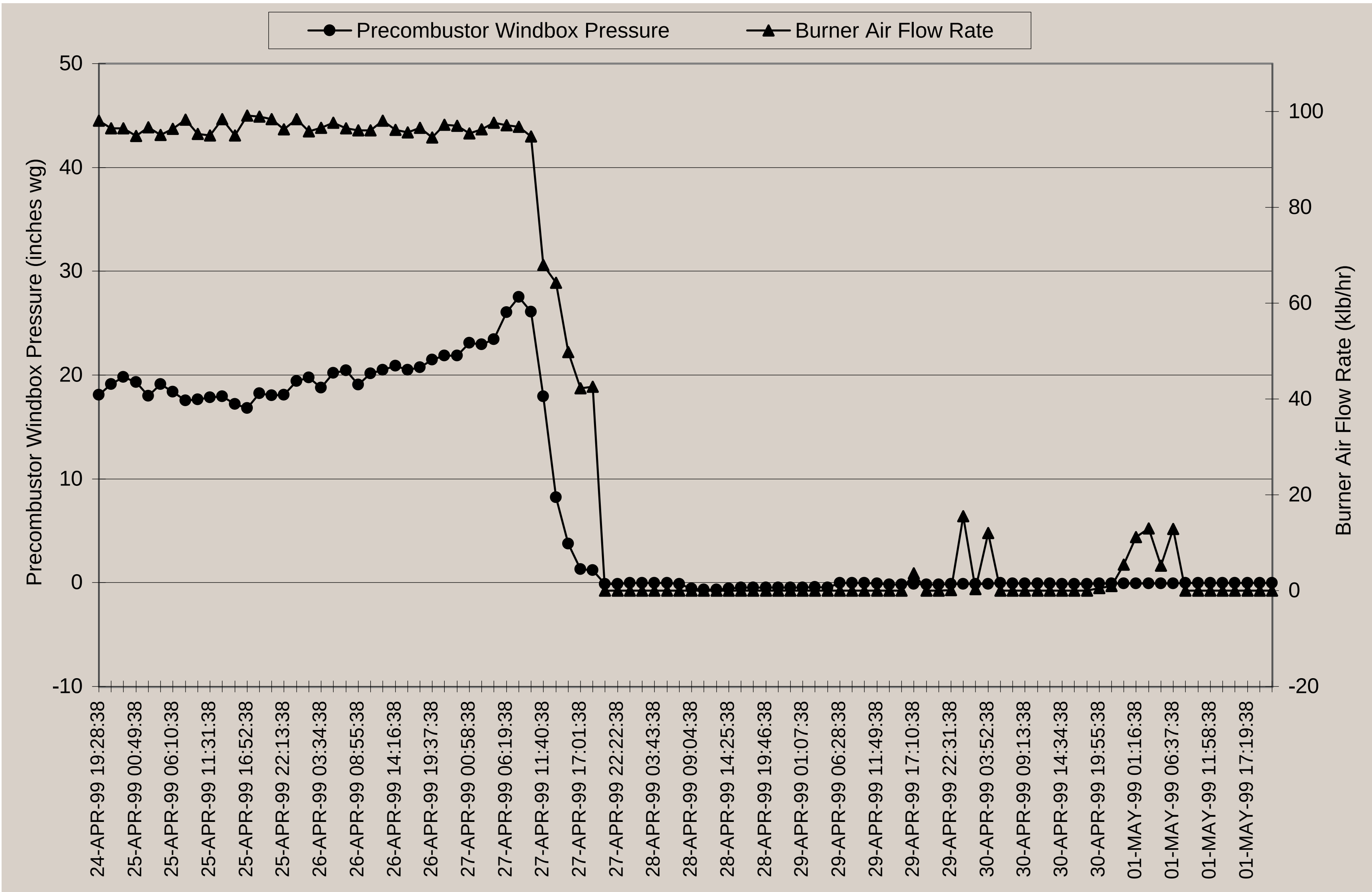
# Figure 4.4.6 - Precombustor A Windbox Pressure and Burner Flow Rate April 10 - 17



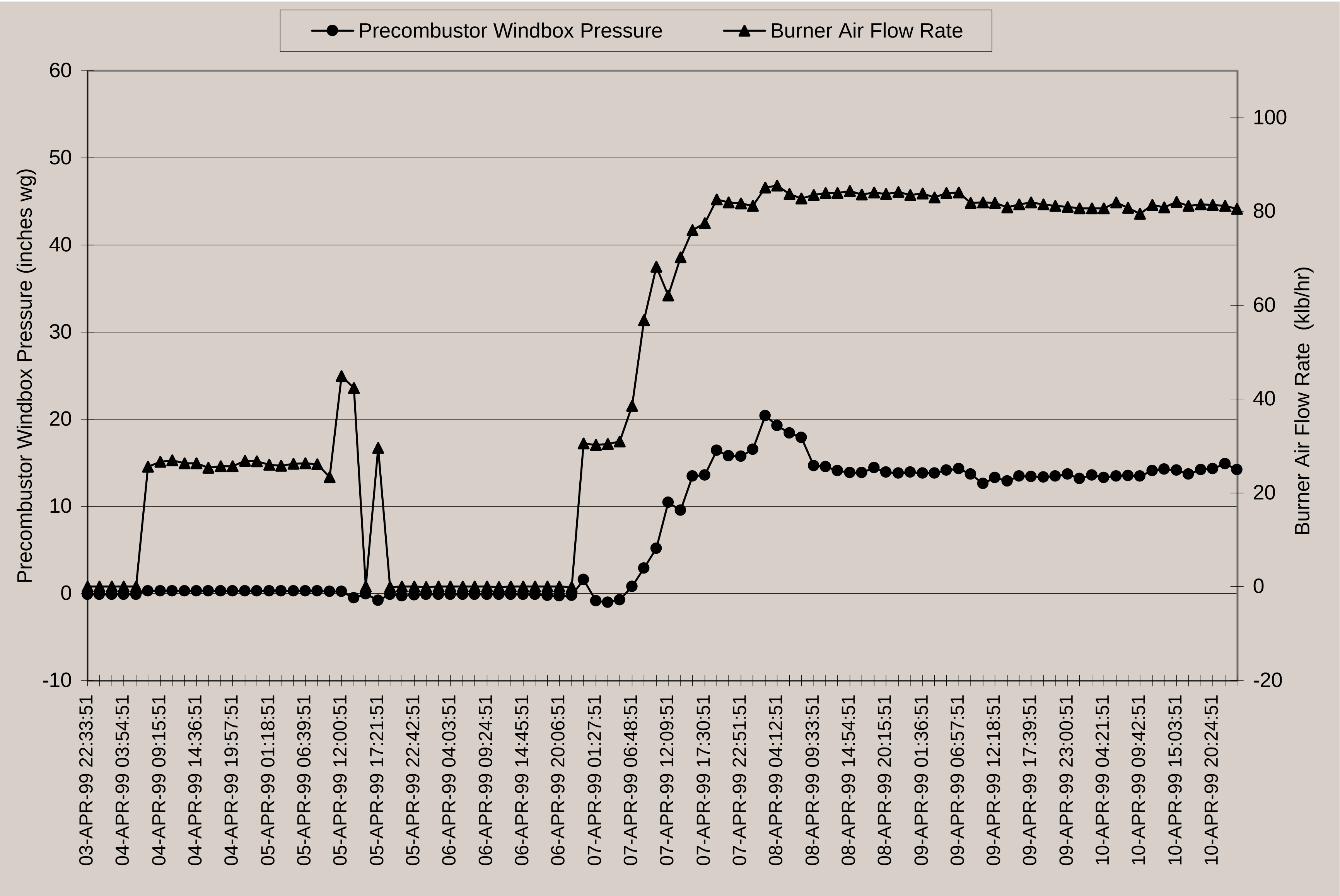
# Figure 4.4.7 - Precombustor A Windbox Pressure and Burner Flow Rate April 17 - 24



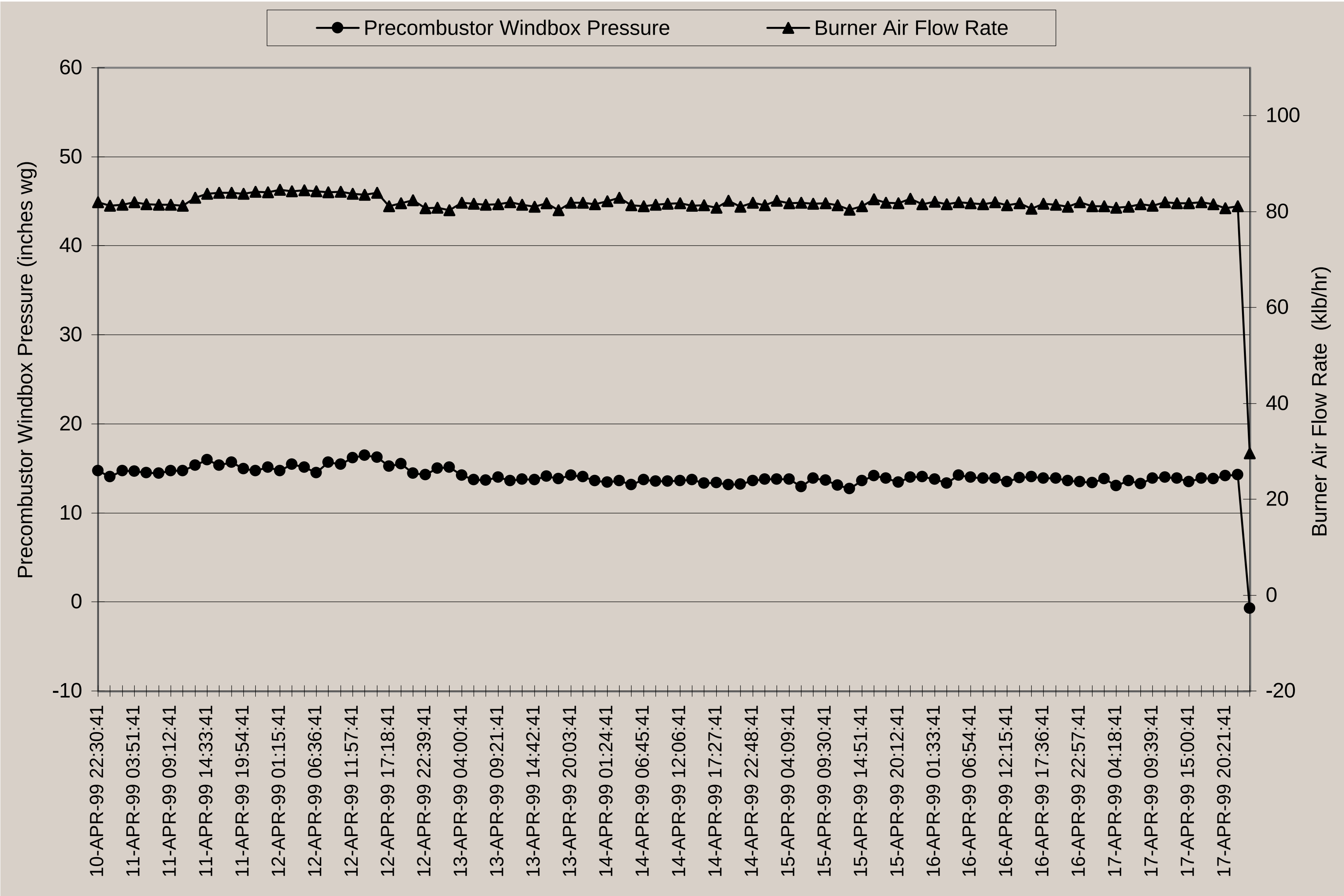
# Figure 4.4.8 - Precombustor A Windbox Pressure and Burner Flow Rate April 24 - May 1



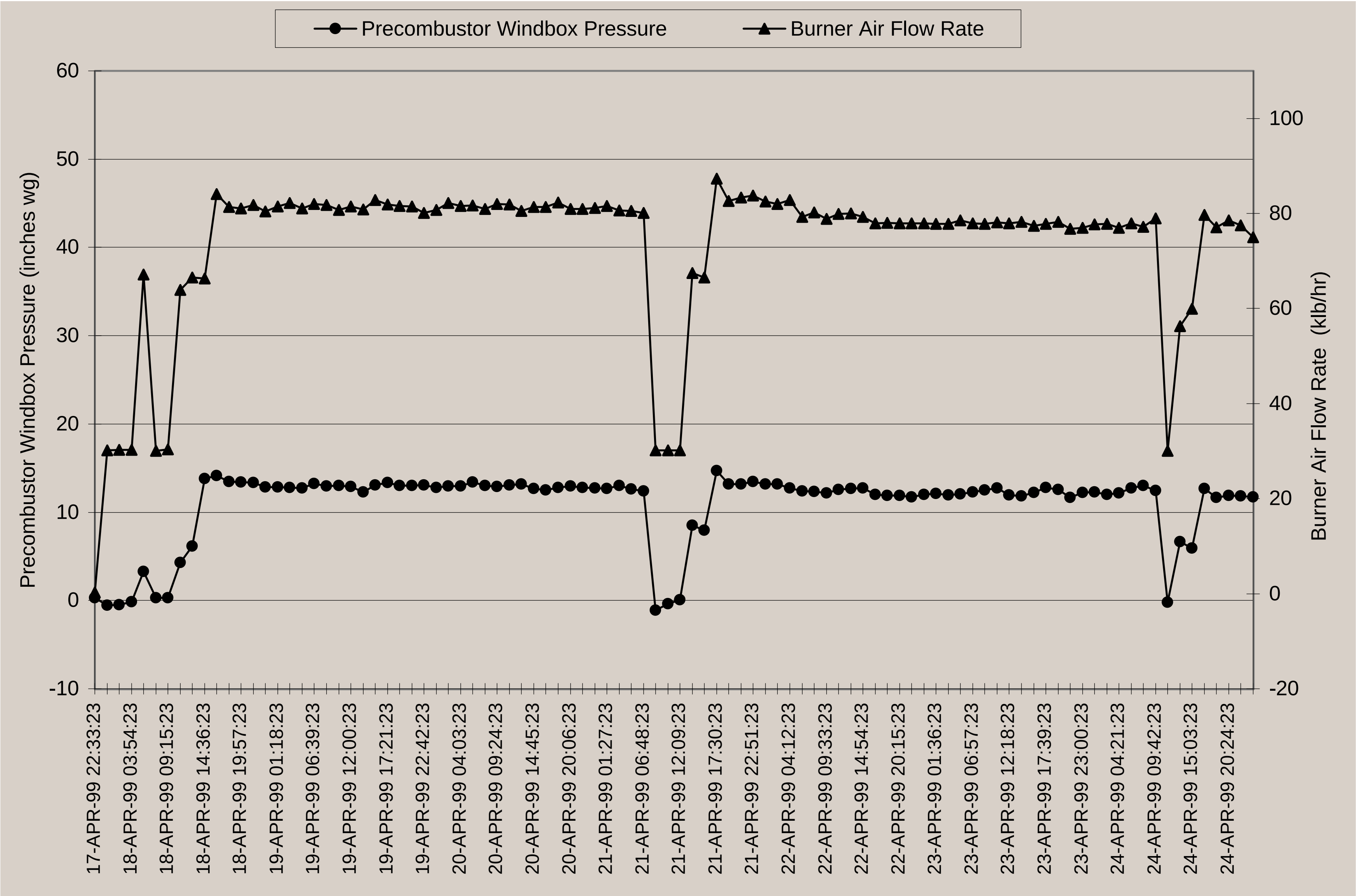
# Figure 4.4.9 - Precombustor B Windbox Pressure and Burner Flow Rate April 3 - 10



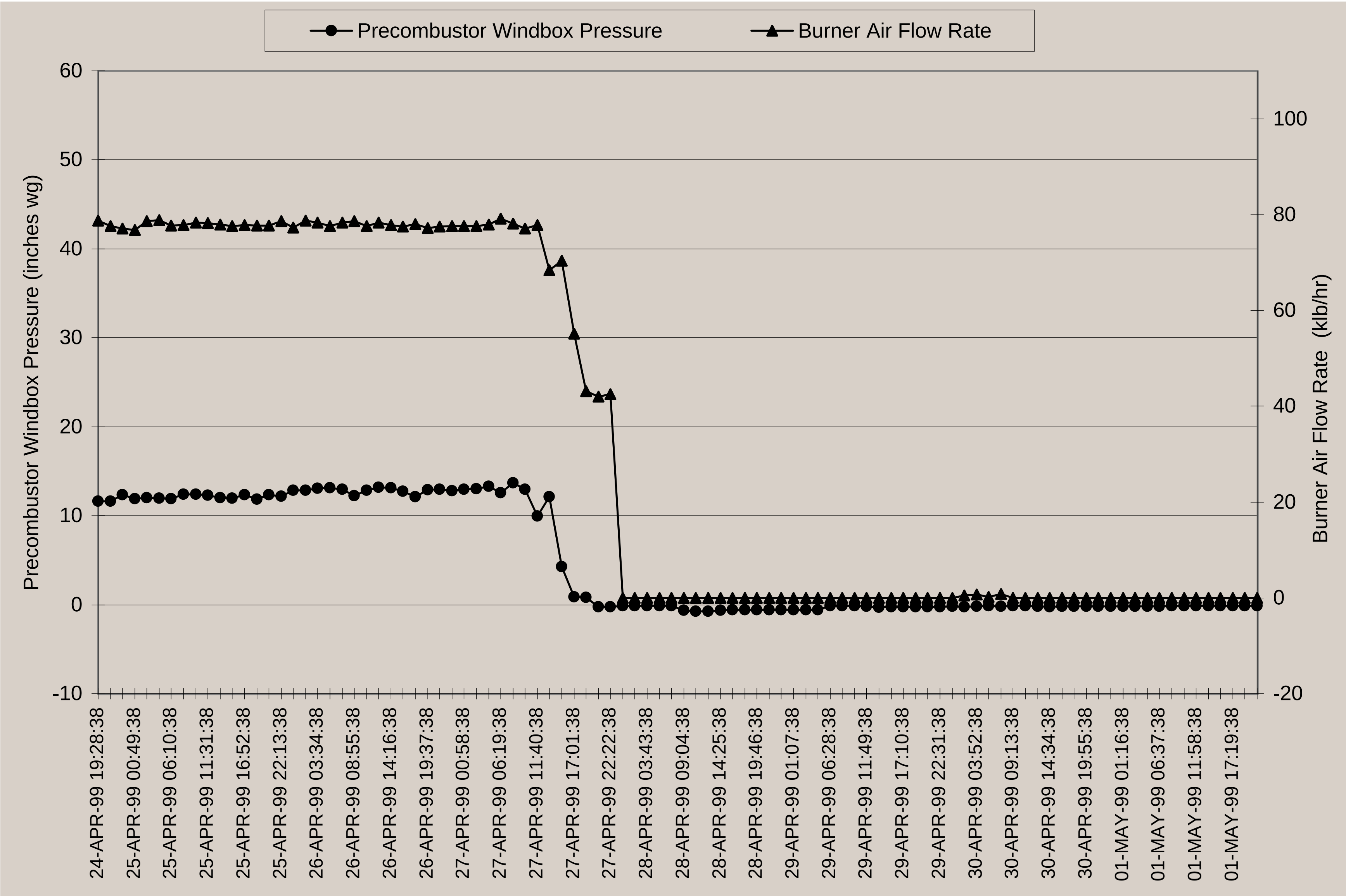
## Figure 4.4.10 - Precombustor B Windbox Pressure and Burner Flow Rate April 10 - 17



# Figure 4.4.11 - Precombustor B Windbox Pressure and Burner Flow Rate April 17 - 24



# Figure 4.4.12 - Precombustor B Windbox Pressure and Burner Flow Rate April 24 - May 1



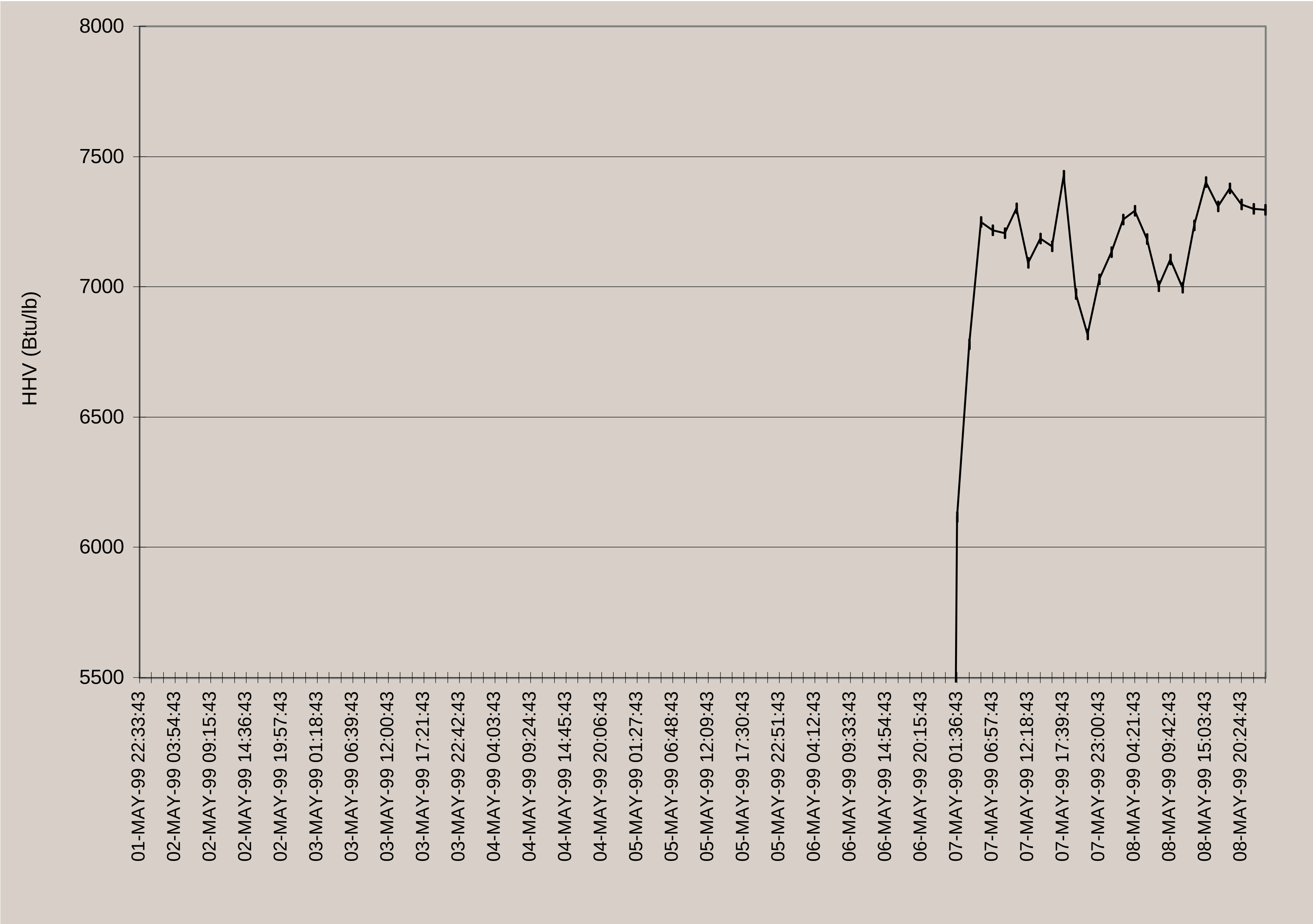
## 4.5 MAY OPERATIONS

During May, staying within environmental compliance was emphasized to prepare HCCP for a flue gas desulfurization (FGD) system test and to prepare for the ninety-day commercial operation test. Two incidents of high stack opacity occurred, when the baghouse was inadvertently bypassed. Both incidents were the result of work on the instrumentation measuring the baghouse pressure drop.

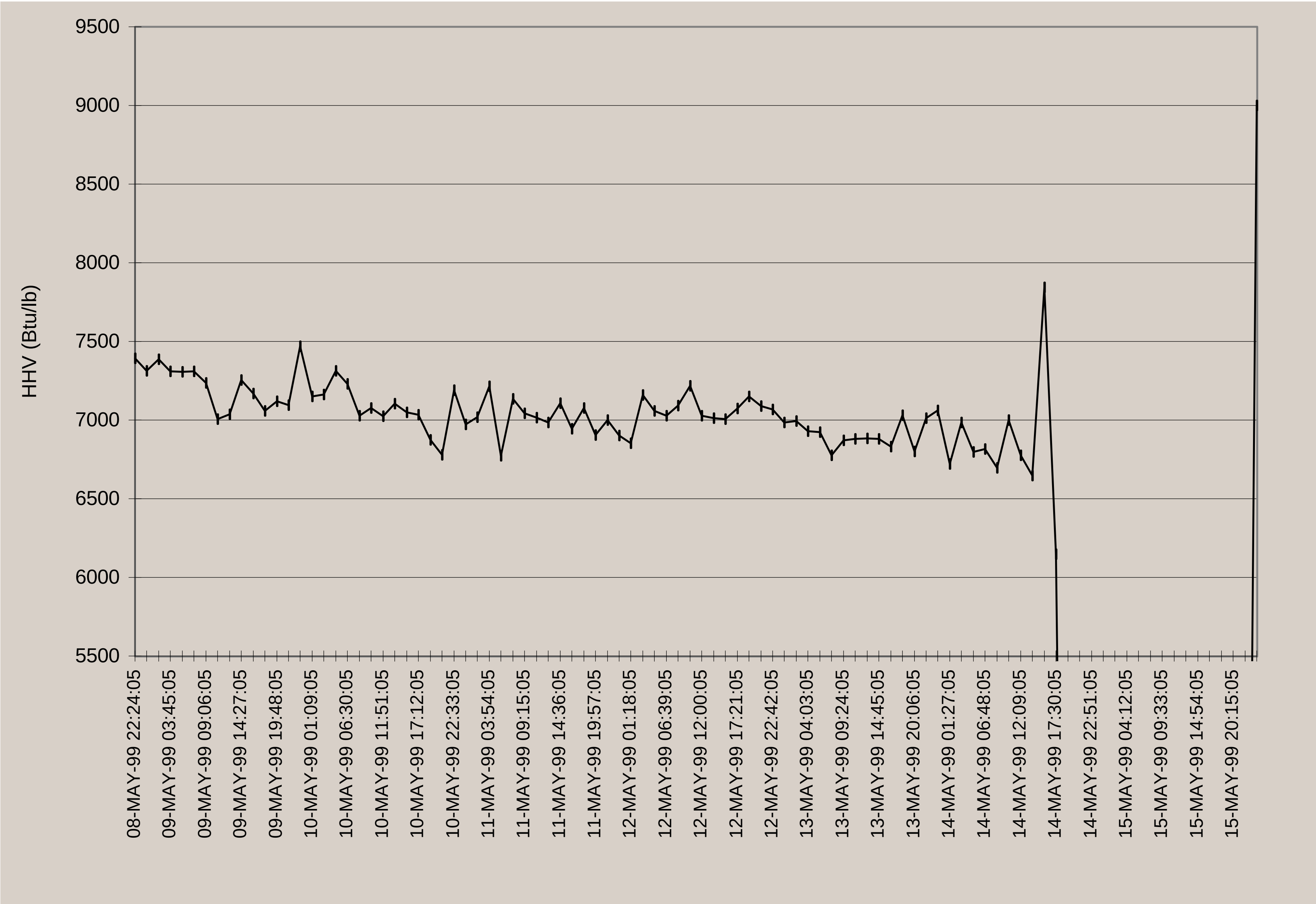
Precombustor windbox pressure remained low (at approximately sixteen inches water column), while firing 7,000 Btu/lb coal, as shown in Figures 4.5.1 through 4.5.9. Coal higher heating value was significantly less than 7,000 Btu/lb for most of the last four days in May and no significant windbox pressure increase occurred during that time frame.

The furnace pressure excursion problem, caused by large slag falls, occurred on May 20 and again on May 29. Water lances had been ordered in April to resolve this problem and the engineering and design changes to provide and install the water lances were in progress.

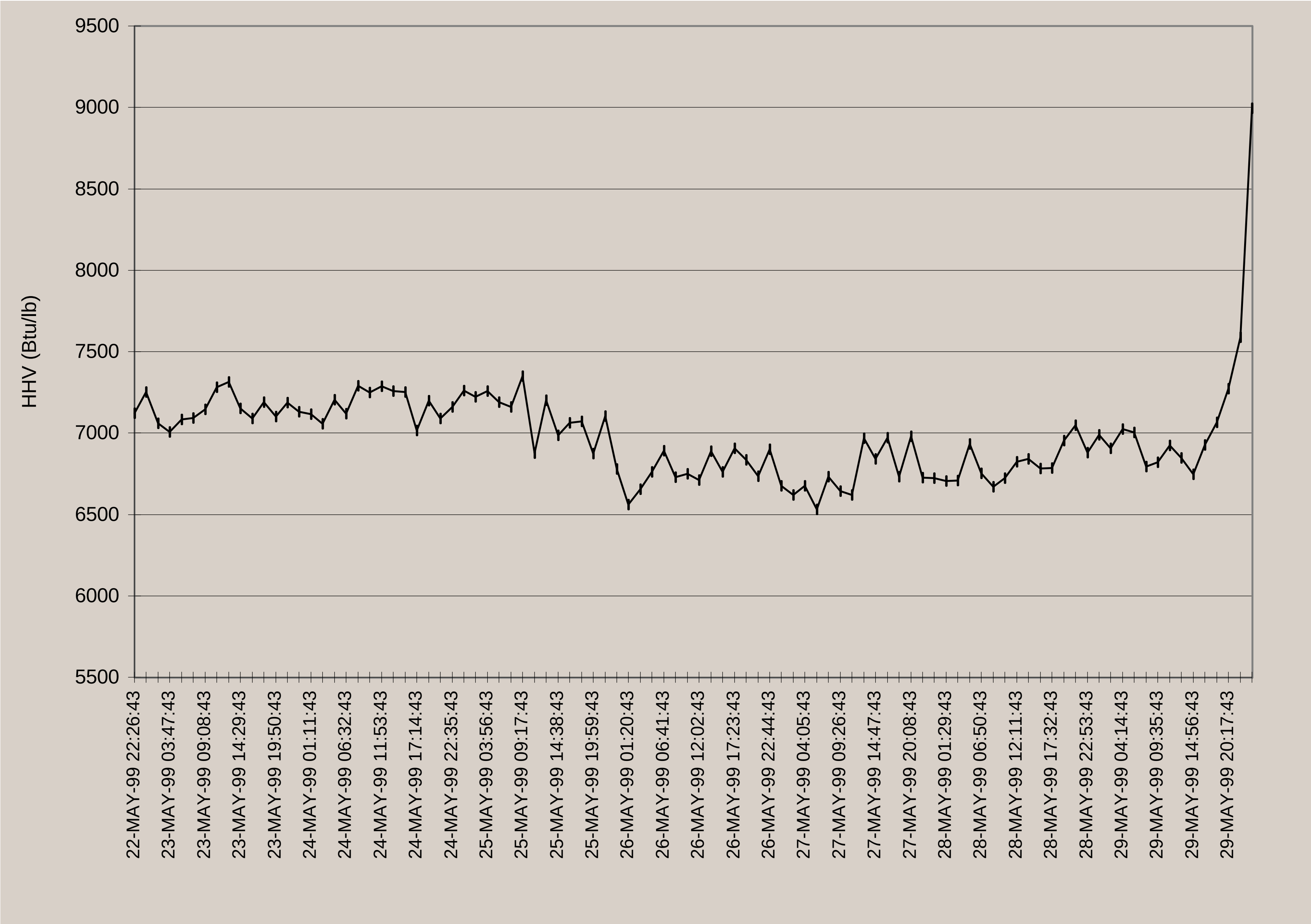
# Figure 4.5.1 - Inferred Coal Heating Value May 1 - 8



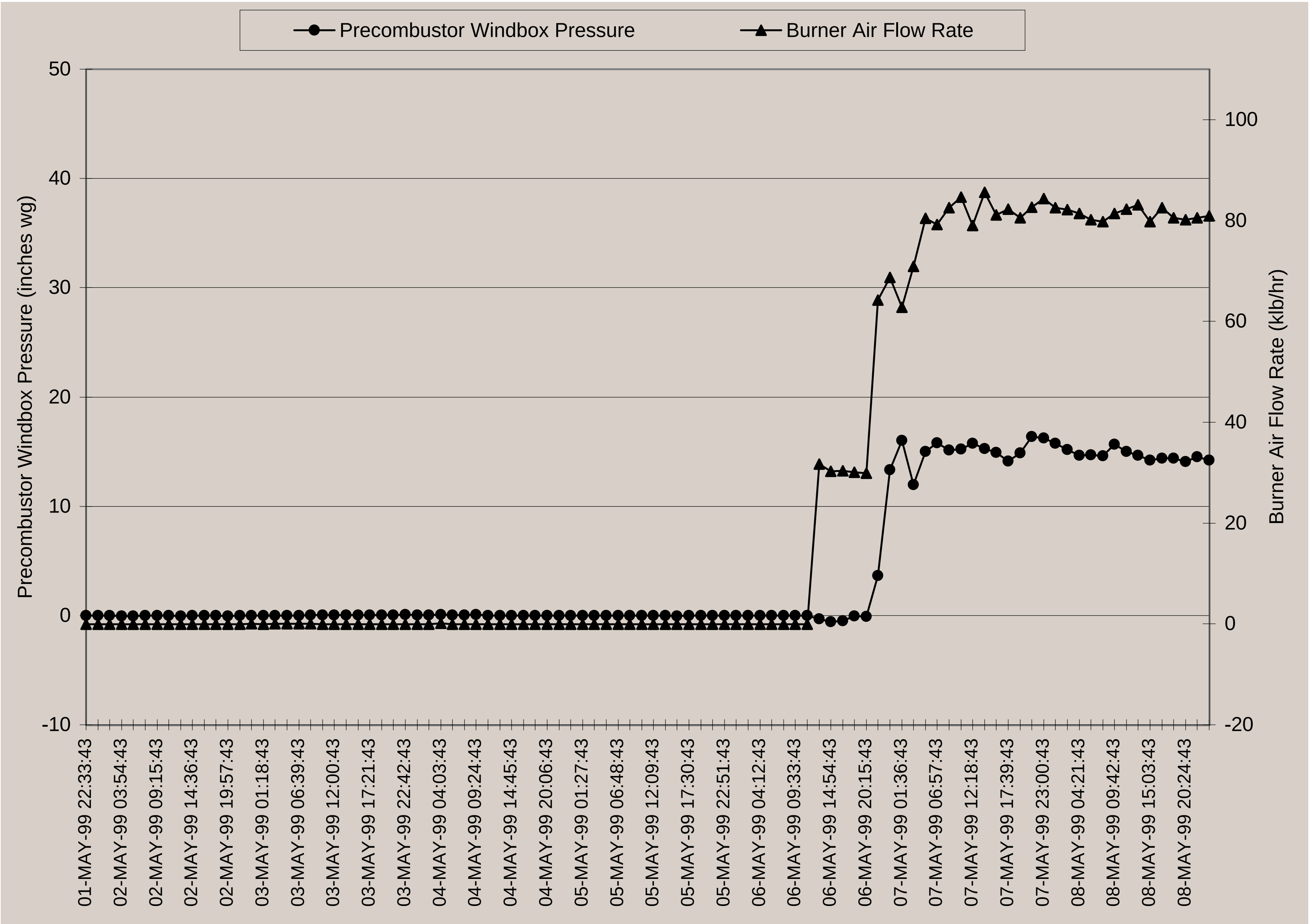
# Figure 4.5.2 - Inferred Coal Heating Value May 8 - 15



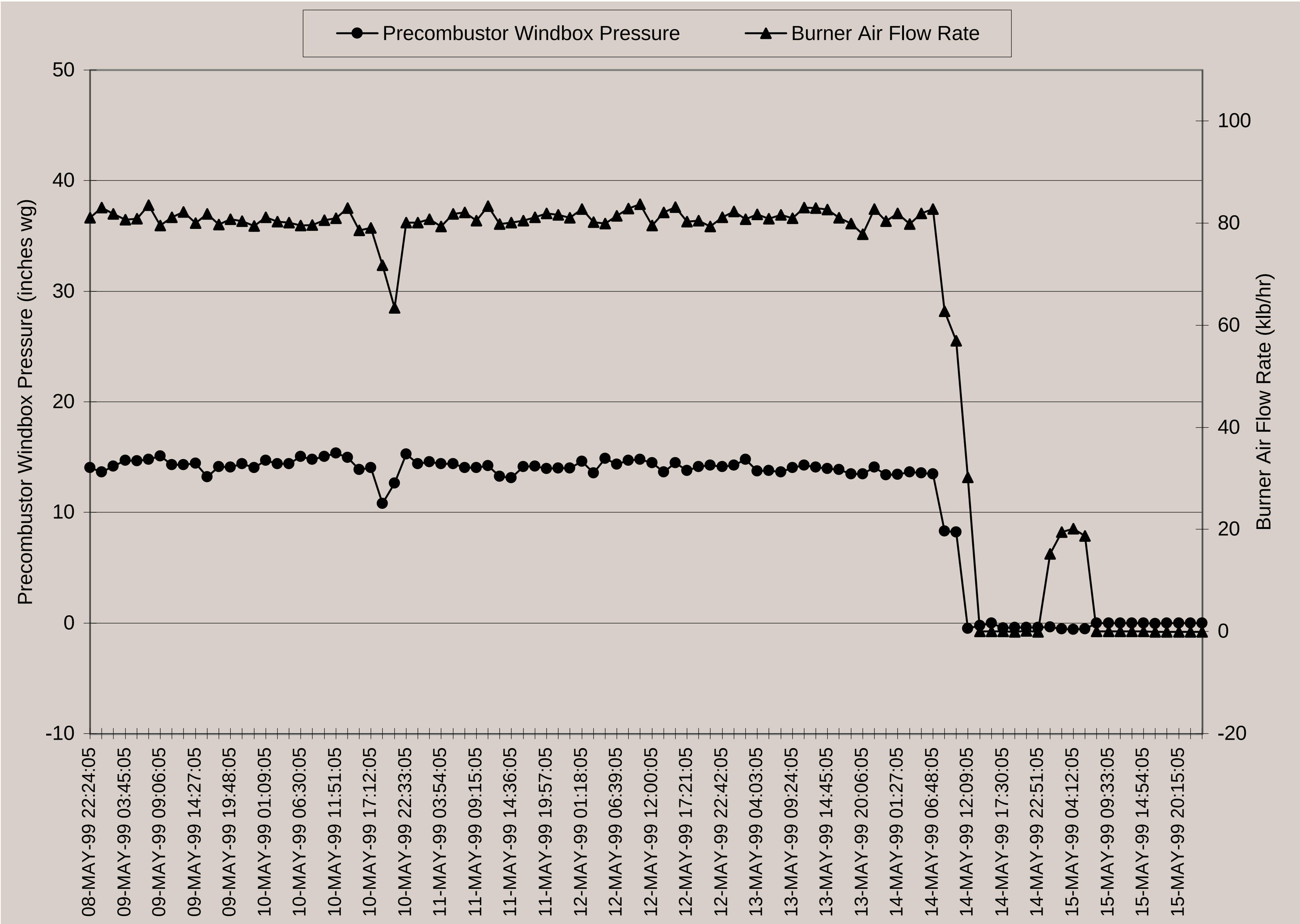
# Figure 4.5.3 - Inferred Coal Heating Value May 22 - 29



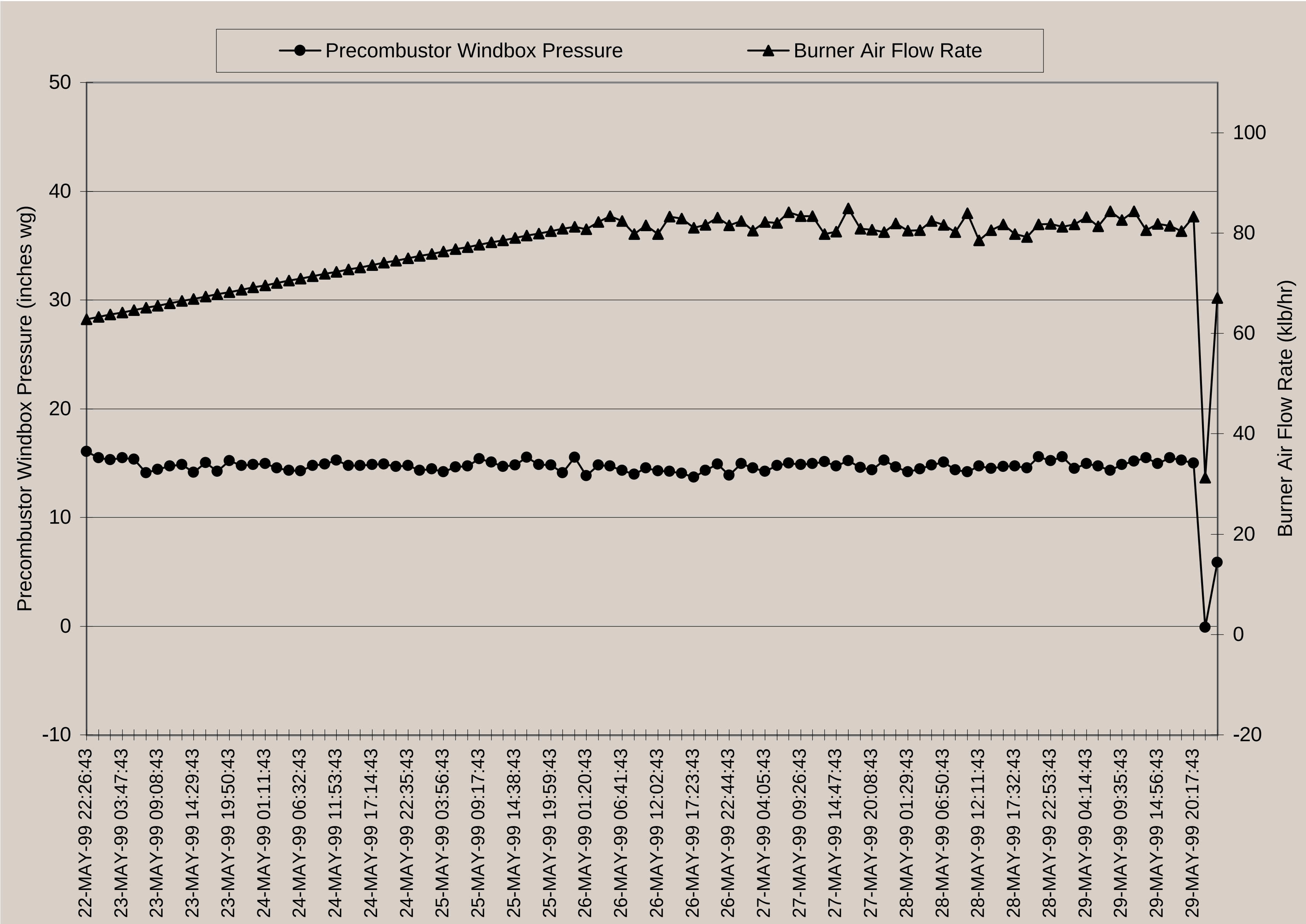
## Figure 4.5.4 - Precombustor A Windbox Pressure and Burner Flow Rate May 1 - 8



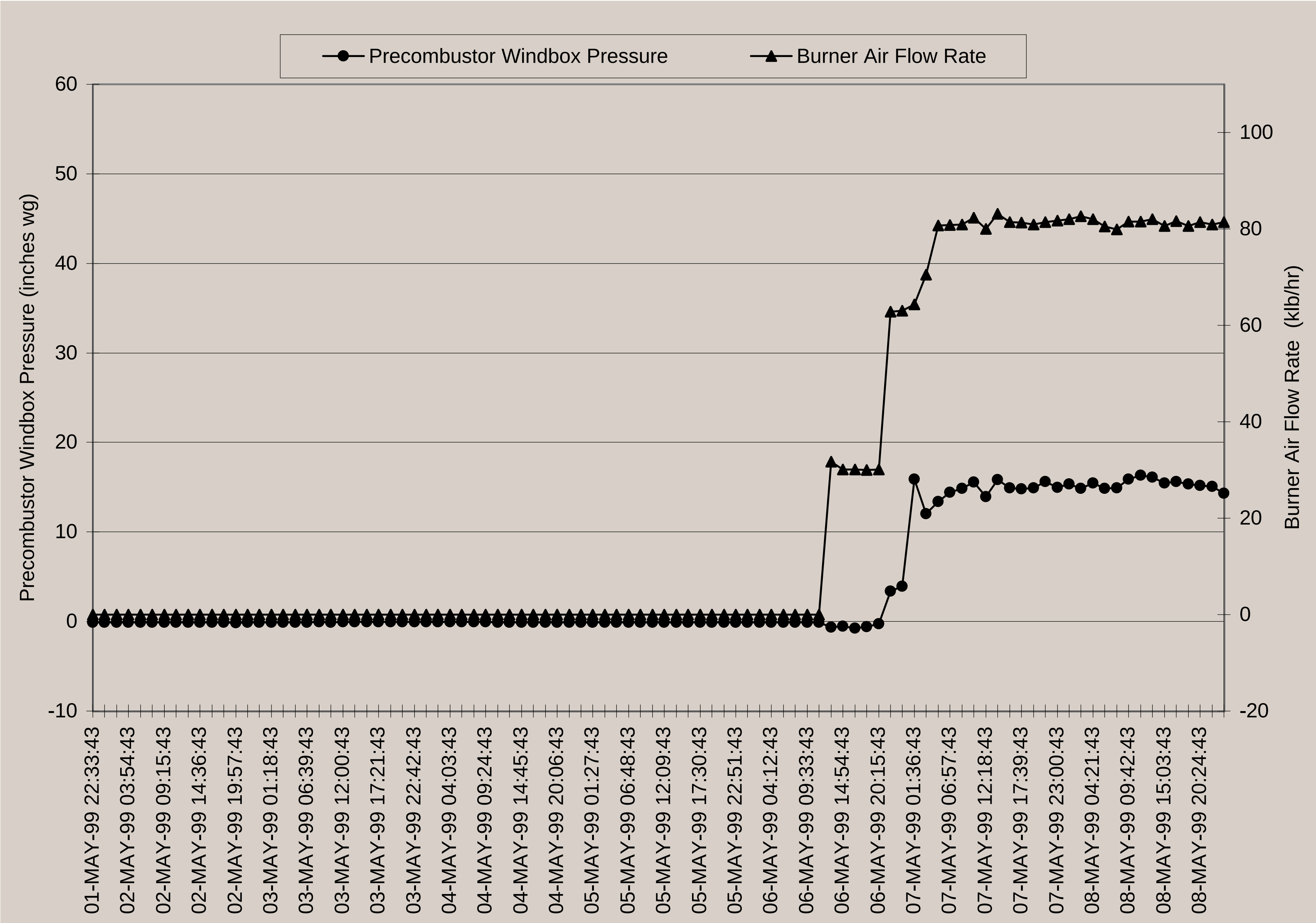
# Figure 4.5.5 - Precombustor A Windbox Pressure and Burner Flow Rate May 8 - 15



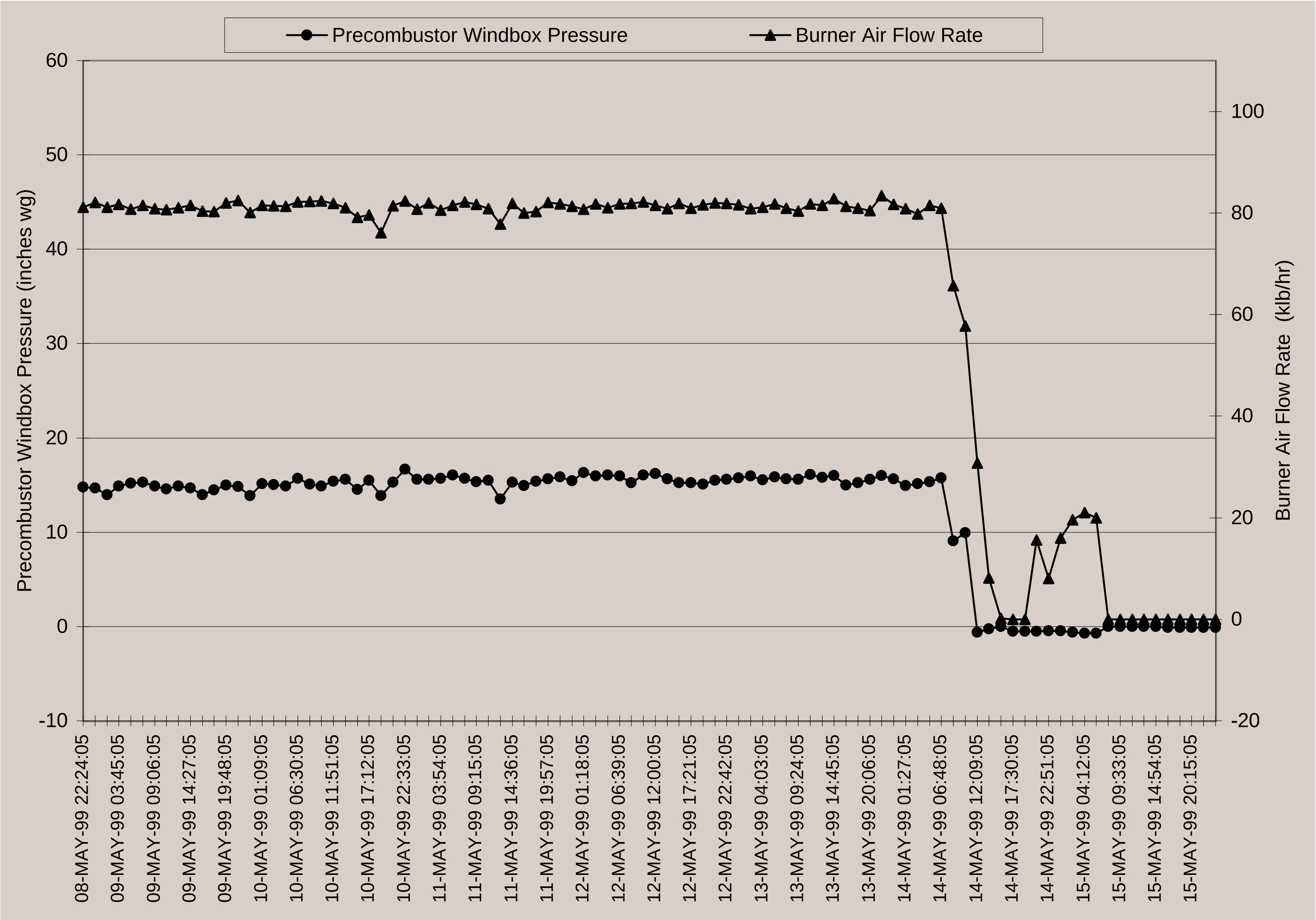
# Figure 4.5.6 - Precombustor A Windbox Pressure and Burner Flow Rate May 22 - 29



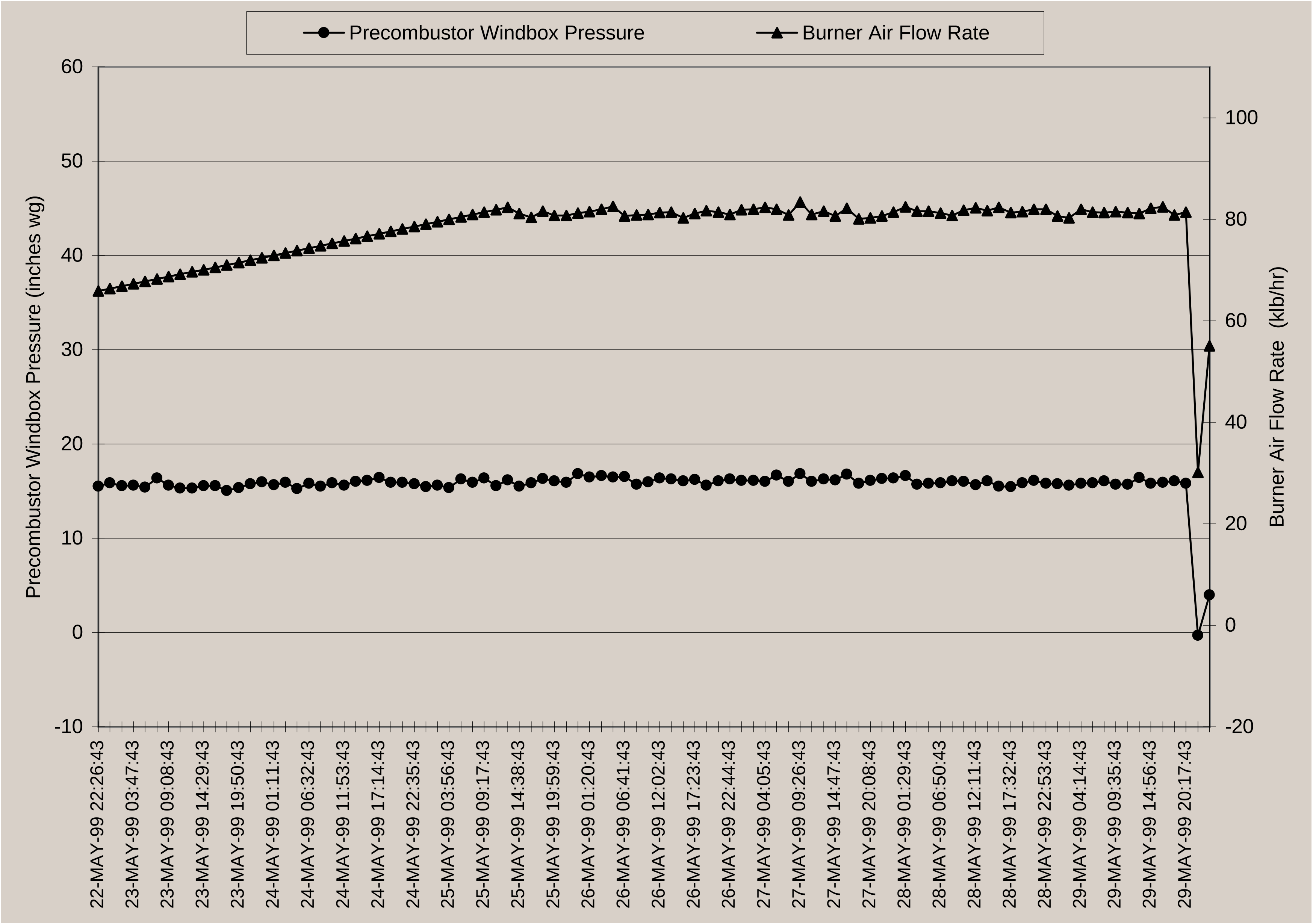
# Figure 4.5.7 - Precombustor B Windbox Pressure and Burner Flow Rate May 1 - 8



# Figure 4.5.8 - Precombustor B Windbox Pressure and Burner Flow Rate May 8 - 15



# Figure 4.5.9 - Precombustor B Windbox Pressure and Burner Flow Rate May 22 - 29



## 4.6 JUNE OPERATIONS

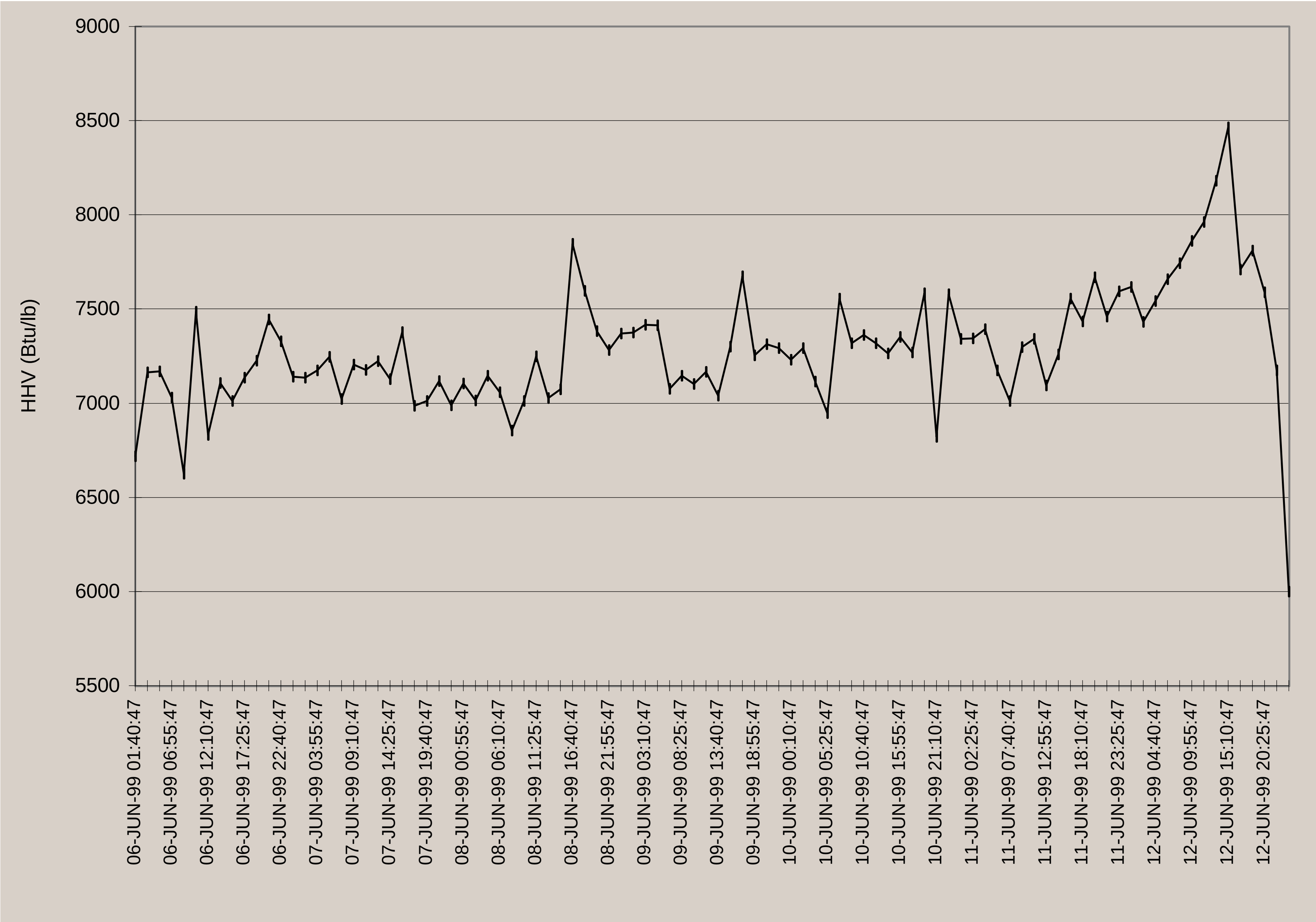
On June 2, the unit was shut down as a precautionary measure so that slag could be cleaned from the sloped hopper area of the furnace to avoid another slag fall, which could cause a furnace pressure trip during the next test run. Operation resumed on June 5 and the spray dryer absorber (SDA) performance testing occurred between June 7 and June 11.

The coal heating values and precombustor windbox pressures during operation are shown in Figures 4.6.1, 4.6.2, and 4.6.3. The precombustor windbox pressures remained low during the entire operation.

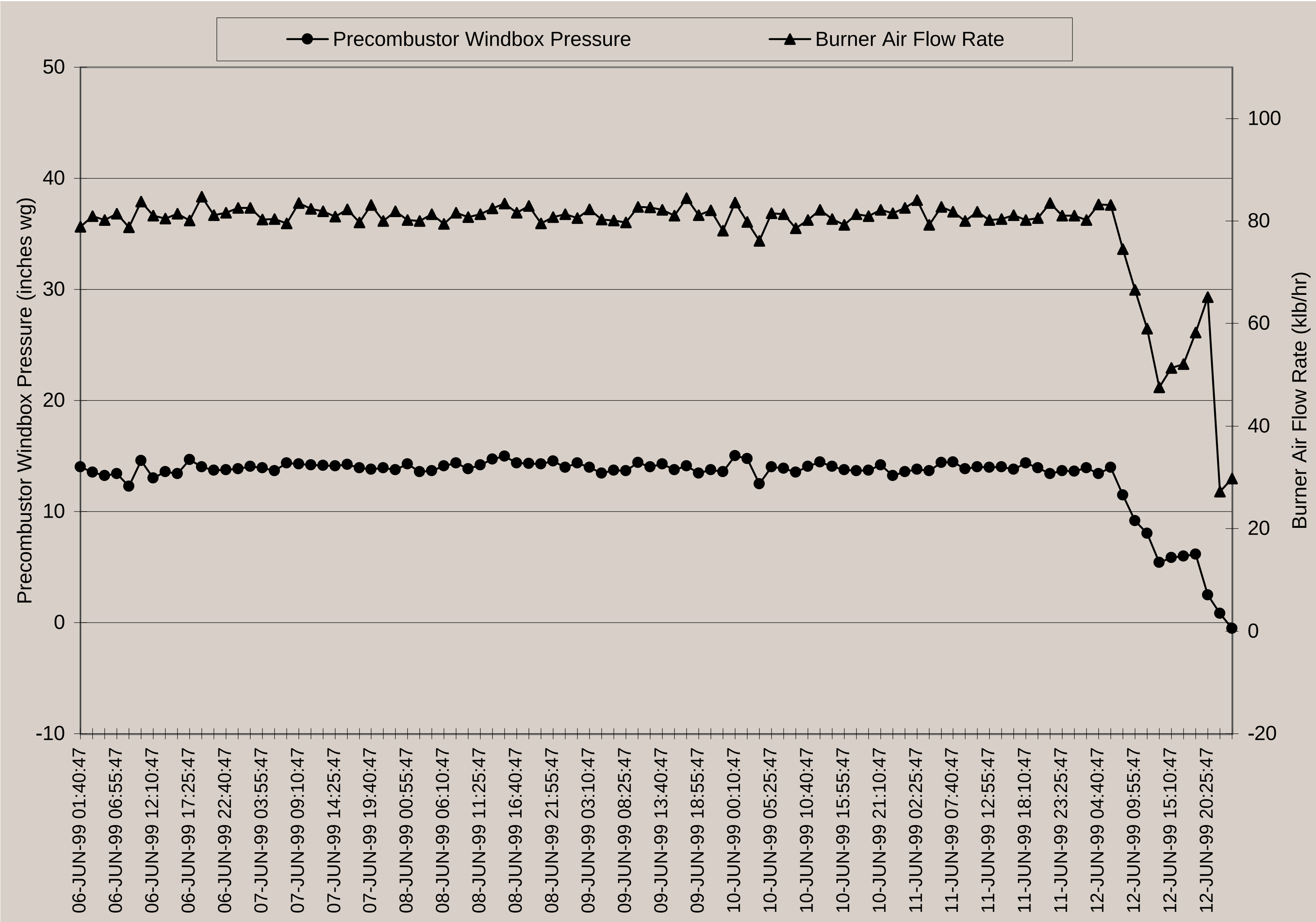
The SDA test results are shown in the Table 3.2 and are compared with the contractual guaranteed values. A total of nine tests were conducted. Test No. 2 was invalid due to equipment malfunction and is not included in the table. A detailed discussion can be found in the SDA Performance Test Report (see Reference 6). Test results show that the SDA system at HCCP surpassed all performance guarantee requirements. HCCP was shut down on June 12 for the water lance installation.

On June 18, while HCCP was offline, the $CO_2$ fire protection systems of two electrical area zones were tested by fully discharging the associated $CO_2$ cylinders into Fire Protection Zone 16 (the relay room) and into Fire Protection Zone 13 (the switchgear room). Required $CO_2$ concentrations of thirty percent (by volume) were achieved in less than two minutes. Also, a concentration of fifty percent $CO_2$ was achieved in seven minutes and maintained for twenty minutes to satisfy the requirements of the National Fire Protection Association's (NFPA) Standard 12 for $CO_2$ fire extinguishing systems. Modifications performed to meet these requirements are described in Section 5 (Equipment and System Problems).

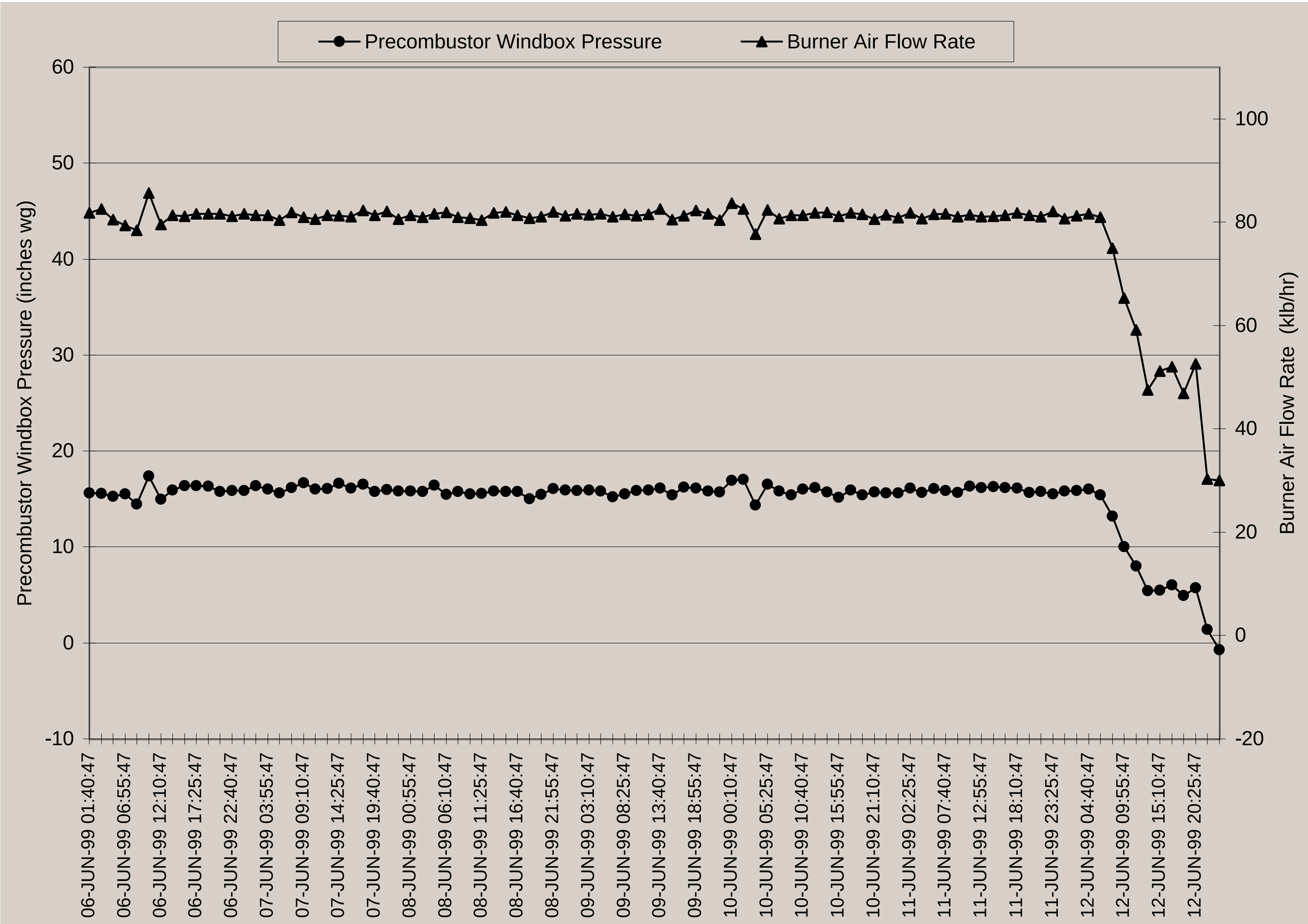
# Figure 4.6.1 - Inferred Coal Heating Value June 6 - 12



# Figure 4.6.2 - Precombustor A Windbox Pressure and Burner Flow Rate June 6 - 12



# Figure 4.6.3 - Precombustor B Windbox Pressure and Burner Flow Rate June 6 - 12



## 4.7 JULY OPERATIONS

The unit remained down until July 15, while waiting for the water lances to arrive (see Section 4.5 – May Operations). Delivery of the water lances was delayed by the lance supplier's labor union problems.

During this outage, an internal boiler gas duct brace was found to be broken. It had rubbed against a boiler tube, causing wear on the tube. The tube was repaired and the brace was replaced.

Based on the windbox pressure performance data, which indicated that the removal of secondary air from the mix annulus had been successful, the precombustor mix annulus was permanently blocked off with refractory protected welded plates.

In 1998, a blank-off plate had been installed over some of the gas-side tubes in the high temperature air heater to prevent the secondary air temperature from exceeding the design limits of the carbon steel secondary air piping. This was accomplished; however, it also decreased the temperature of the hot primary air to the pulverizers. One half of the blanking plate was removed during this outage.

On July 15, the unit was started to ensure that all planned changes (except the installation of the lances) were incorporated and the equipment was restored so that, once the lances were received and installed, plant operation could progress as quickly as possible toward the ninety-day test. On July 18, the unit was shut down again for the installation of the water lances.

New mill exhauster rotors were installed and the water lances arrived and were installed.

## 4.8 AUGUST OPERATIONS

The unit was started on August 7 to test the newly installed water lances and was shut down on August 10 to evaluate the water lance cleaning and to change out and balance the new mill exhauster rotors.

On August 16, startup for the ninety-day test run was initiated and the test began at 5:00 PM on August 17. The unit ran at full load for the remainder of August.

For details of the test and for AIDEA's perspective, the Ninety-Day Commercial Operation Test and Sustained Operations Report: A Participant's Perspective should be reviewed (see Reference 2).

## 4.9 SEPTEMBER OPERATIONS

September operation was steady at full load (approximately 58 megawatts) using the water lances to remove the ash accumulation from the sloped furnace hopper twice per day (at 8:00 AM and 5:00 PM), until September 5. On September 5, at approximately 8:00 PM, increasing condensate flow to Dipper Skirt A was noted. The rate of condensate loss was excessive and HCCP had to be shut down. During the process of shutting down, the inlet primary air duct to Pulverizer B exploded. The events that led to the explosion follow:

| | |
|---|---|
| 3:55 AM | Plant load reduction was initiated. |
| 4:36 AM | During the Coal Feeder B flow reduction to 29,000 lb/hr, the temperature in Pulverizer B was 160° F. |
| 4:55 AM | Pulverizer B temperature had dropped to 111° F, with a coal flow of 22,000 lb/hr. |
| 5:10 AM | The feeder to Pulverizer B was shut off with a 108° F outlet temperature. |
| 5:10 - 5:29 AM | With 97,000 lb/hr of primary air at 131° F flowing into Pulverizer B, its outlet temperature had risen to 154° F and continued to rise gradually from there. |
| 5:32 AM | Pulverizer B was shut down. |
| 5:33 AM | The Slagging Combustor and Precombustor B fire valves were closed, causing the mill exhauster discharge pressure to increase from seventy inches to one hundred inches water column and primary air flow decreased to 55,000 lb/hr. Steam inerting manual valves were opened. Pulverizer B inlet and outlet temperatures continued to rise. The feeder to Pulverizer A was stopped and Pulverizer A was swept. |
| 5:39 AM | The Pulverizer B primary air shutoff dampers were closed, reducing its primary air flow to 40,000 lb/hr. |
| 5:41 AM | Pulverizer B inlet temperature was at 225° F and its outlet temperature was at 175° F. The Pulverizer B exhauster fan was stopped. The Pulverizer B inlet duct exploded, tripping the unit. |

The cause of the explosion is believed to be a spontaneous combustion of coal-derived fuel and volatile gases, which accumulated in Pulverizer B during shutdown. This probably resulted from a combination of inadequate purge time and inadequate purge flow rate coupled with temperatures increasing to values greater than acceptable for the volatility of the coal. The situation was complicated by GVEA's dispatch group's request that the unit stay online. As a result, it was necessary to shut both combustors down at the same time, which complicated the shutdown procedure and was a contributing factor in the explosion. When the Pulverizer B exhauster was stopped, the fuel concentration, at temperature, likely increased to a critical level causing spontaneous combustion and deflagration. A test sample of the coal subjected to a thermo-gravimetric analysis demonstrated high reactivity and an initial devolitization temperature of 225°C. Therefore, the Healy coal is highly volatile.

The following recommendations were provided by the pulverizer manufacturer's coal feed system specialist. These recommendations were implemented as operating procedures.

1. During any controlled shutdown or startup sequence, avoid fast or sudden changes in mill operation. Mill load changes should be made in 5,000 to 10,000 lb/hr increments and stabilization allowed to occur before proceeding with further changes.
2. Mill and exhauster outlet temperatures should not be allowed to exceed 160° F.

3. When the mill is operating with coal feed, mill and exhauster outlet temperatures should not be allowed below 130° F.
4. Minimum mill and conduit purge flow should be 95,000 lb/hr. Minimum mill and conduit purge duration before coal feed (startup) or after grindout (shutdown) should be fifteen minutes.
5. Auto/Control Room initiation of the inerting sequence should be possible without the need to open manual shutoff valves (i.e., the manual valves should be in a normally open position).
6. Alarms alerting personnel in the mill box area of a mill start, mill shutdown, or other hazardous conditions (i.e., mill trip) should be instituted.
7. Automatic mill inerting (operator initiated) should be considered for a mill under-load trip scenario.
8. Review of National Fire Protection Association (NFPA) Code 8503 for pulverized fuel systems concerning installation of appropriate explosion vents/doors should be considered.

For a more in depth report on the deflagration, refer to the pulverizer manufacturer's investigative report (see Reference 3).

Pulverizer A was restarted at 9:00 PM on September 7 and the unit was firing on Combustor A, while repairs were performed on the Pulverizer B inlet duct.

Pulverizer B was restarted at 7:30 PM on September 10 and the splitter outlet damper to the slagging combustor (whose motorized gear operator was damaged from the March deflagration) was found closed. Pulverizer B was shut down (at 8:00 PM), based on abnormally high splitter inlet pressure. The damaged closed damper was reopened and Pulverizer B was restarted at 10:30 PM. At 12:23 AM, a high inboard bearing temperature on Pulverizer B caused the pulverizer to trip. The bearing problem was determined to have been caused by the pulverizer deflagration. This was followed by a furnace pressure excursion, which caused the unit to trip.

The unit was back online at 8:00 AM on September 11. Coal firing on Combustor A resumed at 9:00 AM, while the Pulverizer B motor inboard bearing was replaced and its motor-to-mill shaft alignment was checked.

Pulverizer B was started at 6:00 PM on September 11. Full load (approximately 58 megawatts) was established. Shortly thereafter, high vibration (3.5 mils) was noted on the Mill Exhauster B inboard bearing. On September 20, the Mill Exhauster B inboard bearing vibration had risen to 7.9 mils. At 6:00 PM on September 20, with Coal Silo B almost empty, coal feed was reduced to prepare for the Combustor B shutdown. Pulverizer B was shut down at 9:00 PM without incident.

The unit continued to run on Combustor A, at approximately 30 megawatts, while a different rotor was installed and balanced on Mill Exhauster B. Coal flow to Combustor B was reinitiated on September 23 at 9:15 AM and HCCP ran smoothly at full load through the remainder of September.

On September 28, there was a violation in $SO_2$ emissions, caused by insufficient flow to the atomizer. Chunks in the system plugged the slurry line between the head tank and the atomizer. Attempts to clear lines, strainers, etc., and to clean the head tank mitigated the problems; however, an atomizer swap-out was eventually necessary. The unit was out of compliance from approximately 7:00 PM on September 28 until 1:00 AM on September 29. Prior to and subsequent to this incident, the SDA system performed extremely well.

## 4.10 OCTOBER OPERATIONS

Full-load (58 megawatts), steady-state operation continued into October with no significant operational problems, except on October 10, when the windbox pressure on Precombustor B rose to approximately twenty inches water column. By October 10, it had been surmised from operational data (based on the operational differences between Combustor A and Combustor B) that a damaged cyclone inlet damper on Slagging Combustor B had caused a misdistribution of coal flow. In particular, the coal split to Precombustor B was higher and was believed to be the cause of the Precombustor B windbox pressure increase. Total coal flow was biased away from Combustor B and toward Combustor A, such that the total coal flow was unchanged. According to the combustor supplier, this provided conditions to Precombustor B (based on its higher than desired precombustor coal split) that were closer to what the Precombustor B combustion chamber size was designed for. Each time Precombustor B windbox pressure indicated slag build-up, the biasing technique was used successfully to melt out the accumulated slag. In each case, this caused no noticeable long-term indication of excessive slag build-up in Precombustor A, which received the coal flow biased away from Combustor B.

On October 19, there was a coal leak on Mill Exhauster B, which required the load reduction (starting at 11:30 AM) and shutdown (at 1:30 PM) of the Coal Feeder B system. The leak on the mill exhauster casing was repaired and Mill Exhauster B was restarted at approximately 7:00 that evening. Full load was restored by approximately 10:00 PM.

On October 25 and 26, HCCP operated successfully with coal inferred HHV in the range of 5,960 to 6,258 Btu/lb. Average coal heating value was well below 7,000 Btu/lb during the six day continuous period from October 25 through November 6. During this period, coal with inferred heating values as low as 5,200 Btu/lb was fired for several hours. HCCP performed very well under these conditions. Continuous operation of Combustor B while the adverse situation of an unknown and unintended Precombustor B coal split demonstrated the operational flexibility of the system.

## 4.11 NOVEMBER OPERATIONS

On November 2, the load was reduced from approximately 58 megawatts to prepare for the testing of the flue gas desulfurization (FGD) system during the ongoing ninety-day test. The purpose of the FGD test was to determine the effects of the unit load (affecting reagent retention time), the limestone feed rate, the spray dryer absorber (SDA) approach to adiabatic saturation temperature, and the slurry temperature (affecting the calcium/sulfur stoichiometric ratio) on sulfur dioxide capture in the FGD system. The test matrix is shown in Table 4.11.1.

The effect of reducing the approach to adiabatic saturation temperature from 39° F to 32° F increased $SO_2$ capture from 74.4 percent to 93 percent with a Ca/S molar ratio of 1.30 and no slurry heating as shown in Table 4.11.2. This verifies the effectiveness of using approach to adiabatic saturation temperature in the SDA as an effective means of controlling outlet $SO_2$. Approach temperature had the most significant effect of all parameters tested on $SO_2$ removal.

Table 4.11.3 shows the effect of Ca/S stoichiometric ratio on $SO_2$ capture. The stoichiometric ratio was varied from 1.20 to 1.90 moles of calcium per mole of coal sulfur. Results appear to indicate that excess limestone injection becomes more effective as retention time is increased (at reduced load) as SDA outlet gas temperature is increased and when the slurry is heated. At full load, the data indicated that $SO_2$ capture did not increase significantly at higher stoichiometric ratios (thirty to fifty percent).

The reason for the apparent insensitivity of $SO_2$ capture to stoichiometric ratio in the range of 1.20 to 1.80 at full load was not conclusively determined.

The effect of heat activation is shown in Table 4.11.4 and the effect of residence time is shown in Table 4.11.5. The effectiveness of heat activation suggests that heat maybe significantly more effective than increasing limestone flow, particularly at full load and with a Ca/S stoichiometry in the range of 1.20 to 1.80. This suggests the possible utilization of heat, in addition to adjusting approach to adiabatic saturation temperature, as a means of responding to $SO_2$ emission excursions.

From November 3 to November 7, a test was conducted to determine whether the coal sampling system at the head end of the belt conveyor (which transfers coal from the Unit No. 1 coal yard through Unit No. 1 into HCCP) was obtaining biased samples. Samples were manually obtained by stopping the conveyor belt and removing a twelve inch wide cross section of the coal on the belt (as shown in Figure 4.11.1). This was done at random times during batched sampling intervals. The test compared the average analysis of the stopped belt samples with the analysis from the automated belt sampler.

The average dry basis heating value of the stopped belt samples was 9,917 Btu/lb compared to the 9,877 Btu/lb heating value of the samples automatically collected by the belt sampler. Statistical analysis showed, with a ninety-five percent confidence level, that there were no biases between the stopped belt and the automated sample analyses.

The ninety-day test was completed on November 15 at 4:00 PM. HCCP accomplished a capacity factor of 94.8 percent versus the required 85 percent. Post-test operations resumed on November 29.

HCCP was shut down for inspection on November 16 when the silos ran out of coal. The inspection revealed the following:

- The slag layer in the slagging combustor and slag recovery sections was molten and uniform in thickness, up to approximately one inch, with no bare regions.
- The slag coverage in Precombustors A and B was a thin, black, glassy slag layer extending from the end of the combustion chamber through the tangential inlet. There was a region of approximately eight inch thick slag immediately upstream of the downstream end of the combustion chamber of Precombustor A. Elsewhere, the slag layer in Precombustor A was much thinner. As expected, the slag layer in Precombustor B was thicker in the precombustor combustion chamber than in Precombustor A. This was attributed to the higher precombustor coal split as a result of the coal feed system damper damage at the inlet to the Combustor B precombustor/slagging combustor coal splitter.
- Ceramic tile pieces obstructed coal feed from two of the Precombustor B burner coal ports.
- No erosion on the ceramic tiles lining the Combustor A coal feed system precombustor/slagging splitter, ductwork, cyclone or coal transport piping was seen. Ductwork downstream of the splitter to the Precombustor and Slagging Combustor B coal cyclone inlets were significantly eroded. This was attributed to the two months of operation at extremely high velocity in these regions as a result of the damage to the coal feed system splitter dampers that occurred during the Pulverizer B deflagration on September 6. The extent of damage to these dampers had not been known when the deflagration occurred and, therefore, was not repaired during the shutdown within the ninety-day test.

Following the inspection, tube samples were removed from the inner circular opening region of the slagging combustor baffle bores of both slagging combustors. These samples were sent for water-side and gas-side analyses. Replacement tubes were welded and the boiler was hydrotested prior to resuming coal firing at 11:00 PM on November 28. Load ramp tests started on November 29 and continued into December.

# Table 4.11.1 – SDA Demonstration Test Matrix and Proposed Schedule
# November 10 – November 11, 1999

| Test # | MW Load (Approx Gross) | LS Feed (Approx lb/min) | SDA Outlet Temp (° F) | Approach to Saturation Temp (° F) | Steam Heat Activation | Start | | Finish | | Comment |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Date | Time | Date | Time | |
| 1-1 | 42 | 17 | 180 | 43 | No | 11/3 | 08:00 | 11/3 | 24:00 | |
| 1-2 | | | 180 | 43 | Yes | 11/4 | 08:00 | 11/4 | 20:00 | HA steam on |
| 1-3 | | | 170 | 33 | Yes | 11/4 | 21:00 | 11/5 | 09:00 | Approach reduced |
| 1-4 | | | 170 | 33 | No | 11/5 | 18:00 | 11/6 | 06:00 | HA steam off |
| | | | | | | | | | | |
| 2-1 | 52 | 22.5 | 170 | 33 | No | 11/6 | 20:30 | 11/7 | 06:30 | LS feed change |
| 2-2 | | | 170 | 33 | Yes | 11/7 | 12:00 | 11/7 | 22:00 | HA steam on |
| 2-3 | | | 180 | 43 | Yes | 11/7 | 23:00 | 11/8 | 09:00 | Approach reduced |
| 2-4 | | | 180 | 43 | No | 11/8 | 18:00 | 11/9 | 04:00 | HA steam off |
| | | | | | | | | | | |
| 3-1 | 50 | 17.5 | 170 | 43 | No | 11/9 | 17:00 | 11/10 | 03:00 | LS feed change |
| 3-2 | | | 170 | 43 | Yes | 11/10 | 10:00 | 11/10 | 20:00 | HA steam on |
| 3-3 | | | 180 | 33 | Yes | 11/10 | 22:00 | 11/11 | 08:00 | Approach reduced |
| 3-4 | | | 180 | 33 | No | 11/11 | 14:00 | 11/12 | 24:00 | HA steam off |
| | | | | | | | | | | |
| **Optional** | | | | | | | | | | |
| 4-1 | 35 | 12 | 180 | 43 | No | 11/12 | 12:00 | 11/12 | 22:00 | LS feed change |
| 4-2 | | | 180 | 43 | Yes | 11/13 | 02:00 | 11/13 | 12:00 | HA steam on |
| 4-3 | | | 170 | 33 | Yes | 11/13 | 14:00 | 11/14 | 24:00 | Approach reduced |
| 4-4 | | | 170 | 33 | No | 11/14 | 06:00 | 11/14 | 16:00 | HA steam off |

# TABLE 4.11.2 – Effect of Approach to Saturation Temperature on SDA System Performance

| Test # | Date | Gross Load (MW) | Gas Residence Time (Seconds) | Limestone Feed (lb/min) | Ca/S Ratio | Approach to Saturation Temp ($^{o}$ F) | Slurry Temp ($^{o}$ F) | SDA Inlet $SO_2$ (ppm) | Stack $SO_2$ (ppm) | Removal Efficiency (%) | Difference in Efficiency (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low Load – High Stoichiometric Ratio – No Heat Activation** | | | | | | | | | | | |
| 1.4 | 11/6 | 42.0 | 11.9 | 17.2 | 1.7 | 32.1 | 102.1 | 118.8 | 6.4 | 94.6 | |
| 1.1 | 11/3 | 42.1 | 11.9 | 17.1 | 1.7 | 42.3 | **111.2** | 112.8 | 15.5 | 86.3 | 8.3 |
| **Low Load – High Stoichiometric Ratio – Heat Activation** | | | | | | | | | | | |
| 1.3 | 11/4 | 42.3 | 11.8 | 17.0 | 1.9 | **32.0** | **154.8** | 101.9 | 0.7 | 99.3 | |
| 1.2 | 11/4 | 42.4 | 11.8 | **16.9** | **1.9** | **42.2** | 154.6 | 101.7 | 7.0 | 93.1 | 6.1 |
| **Low Load – Low Stoichiometric Ratio – No Heat Activation** | | | | | | | | | | | |
| 4.4 | 11/15 | 42.1 | 11.9 | **12.6** | **1.4** | **32.0** | 109.1 | 131.2 | 9.1 | 93.1 | |
| 4.1 | 11/13 | 42.1 | 11.9 | 11.5 | 1.2 | **41.4** | **107.1** | 120.5 | 31.6 | 73.8 | 19.3 |
| **Low Load – Low Stoichiometric Ratio – Heat Activation** | | | | | | | | | | | |
| 4.3 | 11/14 | 42.2 | 11.8 | 11.5 | 1.4 | **31.6** | **153.0** | 134.6 | 2.2 | 98.4 | |
| 4.2 | 11/14 | **41.8** | 12.0 | 12.2 | 1.2 | **41.1** | 152.9 | 134.9 | 29.3 | 78.3 | 20.1 |
| **High Load – High Stoichiometric Ratio – No Heat Activation** | | | | | | | | | | | |
| 2.1 | 11/7 | **57.7** | 8.7 | 22.2 | 1.7 | **31.9** | 109.6 | 122.4 | 20.7 | 83.1 | |
| 2.4 | 11/8 | 57.9 | 8.6 | 22.3 | 1.8 | **42.3** | **102.6** | 119.0 | 36.1 | 69.6 | 13.5 |
| **High Load – High Stoichiometric Ratio – Heat Activation** | | | | | | | | | | | |
| 2.2 | 11/7 | 56.4 | 8.9 | 22.3 | 1.8 | **32.5** | **147.6** | 123.2 | 4.9 | 96.0 | |
| 2.3 | 11/8 | 58.0 | 8.6 | **22.2** | **1.8** | **42.1** | 151.2 | 115.8 | 22.7 | 80.4 | 15.6 |
| **High Load – Low Stoichiometric Ratio – No Heat Activation** | | | | | | | | | | | |
| 3.1 | 11/10 | 58.1 | 8.6 | **17.3** | **1.4** | **32.0** | 104.1 | 118.0 | 7.5 | 93.7 | |
| 3.1a | 11/12 | 58.3 | 8.6 | 17.9 | 1.3 | **32.3** | 107.0 | 125.1 | 8.8 | 93.0 | |
| 3.4 | 11/11 | 58.0 | 8.6 | 17.8 | 1.3 | **38.9** | **110.7** | 132.8 | 34.0 | 74.4 | 18.6 |
| **High Load – Low Stoichiometric Ratio – Heat Activation** | | | | | | | | | | | |
| 3.2 | 11/10 | 58.1 | 8.6 | 17.1 | 1.2 | **33.9** | **153.6** | 129.3 | 4.7 | 96.4 | |
| 3.3 | 11/11 | 58.3 | 8.6 | 17.3 | 1.4 | **42.0** | 153.4 | 131.7 | 26.9 | 79.6 | 16.8 |

Note: Shaded areas show change in process parameters

# Table 4.11.3 – Effect of Ca/S Stoichiometric Ratio on SDA System Performance

| Test # | Date | Gross Load (MW) | Gas Residence Time (Seconds) | Limestone Feed (lb/min) | Ca/S Ratio | Approach to Saturation Temp (° F) | Slurry Temp (° F) | SDA Inlet $SO_2$ (ppm) | Stack $SO_2$ (ppm) | Removal Efficiency (%) | Difference in Efficiency (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low Load – Approach to Saturation 42° F – No Heat Activation** | | | | | | | | | | | |
| 4.1 | 11/13 | 42.1 | 11.9 | 11.5 | 1.2 | 41.4 | **107.1** | 120.5 | 31.6 | 73.8 | |
| 1.1 | 11/3 | 42.1 | 11.9 | 17.1 | 1.7 | 42.3 | **111.2** | 112.8 | 15.5 | 86.3 | 12.5 |
| **Low Load – Approach to Saturation 42° F – Heat Activation** | | | | | | | | | | | |
| 4.2 | 11/14 | 41.8 | 12.0 | 12.2 | 1.2 | 41.1 | **152.9** | 134.9 | 29.3 | 78.3 | |
| 1.2 | 11/4 | 42.4 | 11.8 | 16.9 | 1.9 | **42.2** | **154.6** | 101.7 | 7.0 | 93.1 | 14.9 |
| **Low Load – Approach to Saturation 32° F – No Heat Activation** | | | | | | | | | | | |
| 4.4 | 11/15 | 42.1 | 11.9 | 12.6 | 1.4 | **32.0** | **109.1** | 131.2 | 9.1 | 93.1 | |
| 1.4 | 11/6 | 42.0 | 11.9 | 17.2 | 1.7 | 32.1 | **102.1** | 118.8 | 6.4 | 94.6 | 1.5 |
| **Low Load – Approach to Saturation 32° F – Heat Activation** | | | | | | | | | | | |
| 4.3 | 11/14 | 42.2 | 11.8 | 11.5 | 1.4 | 31.6 | **153.0** | 134.6 | 2.2 | 98.4 | |
| 1.3 | 11/4 | **42.3** | 11.8 | 17.0 | 1.9 | **32.0** | **154.8** | 101.9 | 0.7 | 99.3 | 0.9 |
| **High Load – Approach to Saturation 40° F – No Heat Activation** | | | | | | | | | | | |
| 3.4 | 11/11 | **58.0** | 8.6 | 17.8 | 1.3 | **38.9** | **110.7** | 132.8 | 34.0 | 74.4 | ? |
| 2.4 | 11/8 | 57.9 | 8.6 | 22.3 | 1.8 | 42.3 | **102.6** | 119.0 | 36.1 | 69.6 | -4.8 |
| **High Load – Approach to Saturation 42° F – Heat Activation** | | | | | | | | | | | |
| 3.3 | 11/11 | 58.3 | 8.6 | 17.3 | 1.4 | 42.0 | **153.4** | 131.7 | 26.9 | 79.6 | |
| 2.3 | 11/8 | 58.0 | 8.6 | 22.2 | 1.8 | **42.1** | **151.2** | 115.8 | 22.7 | 80.4 | 0.8 |
| **High Load – Approach to Saturation 32° F – No Heat Activation** | | | | | | | | | | | |
| 3.1 | 11/10 | 58.1 | 8.6 | 17.3 | 1.4 | **32.0** | **104.1** | 118.0 | 7.5 | 93.7 | |
| 3.1a | 11/12 | 58.3 | 8.6 | 17.9 | 1.3 | 32.3 | **107.0** | 125.1 | 8.8 | 93.0 | |
| 2.1 | 11/7 | 57.7 | 8.7 | 22.2 | 1.7 | 31.9 | **109.6** | 122.4 | 20.7 | 83.1 | -9.9(?) |
| **High Load – Approach to Saturation 32° F – Heat Activation** | | | | | | | | | | | |
| 3.2 | 11/10 | 58.1 | 8.6 | 17.1 | 1.2 | 33.9 | **153.6** | 129.3 | 4.7 | 96.4 | |
| 2.2 | 11/7 | 56.4 | 8.9 | 22.3 | 1.8 | 32.5 | 147.6 | 123.2 | 4.9 | 96.0 | 0.4 |

Note: Shaded areas show change in process parameters

# Table 4.11.4 – Effect of Heat Activation of Feed Slurry on SDA System Performance

| Test # | Date | Gross Load (MW) | Gas Residence Time (Seconds) | Limestone Feed (lb/min) | Ca/S Ratio | Approach to Saturation Temp (° F) | Slurry Temp (° F) | SDA Inlet $SO_2$ (ppm) | Stack $SO_2$ (ppm) | Removal Efficiency (%) | Difference in Efficiency (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low Load – Approach to Saturation 42° F – Low Stoichiometric Ratio** | | | | | | | | | | | |
| 4.1 | 11/13 | 42.1 | 11.9 | 11.5 | 1.2 | 41.4 | **107.1** | 120.5 | 31.6 | 73.8 | |
| 4.2 | 11/14 | 41.8 | 12.0 | 12.2 | **1.2** | 41.1 | **152.9** | 134.9 | 29.3 | 78.3 | 4.5 |
| **Low Load – Approach to Saturation 42° F – High Stoichiometric Ratio** | | | | | | | | | | | |
| 1.1 | 11/3 | 42.1 | 11.9 | 17.1 | **1.7** | 42.3 | **111.2** | 112.8 | 15.5 | 86.3 | |
| 1.2 | 11/4 | 42.4 | 11.8 | 16.9 | **1.9** | **42.2** | **154.6** | 101.7 | 7.0 | 93.1 | 6.8 |
| **Low Load – Approach to Saturation 32° F – Low Stoichiometric Ratio** | | | | | | | | | | | |
| 4.4 | 11/15 | 42.1 | 11.9 | 12.6 | **1.4** | **32.0** | **109.1** | 131.2 | 9.1 | 93.1 | |
| 4.3 | 11/14 | 42.2 | 11.8 | 11.5 | **1.4** | 31.6 | **153.0** | 134.6 | 2.2 | 98.4 | 5.3 |
| **Low Load – Approach to Saturation 32° F – High Stoichiometric Ratio** | | | | | | | | | | | |
| 1.4 | 11/6 | 42.0 | 11.9 | 17.2 | **1.7** | 32.1 | **102.1** | 118.8 | 6.4 | 94.6 | |
| 1.3 | 11/4 | **42.3** | 11.8 | 17.0 | **1.9** | **32.0** | **154.8** | 101.9 | 0.7 | 99.3 | 4.7 |
| **Full Load – Approach to Saturation 40° F – Low Stoichiometric Ratio** | | | | | | | | | | | |
| 3.4 | 11/11 | **58.0** | 8.6 | 17.8 | **1.3** | **38.9** | **110.7** | 132.8 | 34.0 | 74.4 | |
| 3.3 | 11/11 | 58.3 | 8.6 | 17.3 | **1.4** | 42.0 | **153.4** | 131.7 | 26.9 | 79.6 | 5.2 |
| **Full Load – Approach to Saturation 42° F – High Stoichiometric Ratio** | | | | | | | | | | | |
| 2.4 | 11/8 | 57.9 | 8.6 | 22.3 | **1.8** | 42.3 | **102.6** | 119.0 | 36.1 | 69.6 | |
| 2.3 | 11/8 | 58.0 | 8.6 | 22.2 | **1.8** | **42.1** | **151.2** | 115.8 | 22.7 | 80.4 | 10.7 |
| **Full Load – Approach to Saturation 32° F – Low Stoichiometric Ratio** | | | | | | | | | | | |
| 3.1 | 11/10 | 58.1 | 8.6 | 17.3 | **1.4** | **32.0** | **104.1** | 118.0 | 7.5 | 93.7 | |
| 3.1a | 11/12 | 58.3 | 8.6 | 17.9 | **1.3** | 32.3 | **107.0** | 125.1 | 8.8 | 93.0 | |
| 3.2 | 11/10 | 58.1 | 8.6 | 17.1 | **1.2** | 33.9 | **153.6** | 129.3 | 4.7 | 96.4 | 3.0 |
| **Full Load – Approach to Saturation 3°2 F – High Stoichiometric Ratio** | | | | | | | | | | | |
| 2.1 | 11/7 | 57.7 | 8.7 | 22.2 | **1.7** | 31.9 | **109.6** | 122.4 | 20.7 | 83.1 | |
| 2.2 | 11/7 | 56.4 | 8.9 | 22.3 | **1.8** | 32.5 | 147.6 | 123.2 | 4.9 | 96.0 | 12.9 |

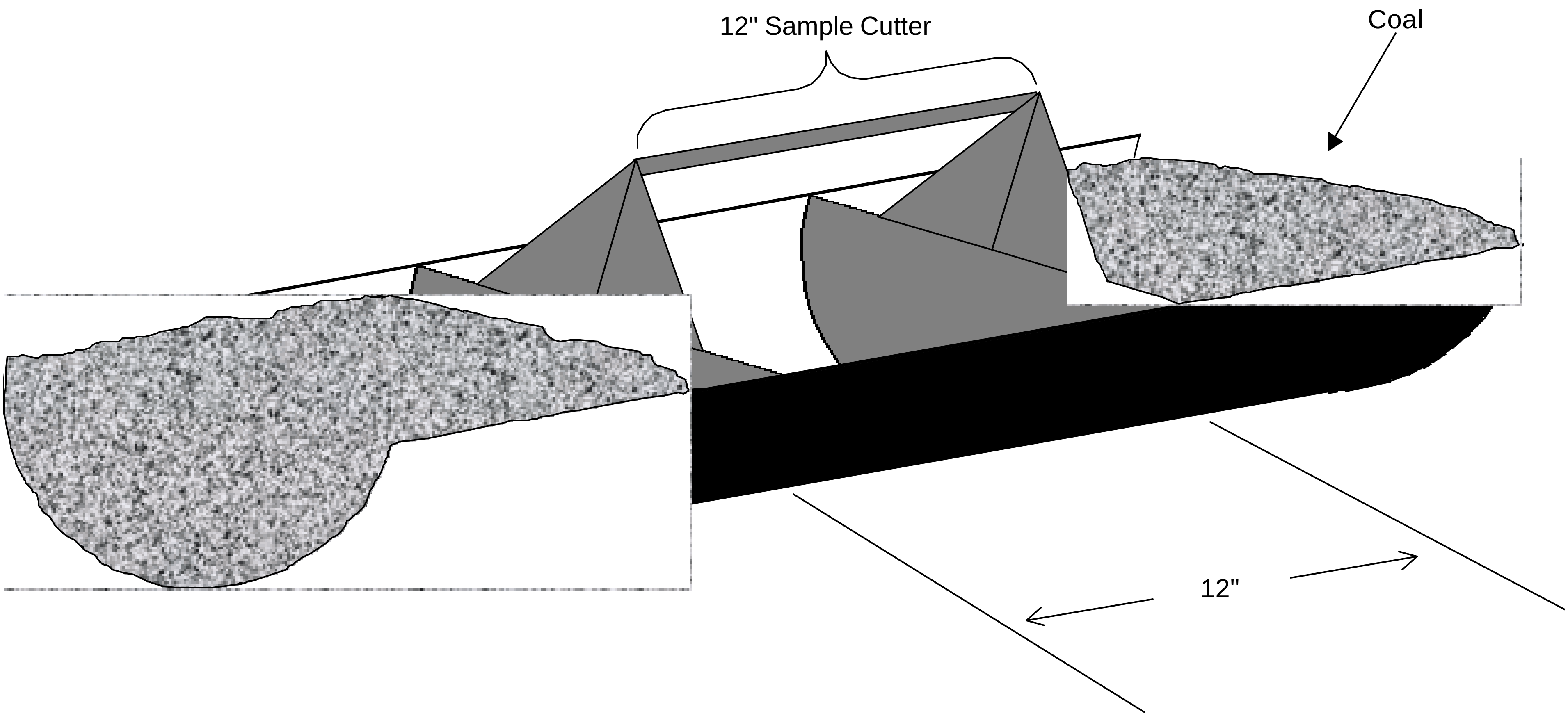
Note: Shaded areas show change in process parameters

# Table 4.11.5 – Effect of Residence Time on SDA System Performance

| Test # | Date | Gross Load (MW) | Gas Residence Time (Seconds) | Limestone Feed (lb/min) | Ca/S Ratio | Approach to Saturation Temp (° F) | Slurry Temp (° F) | SDA Inlet $SO_2$ (ppm) | Stack $SO_2$ (ppm) | Removal Efficiency (%) | Difference in Efficiency (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **High Stoichiometric Ratio – Approach to Saturation 42° F – No Heat Activation** | | | | | | | | | | | |
| 1.1 | | 42.1 | **11.9** | 17.1 | 1.7 | 42.3 | 111.2 | 112.8 | 15.5 | 86.3 | |
| 2.4 | | 57.9 | **8.6** | 22.3 | 1.8 | 42.3 | **102.6** | 119.0 | 36.1 | 69.6 | 16.7 |
| **High Stoichiometric Ratio – Approach to Saturation 42° F – Heat Activation** | | | | | | | | | | | |
| 1.2 | | 42.4 | **11.8** | 16.9 | 1.9 | 42.2 | **154.6** | 101.7 | 7.0 | 93.1 | |
| 2.3 | | 58.0 | **8.6** | 22.2 | 1.8 | **42.1** | **151.2** | 115.8 | 22.7 | 80.4 | 12.8 |
| **High Stoichiometric Ratio – Approach to Saturation 32° F – No heat Activation** | | | | | | | | | | | |
| 1.4 | | 42.0 | **11.9** | 17.2 | 1.7 | **32.1** | **102.1** | 118.8 | 6.4 | 94.6 | |
| 2.1 | | 57.7 | **8.7** | 22.2 | 1.7 | 31.9 | **109.6** | 122.4 | 20.7 | 83.1 | 11.5 |
| **High Stoichiometric Ratio – Approach to Saturation 32° F – Heat Activation** | | | | | | | | | | | |
| 1.3 | | 42.3 | **11.8** | 17.0 | 1.9 | 32.0 | **154.8** | 101.9 | 0.7 | 99.3 | |
| 2.2 | | 56.4 | **8.9** | 22.3 | 1.8 | **32.5** | **147.6** | 123.2 | 4.9 | 96.0 | 3.3 |
| **Low Stoichiometric Ratio – Approach to Saturation 40° F – No Heat Activation** | | | | | | | | | | | |
| 4.1 | | 42.1 | **11.9** | 11.5 | 1.2 | **41.4** | **107.1** | 120.5 | 31.6 | 73.8 | |
| 3.4 | | 58.0 | **8.6** | 17.8 | 1.3 | 38.9 | **110.7** | 132.8 | 34.0 | 74.4 | 0.6 |
| **Low Stoichiometric Ratio – Approach to Saturation 42° F – Heat Activation** | | | | | | | | | | | |
| 4.2 | | 41.8 | **12.0** | 12.2 | 1.2 | 41.1 | **152.9** | 134.9 | 29.3 | 78.3 | |
| 3.3 | | 58.3 | **8.6** | 17.3 | 1.4 | **42.0** | **153.4** | 131.7 | 26.9 | 79.6 | 1.3 |
| **Low Stoichiometric Ratio – Approach to Saturation 32° F – No Heat Activation** | | | | | | | | | | | |
| 4.4 | | 42.1 | **11.9** | 12.6 | 1.4 | **32.0** | **109.1** | 131.2 | 9.1 | 93.1 | |
| 3.1 | | 58.1 | **8.6** | 17.3 | 1.4 | 32.0 | **104.1** | 118.0 | 7.5 | 93.7 | 0.7 |
| 3.1a | | 58.3 | **8.6** | 17.9 | 1.3 | 32.3 | **107.0** | 125.1 | 8.8 | 93.0 | |
| **Low Stoichiometric Ratio – Approach to Saturation 32° F – Heat Activation** | | | | | | | | | | | |
| 4.3 | | 42.2 | **11.8** | 11.5 | 1.4 | 31.6 | **153.0** | 134.6 | 2.2 | 98.4 | |
| 3.2 | | 58.1 | **8.6** | 17.1 | 1.2 | 33.9 | 153.6 | 129.3 | 4.7 | 96.4 | 2.0 |

Note: Shaded areas show change in process parameters

# FIGURE 4.11.1 – CONVEYOR BELT COAL SAMPLE CROSS SECTION



## 4.12 DECEMBER OPERATIONS

The load ramp tests were concluded on December 4 and included load swings, per dispatch's requests. Major process parameters were controlled to within normal tolerances.

On December 5, HCCP continued running and the priorities for December became to transfer the fly ash and bottom ash from the Unit No. 1 middle ash, baghouse, and bottom ash hoppers to the HCCP fly ash and slag ash silos; run the unit on 6,800 to 7,000 Btu/lb coal, and to test the turbine generator. The actual heating values measured averaged between 7,000 and 7,100 for the first ten days of operation. On December 7, the first attempt to pull fly ash from Unit No. 1 into HCCP led to the discovery that the fly ash line between the units was plugged. On December 8, fly ash was successfully pulled from Unit No. 1; however, additional work was required within Unit No. 1 to establish the necessary valving and logic operations. The HCCP side of the fly ash system was complete; therefore, attention was focused on transferring bottom ash.

The HCCP two speed pyrite and bottom ash sluice pump high speed motor windings (required for bottom ash sluicing) were enabled to obtain the higher sluice pump pressure and flow necessary to sluice Unit No. 1 bottom ash. Subsequently, the underground bottom ash sluicing line and slurry return line between Unit No. 1 and HCCP were found to be frozen. The abrasion resistant, heavy wall, ash slurry line utilized mechanical joints. The joints close to the outside building boundary were disassembled on December 9 and a steam hose was fed into the ice-clogged, underground section to thaw it out. While laborers worked on thawing the slurry line, a hole was cut into the HCCP high pressure sluice line and auxiliary steam was connected to thaw the sluice line. On December 10, the slurry line was reassembled and the remainder of the day was spent resealing the joints where they leaked. On December 11, flow was established in the slurry line from Unit No. 1 to HCCP; however, the large flow rate of water caused the bottom ash drag chain reservoir weir overflow drain boxes to overflow. As a result, the slurry piping, routed by design to the bottom ash drag chain reservoir, was rerouted to the slag drag chain reservoir. The rerouted line was finished on December 13 and Unit No. 1 bottom ash was successfully sluiced utilizing the HCCP sluice pump to transport the slurry up to the slag ash drag chain reservoir via the rerouted piping. The unit remained online at full load to prepare for turbine performance testing.

On December 14, between approximately 1:00 PM and 6:00 PM, a turbine performance test trial run was performed with the generation climbing to 64.4 megawatts at 3:30 PM. The valves-wide-open capacity exceeded the predicted value of 61.109 megawatts by approximately 4% After the trial run, the load was reduced to the more normal value of approximately 58 megawatts until approximately 7:00 AM on December 15, when the formal test was started. The formal test was run completing the full load (approximately 62 megawatts) test at 11:00 AM, the eighty percent load (approximately 50 megawatts) test at 2:30 PM and the seventy percent load (approximately 43 megawatts) test at 5:00 PM. Turbine performance test data indicated a full load turbine cycle heat rate of between 8,200 and 8,400 Btu per kilowatt hour compared to the manufacturer's guarantee of 8,420 Btu per kilowatt hour.

Load reduction to shut down HCCP began at approximately 7:00 PM on December 15. Pulverizer A tripped at approximately 9:45 AM, about twenty minutes after lighting the Combustor A oil burners. Pulverizer B oil burners were lit and Pulverizer A was ground out three times as a result of a bridged pyrite chute, which was eventually rodded out with a piece of plastic pipe. Silo B ran out of coal at approximately 1:15 AM on December 16 and was shut down normally. After the Pulverizer A grind out was completed, Pulverizer A was restarted at 3:05 AM at minimum coal flow to finish emptying Silo A. Pulverizer A puffed at approximately 3:15 AM, causing a unit trip. No damage was noted.

A detailed post-test inspection of eight regions of the combustion system was performed between December 18 and 22 as shown in Figure 4.12.1. Results follow:

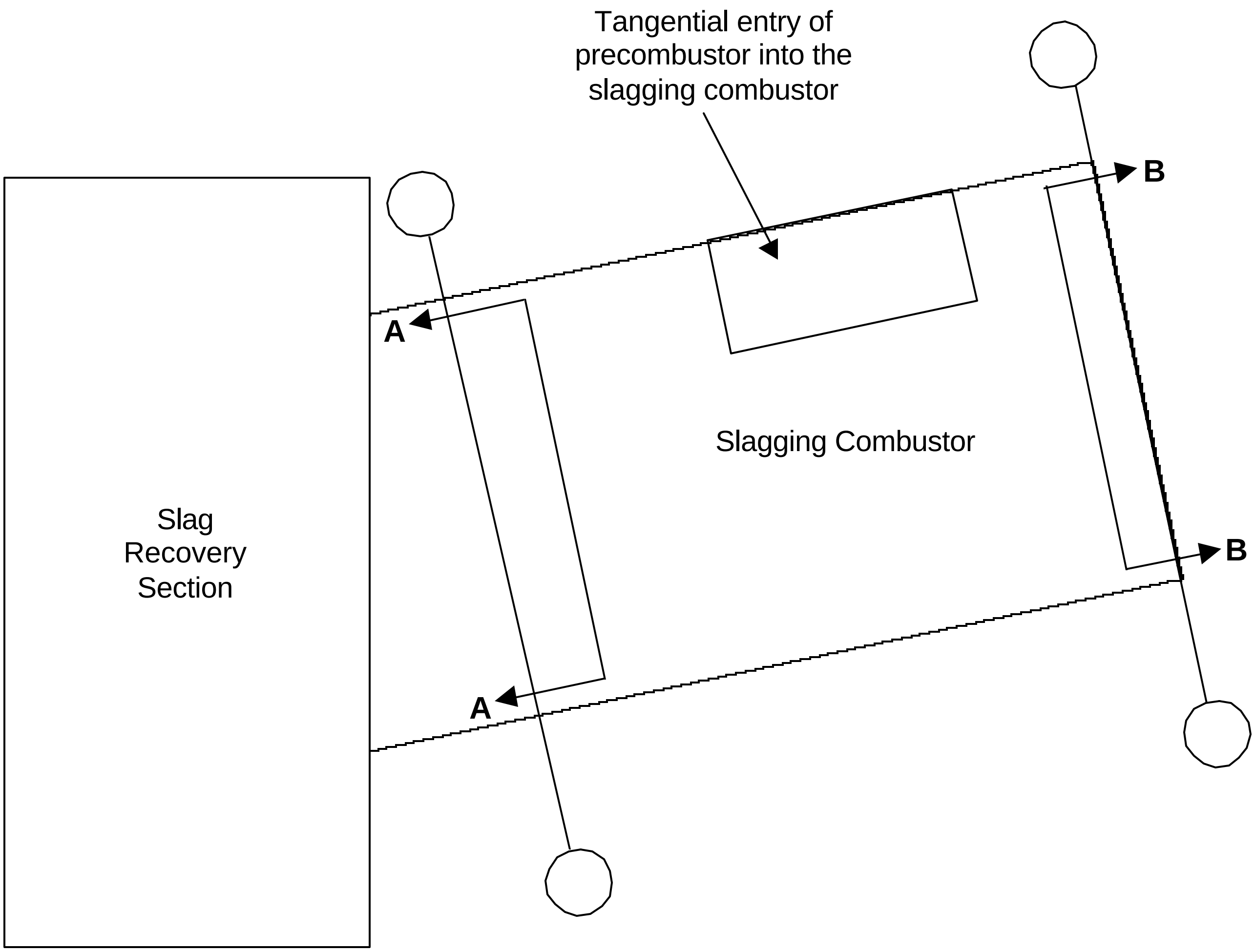
- Eight regions within the slagging combustor were cleaned of all slag and refractory and carefully inspected. The areas inspected were:
  - Two additional locations on the baffle bore tube where the unique shield fins were installed (Regions 1 and 2)
  - Three locations on the head end where the non-integral fin was installed, including the top and bottom of the oil burner (Region 3) and the tops and bottoms of coal ports at nine o'clock (Region 4) and eleven o'clock (Region 5)
  - Two locations on the outer circle of the baffle (Regions 6 and 7), where the adjacent tubes were free floating (i.e. not welded together)
  - In addition, in order to verify that the inspection methodology was adequate to observe any crack indications, another portion of the circular region of the baffle bore where the unique shield fins were installed (i.e., consistent with the location of the original tube sample that had been removed in November) was inspected (Region 8)
- The only location where crack indications were observed was on the unique shield fin attachment welds within the circular region of the baffle bore. This tube region is consistent with the location where the tube samples were removed previously and observations of crack indications in this region confirmed that the inspection methodology was adequate for observing any weld crack indications in other regions. This is the only region in the combustion system where this unique shield fin design was installed. No crack indications were observed within the other seven inspected locations.

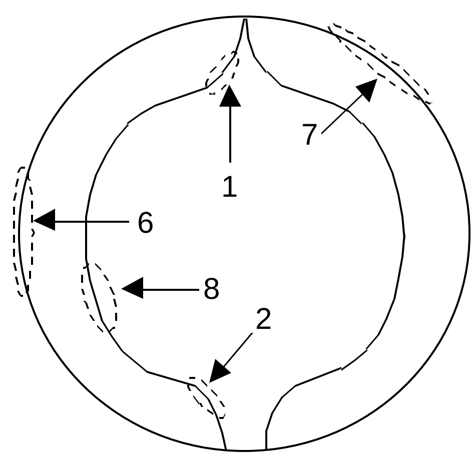
In conjunction with the inspection activities, a detailed thermal/stress analysis was performed on the unique baffle bore shield fin design. Based on the inspection results and preliminary thermal/stress analysis results, the crack indications in the heat affected zone of the weld appear to be caused by high thermal stresses at the weld interface between the shield fins and tube, in conjunction with possible residual stresses resulting from the tube cold/hot working. Micro-hardness tests performed within the weld zone did not identify any ductility problems.

In late December, the unique baffle bore shield fins were re-designed to reduce thermal stresses at the weld interface. The height of the fins was reduced from one inch to five-eighth inch and slots were installed along the length of the fins at three-quarter inch intervals. According to the analysis, these changes reduced the thermal stresses at the weld interface by a factor of three and increased the cycle life by nearly a factor of fifty.

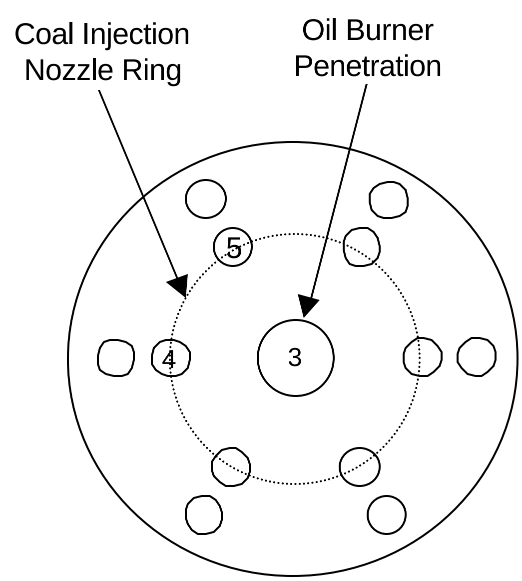
Fabrication of the replacement baffle bore tubes was initiated in December and continued into January, 2000. A stress relief cycle was performed on the tubes after the completion of the fabrication. The tubes were delivered to Healy on January 21, 2000, and installed between January 24 and January 31, 2000. A local stress relief cycle was performed on the field welded tube-to-fin welds. The combustor supplier oversaw the installation of the replacement tubes.

# Figure 4.12.1 – Slagging Combustor Tubing Crack Inspection Areas




**Section A-A**
**Slagging Combustor Baffle Tubes**




**Section B-B**
**Head End of Slagging Combustor**

## 5.0 EQUIPMENT AND SYSTEM PROBLEMS

The resolution or status of the following system and equipment problems that occurred in 1999 is discussed in this section.

- Fuel Coal System
  - Modifications to Isolate Coal Cyclone Vent Air from the Precombustor
  - Precombustor Rodding Port and Cyclone Vent Air Port Overheating
  - Mill Exhauster Abrasion
- Ash Systems
  - Water Lances to Remove Slag Accumulation on Sloped Furnace Hopper
  - Inclined Slag Drag Chain
  - Accumulation of Solids in the Ash Water Surge Tank
  - Excessive Fabric Filter Bag Wear
- Boiler Steam and Water
  - Unstable Turbine Throttle Valve Operation
  - Poor Pressure Regulation of Steam Jet Air Ejector Motive Steam
  - Boiler/Combustor Water Chemistry and Tube Metallurgy
  - Slag Tap Dipper Skirt Shield Tube Heat Exchanger Vent and Drain Piping Leaks
- Miscellaneous Systems
  - Induced Draft Fan Noise
  - Restricted Flow Through Multi-Media Waste Water Filters (MMWWF's)
  - $CO_2$ Fire Protection System Test Failures

### MODIFICATIONS TO ISOLATE COAL CYCLONE VENT AIR FROM THE PRECOMBUSTOR

During startup, coal cyclone vent fines must be directed into the precombustor in the immediate vicinity of the oil flame to ensure proper combustion of this dust. Then, after reaching a higher load, these fines can be transferred to the boiler $NO_X$ ports for combustion, because sufficient flame intensity exists in the $NO_X$ ports at higher loads. It is advantageous to transfer this source of cold air away from the precombustor to avoid slag accumulation. However, there is a vertical leg above the isolation valve on the cyclone vent line to the precombustor. A purge line was cross-tied into this vertical cyclone vent line so that the fine coal dust would not form a pile on top of the cyclone vent isolation valve to the precombustor. This configuration is shown in Figure 5.0.1.

This was effective at preventing the accumulation of coal dust on top of the closed cyclone vent air isolation valve. This configuration requires manual operation and it is important to close the purge air valve, because whenever the cyclone vent air to the boiler $NO_X$ ports is throttled, the discharge pressure from the mill exhauster fan increases and could eventually overcome the discharge pressure of the purge air (provided from the pulverizer tempering air duct) where purge air normally flows into the coal feed system piping. This could cause coal dust in the cyclone vent air to be fed into some of the flame scanner purge air ports and, possibly, to other places in the purge air system where coal dust would be undesirable. There may also be a risk that the precombustor ports that accept cyclone vent air could become slagged over. If this occurred, coal dust could pile up over a slagged-over port creating a potentially dangerous situation when coal fines in the cyclone vent air are directed to the precombustor cyclone vent ports.

One method of eliminating the complications and potential problems associated with the above method of eliminating vent air from the precombustor would be to provide oil burners at the current furnace $NO_X$ ports so that fines could be reliably incinerated with a sufficiently intense flame during startup. Such a proposal was received in February, 2000 in response to a request by AIDEA for the design and supply of oil igniter equipment and waterwall tubing to modify the boiler $NO_X$ ports, and to provide the $NO_X$ port windbox. Plans were made to carry out this modification during the year 2000.

### PRECOMBUSTOR RODDING PORT AND CYCLONE VENT AIR PORT OVERHEATING

Purge air (provided from pulverizer tempering air) flow valves had reportedly been left closed, causing overheating of the rodding ports on top of the tangential entry of the precombustor into the slagging combustor. However, here was some concern that, even with the purge air flow valves open, these ports could slag over and block the flow of purge air, thereby shutting off a needed supply of air to cool the rodding ports. Therefore, cooling air for these ports was provided with compressed air from the plant service air system, which operates at a minimum pressure of 90 psi. This source of air is presumed to be capable of overcoming any slag layer so as to prevent the plugging off of the cooling/purge air flow. The one inch lines providing service air to these rodding ports, if left wide open, could significantly contribute to the overloading of the service air compressors and could potentially depressurize the vital instrument air system. Consequently, orifices were provided to ensure that the flow would not be excessive.

There were also instances when the six-inch cyclone vent air connections to the precombustor became overheated. These connections had also been fitted with purge air connections when the operating configuration, which completely isolated the cyclone vent air from the precombustors at a designated total coal flow rate, was incorporated (discussed in Section 4.1 –

January Operations). Non-orificed one-inch, valved service air lines were provided to each of these six connections (per precombustor) to provide the extra flow and pressure, as required to protect the connections from overheating.

#### MILL EXHAUSTER ABRASION

Mill Exhauster A achieved its longest continuous run starting with the ninety-day test and continuing through the additional seventeen days of post-test November and December operations. During this period there was no internal maintenance done to the exhauster's wear surfaces. There were occasions when coal abraded completely through the outer casing and the resulting coal leaks were repaired online with an external patch plate lined with ceramic tile.

HCCP mill exhauster wear rate exceeds normal levels for two primary reasons:

1. The mill exhauster rotor tip speed (approximately 24,000 feet per minute) is very high and
2. The coal and contaminants in it (sandstone and other constituents from overburden and interburden) are very abrasive.

Both exhauster rotors rotate in the same direction. Therefore, since Mill Exhauster A discharges to the north and Mill Exhauster B discharges to the south, the discharge from Mill Exhauster A is from the bottom of its casing and Mill Exhauster B discharges from the top of its casing. The ceramic tile, which was utilized as an internal casing wear overlay, tended to wear excessively as shown in Figure 5.0.2.

During the outage following the December 16 shutdown, the worn ceramic tile lining inside the mill exhauster casings was replaced and an additional half inch thick overlay material was placed on the original ceramic tiles located in the high wear zones as shown in Figure 5.0.3.

#### WATER LANCES TO REMOVE SLAG ACCUMULATION ON SLOPED FURNACE HOPPER

Water lances were selected instead of steam or air devices to remove slag from the sloped furnace hopper, because of the ability of a water jet to more effectively wash slag from waterwall surfaces at distances up to twenty feet. Steam or air cleaning devices clean effectively only up to distances of approximately three or four feet.

Two water lances (as shown in Figure 5.0.4) are required to cover the total north to south span across the sloped tube wall of the furnace hopper. The lance to the north is the longer of the two at approximately twenty-nine feet (overall length), because there is much more open space between the north (front) waterwall and the deaerator for the lance in its retracted position. The south lance covers the distance uncovered by the north lance and is approximately eleven feet (overall length). These lances are mounted on the north (front) and south (rear) waterwalls and are configured very similarly to the standard retractable superheater steam sootblowers on the upper west (left) furnace waterwall.

Each lance has four nozzles, two of which direct straight streams of water to the area of the sloped hopper being washed and the other two provide diffuse streams for thrust balancing to prevent the lance from being moved around by an unbalanced radial thrust. The lance rotates in a circle as it advances (or retracts) axially. Thus, its spray pattern is a helix. The speed at which the lance advances is variable and is controlled by a programmable controller so that the velocity of the wash point on the washed surface is constant. Water flow is maintained for cooling at all times while the lance is inserted into the furnace. Two solenoid operated valves provide water pressure control so that high pressure water is only provided to the lance nozzles when the straight stream nozzles are directed to the surface areas to be washed. The rest of the time, water flow is provided to maintain cooling as required for the inserted lance.

### INCLINED SLAG DRAG CHAIN

The tail end of the slag transfer drag chain was fitted with a pyramidal hopper with an eductor at its base. The eductor is provided with venturi-jet water from the pyrites sluicing system and operates in a manner similar to the eductors used for removing pyrites from the pulverizers. The system discharges to the submerged drag chain reservoir and has functioned well.

Removal of the top table and reversal of the direction of the inclined drag chain (as discussed in the Quarterly Technical Report No.29-32 for 1998) also worked well. However, removing the top table caused the chain to wear as shown in Figure 5.0.5. Particles of slag acted as a grinding compound because of sliding contact between the drag chain and the plate under it. This plate was completely removed and the drag chain was supported by the rolling idlers. This essentially eliminated chain wear from sliding contact. There was some wear to the rollers, especially at the head end of the conveyor where chain tension is greatest because of the head end sprocket drive. Head end rollers of hardened steel have greatly reduced idler wear at this point and the rate of wear elsewhere appears to be acceptably low.

### ACCUMULATION OF SOLIDS IN THE ASH WATER SURGE TANK

Large quantities of flow from the ash water recycle pumps to the drag chain reservoirs and, subsequently, over their overflow weirs caused solids to be entrained in the overflow water. The ash water surge tank acted as a settling basin for the entrained solids.

During normal operation, the ash water system, as designed, used recycle pumps to circulate ash water from the ash water surge tank through the ash water heat exchangers to reject waste heat to the once-through type circulating water system, which is water from the Nenana River. This cooled ash water was to flow to the slag ash and bottom ash drag chain reservoirs, where heat is rejected from the slag to the ash water. The ash water flowed over weirs and returned via piped weir drains back to the ash water surge tank to be recirculated through the cycle. Because of the submergence of the slag tap dipper skirt and the finned tube heat exchanger that serves as its heat shield, these heat exchangers provided enough heat exchange capability to render the ash water heat exchangers, for rejecting heat to the circulating water system, unnecessary. Consequently, the ash water heat exchangers were valved out of service and bypassed. The heat rejected to the ash water from the slag and slag tap losses (other than evaporation and ambient losses) was incorporated as part of the heat duty of the slag tap dipper skirt shield tubes and was recovered into the condensate system.

Since operating experience showed that a high volume of recirculation flow was unnecessary, weir overflow was minimized. This reduced the amount of suspended solids and, therefore, substantially reduced the solids accumulation in the ash water surge water tank.

### EXCESSIVE FABRIC FILTER BAG WEAR

Review of the 1998 baghouse fabric filter replacement records indicated that excessive bag wear in the pulse jet baghouse was occurring. Bag failures were much more frequent on bags along the walls opposite the flue gas entrance duct. This wear was attributed to turbulent flow conditions external to the bags, causing the bag filter inner support cages, which hang from the top tube sheet support, to sway. This swaying caused the fabric filter bags around the outside of the support cage to rub on the adjacent wall and on other bags.

In January full width turning vanes were installed, as shown in Figure 5.0.6, significantly reducing the number of bag failures.

### UNSTABLE TURBINE THROTTLE VALVE OPERATION

The turbine throttle valve failed to move smoothly in response to normal control parameter variations, causing the unit to trip. This problem was attributed to thyristor damage, which may have been caused by a transmission system voltage surge as the result of a Unit No. 1 trip. The turbine manufacturer engineers replaced the damaged thyristors and a defective throttle valve control cable. The unstable turbine throttle operation did not recur.

### POOR PRESSURE REGULATION OF STEAM JET AIR EJECTOR MOTIVE STEAM

It was necessary to operate the control valve that maintains 300 psig ejector supply steam to the condenser air ejectors with its inlet isolation valve throttled. Otherwise, it operated at near zero percent open. The control valve seat and plug were replaced to provide a smaller trim with the proper valve flow coefficient for normal operating conditions. The valve now operates at approximately fifty to sixty percent open with its isolation valves fully open.

### BOILER/COMBUSTOR WATER CHEMISTRY AND TUBE METALLURGY

Various concerns, primarily as the result of operation with alleged low pH for very short periods of time during early 1998 and high silica levels following a dipper skirt shield leak in February, 1999, led to a decision to obtain and analyze material samples from potentially damaged or compromised areas of the combustors and the boiler.

Four waterwall tube samples and two combustor tube samples were taken in December, 1999. Two of the waterwall samples were taken from the right and left side waterwalls (one each) and two waterwall samples were taken from the nose of the boiler. The two combustor samples were taken from the slagging combustor baffle inner tubes where the highest heat flux exists. This location was chosen because it is considered to be the area most sensitive to water chemistry.

The boiler tubes are three inch (outside diameter) by 0.165 inch (minimum wall), SA-178 Grade C material. The combustor tubes are one and a half inch (outside diameter) by 0.180 inch (minimum wall), SA-213 Type T22 material with internal rifling.

The laboratory analysis of the submitted samples indicated that:

- Each of the waterwall samples was in good condition and contained a thin deposit on the inside surface. After the deposit was removed, the inside surface exhibited shallow pitting, indicating that the low pH conditions, which occurred during the initial operation of the unit, had no detrimental effects.
- Both combustor tube samples contained circumferentially oriented cracks that initiated at the shield fin-to-tube welds, primarily in the welds that attached the fins to the top (or concave) half of the tube. The morphology of the cracks indicated that they developed from an oxidation fatigue mechanism and appeared to be still propagating at the time the samples were removed. In the four sections evaluated from one of the samples, the deepest crack had not yet reached the midpoint of the tube wall.
- Aside from the cracks, the combustor tubes displayed no additional distress. The wall thickness measurements were still above minimum wall thickness, the inside surface contained a thin deposit and the microstructure exhibited no evidence of significant overheating.

Based on the above results, the combustor designer determined that the original shield fin design should have been of a different configuration to withstand thermal cycling. Therefore, spare tube material at the HCCP site was sent to a tube bender so that a better shield fin and weld stud configuration could be incorporated. The original inner baffle tubes were removed and replaced with inner baffle tubes with the improved design.

### SLAG TAP DIPPER SKIRT SHIELD TUBE HEAT EXCHANGER VENT AND DRAIN PIPING LEAKS

Problems occurred in the small bore vent and drain piping of the slag tap dipper skirt shield tubes. In February, the drain piping leaked from a drain valve, which apparently opened during operation. One possible cause is that falling slag opened the ball valve handle on the drain valve. Then, in September, a drain valve was severed from the bottom dipper skirt shield tube heat exchanger header. As a result, all of these drain valves were removed and replaced with a pipe cap.

Small bore (one inch or smaller) vent piping was provided on the upper headers of the dipper skirt shield tube heat exchangers. On several occasions, this piping developed small leaks at the connection to the header pipe it vented. To prevent future vent piping leaks, the vent piping was removed and the connections were plugged. The basis for this was that the average flow velocity (greater than 2 ft/sec) within the four-inch horizontal header pipe would likely sweep sufficient air through the horizontal top header of the shield tube heat exchangers to maintain the water level up to the elevation of the vent connection on the header without a vent. No further problems occurred after these modifications.

### INDUCED DRAFT FAN NOISE

The induced draft (ID) fan at HCCP is audible from locations near the plant, as well as from various locations within the local community. In January, an ID fan inlet silencer was installed into the breeching duct between the ID fan and the stack to reduce the noise levels. The silencer consists of two side by side baffles installed as shown in Figure 5.0.7. The silencer substantially reduced tonal noise.

### RESTRICTED FLOW THROUGH MULTI-MEDIA WASTE WATER FILTERS (MMWWF'S)

Use of river water, instead of slag ash water, as the makeup source to the dirty waste water tank greatly reduced the rate at which MMWWF flow became restricted; however, backwash water from the ash water sluice pumps continued to contaminate these filters.

Filtered waste water was adopted as a backwash source. This water is relatively free of silt, since it is the clean product from the MMWWF's and its pH is already at an acceptable level, as a result of river water being used as the makeup source to the dirty waste water tank.

The new backwash pump, the associated piping, and their interfaces with the existing system are shown in Figure 5.0.8. These modifications increased the cycle time between backwashes, because the source of backwash water was less silty. It also decreased the amount of rinse water required, because less, if any, was required for pH adjustment.

### $CO_2$ FIRE PROTECTION SYSTEM TEST FAILURES

Multiple full discharge $CO_2$ tests were attempted on the switchgear room (Fire Protection Zone 13) and the relay room (Fire Protection Zone 16), during the construction and startup phases of HCCP. These tests failed to meet the requirements of NFPA 12, which requires the following $CO_2$ concentrations in these two zones during and after a full discharge of $CO_2$:

| Minimum $CO_2$ Concentration | Time After Discharge |
|---|---|
| Thirty percent | Three minutes |
| Fifty percent | Seven minutes |
| Fifty percent (maintained) | Twenty minutes |

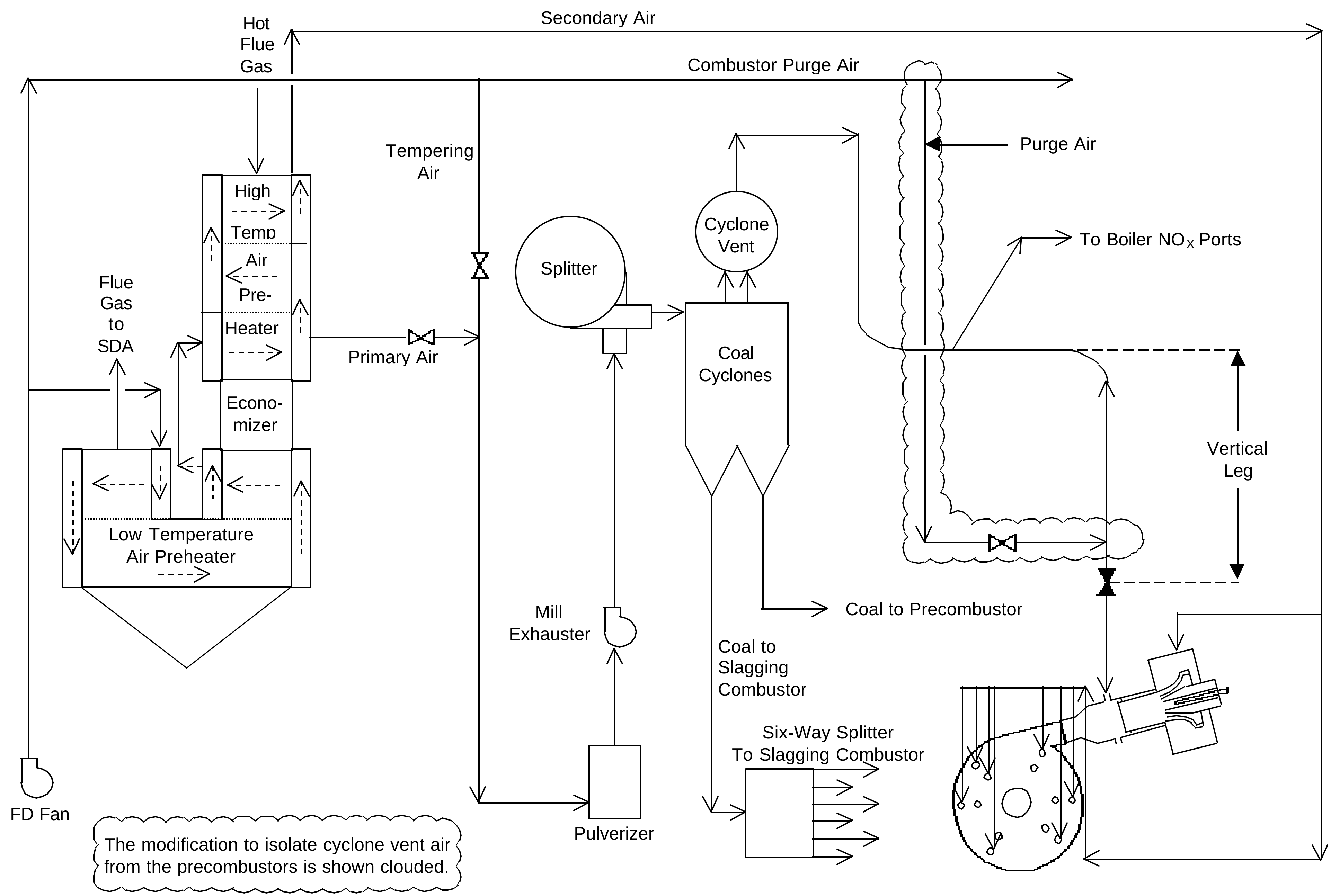
The contractor had attempted to better seal the rooms; however, in subsequent full discharge tests, the required fifty percent concentration was still not maintained in Zone 16. Also, in Zone 13, the discharge rate was insufficient to achieve thirty percent concentration within three minutes of discharge and leakage from Zone 13 prevented a concentration of fifty percent or more of $CO_2$ from being maintained until twenty minutes after discharge.

In order to satisfy minimum concentration versus time requirements, the following modifications were implemented:

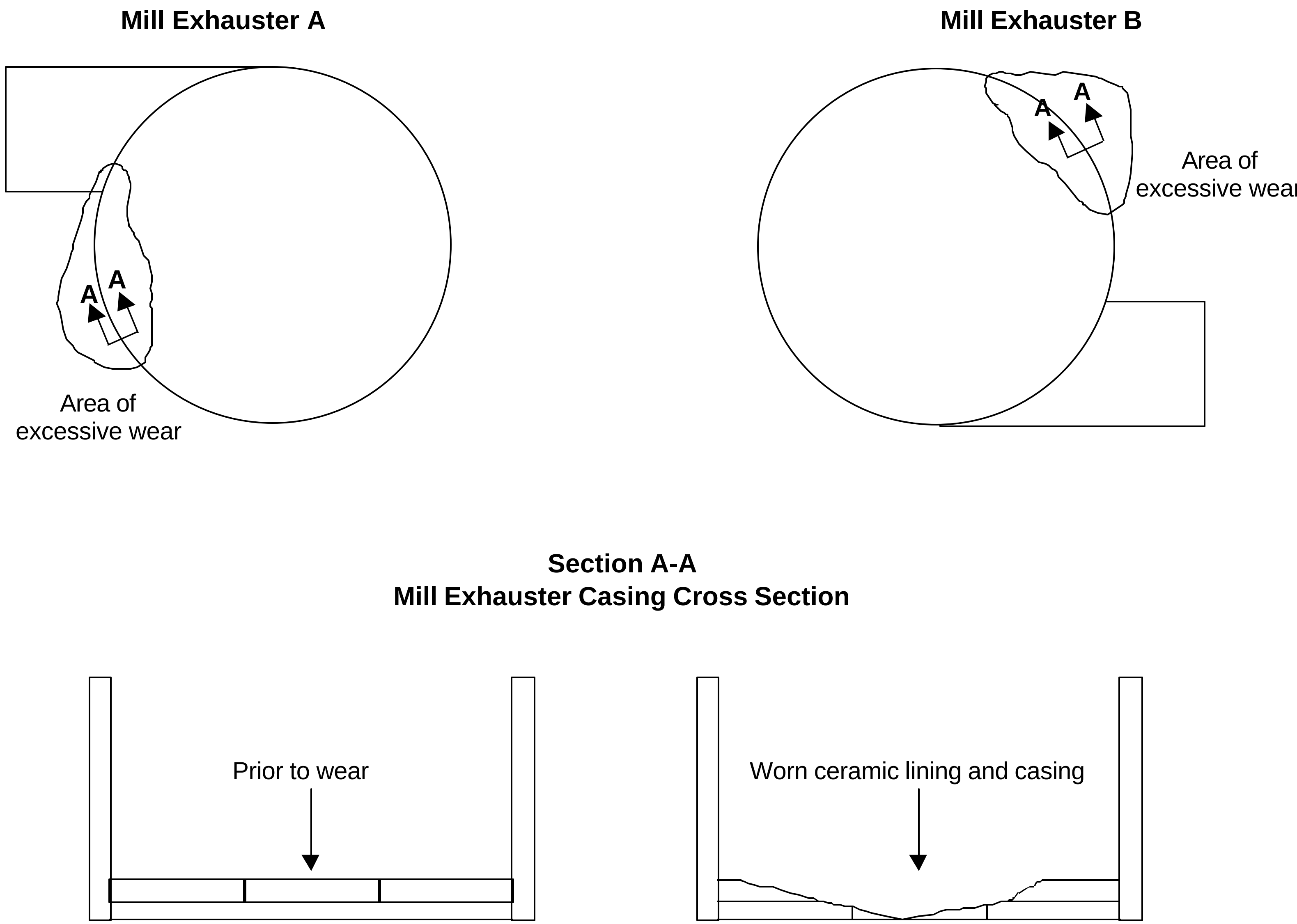
1. Three additional cylinders were headered into the existing bank of cylinders, so that they would only discharge if Zone 13 discharged. A loop header was provided from the three additional cylinders to tie into the discharge end of the original header from the $CO_2$ cylinder bank to Zone 13. This new loop header significantly reduced head loss between the $CO_2$ cylinders and the discharge piping in Zone 13. Consequently, nozzle discharge pressure increased, resulting in a more rapid injection of $CO_2$ into Zone 13 to obtain the required thirty percent concentration within three minutes.
2. Four additional cylinders were headered together to flow through a single orifice sized to provide $CO_2$ from those cylinders for approximately twenty minutes. The header downstream of the orifice was tied into the existing header piping so that the four additional cylinders would be discharged whenever either Zone 13 or Zone 16 was activated. This extended $CO_2$ discharge compensated for any leakage of air into the two zones (and the leakage of $CO_2$ from those zones) after the non-orificed bottles stopped discharging $CO_2$.
3. Additional sealant was applied to the cable tray penetrations, magnetic sealant strips were installed on the doors and the cinder block walls were coated with a sealant to better seal the rooms.

Following these changes, full discharge tests were conducted on Zones 13 and 16 and the required concentrations were achieved and maintained for the required amount of time.

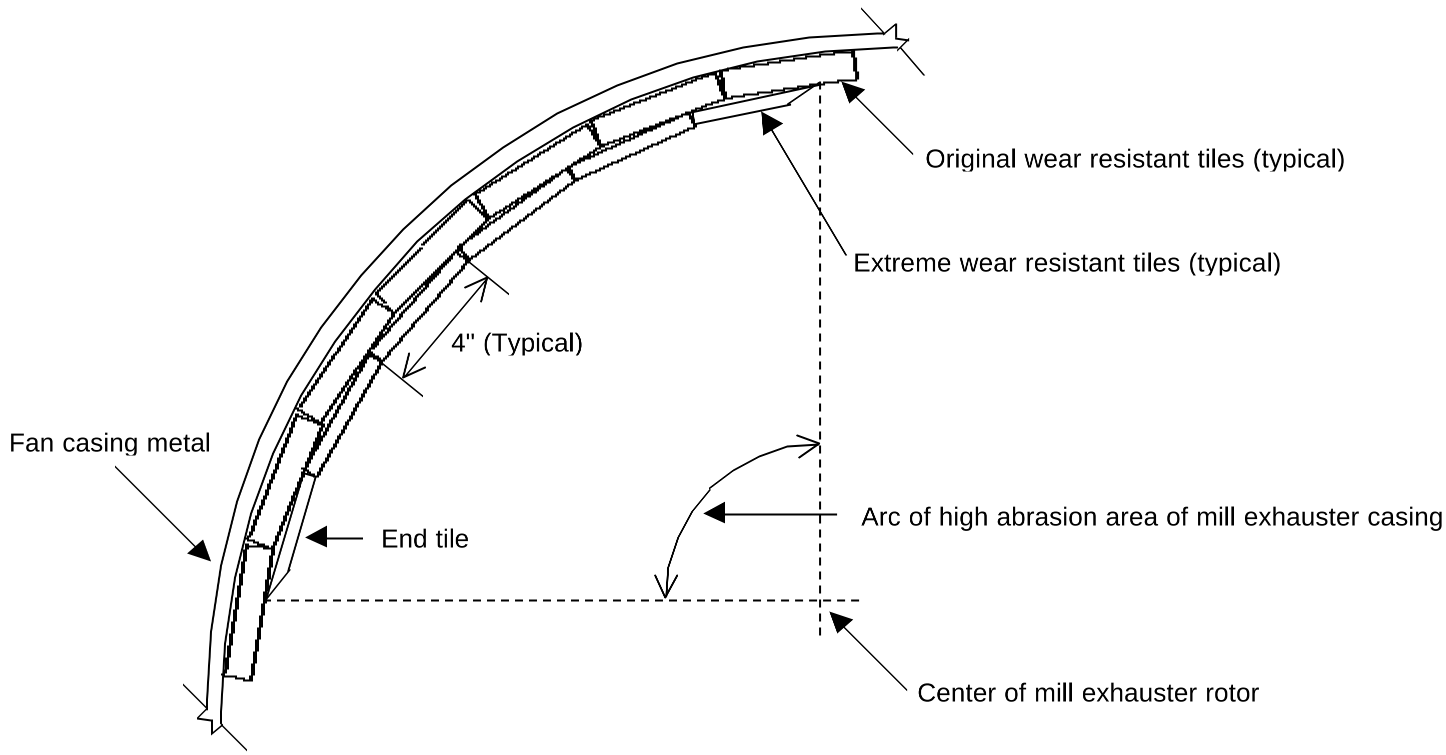
# Figure 5.0.1 – Modifications to Isolate Cyclone Vent Air From the Precombustors



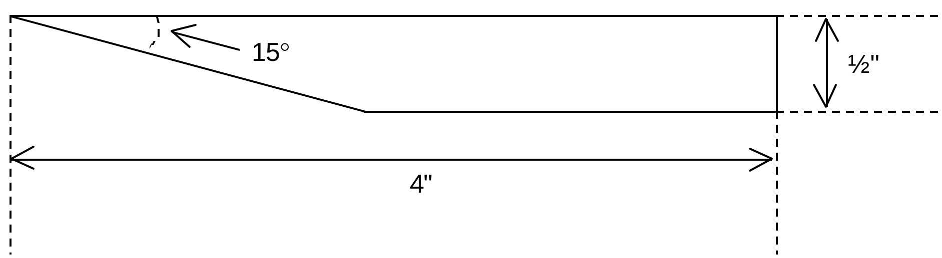
# Figure 5.0.2 – Mill Exhauster Casing Wear Pattern



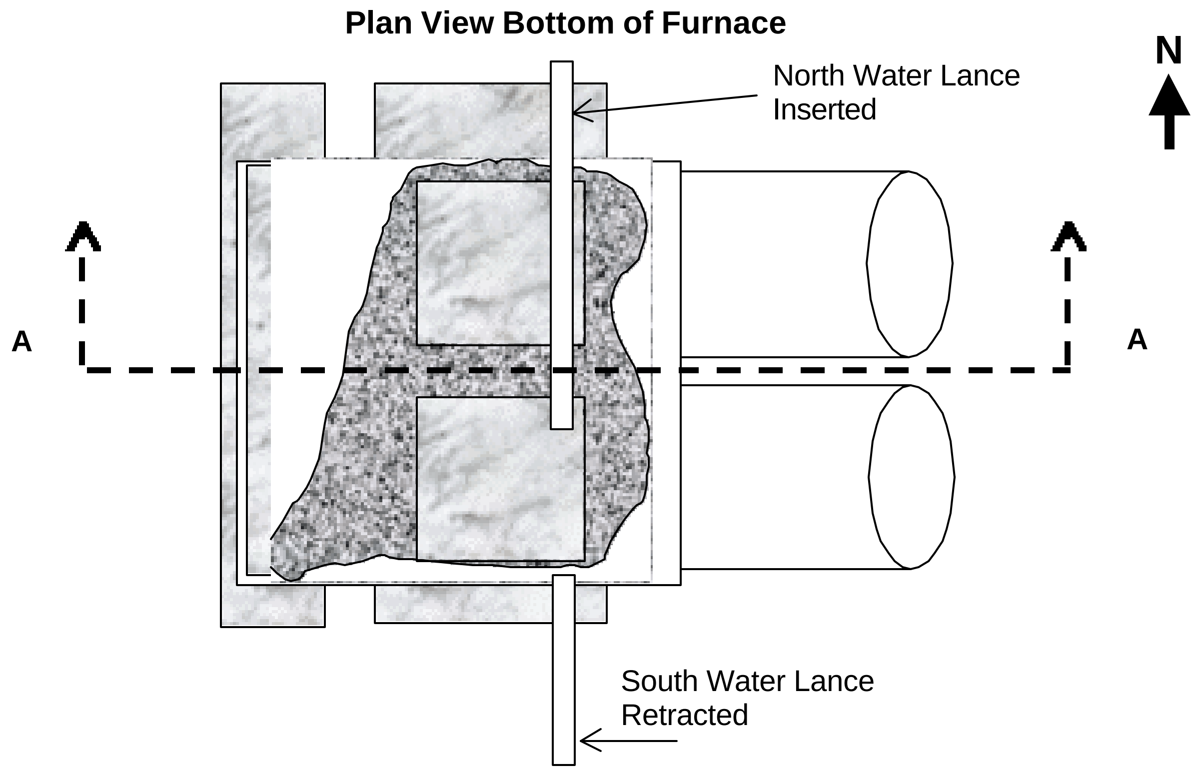
# Figure 5.0.3 – Extreme Wear Resistant Mill Exhauster Casing Liner Tiles

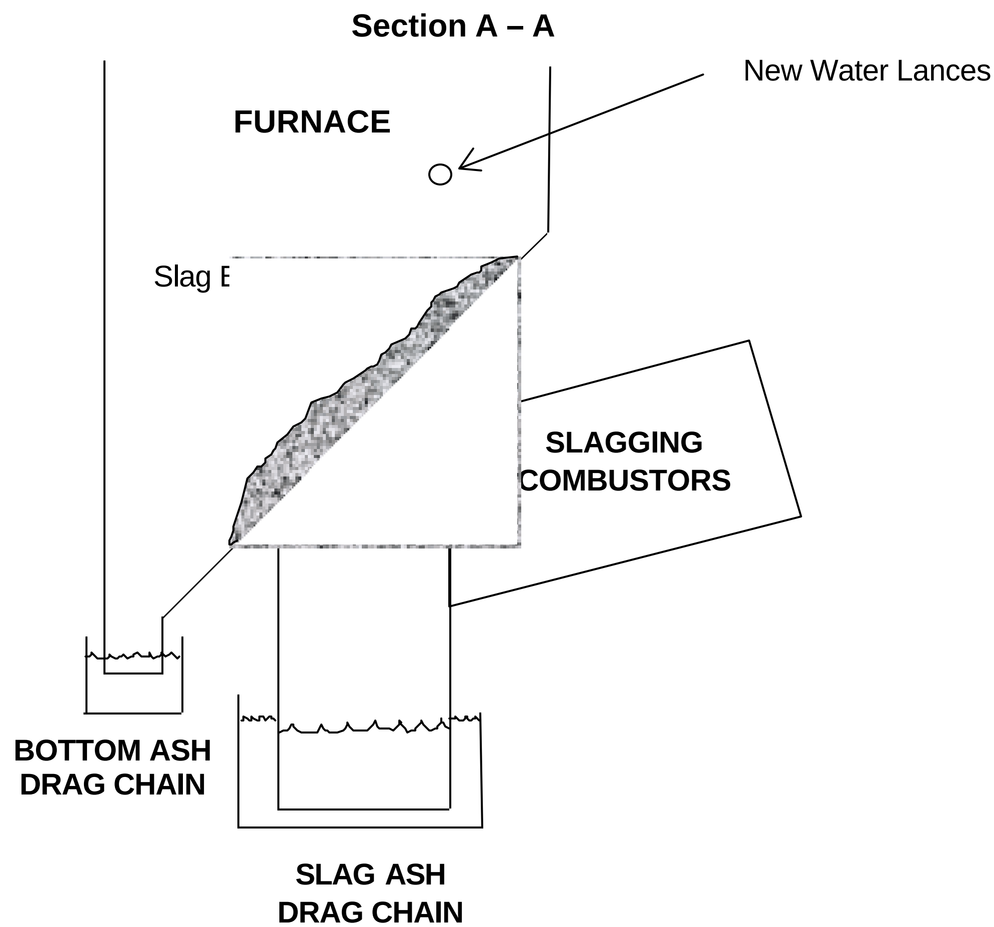



## Detail Of A Typical End Tile

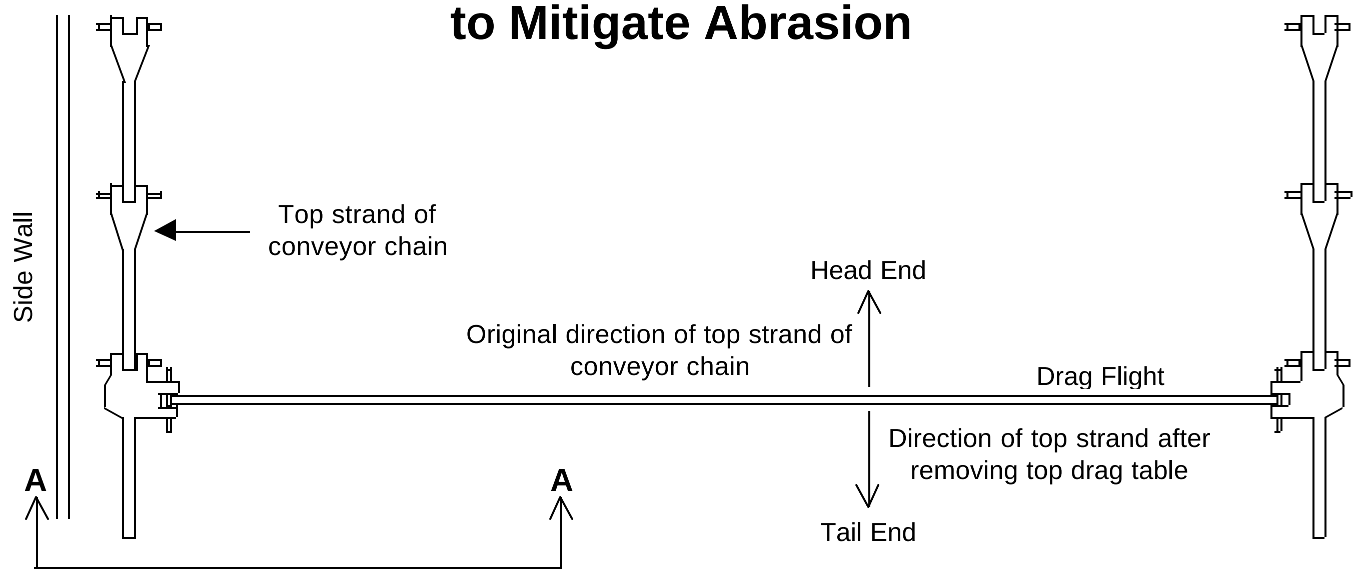


# FIGURE 5.0.4 - SLAG ACCUMULATION ON SLOPED FURNACE HOPPER



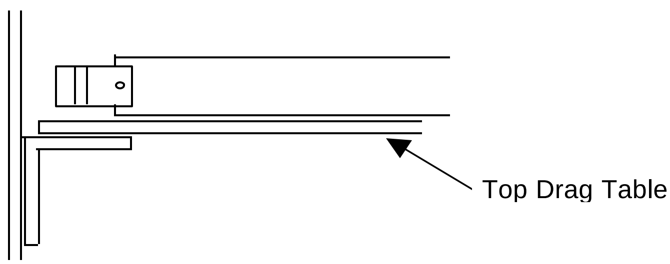



# Figure 5.0.5 – Incline Drag Conveyor Modifications to Mitigate Abrasion

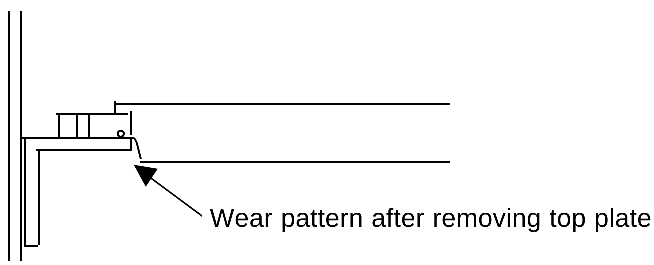



**Section A-A (Three Configurations)**

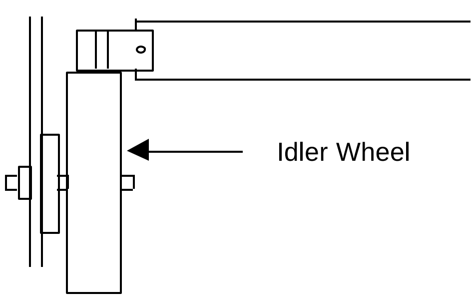
**1) Original Configuration** (top strand travels toward head end)



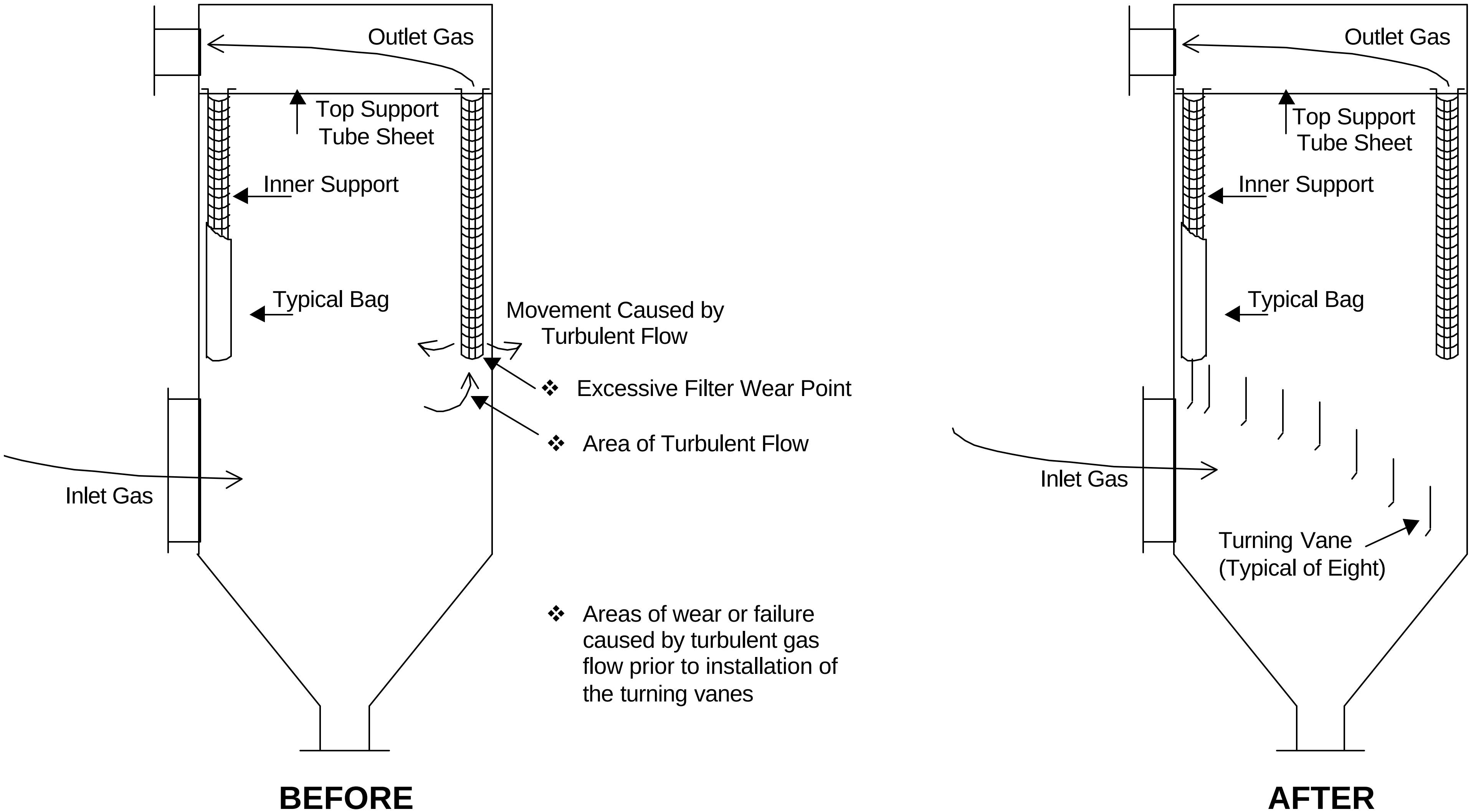

**2) First Modification** (top drag table removed, top strand travels toward tail end)



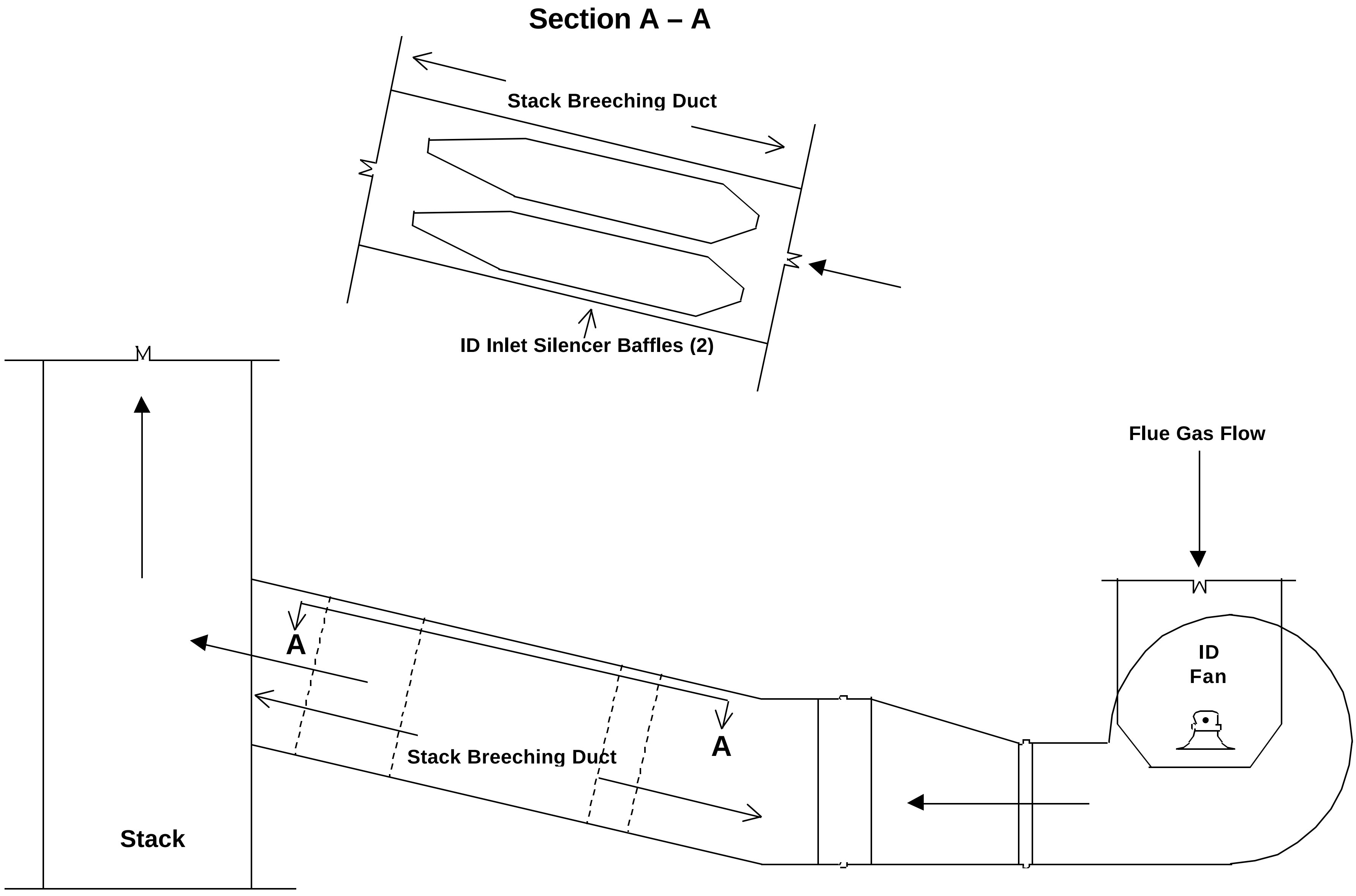

**3) Final Modification** (idler wheels added to reduce chain wear, top strand travels toward tail end)



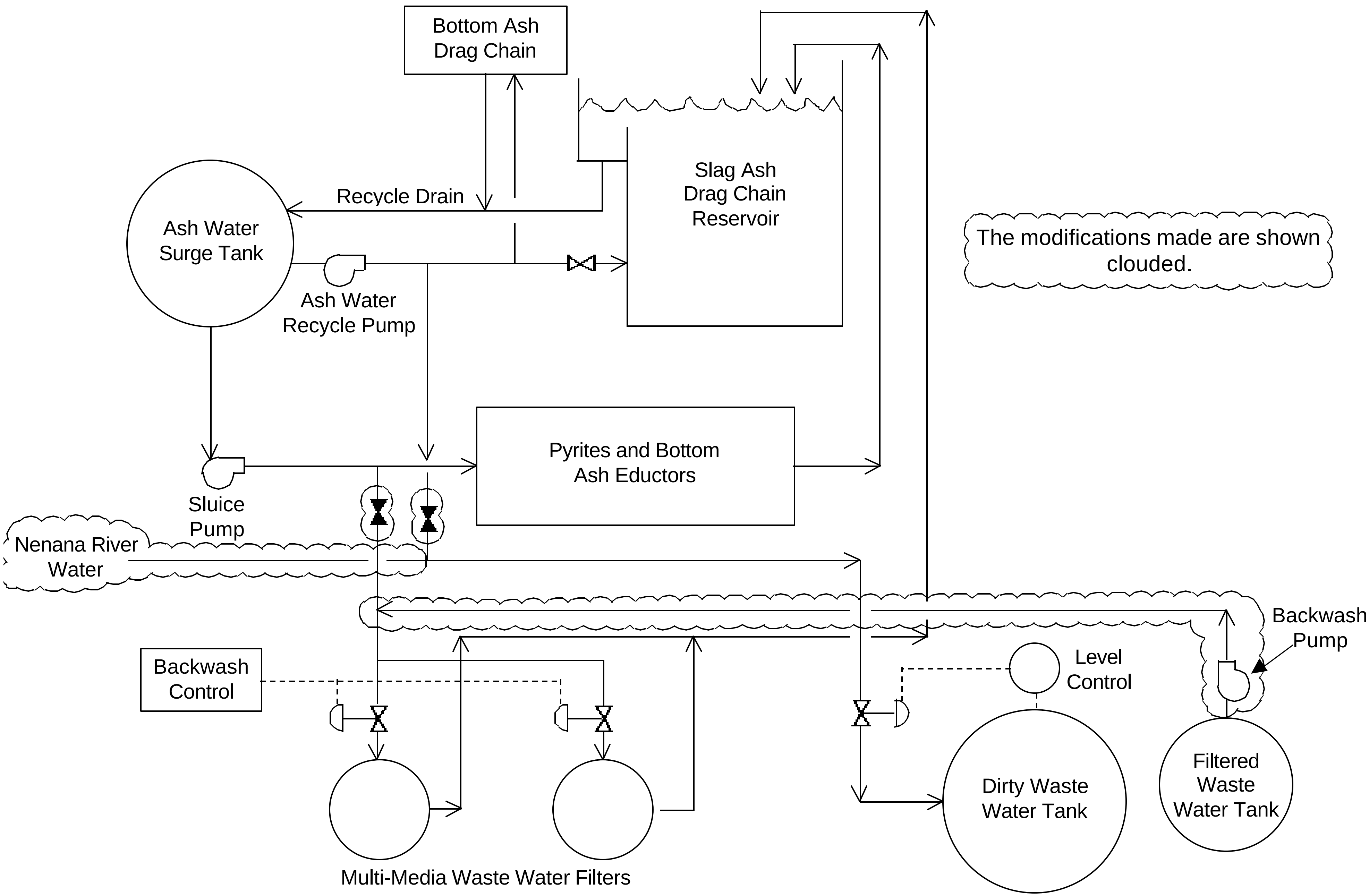
# Figure 5.0.6 – Fabric Filter Bag Compartment (Before and After Turning Vane Installation)



# Figure 5.0.7 – ID Fan Silencer and Stack Breeching Duct



# Figure 5.0.8 – Revised Source of Waste Water Multi-Media Filter Backwash



## 6.0 EMISSIONS

Maximum allowable emissions are as follows:

| | |
|---|---|
| Stack $SO_2$: | 0.10 pounds per million Btu |
| Stack $NO_X$: | 0.35 pounds per million Btu |
| Stack opacity: | Twenty percent |
| Stack CO: | 200 parts per million |

Actual $NO_X$ emissions, $SO_2$ emissions, stack opacity, and CO emissions are discussed in the following paragraphs.

### $NO_X$ EMISSIONS

A slagging combustor stoichiometric ratio of 0.78 to 0.80 was established in 1998 and used in 1999 to minimize $NO_x$ emissions. Potential for further reduction of $NO_X$ at lower slagging combustor stoichiometry exists; however, this was not tested because of the emphasis on achieving and maintaining reliable operation. The precombustor stoichiometry, although it has some effect on $NO_X$ emission, was typically set between 1.00 and 1.10 to create precombustor slagging characteristics required for reliable continuous operation. $NO_X$ emissions for 1999 are show in Figure 6.0.1 to average approximately 0.27 lb/million Btu, twenty percent less than the maximum permitted value of 0.35 lb/million Btu.

### $SO_2$ EMISSIONS

$SO_2$ emissions were well below the limit of 0.10 pounds per million Btu, except for a few brief periods that were the result of equipment problems such as a plugged slurry line or the occasional (generally less than once a month) swap-out of an atomizer. The highest daily three-hour averages for stack $SO_2$ emissions are provided in Figure 6.0.2. The mode of control showing the greatest success was to maintain the SDA outlet temperature at approximately 180 to 185° F, which is fifteen to twenty degrees above the minimum allowable outlet temperature. This allowed the SDA outlet temperature to be lowered quickly as a short-term method to obtain increased $SO_2$ removal efficiency, while adjusting limestone flow as required for long-term $SO_2$ removal adjustments. It is evident from Figure 6.0.3 that the daily maximum $SO_2$ emissions were 0.07 pounds per million Btu or lower; therefore, average $SO_2$ emissions were much lower than that. It is important to note that increased coal sulfur content sometimes trends with increasing ash content as indicated in Figures 6.0.3 and 6.0.4. When high sulfur, high ash and low heating value coal are encountered, the difficulty in removing $SO_2$ increases because of the resulting decrease in the concentration of flash calcined material in the fly ash.

### STACK OPACITY

Stack opacity, averaging approximately five percent, was well below the maximum allowable limit of twenty percent. Gas distribution was improved by installing turning vanes between the inlet duct to the baghouse compartments and the area under the bags. This configuration significantly decreased bag wear and stack opacity.

### CO EMISSIONS

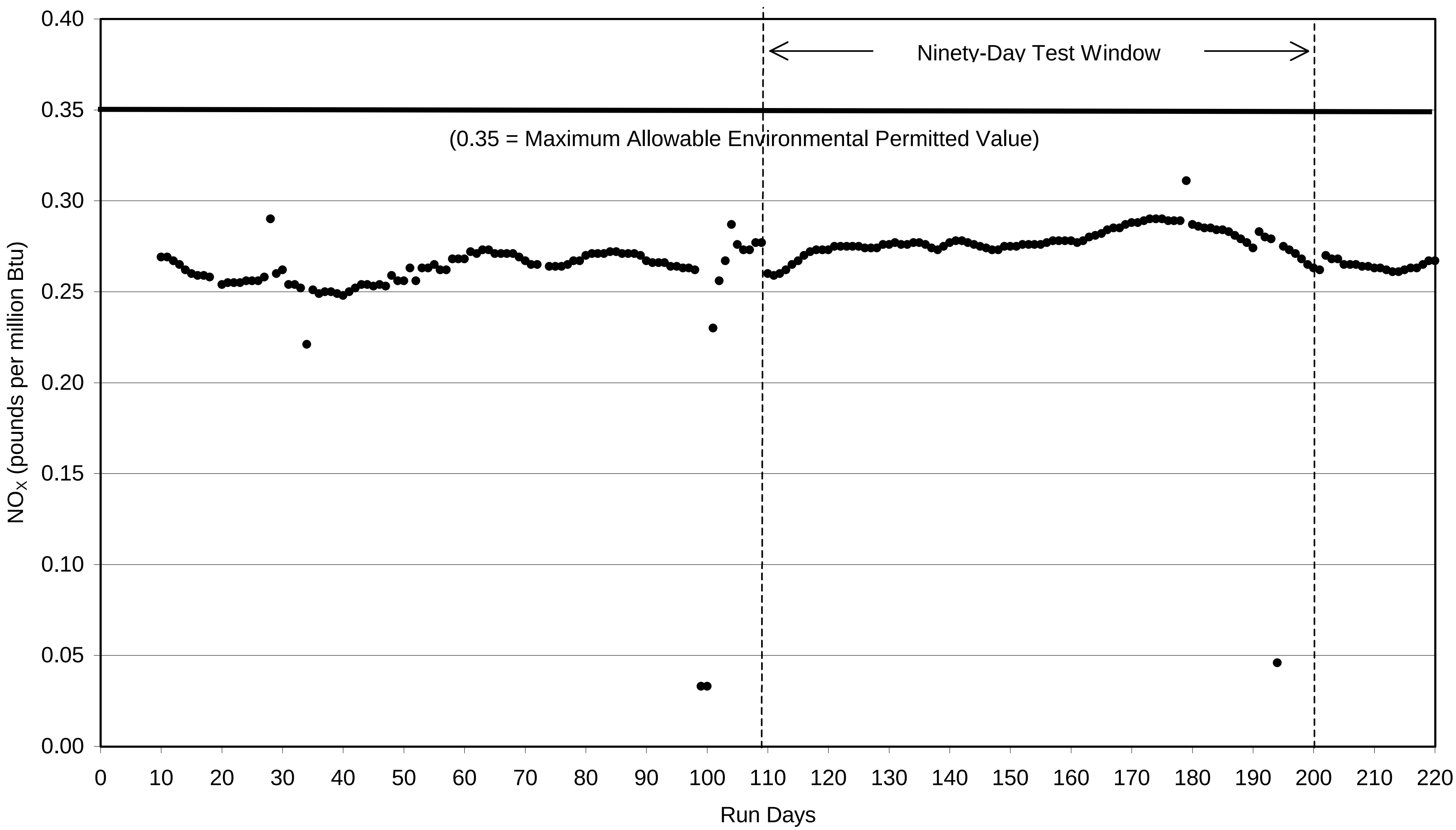
CO emissions typically ranged from 20 to 40 ppm. The maximum allowed value was 200 ppm. This performance, in conjunction with $NO_X$ emissions averaging approximately 0.28 pounds per million Btu, was achieved with excess air. This excess air sometimes exceeded thirty percent, which was caused, in part, by the leaking secondary air dampers. No optimization of $NO_X$ and CO was performed, because of the emphasis on achieving and maintaining reliable operation in

1999.

# Figure 6.0.1 - $NO_X$ Emissions for 1999

HCCP NOx 30 day rolling Average (lbs/mmbtu)

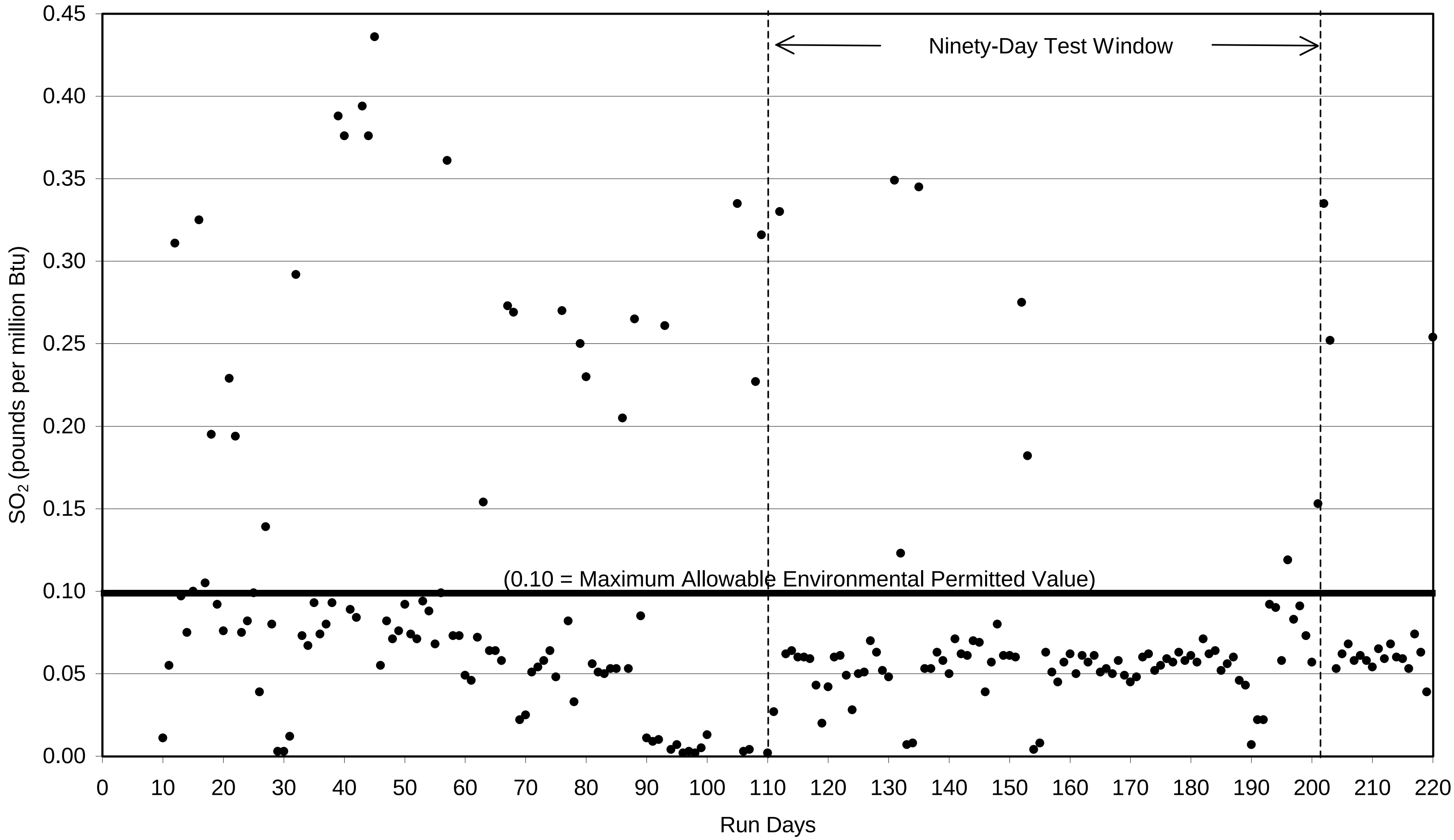
Conversion factor to estimate pounds per million Btu with 4% excess air and 7% leakage downstream of furnace exit = 545



# Figure 6.0.2 - Highest Daily Three Hour Average for Stack $SO_2$ Emissions for 1999

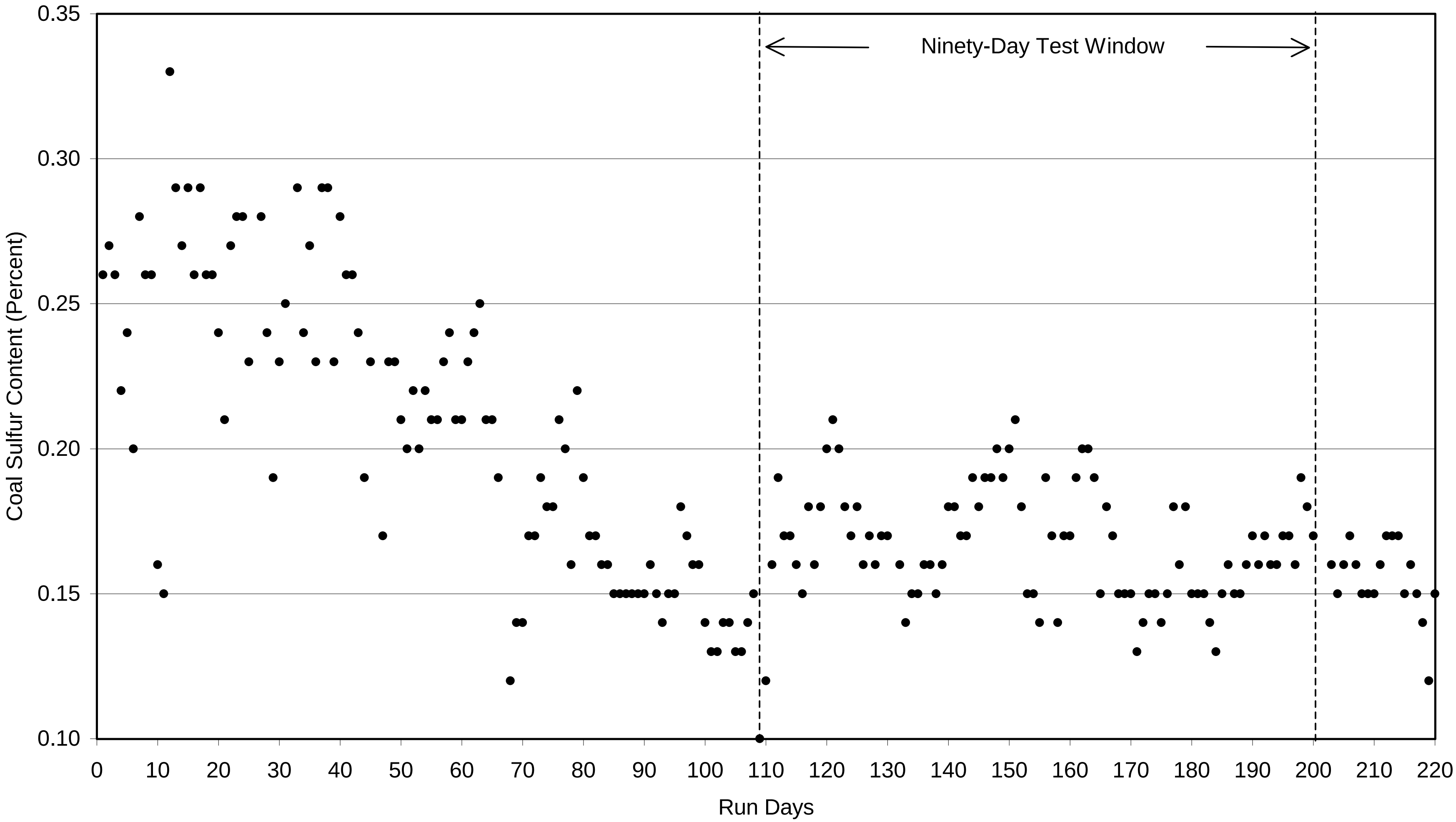
Run Dates: January 18, 1999 to January 25, 1999 HCCP SO2 Highest 3hr/Avg (lbs/mmbtu)

Conversion factor to estimate pounds per million Btu with 4% excess air and 7% leakage downstream of furnace exit = .00255

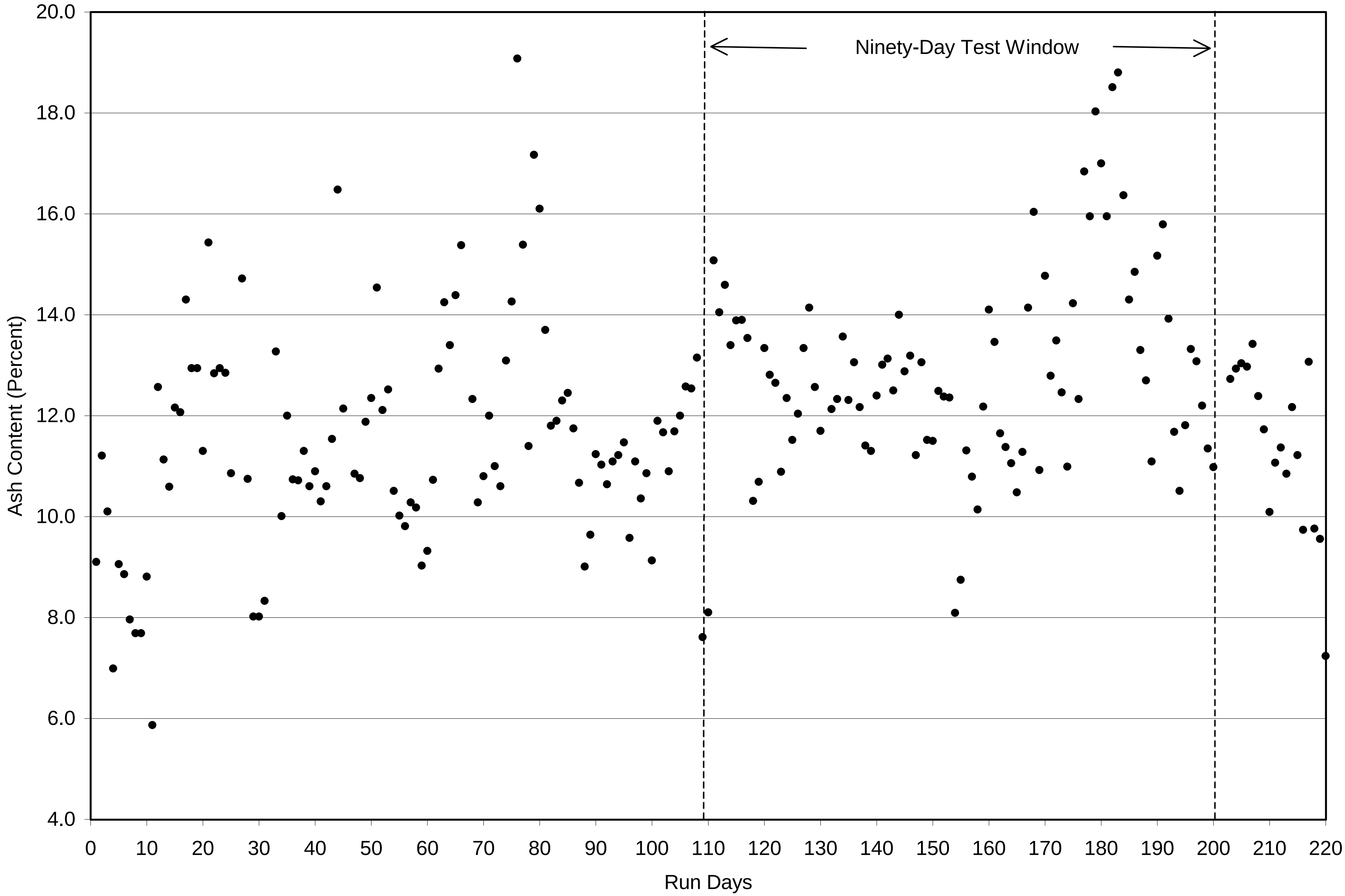


# Figure 6.0.3 - Coal Sulfur Range for 1999

Run Dates: January 18, 1999 to January 25, 1999 HCCP Sulfur (%)



# Figure 6.0.4 - Coal Ash Range for 1999



## 7.0 2000 SCHEDULE

The following additional work was/is under evaluation for future plant operations:

- Modify the secondary air injection to the head end of the slagging combustors to provide lower pressure drop, better accessibility to the flame scanners and to minimize congestion in that area. These changes were implemented.
- Run HCCP without the presence of supplemental staff for data and sample gathering, plant enhancement construction and design, and all other functions nonessential to operations, so that records can be compiled, demonstrating HCCP's operating and maintenance costs.
- Install and test a more wear resistant material in the most wear susceptible areas in the mill exhausters. Trial sections of different wear material were installed, but not tested.
- Establish the operating and maintenance costs associated with the mill exhausters utilizing the enhanced internal wear resistant liner material.
- Obtain cost estimates for the elimination of the existing mill exhausters (this process was started, but not completed). Evaluate the best alternative to the mill exhausters as it compares to preserving the enhanced mill exhausters.
- Eliminate the fines piping going to the precombustors and install ignitors in the boiler fines piping.
- Carryout fine tuning of the unit and tune for lower $NO_x$ levels of emission.

## REFERENCES


1. Independent Engineer's Review of HCCP Ninety-Day Test and Determination of Sustained Operations, Harris Group, December 1999

2. Ninety-Day Commercial Operation Test and Sustained Operations Report: A Participant's Perspective, Healy Clean Coal Project, Alaska Industrial Development and Export Authority, March 2000

3. Investigative Report: Pulverized Fuel System Explosion of September 6, 1999, Healy Clean Coal Project, John Pranitis, Foster Wheeler Energy Corporation, May 3, 2000

4. $NO_X$ Port Coal Fine Ignitor Project Proposal 0-06-266954, Healy Clean Coal Project, Foster Wheeler Energy Corporation, February 15, 2000

5. Turbine Performance Test Report, Healy Clean Coal Project, Fuji Electric Co., Ltd., March 21, 2000

6. Spray Dryer Absorber System Performance Test Report June 7 – 11, 1999, Healy Clean Coal Project, Stone and Webster Engineering Corporation, February 14, 2000

7. Spray Dryer Absorber System Demonstration Test Report November 3 – 15, 1999, Healy Clean Coal Project, Stone and Webster Engineering Corporation, May 29, 2000

8. Quarterly Technical Report No. 29-32 for the Period of January 1 to December 31, 1998 and Startup Topical Report, Alaska Industrial Development and Export Authority, June 2000.

# QUARTERLY TECHNICAL PROGRESS REPORT NO. 33-36
# JANUARY 1 TO DECEMBER 31, 1999

## APPENDICES

**A. HCCP OPERATIONS REPORT 1999**

**B. GLOSSARY OF TERMS**

**C. HCCP OPERATIONAL HISTORY 1999**

# Appendix A – HCCP Operations Report for 1999

| | January | February | March | April | May | June |
|---|---|---|---|---|---|---|
| **Gross (MWHr)** | 8,177.3 | 9,456.1 | 28,359.6 | 27,128.4 | 29,751.8 | 12,669.4 |
| **Station Use (MWHr)** | 1,854.9 | 1,878.8 | 4,275.0 | 3,959.6 | 4,063.3 | 2,570.8 |
| **Net (MWHr)** | 6,322.4 | 7,577.2 | 24,084.7 | 23,168.8 | 25,688.6 | 10,098.6 |
| **Average Net (MWHr)** | 33.6 | 42.2 | 45.2 | 47.7 | 48.6 | 43.9 |
| **Gross Heat Rate (Btu/KWhr)** | 11,591.1 | 11,105.0 | 10,833.4 | 10,720.3 | 10,937.3 | 10,972.8 |
| **Run Time (Hrs)** | 188.4 | 179.7 | 532.4 | 485.5 | 528.6 | 230.2 |
| **Scale vs Feeder** | 0.0% | 9.1% | -1.0% | -5.3% | -1.3% | -5.0% |
| **Coal Use (Tons)** | 5,855.7 | 7,542.8 | 20,267.5 | 18,170.4 | 21,816.0 | 8,640.3 |
| **Coal Use (mmBtu)** | 89,697.2 | 111,828.1 | 295,097.3 | 267,917.0 | 317,469.5 | 130,377.6 |
| **$SO_2$ in Coal** | 0.24% | 0.26% | 0.25% | 0.22% | 0.17% | 0.16% |
| **Coal Weighted Average (Btu/lb)** | 7,658.9 | 7,412.9 | 7,280.1 | 7,372.3 | 7,276.1 | 7,544.7 |
| **Coal Average Cost (mmBtu)** | $1.44 | $1.34 | $1.28 | $1.32 | $1.28 | $1.39 |
| **Coal and Ash Average Cost (mmBtu)** | $1.47 | $1.38 | $1.33 | $1.37 | $1.33 | $1.43 |
| **Total Coal and Ash Cost** | $131,606.00 | $154,367.00 | $391,518.00 | $365,810.00 | $421,802.00 | $186,448.00 |
| **Total Fuel Oil Cost** | $47,631.00 | $32,506.00 | $55,349.00 | $44,698.00 | $26,128.00 | $8,464.00 |
| **Fuel Oil – Steam Boiler (BBL)** | 921.4 | 473.4 | 1,745.0 | 1,387.7 | 792.1 | 264.1 |
| **Fuel Oil – Steam Boiler (mmBtu)** | 5,253.8 | 2,699.4 | 9,950.0 | 7,912.8 | 4,516.8 | 1,505.6 |
| **Total Fuel Oil – Steam and Auxiliary Boiler (BBL)** | 1,744.7 | 1,263.0 | 2,150.6 | 1,661.7 | 890.5 | 288.5 |
| **Fuel Oil and Sulfur (Unit No. 1 and HCCP)** | 0.28% | 0.27% | 0.30% | 0.30% | 0.30% | 0.30% |
| **HCCP Auxiliary Boiler Hours of Operation** | 743.3 | 460.0 | 189.2 | 197.6 | 77.5 | 21.1 |
| **HCCP Auxiliary Boiler Fuel Oil (BBL)** | 823.3 | 789.6 | 405.6 | 274.0 | 98.4 | 24.4 |
| **Maximum Outdoor Temperature (°F)** | 38 | 39 | 47 | 64 | 70 | 84 |
| **Minimum Outdoor Temperature (°F)** | -39 | -50 | -30 | -4 | 19 | 32 |
| **Average Outdoor Temperature (°F)** | -5 | -8 | 12 | 33 | 46 | 58 |

# Appendix A – HCCP Operations Report for 1999

| | July | August | September | October | November | December | Totals |
|---|---|---|---|---|---|---|---|
| **Gross (MWHr)** | 3,837.2 | 25,600.8 | 35,554.6 | 42,956.2 | 20,607.3 | 20,369.6 | 264,468.4 |
| **Station Use (MWHr)** | 1,384.3 | 3,563.4 | 4,695.0 | 5,296.6 | 3,377.7 | 3,031.4 | 39,950.0 |
| **Net (MWHr)** | 2,452.9 | 22,037.4 | 30,859.6 | 37,659.6 | 17,229.7 | 17,338.2 | 224,517.6 |
| **Average Net (MWHr)** | 27.4 | 47.9 | 45.7 | 50.6 | 41.5 | 47.7 | 43.5 |
| **Gross Heat Rate (Btu/KWhr)** | 12,825.5 | 10,960.0 | 11,014.1 | 11,207.7 | 11,495.5 | 11,323.4 | 11,248.0 |
| **Run Time (Hrs)** | 89.6 | 460.5 | 675.9 | 744.0 | 415.4 | 363.3 | 4,893.5 |
| **Scale vs Feeder** | -1.6% | 0.9% | -1.4% | 0.1% | -0.7% | -1.9% | -0.7% |
| **Coal Use (Tons)** | 3,013.8 | 18,928.9 | 25,870.8 | 33,747.8 | 16,327.4 | 15,416.4 | 195,597.8 |
| **Coal Use (mmBtu)** | 45,225.8 | 276,984.9 | 377,260.5 | 481,604.8 | 232,013.8 | 223,440.3 | 2,848,916.8 |
| **$SO_2$ in Coal** | 0.14% | 0.16% | 0.17% | 0.16% | 0.16% | 0.16% | 0.19% |
| **Coal Weighted Average (Btu/lb)** | 7,503.1 | 7,316.5 | 7,291.2 | 7,135.4 | 7,105.0 | 7,246.8 | 7,345.3 |
| **Coal Average Cost (mmBtu)** | $1.38 | $1.30 | $1.29 | $1.22 | $1.21 | $1.27 | $1.31 |
| **Coal and Ash Average Cost (mmBtu)** | $1.42 | $1.34 | $1.33 | $1.27 | $1.26 | $1.31 | $1.35 |
| **Total Coal and Ash Cost** | $64,082.00 | $372,502.00 | $503,351.00 | $612,938.00 | $291,192.00 | $293,091.00 | $3,788,708.63 |
| **Total Fuel Oil Cost** | $18,783.00 | $25,059.00 | $46,651.00 | $3,061.00 | $23,506.00 | $17,753.00 | $349,590.00 |
| **Fuel Oil – Steam Boiler (BBL)** | 579.8 | 813.5 | 1,561.7 | 104.3 | 441.9 | 184.2 | 9,269.1 |
| **Fuel Oil – Steam Boiler (mmBtu)** | 3,305.9 | 4,638.5 | 8,904.8 | 594.8 | 2,519.9 | 1,050.3 | 52,852.8 |
| **Total Fuel Oil – Steam and Auxiliary Boiler (BBL)** | 640.2 | 854.1 | 1,590.0 | 104.3 | 801.2 | 605.1 | 12,593.9 |
| **Fuel Oil and Sulfur (Unit No. 1 and HCCP)** | 0.30% | 0.30% | 0.29% | 0.28% | 0.28% | 0.27% | 0.29% |
| **HCCP Auxiliary Boiler Hours of Operation** | 203.2 | 37.8 | 44.6 | 0.0 | 301.6 | 374.2 | 2,650.1 |
| **HCCP Auxiliary Boiler Fuel Oil (BBL)** | 60.4 | 40.6 | 28.3 | 0.0 | 359.2 | 420.9 | 3,324.8 |
| **Maximum Outdoor Temperature (°F)** | 84 | 80 | 62 | 50 | 35 | 43 | 84 |
| **Minimum Outdoor Temperature (°F)** | 40 | 32 | 10 | -8 | -20 | -41 | -50 |
| **Average Outdoor Temperature (°F)** | 60 | 56 | 44 | 17 | 3 | -7 | 26 |

# Appendix B – Glossary of Terms

| | |
|---|---|
| Blended Coal | A blend of waste coal with any combination of run-of-mine (ROM) seam coal and/or fines |
| Ca/S Ratio | Calcium to sulfur ratio; refers to the ratio of reactive calcium leaving the furnace divided by the theoretical amount required to completely react with all of the sulfur in the coal |
| Clinker | A large piece of frozen slag having no dimension smaller than approximately eight inches |
| Fines | Material which passes through a one-quarter inch by two inch mesh, while screening the larger sized coal |
| Higher Heating Value | The total chemical energy released during combustion, including the latent heat associated with condensing all water vapor |
| Inferred Higher Heating Value | The inferred higher heating value is calculated as a function of boiler duty (estimated as turbine gross generation multiplied by the gross turbine heat rate) divided by an assumed boiler efficiency and then divided by the mass flow of coal into the pulverizers to determine energy released per unit (mass) of fuel fired |
| Slag | Molten ash or ash that was once molten and then refrozen |
| Stoichiometric Ratio | The ratio of reagent actually supplied to react with a given quantity of reactant divided by the amount of reagent theoretically required to completely react with that quantity of reactant |
| Stoichiometric Ratio, Precombustor | When used in relation to the precombustors, it is the air provided relative to the quantity of air required to (in theory) completely combust all of the coal flowing to the precombustor |
| Stoichiometric Ratio, Slagging Combustor | When used in relation to the slagging combustors, it is the total air provided to the precombustor and slagging combustor relative to the quantity of air required to (in theory) completely combust all of the coal entering the head end of the slagging combustor, plus the coal entering the precombustor |
| $T_{250}$ | The temperature (° F) at which molten slag has a viscosity equal to 250 Poise |

**Glossary of Terms**

| | |
|---|---|
| HCCP | Healy Clean Coal Project |
| DOE | U.S. Department of Energy |
| AIDEA | Alaska Industrial Development and Export Authority |
| GVEA | Golden Valley electric Association |
| ROM | Run of Mine |
| FGD | Flue Gas Desulfurization |
| $No_x$ | Nitrogen Oxide |
| $So_2$ | Sulfur Oxide |
| CaO | Calcium Oxide |
| SDA | Spray Dryer Absorber |
| $N_2$ | Molecular Nitrogen |
| $CaCo_3$ | Calcium Carbonate |
| CaO | Calcium Oxide |
| CO | Carbon Monoxide |
| MFT | Main Fuel Trip |
| ID | Induced Draft |
| DCS | Digital Control System |
| MCR | Maximum Capacity Rating |
| TBR | Two Bull Ridge |
| NFPA | National Fire Protection Association |
| MMMWF | Multi-Medial Waste Water Filters |

# Appendix A – HCCP Operations Report for 1999

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|---|---|---|---|---|---|---|---|
| **Gross (MWHr)** | 3,837.2 | 25,600.8 | 35,554.6 | 42,956.2 | 20,607.3 | 20,369.6 | 264,468.4 |
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| **Net (MWHr)** | 2,452.9 | 22,037.4 | 30,859.6 | 37,659.6 | 17,229.7 | 17,338.2 | 224,517.6 |
| **Average Net (MWHr)** | 27.4 | 47.9 | 45.7 | 50.6 | 41.5 | 47.7 | 43.5 |
| **Gross Heat Rate (Btu/KWhr)** | 12,825.5 | 10,960.0 | 11,014.1 | 11,207.7 | 11,495.5 | 11,323.4 | 11,248.0 |
| **Run Time (Hrs)** | 89.6 | 460.5 | 675.9 | 744.0 | 415.4 | 363.3 | 4,893.5 |
| **Scale vs Feeder** | -1.6% | 0.9% | -1.4% | 0.1% | -0.7% | -1.9% | -0.7% |
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| **HCCP Auxiliary Boiler Fuel Oil (BBL)** | 60.4 | 40.6 | 28.3 | 0.0 | 359.2 | 420.9 | 3,324.8 |
| **Maximum Outdoor Temperature (°F)** | 84 | 80 | 62 | 50 | 35 | 43 | 84 |
| **Minimum Outdoor Temperature (°F)** | 40 | 32 | 10 | -8 | -20 | -41 | -50 |
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