Appendix A

Slipstream Heat Pipe Air Heater Tests

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MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

MILLIKEN UNIT 2 SLIPSTREAM HEAT PIPE TESTS
October 27, 1993 to May 21, 1994
Final Report

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LIST OF ABBREVIATIONS

$\eta_{air\text{-}side}$	Air-Side Thermal Effectiveness (Equation 2)
A	Area
ABB API	Asea Brown Boveria Air Preheater Incorporated
ABS	Ammonium Bisulfate
CCT-IV	Clean Coal Technology IV
CF	Corrected Flow
DP_0	Flue Gas Side Pressure Drop At Base Condition 0
DP_1	Flue Gas Side Pressure Drop At Condition 1
dP_A	Heat Pipe Total Air Side Pressure Drop
dP_G	Heat Pipe Total Flue Gas Side Pressure Drop
EPA	Environmental Protection Agency
FGR	Flue Gas Rate
lb/hr	Pounds Per Hour
LMTD	Log Mean Temperature Difference
M_A	Mass Flow Air Side
M_G	Mass Flow Flue Gas Side
ml	Milliliter
N	Normality
NYSEG	New York State Electric & Gas
OD	Outside Diameter
PDFF	Pressure Drop Flow Factor (Equation 6)
ppmv	Parts Per Million by Volume
ppmwt	Parts Per Million by Weight
Q	Heat Transfer Duty
R_0	Flue Gas Flow Rate At Condition 0
R_1	Flue Gas Flow Rate At Condition 1
RF	Reported Flow
RTD	Resistance Temperature Device
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
T_{AI}	Heat Pipe Air Side Inlet Temperature
T_{AO}	Heat Pipe Air Side Outlet Temperature
TC	Thermocouple
T_{GI}	Heat Pipe Flue Gas Side Inlet Temperature
T_{GO}	Heat Pipe Flue Gas Side Outlet Temperature
U	Overall Heat Transfer Coefficient
wt	Weight
$X_{air\text{-}side}$	Temperature Ratio (Equation 1)

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ABSTRACT

As part of the Clean Coal IV Demonstration Project for the Milliken Station, New York State Electric & Gas (NYSEG) will install a full-scale heat pipe to preheat both the primary and secondary air to the Unit 2 boiler. To obtain a preview of heat pipe performance in a utility environment, a slipstream heat pipe air preheater was installed and tested at the Milliken Station. The tests were mainly concerned with heat pipe fouling due to cold-end heat transfer metal temperatures and fouling caused by ammonia salt formation when the unit is operated downstream of a post-combustion NO_x reduction process. This report describes the results of parametric tests conducted on the heat pipe to quantify clean system performance and the performance with and without ammonia in the flue gases.

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SUMMARY

The Milliken Unit 2 Slipstream Heat Pipe Air Preheater Test Program was conducted from October 27, 1993, to May 21, 1994. The purpose of the program was to determine the impact of various levels of ammonia slip and cold-end operating temperatures on heat transfer effectiveness of the heat pipe. Testing consisted of three phases.

- Phase I (October 27, 1993, to December 13, 1993) assessed heat pipe operation at design cold-end metal temperatures with no ammonia (NH_3) addition (i.e., fly ash only). Analysis of heat transfer performance indicated minor cold-end tube bank fouling with a small increase in flue gas-side pressure drop. The pressure drop rise extrapolated for a six month period was only 2.2 times the base, clean system pressure drop. The fouling did not progress enough to decrease the thermal performance as measured by the air-side effectiveness ratio.

- Phase II (December 16, 1993, to January 16, 1994) assessed heat pipe operation with NH_3 injection (constant 2 ppmv) into the feed flue gas stream to simulate slip from a NO_x reduction process. The concern was that fouling would increase in the cold-end of the heat pipe due to the formation of ammonium bisulfate (ABS) deposits. Initial results indicated little or no fouling of the cold-end tube bank and very low fouling of the hot-end tube bank. The fouling for both tube banks increased when the sootblowers failed. Flue gas-side pressure drops gradually increased while the air-side effectiveness ratio gradually decreased. Some recovery of the thermal performance and pressure drops across both tube banks occurred when sootblower operation was recovered. The system performance with sootblowers operating indicates that a 2 ppmv NH_3 slip may be acceptable with a reasonably long period (i.e., six months) between scheduled air heater washings.

- Phase III (February 7, 1994, to May 21, 1994) assessed heat pipe air preheater operation with NH_3 slip from a SCR catalyst bed. The flue gas contained fly ash and a varying concentration of NH_3 due to process variations. During testing, the thermal effectiveness ratio declined and the pressure drop across the hot-end tube bank increased significantly. This indicated that fouling was occurring in the hot-end tube bank. Subsequent visual inspection confirmed that heavy localized fouling occurred near the outlet end of the hot-end tube bank. The fouling appeared to be triggered by operation at higher than 2 ppmv NH_3 slips and promoted by a second temporary loss of sootblower operation. The deposits were successfully removed by water wash; although wash out was difficult and time-consuming.

Recommendations for minimizing fouling on the full-scale heat pipe are to: (1) use retractable, traversing sootblowers rather than fixed, multi-nozzle sootblowers, (2) increase the number of sootblowers, increase sootblowing frequency and intensity, and (3) limit NH_3 slip levels in flue gases entering the heat pipe to 2 ppmv or less.

Any future slipstream testing should emphasize improvements to: (1) the sootblower system to improve effectiveness, coverage, and reliability, (2) ammonia concentration monitoring and control at the heat pipe inlet, and (3) heat pipe construction to eliminate air leakage across the divider plate between the air and flue gas sides.

RESULTS AND CONCLUSIONS

The following results and conclusions were drawn from the Milliken Unit 2 Slipstream Heat Pipe Test Program:

- Phase I (October 27, 1993, to December 13, 1993)

Heat pipe operation in a fly ash-only environment should not pose significant operating problems. Analysis of heat transfer performance indicated minor cold-end tube bank fouling with no appreciable increase in flue gas-side pressure drop or decrease in the air-side thermal effectiveness ratio over the time of the test. A minimal buildup of loose, crumbly deposits was apparent in the cold-end bank of tubes before sootblowing. Sootblowing removed most of this material. Final data analysis and a review of Phase I and II photographs of the cold-end tube bank indicates that a small amount of hard deposit material was forming on the coldest tubes in the cold-end tube bank. The high sulfur content of the deposits (11.2 wt % as received) indicates that the deposits probably formed as a result of SO_3 condensation. To completely eliminate the deposits may require higher sootblowing pressures or operation of the heat pipe at slightly higher heat transfer surface metal temperatures; perhaps 180°F-200°F instead of 170°F.

For the Phase I test period (i.e., fly ash-only environment), the staggered-tube design arrangement of the slipstream heat pipe did not appear to adversely affect heat transfer performance or increase fouling potential.

- Phase II (December 16, 1993, to January 16, 1994)

Heat pipe operation with scheduled wash outs every six months appears to be attainable if ammonia slip is limited to 2 ppmv and sootblowers are properly maintained. Data analysis indicates little or no cold-end fouling and only a low rate of fouling in the hot-end tube bank as long as sootblowers were maintained in operation.

Fouling increased in both tube banks after sootblowers failed to operate. Flue gas-side pressure drop gradually increased while the air-side thermal effectiveness ratio decreased. This indication of fouling was corroborated by a visual and video inspections which revealed tenacious deposits on the bottom row or outlet of the cold-end tube bank and crusty, loose deposits on the top sides of tubes within the cold-end tube bank. Recovering the sootblower operation improved unit performance, although not completely to the "clean" condition level. The results indicate that full recovery of performance is difficult after an extended loss of sootblower operation.

Gas analyses at the heat pipe inlet and outlet showed high losses of gas phase SO_3 and NH_3 across the heat pipe. The SO_3 drop out was 42% while NH_3 drop out was 73%. Based on outlet particulate analyses, much of the NH_3 appears to condense or react to form ammonia salts on the fly ash.

- Phase III (February 7, 1994, to May 21, 1994)

When ammonia slip concentrations exceed about 2 ppmv for an extended time period, serious localized fouling in the heat pipe is likely to occur. Visual inspections revealed heavy fouling near the outlet of the hot-end tube bank. Analysis of heat pipe performance showed a significant increase in flue gas-side pressure drop across the upper (hot-end) tube bank as well as a decrease in the air-side thermal effectiveness ratio during the testing. The fouling appeared to be triggered by operation at higher than 2 ppmv NH_3 slips and was likely promoted by a loss of sootblower operation which went undetected for three weeks.

Use of high-volume, low-pressure water wash was found to be an effective method of removing tube deposits. High water volumes allow the tube areas to be flooded. This soaks and softens the deposits which can then be flushed away by the water flow. The use of low-volume, high-pressure water sprays rapidly cleaned tubes on which the water spray impinged directly but failed to clean tubes buried deep in the tube bank. This is likely because the staggered tube arrangement shields tubes buried in the tube bank and the low water flow rate does not adequately wet the deposits.

RECOMMENDATIONS

The following recommendations were formulated based on results and experiences from the Milliken Unit 2 Heat Pipe Slipstream Test Program.

- The design of the flue gas-side sootblowing system will be critical to the performance and operation of the full-scale heat pipe in a fly ash and ammonia environment. Based on Phase II and III test periods, it is apparent that even temporary loss of sootblowering capacity can cause significant performance degradation. As a result, careful analysis should be made of sootblower system design including the number and placement of sootblowers and the frequency, and intensity of the sootblowing. Sootblower nozzle pressure should be increased over the relatively low 90-110 psi level obtained for the slipstream tests. Retractable units which give good coverage and high sootblowing intensity should be installed rather than multi-port, fixed position, rotatable units used during the slipstream tests.

- The ammonia slip concentration resulting from any type of post-combustion NO_x control technology should not exceed 2 ppmv at the heat pipe inlet. When the ammonia slip at 2-2.5 ppmv was increased to a level of 3.4-3.6 ppmv during the Phase III test period, acute localized fouling in the upper bank commenced. Efforts should be made to prevent even temporary deviations over 2 ppmv since this may result in the formation of a critical initial deposit layer on the tubes. With experience on the full-scale heat pipe, some relaxation in the NH_3 slip constraint may be possible later.

- Even if the unit operates with NH_3 slips at or below 2 ppmv, the heat pipe will likely need to be washed every six months. As a result, a planned wash out procedure as well as required facilities and equipment should be available once the full-scale unit is operational. Phase III testing proved that washing the tubes free of NH_3/fly ash deposits can be difficult, expensive, and time-consuming if deposition is allowed to proceed to a high degree. Care should be taken to facilitate the full-scale wash process and to make it as efficient and effective as possible. Providing water spray headers within the heat pipe is recommended. To minimize water usage during air preheater wash outs, consideration should be given to providing facilities for solids separation and recirculation of wash waters. Finally, since the wash waters from the slipstream heat pipe wash outs were highly acidic with pH's at times below 2.0, consideration should be given to providing equipment for neutralization.

INTRODUCTION

The purpose of the NYSEG Milliken Unit 2 Slipstream Heat Pipe Air Preheater Test Program was to determine the effect of fouling due to fly ash or fly ash-ammonium bisulfate deposits on air preheater heat pipe performance for a given design cold-end metal temperature. The testing provided a first glimpse of the performance and operating problems which might be expected from the full-scale unit being installed at Milliken as part of the CCT-IV program plant modifications. The slipstream test facility was operated by CONSOL from October 27, 1993, to May 21, 1994.

Asea Brown Boveri Air Preheater Incorporated (ABB API) designed and built the pilot slipstream heat pipe heat exchanger. The unit was constructed with tubes which, except for length, were identical (i.e., same diameter, fin height, number of fins/inch) as those to be used for the Milliken full-scale heat pipe air preheater. For flexibility, the slipstream unit was designed with a tube sheet between the flue gas and air sides which allowed for tube removal and tube pitch adjustment. Initial tests by ABB API evaluated the operation of staggered versus in-line tube arrangements. Prior to turning the unit over to CONSOL, ABB API converted the heat pipe to an all staggered triangular pitch tube arrangement.

The slipstream heat pipe consists of two tube banks which are referred to throughout this report as the hot-end and cold-end tube banks. Inlet flue gas temperatures to the hot-end bank ranged between 630°F to 540°F while cold-end bank outlet temperatures ranged between about 350°F to 250°F. On the air side, air entered at ambient temperatures and exited at temperatures ranging from 200°F to +500°F depending upon the operation. The unit was designed to handle a wide range of flue gas and air flows. For the tests covered in this report, flue gas rates ranged between 10,000 lb/hr and 25,000 lb/hr.

The coal burn during the majority of the test program was a medium-sulfur (1.4 wt % dry), high-volatile, low-ash, Pittsburgh seam bituminous coal. During the Phase III test period, the coal burn was switched to a higher sulfur (2.8 wt % dry) Pittsburgh seam coal for one week (March 7 to March 14). Afterwards, the coal burn was returned to the medium-sulfur coal.

The data acquisition consisted of a Helios™ scanning system (update every 30 seconds) with data transfer to an on-site personal computer (PC). Data were automatically recorded on the PC hard drive every 15 minutes with over 60 variables transferred at a time. Logged data related to the heat pipe were instantaneous values, with the exception that during the Phase III testing the flue gas flow rate was recorded as a 15 minute average.

The test program was divided into a parametric testing period and three test phases. The parametric testing was conducted to characterize unit baseline performance before any fouling had occurred for a range of flue gas and air flow rates. Phase I testing assessed heat pipe performance in a fly ash-only environment. Phase II evaluated heat pipe performance in a fly ash and 2 ppmv ammonia (NH_3) slip environment. Phase III assessed heat pipe performance downstream of a selective catalytic NO_x reduction (SCR) catalyst bed. Like the Phase II testing, the flue gas environment contained both fly ash and NH_3. However, for Phase III testing, the NH_3 slip concentration varied due to changing test conditions for catalyst parametric testing as well as changing catalyst performance over time.

PROCESS DESCRIPTION

The configuration of the slipstream heat pipe test facility is shown in Figures 1 and 2. Figure 1 shows the system as originally installed for heat pipe only tests (all tests before February 1994); while Figure 2 shows the system after installation of SCR catalyst beds and NH_3 injection system. Both configurations rely upon the pressure drop across the Unit 2 Ljungstrom air preheater to provide the driving force for flue gas flow through the slipstream unit. As originally installed, gas from the Unit 2 economizer outlet (Ljungstrom inlet) is supplied to the flue gas side of the slipstream heat pipe through a 28" OD duct. The flue gas flow is controlled by an electric motor-driven damper in the inlet line. Initially, the damper position was manually set. Later, the damper position was automatically controlled by the measured inlet flue gas flow rate.

Hot flue gas enters the top of the heat pipe and passes through two banks of finned heat pipes. In this report, the top tube bank is referred to as the "hot-end," and the bottom bank as the "cold-end." Flue gas exits the cold-end tube bank and flows into the ductwork leading to the Unit 2 ESP. During shutdown periods, the heat pipe is isolated from the main plant by closing the inlet flue gas flow control damper and the manual outlet damper.

On the air side, ambient air is pulled across the tube banks by the vacuum in the flue gas duct leading to the Unit 2 ESP. The air is heated as it passes up through the tube banks. Control of the air flow is by an automatic damper in the air line from the heat pipe (see Figures 1 and 2).

Skin thermocouples (TCs) which measure the surface temperature of individual heat pipes, were installed on two tubes at the top and two tubes at the bottom of each tube bank (see Figure 1). The air flow to the heat pipe was controlled by the cold-end outlet temperature of TC-8. Although TC-7 and TC-8 were on the same outlet row of heat pipes, the two TCs did not register the same temperature. The TC-8 temperature was normally set to maintain TC-7 in the range of 170°F to 180°F.

The air and flue gas stream temperatures to and from the heat pipe were determined by resistance temperature devices (RTDs). The RTDs provide an average temperature over the sensor length rather than a point value like the TCs. Use of RTDs provided average cross duct temperatures.

To remove fly ash and other deposits from the heat pipes, two air-operated, wall-mounted sootblowers were installed. Each blower extended across the width of the heat pipe cross section, had multiple blow ports along its length, and rotated during operation. One blower was located between the hot-end and cold-end tube banks; the other was below the outlet of the cold-end tube bank. Sootblowing effectiveness was compromised because of the multiport design which bled down the air supply pressure. During operation, the air supply pressure at the sootblower was typically only 90 to 110 psi. A nozzle pressure of 150 to 200 psi is desirable.

DISCUSSION

Parametric Testing (November 18 to 24, 1993)

Summary. Heat pipe performance in an unfouled condition was measured for a range of flue gas and air flow rates. The data were correlated to provide a means of calculating clean condition performance for comparison with fouled condition results. Other parametric tests results are listed below.

- Sootblowing was effective in restoring heat pipe performance lost due to tube fouling with NH_3-free fly ash.
- Clean condition air-side and flue gas-side mass flow rates were correlated with the air-side and flue gas-side pressure drops respectively. This was done to provide a means of quickly checking air flow rates and estimating the extent of flue gas-side fouling.
- Heat losses from the inlet ductwork resulted in an average flue gas inlet temperature decline of 1.6°F for each 1,000 lb/hr decline in flow.

General Discussion. Slipstream heat pipe parametric testing was conducted from November 18 to 24, 1993. The testing was done in an NH_3-free flue gas environment with the heat pipe in an essentially unfouled condition. The thirteen run conditions investigated are listed below.

Run	Flue Gas Flow lb/hr	Skin Temp. TC #8 °F
1	25,000	220
2	25,000	235
3	25,000	245
4	25,000	268
5	15,000	220
6	15,000	230
7	15,000	245
8	15,000	265
9	10,000	220
10	10,000	235
11	10,000	245
12	10,000	255
13	20,000	247[1]

1. Air flow set at 10,000 lb/hr

The values listed in the table above were targets. The actual flows and temperatures for each run varied slightly from the targeted values. For each run, the heat pipe was allowed to come to thermal equilibrium before data were taken. Typically, this took one to two hours after changing operating conditions. The collected data are presented in Appendix I.

Correlation of Performance. The data associated with the runs listed in Appendix I were used to correlate the performance of the heat pipe unit in an un-fouled condition. The performance of the heat pipe is expressed in terms of an X-ratio and an effectiveness term as follows:

$$X_{air\text{-}side} = \frac{[T_{GI} - T_{GO}]}{[T_{AO} - T_{AI}]} \qquad (1)$$

$$\eta_{air\text{-}side} = \frac{[T_{AO} - T_{AI}]}{[T_{GI} - T_{AI}]} \qquad (2)$$

Where:

$T_{AI,AO}$ = Air-side inlet and outlet temperatures, respectively

$T_{GI,GO}$ = Gas-side inlet and outlet temperatures, respectively

$X_{air\text{-}side}$ = X-ratio with respect to air-side

$\eta_{air\text{-}side}$ = Air-side thermal effectiveness

The thermal performance is plotted against X-ratio in Figure 3. The plot indicates a linear relationship between thermal effectiveness and the X-ratio with flue gas flow as a parameter. The data scatter is probably due to variations in temperatures and flue gas and air flow rates. Since the air-side thermal effectiveness should approach 1.0 when the X-ratio goes to zero, performance lines were extrapolated to a Y intercept of 1.0. The following correlation (r^2 = 0.99) for air-side effectiveness was obtained.

$$\eta_{air\text{-}side} = 1 - [0.2737 + 6.2x10^{-6}FGR]X_{air\text{-}side} \qquad (3)$$

Where:

FGR = Flue gas rate, lb/hr

Using the flue gas mass flow rate and inlet and outlet temperatures for the air and flue gas sides, Equations (1) through (3) can be used to compare predicted heat pipe heat transfer effectiveness to measured effectiveness. This provides a method of comparing clean heat pipe performance to actual performance. A reduction in heat transfer effectiveness can be interpreted as a measure of fouling. The correlations are for a specific design and set of operating parameters (tube arrangement, layout, air leakage). They are for estimating the performance of the slipstream unit only and can not be used for the full-scale system. However, similar performance curves could be developed for the full-scale unit.

Fouling Control. The short-term fouling impact on the heat pipe tube temperature is shown in Figure 4. The plot data were recorded during evening and early morning hours of November 20 and 21, 1993. Thermocouples TC7 and TC8 refer to skin thermocouples placed on separate pipes located in the last row of the cold-end tube bank (see Figure 1). Sootblowing was scheduled for 1 p.m., 9 p.m., and 5 a.m. daily.

The TC7 response clearly indicates fouling on the tubes. Sootblowing temporarily recovered heat transfer to the tube and increased the TC7 temperature. However, the tube returned to the fouled state within one to two hours. The constant temperature response of TC8 may indicate that the temperature control, which uses TC8 to regulate air flow to the heat pipe, is rapid enough to prevent a slight temperature excursion when sootblowing occurs.

Inlet Flue Gas Temperature Losses. Data showing the impact of flue gas flow rate on flue gas inlet temperature are shown in Figure 5. The regression line through the data suggested a 1.6°F decrease in flue gas inlet temperature for every 1,000 lb/hr reduction in flue gas flow. This level of ductwork heat loss was not of concern for heat pipe operations. However, it did at times affect the operation of the SCR catalyst system which was installed in January 1994. To prevent formation of NH_3/sulfur compounds within the catalysts, NH_3 injection was stopped whenever the inlet flue gas temperature to the catalysts dropped below 600°F.

Correlation of Pressure Drop Data. Parametric test data on the air-side and flue gas-side pressures are shown in Figures 6 and 7. The pressure drop data were each correlated against the respective air or flue gas flow rates. The correlations ($r^2 = 0.87$ for flue gas and $r^2 = 0.78$ for air) are shown below.

$$dP_A = [7.00x10^{-5}M_A - 0.0876]^2 \quad (4)$$

$$dP_G = [4.95x10^{-5}M_G + 0.2280]^2 \quad (5)$$

Where:

$dP_{A,G}$ = *Total heat pipe pressure drop on air or gas sides, respectively, inches of water*

$M_{A,G}$ = *Mass flow rate of air or flue gas, respectively, lb/hr*

These correlations were useful in comparing clean condition versus fouled condition pressure drops. Additionally, Equation 4 was rearranged and used to calculate the air flow rate during times when the flow transmitter failed or was out of calibration.

Phase I Test Period (October 27, 1993, to December 13, 1993)

Summary. The Phase I test period investigated heat pipe performance in a fly ash-only flue gas environment. Data analysis and visual inspections indicated that some fly ash deposits formed in the cold-end bank of tubes. However, sootblowing every eight hours was effective in removing the deposits and returning the unit to "clean" condition performance. Data analysis showed only a very small increase in flue gas-side pressure drop across the cold-end tube bank and no trend in air-side heat transfer effectiveness ratio. The Phase I testing included parametric tests of the heat pipe in late November (see Parametric Test Period Section).

General Discussion. The Phase I test period ran from October 27, 1993, until December 13, 1993. The objective of Phase I testing was to simulate full-scale heat pipe operations at either a 250°F flue gas exit temperature or the design metal skin temperature of 170°F in the cold-end tube bank. Targeting for a heat pipe skin temperature of 170°F was normally done because ABB API reported that corrosion and fouling are more dependent on the heat transfer surface temperature than on the outlet flue gas temperature.

During the Phase I test period, the heat pipe was operated in a fly ash-only environment, without NH_3 injection, and with the flue gas flow rate set between 20,000 and 30,000 lb/hr.

Inspections. Inspections of the heat pipe were performed during shutdown periods on October 27, 1993, and November 16, 1993. Both inspections found minimal fouling of heat pipes and fins. Figures 8a, 8b, and 8c show the condition of the cold-end tube bank outlet row of heat pipes before the Phase I tests were initiated. These tubes operated under conditions which were prone to fouling by sulfuric acid condensation. The heat pipe condition after about 500 hours of operation appeared to be unchanged (see Figures 9a, 9b, and 9c).

Sootblower Operation. For the Phase I testing, sootblowers on the flue gas side of the heat pipe were operated once every eight hours. When the blow cycle was initiated, one sootblower would be activated, go through one revolution of the blower shaft (a process taking about 15 to 20 seconds), and shut down. The other sootblower would then be activated to go through an identical cycle. The process continued for one minute until the cycle timer timed out. This sootblower cycle kept the heat transfer surfaces reasonably clean. The sootblowers were located between the hot-end and cold-end tube banks and at the outlet of the cold-end tube bank.

System Performance. The flue gas rates to the heat pipe are shown in Figure 10. Corresponding flue gas side pressure drops (total, hot-end tube bank, and cold-end tube bank) are shown in Figure 11. Based on a review of Figures 10 and 11, the flow rate appears to be essentially constant for two long periods (0-450 hrs and 650-1137 hrs). The tube bank pressure drops also appear stable over these time periods. However, a closer examination of the data shows that there was a gradual increase in the cold-end tube bank pressure drop with time. This is clearly indicated in Figure 12. Since the gas flow rate through a resistance, such as a tube bank, is proportional to the square root of the pressure drop, the following factor can be plotted against time to determine if fouling is occurring:

$$PDFF = \frac{\sqrt{\frac{DP_1}{DP_0}}}{\frac{R_1}{R_0}} \qquad (6)$$

Where:

$PDFF$ = *Pressure Drop Flow Factor*
DP_1 = *Pressure Drop At Condition 1*
DP_0 = *Pressure Drop At Base Condition*
R_1 = *Flue Gas Flow At Condition 1*
R_0 = *Flue Gas Flow At Base Condition*

As shown in Figure 12, the PDFF centered around 1.0 for the hot-end tube bank; indicating no increase in fouling. However, for the cold-end tube bank some flow restriction was occurring since the factor steadily increased to about 1.3 over the course of the 1137 hour test period. Placed in perspective, this is not a large increase in the pressure drop. The result shows that the sootblower operation was not adequate to completely remove tube deposits when the cold-end heat pipes were operated with metal skin temperatures in the range of 170°F (see Figure 13), a temperature below the acid dew point. The PDFF across the heat pipe increased to about 1.15 over the 1137 hours of testing. This represents a 32% ($1.15^2=1.32$) increase in the expected pressure drop. At this rate, the pressure drop would be expected to increase 2.2 times over a six month period (1.0 + 0.32*4380 hrs/ 1137 hrs = 2.24). Such an increase in air heater pressure drop could probably be accommodated between scheduled air heater wash outs. Alternately, providing more sootblowing capacity and better coverage could minimize or eliminate this problem.

Normally, the heat pipe was operated to maintain nominally a 170°F metal skin temperature on the cold-end tube bank thermocouple TC7. However, as shown in Figure 13, there were times when the TC7 temperature dropped as low as 150°F. This was due to the way the temperature control system operated. The automatic temperature control used the reading on TC8. Initially, the temperature difference between TC7 and TC8 was only about 15°F with TC8 registering hotter. As the unit fouled, the TC7 temperature would drop while the TC8 temperature held constant. To maintain the TC7 temperature at 170°F, the set point control for TC8 had to be increased throughout the test program. At the end of Phase I, the temperature difference had increased to over 60°F.

Thermal Performance. The air-side thermal effectiveness ratio is shown in Figure 14. This ratio is the measured thermal effectiveness (Equation 2) divided by the expected effectiveness for a clean system (Equation 3). Over the test period, the effectiveness ratio remained relatively constant. The heat pipe thermal performance did not decline measurably for the fly ash-only test period (Phase I); another conformation that fouling was minimal.

Flue Gas Flow Measurement. During the Phase I test period, the flow sensing element pressure taps often plugged when the equipment ran unattended. During the parametric tests, the flue gas flow element taps were back-blown frequently to insure that they remained open and unrestricted. Using the parametric test flow rate data and the calculated heat balance flue gas flow rates, a correlation was developed (r^2 = 0.85) for actual flue gas flow rate as a function of calculated heat balance flue gas flow rate. This correlation, shown below, was used to estimate the expected flow rate when frequent back blowing of the flow element pressure taps was not possible.

$$CF = 2243 + 1.0373RF \qquad (7)$$

Where:

CF = Corrected Flue Gas Flow Rate, lb/hr
RF = Reported Heat Balance Flue Gas Flow, lb/hr

The flue gas flow rate (Figure 10) remained steady throughout the test period, excluding instances where target set points were changed (for example, at the 300 hour mark). The variation shown in the flue gas flow (attenuated in the figure through the use of two hour running averages) over a given time period is attributed to the lack of damper control, which was corrected later in the test program (late Phase II).

Phase II Test Period (December 16, 1993, to January 16,1994)

Summary. Phase II tests were conducted with NH_3 injected into the flue gas ahead of the heat pipe to simulate a 2 ppmv NH_3 slip from a NO_x control process. The test purpose was to monitor the heat pipe performance for signs of fouling associated with possible formation of ammonium bisulfate (NH_4HSO_4). The results indicate that: (1) the heat pipe suffered a small thermal performance decline due to fouling, and (2) pressure drops increased slightly across both the hot-end and cold-end tube banks on the flue gas side. The pressure drop increases appear to be mainly associated with the loss of sootblower operation. When sootblowers were operating, the system pressure drop rise was small. Assuming a six-month period between washings to remove deposits for the full-scale heat pipe, the total heat pipe pressure drop is projected to increase by about 2.4 times the base pressure drop. This is roughly the same pressure drop increase as obtained for the Phase I tests.

General Discussion. Phase II of the Milliken Unit 2 Slipstream Heat Pipe Test Program was conducted between December 16, 1993, and January 16, 1994. The objective was to simulate a flue gas with a 2 ppmv NH_3 slip from a NO_x control process and observe heat pipe performance and fouling.

On December 16, 1993, continuous NH_3 injection was begun. Operations proceeded smoothly except for a sootblower actuator failure between January 1, 1994, to January 14, 1994. This sootblower failure was not detected during the test period but was identified during final data review. Sootblower failures also plagued operations during the Phase III testing.

Ammonia System Checkout. On November 15, 1993, the ammonia injection system was installed. Feed system tuning and accuracy checking were accomplished between November 22, 1993, and November 24, 1993. For the system checkout, the NH_3 mass flow controller was set to deliver the amount required for a 2 ppmv concentration level in the flue gas. Nine NH_3 measurements were made in the heat pipe flue gas inlet duct. Three of the measurements were full traverses, five were single quadrant points, and one was at the mid-point of the duct (see Figure 15).

Flue gas was sampled through a stainless steel probe equipped with a fiber glass filter plug followed by 4-impingers in an ice bath. The first two impingers each contained 100 ml of 0.1 N HCl solution. The third impinger was empty to collect any mist carryover; and the fourth impinger was filled with silica gel. Probe washings and impinger contents were combined and analyzed in the CONSOL lab in Library, Pa., for NH_3 using ion chromotrography. The data are listed in Table 1.

The average NH_3 concentration in the flue gas for the three full traverse measurements was 2.4 ppmv with a 0.6 ppmv standard deviation. The lower than expected result for port A-2 is likely due to air in-leakage at the flange during measurement.

The flue gas concentration measurements indicate that the NH_3 injection system could reliably maintain the 2 ppmv NH_3 concentration with acceptable accuracy, duct distribution, and uniformity.

Inspections. At the conclusion of Phase II on January 17, 1994, a visual inspection was performed which indicated significant flue gas side fouling, especially in the cold-end tube bank. Tubes at the outlet of the hot-end tube bank (Figure 16) and inlet to the cold-end tube bank (Figure 17) had soft deposits on the leading edges which are not of concern since these appeared to be readily sootblowable.

Deposits on the cold-end outlet row of tubes were hard and difficult to remove (see Figures 18a, 18b, and 18c). The outlet row deposits were only slightly larger than the deposits seen after the first 500 hours of Phase I fly ash-only testing (compare Figures 18a and 18b with 9b and 9c). Since the system pressure drops did not appear to increase significantly during the Phase I testing, the heat pipe was not shut down and inspected between the Phase I and II tests. Because the cold-end outlet row deposits contained a high amount of sulfur (11.2 wt. % as received) and only a very small amount of NH_3 (25 ppmwt, see Table 2), the deposits are likely only the result of SO_3 condensation from the Phase I testing. If cold-end outlet deposits become a problem for the full-scale heat pipe, a small increase in the cold-end heat pipe skin temperatures may be required. Perhaps increasing the skin temperatures to 180°F by bypassing a small amount of air around the heat pipe would be sufficient.

A flexible borescope was used to view heat pipes up through the cold-end tube bank. NYSEG personnel used a video camera attached to the borescope to obtain a picture record. The inspection revealed considerable fouling and deposits on the side of the tubes and fins facing the flue gas flow. In general, these deposits appeared to be somewhat loose and crumbly while the deposits on tubes at the outlet of the tube bank were hard and difficult to chip out. The deposit structure provides evidence that direct impaction of particles on surfaces is important for lay-down.

After the inspection, the cold-end tube bank was washed with approximately 100 gallons of water. This removed the tube deposits. As shown in Table 3, the wash waters contained high levels of NH_3 and were highly acidic. The NH_3 level was approximately 1% of the suspended solids + Fe + S (as SO_4) + NH_3; a much higher level than in the hard deposits on the outlet row of tubes. Based on industry experience in Japan and Europe with SCR units, condensation of ammonium bisulfate (NH_4HSO_4) in the tube bank is the most likely source of the NH_3.[2] Because this material is sticky at intermediate air preheater temperatures, condensation will cement fly ash and form deposits.

System Performance. As with the visual inspection, analysis of the heat pipe operating data for the Phase II test period indicated loss of performance due to fouling. The flue gas flow rate (based on Equation 7) for the Phase II test period is shown in Figure 19. The average flue gas rate remained essentially constant at 20,000 to 21,000 lb/hr. The flue gas-side total and individual bank pressure drops are plotted in Figure 20.

To better evaluate the system behavior, the flow and pressure drop data were combined into a pressure drop flow factor (PDFF) using Equation 6. The results are presented in Figures 21, 22, and 23 for total system pressure drop, hot-end tube bank pressure drop, and cold-end tube bank pressure drop, respectively. Over the first 400 hours of Phase II operations, the PDFF for total flue gas side pressure drop increased only slightly from 1.0 to 1.05 (see Figure 21). This represents a 10% increase in expected pressure drop ($1.05^2 = 1.10$). Assuming a six-month period between air preheater washings, the pressure drop rise would be only about 2.4 times the base pressure drop; essentially the same as for the no ammonia operations of Phase I. These results indicate that a 2 ppmv NH_3 slip can be tolerated for the full-scale heat pipe operation.

Unlike for Phase I, the pressure drop increase during the first 400 hours of Phase II operation was only across the hot-end (PDFF=1.1 at 400 hrs) rather than the cold-end tube bank (PDFF=1.0 at 400 hrs). Perhaps the NH_3 injection reduced the amount of free SO_3 in the flue gases reaching the cold-end tube bank by reacting to form NH_4HSO_4 and or $(NH_4)_2SO_4$. Lower SO_3 levels due to reaction with NH_3 would tend to reduce cold-end tube bank fouling due to condensing acid. However, reaction with NH_3 would be expected to cause fouling in higher temperature regions of the heat pipe because the NH_4HSO_4 formation temperature is generally higher than the SO_3 dew point. The slight increase in hot-end tube bank pressure drop during NH_3 injection indicates that this may have happened. For the Phase II tests, hot-end outlet row thermocouples, TC3 and TC4, operated nominally between 280°F and 380°F (see Figure 24). Often TC3 was below the expected formation temperature for NH_4HSO_4 (i.e., 315-320°F for 5 ppmv SO_3 and 2 ppmv NH_3).

The steep rise in pressure drops corresponds roughly with the time period when sootblower operation was lost. Over the period between about 400 hours and 700 hours, the PDFF increased substantially for both the hot-end and cold-end tube banks. Total pressure drop across the heat pipe increased 42% ($(1.25/1.05)^2$ Figure 21) above expected. Over a six-month period, this would translate into a 15.4-fold increase in the base pressure drop; a condition which would likely force an early shutdown for clean out.

The gradual decrease in pressure drops after 700 hours is attributed to multiple sootblowing cycles prior to shutdown and inspection. The sootblowing did not completely recover the system pressure drops back to original start values. Apparently, once deposits are allowed to build up, removal becomes more difficult. For the full-scale Milliken heat pipe preheater, special efforts should be made to keep the sootblower systems in good working order at all times. Failure to do so will likely result in rapid fouling of the air heater when flue gases contain NH_3.

Thermal Performance. Over the first 400 operating hours, the air-side thermal effectiveness ratio showed little decline (see Figure 25). When the sootblower operation ceased, a near linear decline in thermal effectiveness ratio was observed. The effectiveness ratio later recovered when sootblower operation resumed. This performance matches the results of the pressure drop analysis. Pressure drop and thermal performance analyses show increased fouling for the 400 hr to 700 hr time period followed by recovery when the sootblower operation was restored.

The immediate impact of not operating the sootblowers is illustrated in Figure 26. Sootblower operation is indicated by temperature spikes above the bulk of data points i.e., the general temperature trend. For the first 275 hours, there was a general decline in TC7 temperature. Between hours 275 and 405 the temperature stabilized. When the sootblowers failed, the TC7 temperature began a steady decline, which ended when the sootblowers resumed operation. After the first sootblow, the TC7 skin temperature immediately increased more than 10°F. Still, the temperature was about 5°F lower than before the sootblower failure. This net loss in skin temperature may be due to the prolonged deposit formation period when the sootblowers were out of service; making subsequent cleaning more difficult.

Air Leakage. Results of the Phase II flue gas-side oxygen level traverses are shown in Table 4 and Figure 27. The heat pipe appeared to have a significant amount of air in-leakage on the flue gas-side next to the divider plate. Using the average oxygen

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concentration across the outlet duct (6.1%) and assuming that the low oxygen level for port 1 represents the undiluted oxygen concentration in the flue gas, the leak rate was calculated to be over 12% of the inlet flow rate. This compares reasonably well with over 9% leakage based on a similar calculation using the temperature measurements presented in Table 5 and an ambient air temperature of 53°F. The plot of the temperature data (Figure 28) shows low temperatures where the highest oxygen levels were later measured; again indicating air leakage along the divider wall between the flue gas and air sides.

The slipstream heat pipe was built with a tube sheet divider wall which allowed rearrangement of tube layouts. In this design, the tubes were not welded to the divider wall but had caulking or gasket material between the tubes and divider wall plates. Air leakage would be more likely for this type design than for the all-welded construction of the full-scale unit. Air leakage is not expected to be a problem for the full-scale unit.

SO_3/NH_3 Losses Across Heat Pipe. Shortly before the end of Phase II testing, gas samples were taken at the inlet and outlet of the heat pipe to determine the SO_3 and NH_3 losses. Tables 6 and 7 present the SO_3 and NH_3 data, respectively. The inlet/outlet SO_2 values for the January 13 data are also presented in Table 6. The gas sampling is representative because the average inlet and outlet SO_2 values differ by less than 1%. For the test conditions, 42% of the SO_3 and 73% of the NH_3 were removed in the heat pipe. These high losses point to the potential for fouling and corrosion of the heat pipe. Assuming that these materials can be absorbed by fly ash depositing in the air heater, sootblowing provides the only on-line method of removal.

Analysis of flue gas particulates taken non-isokinetically with an in-stack filter at the heat pipe inlet and outlet are presented in Table 7. The results show no absorption of NH_3 at the inlet where temperatures are above 600°F and very high levels (127-287 ppmwt) at the outlet, where temperatures are about 300°F or less. These results confirm the losses shown by the gas phase NH_3 analyses and indicate that fly ash NH_3 levels may limit fly ash sales. The problem can be solved by tightly controlling NH_3 slip levels to limit NH_3 salt formation and/or absorption on fly ashes.

Phase III Test Period (February 7, 1994, to May 21, 1994)

Summary. Phase III of the Milliken Unit 2 Slipstream Heat Pipe Test Program ran from February 7, 1994, to May 21, 1994. The test objective was to operate the slipstream heat pipe in an NH_3, fly ash laden flue gas environment simulating conditions downstream of a post-combustion NO_x control process. Through the test period, significant increases in flue gas-side pressure drop and decreases in flue gas mass flow rate and air-side thermal effectiveness ratio were observed. These results were likely due to a combination of sootblower failure early in the Phase III test period and extended operation of the heat pipe with greater than 2 ppmv NH_3 slip. The increase in flue gas-side pressure drop was due to fouling of the upper or hot-end tube bank. Visual inspection revealed the fouling to be highly localized between two rows of tubes. The lower, cold-end tube bank remained relatively unfouled.

General Discussion. The Milliken Unit 2 Slipstream Heat Pipe Phase III Test Program ran from February 7, 1994, to May 21, 1994. The purpose was to assess heat pipe performance in an environment downstream of a post-combustion NO_x control process. As shown in Figure 2, additional ductwork and a catalyst holder for two test catalysts were installed ahead of the heat pipe. An automatic blow back system was also installed to keep the flue gas flow element sensing taps clear. This allowed use of the flue gas mass flow rates reported by an annubar-type flow meter to be used for the Phase III tests. These flow rates were adjusted slightly based on the following correlation between manual pitot measurements and the annubar flow (r^2 = 0.83 for 63 data points).

$$CF = 4736 + 1.254RF \tag{8}$$

Where:

CF = Corrected Flue Gas Flow Rate, lb/hr
RF = Reported Flow Rate, lb/hr

As during the Phase II operations, sootblower operation was again unreliable. The sootblowers failed initially at about 290 hours into the testing. This was not discovered until about 850 hours into the run; when repairs were made. Probably both the sootblower failure and high NH_3 slips ahead of the heat pipe contributed to the fouling experienced during the testing.

The system was shut down on April 12, 1994, and washed out because the pressure drop across the hot-end tube bank severely limited flue gas flow through the heat pipe. Cleaning was done using a hand-held, low-volume, high-pressure (2,500 psi) water spray nozzle. A little over 300 gallons of water were used. The technique was very effective in cleaning tubes one to two rows deep into the tube bank. However, because of the staggered tube arrangement, tubes deeper in the banks were largely unaffected by the cleaning. This became apparent when the unit was placed back in service after the April 12, 1994, wash out and pressure drops were essentially unchanged from pre-wash values. Once the unit was restarted, fouling continued.

The second wash out on May 3, 1994, was effective and returned the flue gas pressure drops to clean condition levels. For this washing, a high-volume, low-pressure water spray technique was used. Approximately 15,000 gallons of water were used to clean the deposits from the two heat pipe tube banks. Final cleaning of the heavily plugged area in the hot-end tube bank was accomplished using a water lance between tubes. This used 300 to 400 gallons of water.

The heat pipe remained shut down until May 14 because of an ongoing test program. During the last week of testing (May 14 to May 21), parametric tests were conducted to establish the performance of the post-combustion NO_x control process. Since the testing required considerable variation in flue gas flow rates through the heat pipe, it is difficult to discern any trend in thermal performance for this period.

<u>System Performance</u>. The Phase III flue gas flow to the heat pipe and the total flue gas side pressure drop are plotted in Figures 29 and 30, respectively. Initially, the flue gas flow rate was varied between about 14,000 and 20,000 lb/hr because of parametric tests. After the 130 hour mark to the 525 hour mark, the flue gas flow rate was set and normally held constant at about 14,000 lb/hr. During this period, the pressure drop remained stable as shown in Figure 30.

A step change in pressure drop occurred at the 525 hour mark when the flue gas flow was increased. The targeted flow was 20,000 lb/hr. However, because of system pressure drop limitations only about 19,000 lb/hr was obtained with both the inlet flue gas flow control and the outlet isolation dampers wide open. The large variation in the flue gas flow rate after the 525 hour mark is due to lack of damper control. After about the 790 hour mark, fouling increased heat pipe pressure drops which reduced the flue gas flow.

To better assess what occurred in the heat pipe, the pressure drop flow factors (PDFF) (Equation 6) across the heat pipe and separately across the hot-end and cold-end tube banks are plotted in Figures 31, 32, and 33, respectively. These figures indicate that relatively little fouling occurred up to about the 790 hour mark. At which time, the hot-end tube bank pressure drop began to increase slowly and the cold-end tube bank pressure drop began to increase sharply.

In Figure 34a the heat pipe total PDFF and the estimated NH_3 slip concentrations are plotted together. Much of the scatter in the NH_3 slip concentrations is due to testing when flow rates were intentionally changed. As shown in Figure 34a, the sudden increase in system pressure drop appears to coincide with a step change in the estimated composite NH_3 slip level. This is better shown in Figure 34b in which the time scale is expanded. When the NH_3 slip concentration averaged about 2.2 ppmv, there was little or no increase in system pressure drop. When the NH_3 slip concentration increased to about 3.5 ppmv, the pressure drop increased rapidly.

Based on the results of the Phase II tests and the lack of a pressure drop increase for the first 790 hours of Phase III testing, a 2 ppmv or less slip appears to be a good target to protect the air heater. The results shown in Figures 34a and 34b suggest that the limit is very tight and that exceeding it will result in rapid fouling. Our findings are reasonably consistent with Japanese experience which required air preheater cleaning after 12 months when NH_3 slip was limited to <3 ppm for a high fly ash case (6.6 grains/scf) and to 7 months for 2.5 ppm NH_3 slip for a low fly ash case (0.044 grains/scf).[3]

Due to loose wiring in one of the sootblow motors, the sootblower system failed to operate from approximately 290 hours until about 860 hours. Once the sootblowers were back on-line, the pressure drop across the cold-end tube bank dropped sharply and appeared to stabilize (see Figure 33—860 hrs to 1,500 hrs). The pressure drop across the hot-end tube bank, however, continued to rise (see Figure 32). As a result, it appears that the once the sootblowers were back on-line, they were not effective in removing the hot-end tube bank deposits that formed.

The increase in total flue gas-side pressure drop was due primarily to the increase in hot-end tube bank pressure drop. The fouling severely restricted flue gas flow. As stated above, the first wash out on April 12, 1994, (1550 hours) had little impact on the hot-end bank pressure drop while the wash out on May 3, 1994, (2050 hours) was effective in returning the unit to original flow capacity. Note the PDFF results for 2300-2500 hours Figures 32 and 33. In Figure 32, the PDFF value of 1.0 indicates complete cleaning of the hot-end tube bank and recovery of pressure drop. The PDFF value of 0.6-0.7 for the cold-end tube bank (Figure 33) indicates that the tube bank was a little cleaner after the Phase III wash out than at the beginning of the testing.

The slipstream heat pipe was fouled to a greater extent than would be allowable for a full-scale unit. As a result, cleaning was more difficult for the slipstream than would normally be expected. For full-scale operations, gas flow rates must be maintained to achieve target boiler loads. Once fan capacities are reached, the unit would be shut down for cleaning. The increased forced outage time is not a desirable outcome.

For the slipstream heat pipe, the flue gas flow rate was not maintained but decreased as pressure drop increased. When the unit was first shut down for cleaning, the PDFF for the unit had increased from a value of 1.0 to about 3.5 (Figure 31). This would be equivalent to over a 12-fold change in baseline pressure drop ($3.5^2 = 12.25$). It is unlikely that a full-scale operation could tolerate this level of pressure drop increase before shutting down.

Thermal Performance. Although the unit suffered a significant reduction in flow capacity after 1000 hours, the air effectiveness ratio did not degrade as sharply or significantly (Figure 35). This tends to indicate that the fouling was localized, occurred on only a few rows of the tube banks, and affecting a small percentage of the total heat transfer tube surface area. This was corroborated by the unit inspection in May. Although the fouling was not enough to significantly affect heat transfer performance at low flow rates, it did significantly impede flue gas flow through the unit.

Figures 31, 32, and 33 show complete recovery of flue gas flow and pressure drop levels after the heat pipe was washed the second time. One concern with Figure 35 is the indicated lack of thermal performance recovery after the second washing. The bulk of the data indicate that the effectiveness ratio only increased from a value of 0.87 before clean out to 0.90 after clean out. The expected clean value is 1.0.

The reason for not recovering heat pipe thermal performance after the unit was cleaned could not be definitely identified. A possibility is that the shutdown and cleaning increased air in-leakage on the flue gas side. This could result in a lower actual air temperature rise and reduced measured effectiveness for a given X-ratio. Since the oxygen levels across the heat pipe were not determined during the last week of testing, this cannot be confirmed. Other possibilities are: extrapolation of the effectiveness correlation beyond the range of test data (X-ratio too high) and/or that the correlation does not adequately account for operation at lower flue gas inlet temperatures. As shown in Figure 3, the expected effectiveness correlation is based on X-ratios between 0.54 and 0.80. For the last week of operation, the X-ratio ranged between about 0.92 to over 2.8 and averaged 1.47.

According to ABB API the slipstream heat pipe was designed for a 680°F flue gas inlet temperature. For the parametric studies on which the expected effectiveness factors are based, the inlet temperatures were somewhat lower and ranged between 610°F and 635°F. For the final week of testing with a clean system, the flue gas inlet temperatures ranged between 540°F and 616°F and averaged 573°F. Different working fluids are used at different levels in the heat pipe. Therefore, operation at lower than design flue gas inlet temperatures could result in low efficiency for heat pipes designed to operate at the highest temperatures. This could then result in a lower than expected effectiveness ratio.

Another way of evaluating the heat transfer performance is to calculate the Q/LMTD (duty/log mean temperature difference) which is equivalent to UA (overall heat transfer coefficient times heat transfer area). Since U will vary with flue gas flow rate, it is somewhat difficult to use the ratio to follow the progress of fouling if flow rates are changing. However, when flow rates are constant, fouling can be recognized by a decrease in the ratio value.

Figure 36 shows Q/LMTD, or UA, for the Phase III tests. As shown in Figure 29, the flue gas rate remained constant at about 14,000 lb/hr between about 130 to 525 hours. Figure 36 shows an essentially constant UA between 130 and 290 hours. Immediately after the sootblowers failed at the 290 hour mark, UA began a steep decline indicating fouling. At the 525 hour mark, a step change was made to increase the flue gas rate from 14,000 lb/hr to 19,000 lb/hr. This increased UA. However, the value of UA then declined from the new level until the sootblowers were in operation. When the sootblowers became operational, there was another step change in UA because the bottom, or cold-end tube bank was cleaned. Since the sootblowers were ineffective in removing deposits from the hot-end tube bank, the overall UA continued to decline until the final clean out. The UA results do, however, indicate that most if not all the thermal performance of the heat pipe was recovered after the second heat pipe washing.

Coal Feedstock Considerations. The coal feed was changed from a medium-sulfur (1.4% dry) Pittsburgh seam coal to a higher sulfur (2.8% dry) Pittsburgh seam coal from March 7 until March 14, 1994. After March 14, 1994, the coal feed returned to the medium-sulfur Pittsburgh seam coal. Because of holdup in the coal bunkers, the high-sulfur coal did not begin entering Unit 2 boiler until about 16:00 hrs on March 8 (712 hours) and did not begin to be replaced until 10:00 hrs on March 19 (970 hours). Since the flue gas SO_2 levels increased for the time period, it is expected that the SO_3 levels also increased in proportion, creating a somewhat higher potential for SO_3 fouling in the cold-end of the heat pipe. This may not have significantly increased the potential for NH_4HSO_4 caused fouling; since even for the lower sulfur coal, the flue gas SO_3 always greatly exceeded the moles of NH_3 (typically by three to five times). The time period when high-sulfur coal was in the system is denoted in Figure 34a with the system pressure drop. As can be seen, the rate of rise in system pressure drop actually increased after the high-sulfur coal was removed.

Inspections. The heat pipe inspection on May 2, 1994, was the most extensive done during the test program. In addition to opening all access doors, the insulation and the plates covering the tube ends on the flue gas side of the heat pipe were removed. This allowed viewing the areas between tube rows.

Most of the fouling occurred at one level, between two tube rows near the outlet of the hot-end tube bank. This is shown in Figure 37. Figure 38 is a close-up view of the fouled area. The photo shows near complete obstruction of the gas flow path between two tube rows. Tube rows above and below this area were much less fouled.

Figure 39 is a bottom side view of the outlet row of the hot-end tube bank (bottom row of Figure 37). The photograph shows the formation of hard deposits on the top side of the tubes. Samples of these hard deposits were taken before the April 12 washing of the heat pipe. The deposits contained high amounts of NH_3 1.89 wt. % and 3.06 wt. % S. When NH_3 is present in flue gases, NH_4HSO_4 (ABS) and $(NH_4)_2SO_4$ salts can form from gas phase reactions between NH_3, SO_3, and H_2O before H_2SO_4 condenses as flue gases are cooled. Radian found that, thermodynamically, formation of solid $(NH_4)_2SO_4$ is favored.[4] However, because of kinetics, ABS is formed first and significant amounts of $(NH_4)_2SO_4$ only form if there is an excess of NH_3 to react with the ABS. Based on the 0.86 NH_3/S mole ratio of the deposit, it is likely that both ABS and H_2SO_4 condensed on the heat pipes and fins. When first formed, both the ABS and H_2SO_4 exist as sticky liquids which will trap and glue together fly ash particles forming agglomerates. Formation of hard deposits would occur upon cooling with solidification of ABS or by reactions between the ABS and the fly ash or the heat pipe metal.

What appears to have occurred in the hot-end tube bank as flue gases were cooled, is a point was reached where the heat pipe skin temperatures were below the formation temperature for ABS. The ABS condensed mostly at this level in the tube bank forming hard deposits which bridged areas between tubes and fins. The deposits then filter fly ash from the flue gases which rapidly increased the unit pressure drop. Two core samples of the deposit shown in Figure 38, averaged 990 ppmwt and 608 ppmwt NH_3 and 1.71 wt % and 1.63 wt % S respectively. These are still high NH_3 levels for the fly ash although much lower than that of the hard deposits mentioned above. The hard deposit and core analyses tend to support the filtering hypothesis since mechanically trapped fly ash would reduce the level of ABS in the core sample mixture.

Figure 40 shows the condition of the heat pipes in the hot-end tube bank after the wash out cleaning. Water washing is highly effective in removing the deposits since ABS is water soluble. To be effective in removing tightly packed deposits, water must soak into the deposits. After wetting the deposits, sufficient water flow must be directed against the deposits to flush away the pasty mixture that forms.

REFERENCES

1. DeIuliis, N. J., McCoy, D. C., and Statnick, R. M., "Milliken Station Slipstream Heat Pipe Parametric Performance Data," Draft NYSERDA Report, January 18, 1994.

2. Burke, J. M., and Johnson, K. L.. "Ammonium Sulfate and Bisulfate Formation in Air Preheaters," Radian Report to EPA, EPA-600/7-82-025a, April 1982.

3. Omote, M., Rentz, O., Issle, F., and Weibel, M., (eds.) "Ljungstrom Heat Exchangers in Plants Having a Flue Gas Denitration (De-NOx) System," NO_x Symposium, Karlsruhe 1985: International Operational Experience, Darlsruhe, F.R. Germany, February 21, 1985, pp. K15-K19.

4. Op. cit. Burke, J. M., pp 22-28.

Table 1

Ammonia Measurements
Milliken Slipstream Heat Pipe Inlet
11/23/93 to 11/24/93

Location	NH3, ppmv
Full Traverse	2.1
Full Traverse	3.1
Full Traverse	1.9
Average	2.4
STD	0.6
Single Points	
A-1	2.5
A-1	2.1
B-2	1.8
A-2	1.0
B-1	2.1
B-1	2.7
Mid-Point	1.3

TABLE 2

Heat Pipe Cold-End Module Deposit Analysis
Milliken Station -- January 17, 1994

Lab Analysis Results

Component	AR Basis Wt %	Dry Basis Wt %
Free Moisture	4.43	--------
Ash	63.30	66.23
C	0.48	0.50
H	0.75	0.78
N	0.12	0.13
NH3	0.0025	0.0026
S	11.20	11.72

Overall Sample Composition (Calculated Balance)

Component	AR Basis Wt %	Dry Basis Wt %
Free Moisture	4.43	--------
Ash	63.30	66.23
S as SO3 (2.497*%S)	27.97	29.26
C	0.48	0.50
Bound H2O by H Balance	6.66	6.97
N (minus Ammonia)	0.12	0.13
NH3	0.0025	0.0026
Undetermined	-2.95	-3.09
Total	100.00	100.00

Major Elemental Analysis

Component	AR Basis Wt %	Dry Basis Wt %
Free Moisture	4.43	--------
Bound H2O by H Balance	6.66	6.97
C	0.48	0.50
N	0.12	0.13
SiO2	26.77	28.01
Al2O3	14.49	15.16
TiO2	0.74	0.77
Fe2O3	13.56	14.19
CaO	1.75	1.83
MgO	0.53	0.55
Na2O	0.48	0.50
K2O	1.19	1.25
P2O5	0.38	0.40
SO3	28.18	29.49
Undetermined	0.24	0.25
Total	100.00	100.00

AR -- As Received

Table 3
Slipstream Heat Pipe Wash Water Analyses
Samples Collected 2/3/94

Sample	Sample #1	Sample #2	Sample #3	Sample #4	
Time Taken	1520 Hrs	1530 Hrs	1540 Hrs	1600 Hrs	Averages
pH	1.72	1.78	2.00	2.09	
Suspended Solids, mg/l	90,200	75,000	38,300	26,000	57,375
Total Fe, mg/l	19,300	17,100	11,100	9,370	14,218
Dissolved Fe, mg/l	13,500	12,600	8,400	7,460	10,490
Total S, mg/l	18,900	16,900	10,000	8,050	13,463
Dissolved S, mg/l	17,500	15,900	9,560	7,660	12,655
NH3, mg/l	2,350	1,500	585	406	1,210

Total Wash Water, gal (1)	100		
Suspended Solids, lbs	47.88		
Dissolved Fe, lbs	8.75	0.157	lb-mols
Dissolved S, lbs	10.56	0.329	lb-mols
NH3, lbs	1.01	0.059	lb-mols
S/Fe Ratio		2.10	
S/NH3 Ratio		5.55	

(1) Visual Estimate of Wash Water Volume

TABLE 4

Oxygen Concentrations At Heat Pipe Outlet

Date 01/13/94					
Start Time	11:30 AM				
End Time	12:15 PM				
Distances	Port 1	2	3	4	5
From West Wall, Inches	4.1	12.4	20.7	29.0	37.2
From North Wall, Inches	Oxygen Level, mol %				
2	5.6	6.0	5.6	6.0	5.5
10	5.2	6.0	5.6	5.4	5.2
18	4.2	5.4	6.4	5.3	4.7
26	4.2	6.0	6.6	6.1	5.2
34	4.4	6.1	6.8	6.5	5.5
42	4.7	5.9	7.0	6.7	6.8
50	5.5	6.3	7.9	7.8	7.6
58	6.0	7.2	8.5	9.1	9.0

Composite Average	6.1
Composite Standard Deviation	1.2

TABLE 5

Temperature Traverse Slipstream Heat Pipe Outlet

Date 11/19/93					
Start Time	16:47	16:15	15:30	14:44	14:20
End Time	17:23	16:47	16:15	15:30	14:44
Distances	Port 1	2	3	4	5
From West Wall, Inches	4.1	12.4	20.7	29.0	37.2
From North Wall, Inches	Temperatures, F				
5.8	378	365	359	368	383
15.8	385	375	361	357	375
25.8	381	369	357	364	375
35.8	370	355	348	358	348
45.8	344	331	328	341	340
55.8	265	259	259	255	259

Ambient Temperature 53 deg F

TABLE 6

SO_2/SO_3 MEASUREMENTS ACROSS HEAT PIPE
January 13, 1994

Inlet Samples	1	2	3	4	Avg	SDEV
SO_2, ppmv @ 0% O_2	1455	1432	1459	1488	1459	23
SO_3, ppmv @ 0% O_2	15.5	13.2	13.0	13.8	13.9	1.1
% SO_3 on Solids	1.0	3.2	0.0	0.0	1.0	1.5
% SO_3 in SOx	1.07	0.95	0.88	0.92	0.95	0.08
Outlet Samples	**1**	**2**	**3**	**4**	**Avg**	**SDEV**
SO_2, ppmv @ 0% O_2	1498	1439	1503	1447	1472	33
SO_3, ppmv @ 0% O_2	6.6	7.8	7.9	10.0	8.1	1.4
% SO_3 on Solids	5.6	6.3	4.9	1.9	4.6	1.9
% SO_3 in SOx	0.46	0.57	0.55	0.70	0.57	0.10

Difference between inlet and outlet SO_2 = 0.9%
Reduction in SO_3 across heat pipe = 42.0%

TABLE 7

NH_3 MEASUREMENTS ACROSS HEAT PIPE
January 14, 1994

Inlet Samples	1	2	3	4	Avg	SDEV
NH_3, ppmv @ 0% O_2	3.2	2.4	3.4	(1)	3.0	0.5
NH_3 on Ash Samples, ug/g		<2		<2		
Outlet Samples	**1**	**2**	**3**	**4**	**Avg**	**SDEV**
NH_3, ppmv @ 0% O_2	0.7	0.9	0.9	0.8	0.8	0.1
NH_3 on Ash Samples, ug/g			287	127		

Difference between inlet and outlet NH_3 = 72.7%

(1) Sample "froze-up" before completing traverse so gas sample not used in analysis.

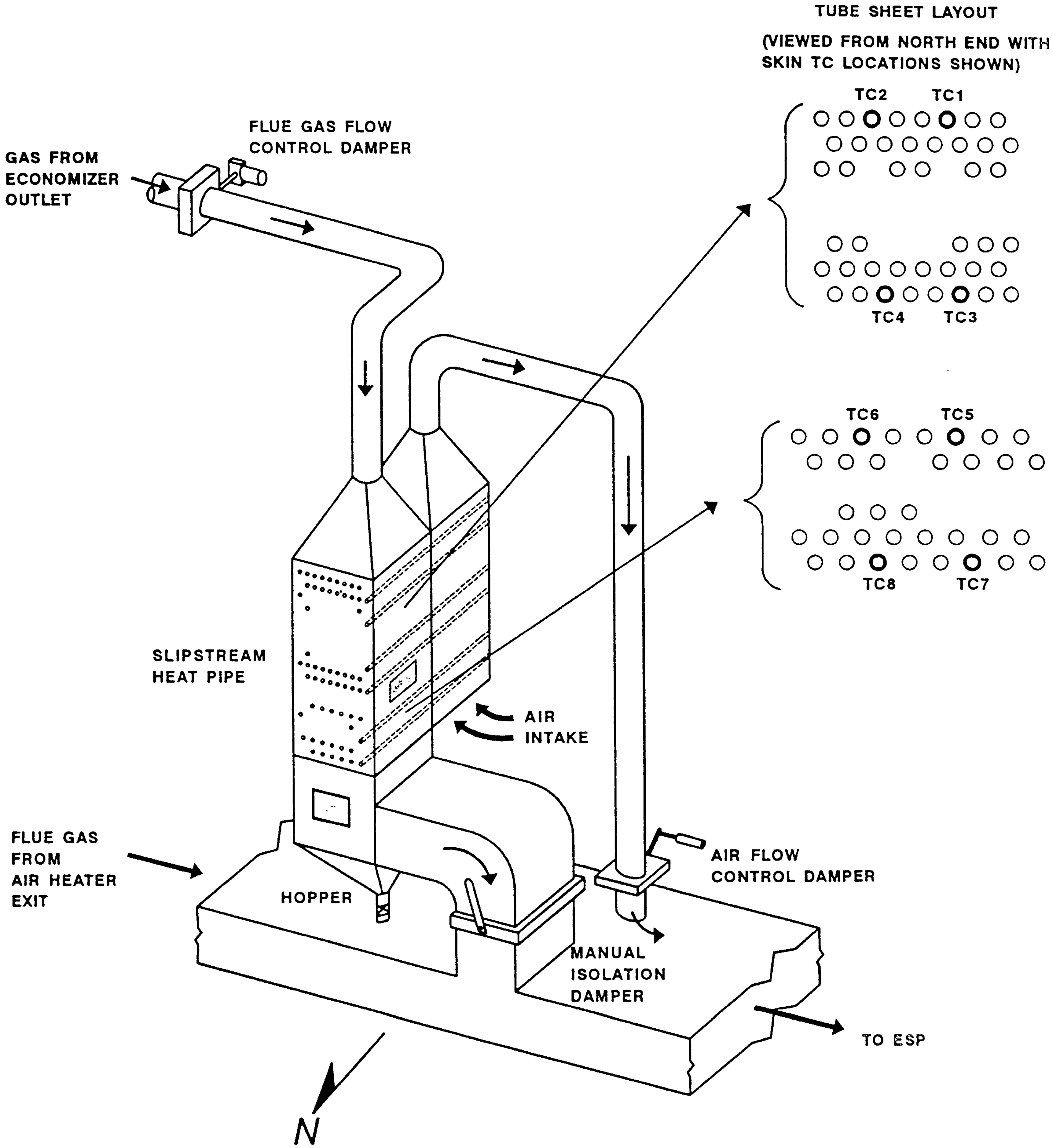

Figure 1.

SLIPSTREAM HEAT PIPE - ORIGINAL LAYOUT

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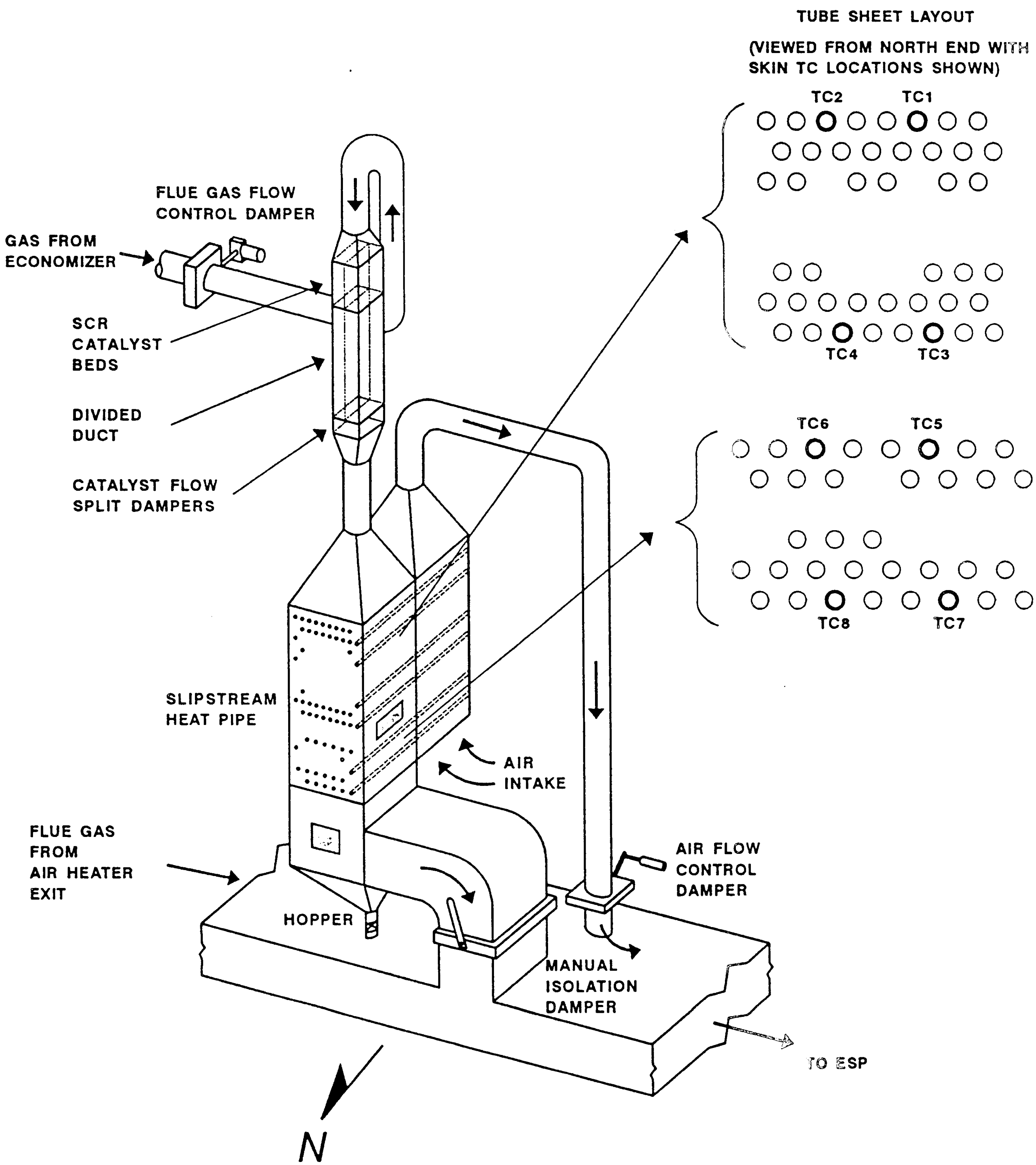


Figure 2.

SLIPSTREAM HEAT PIPE - LAYOUT WITH SCR CATALYST BED

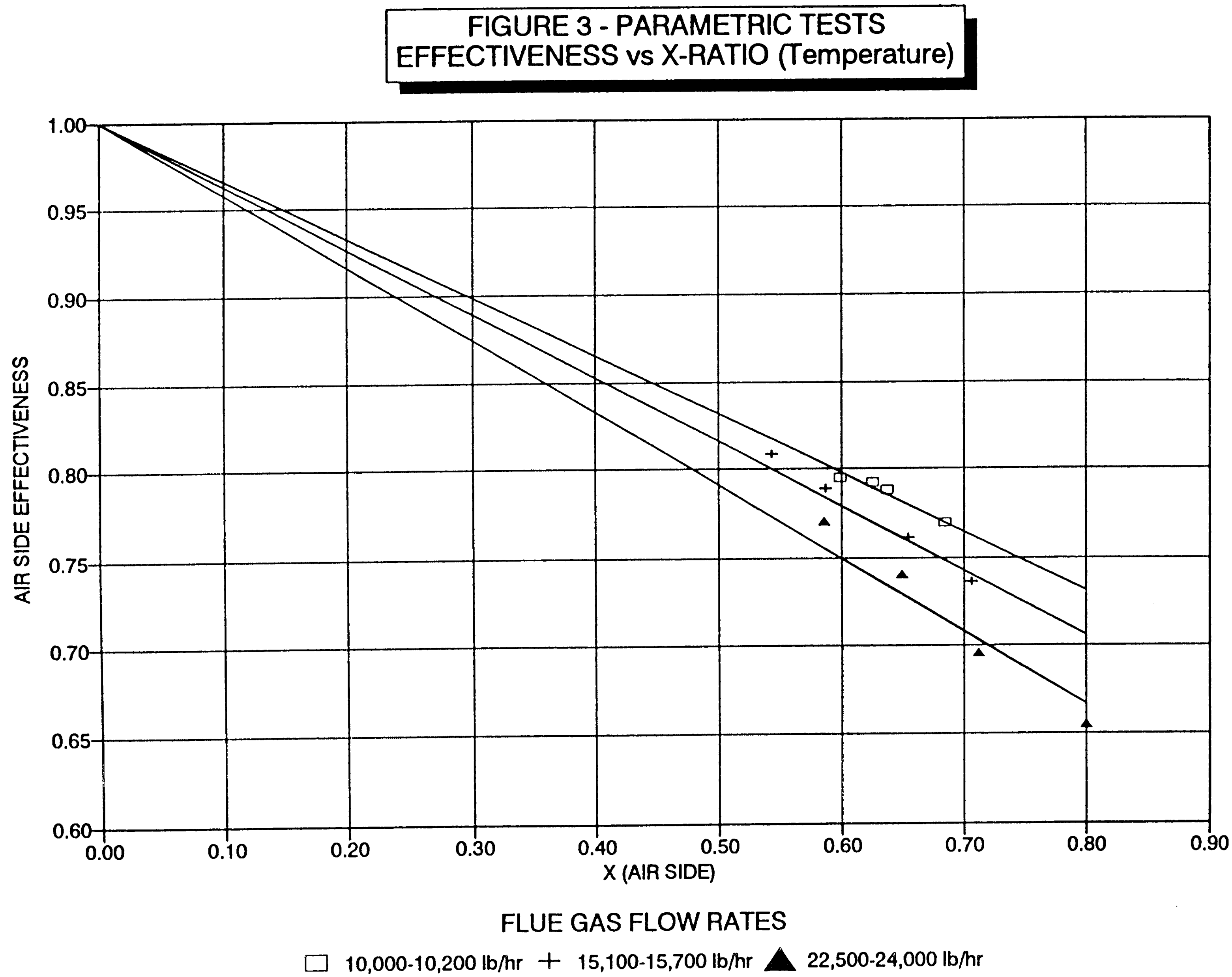


FIGURE 3 - PARAMETRIC TESTS
EFFECTIVENESS vs X-RATIO (Temperature)
AIR SIDE EFFECTIVENESS
1.00
0.95
0.90
0.85
0.80
0.75
0.70
0.65
0.60
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
X (AIR SIDE)
FLUE GAS FLOW RATES
10,000-10,200 lb/hr
15,100-15,700 lb/hr
22,500-24,000 lb/hr

130

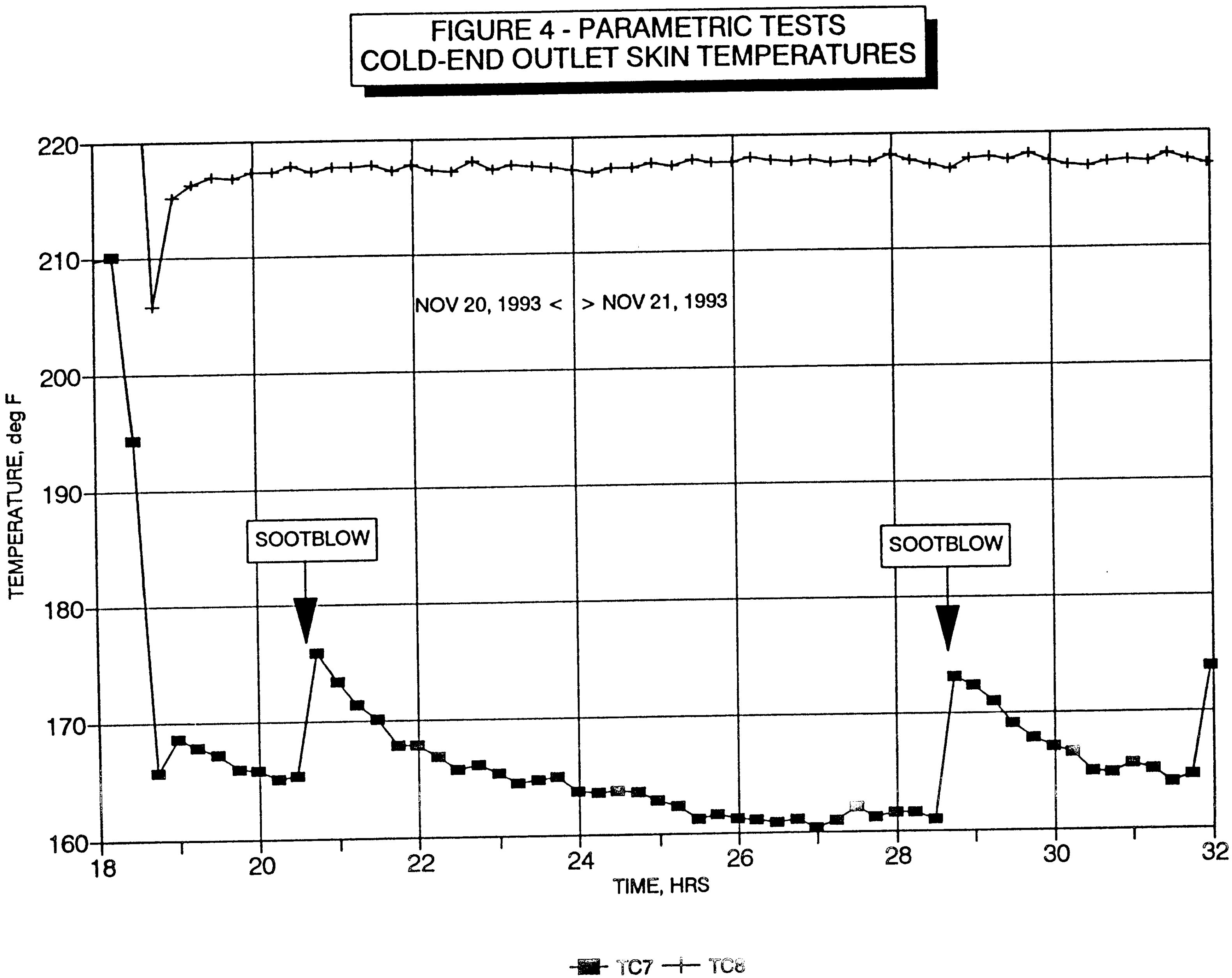
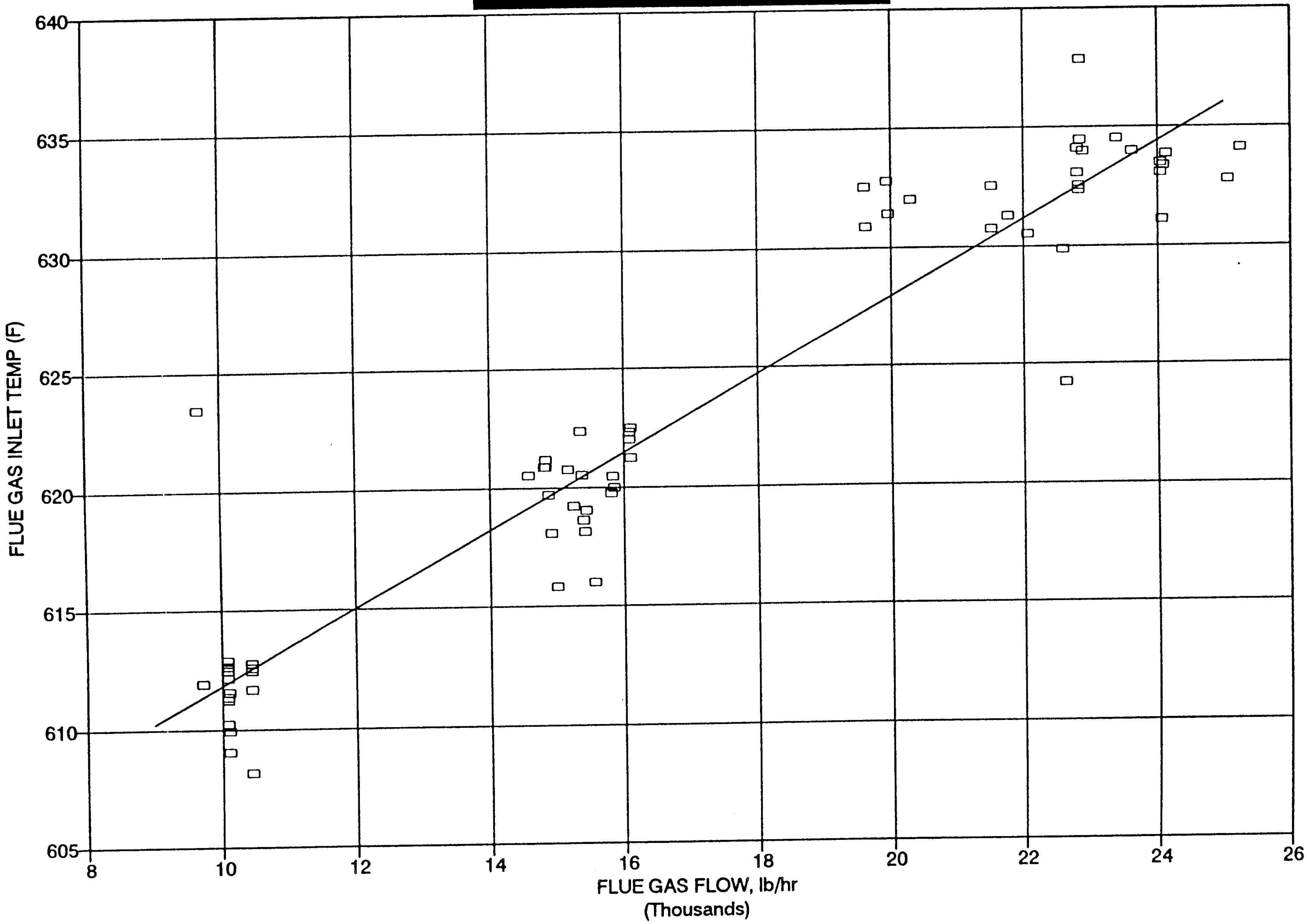


FIGURE 4 - PARAMETRIC TESTS
COLD-END OUTLET SKIN TEMPERATURES
220
210
200
190
180
170
160
TEMPERATURE, deg F
NOV 20, 1993 < > NOV 21, 1993
SOOTBLOW
SOOTBLOW
18
20
22
24
26
28
30
32
TIME, HRS
TC7
TC8

FIGURE 5 - PARAMETRIC TESTS
FLUE GAS INLET TEMP vs FLOW



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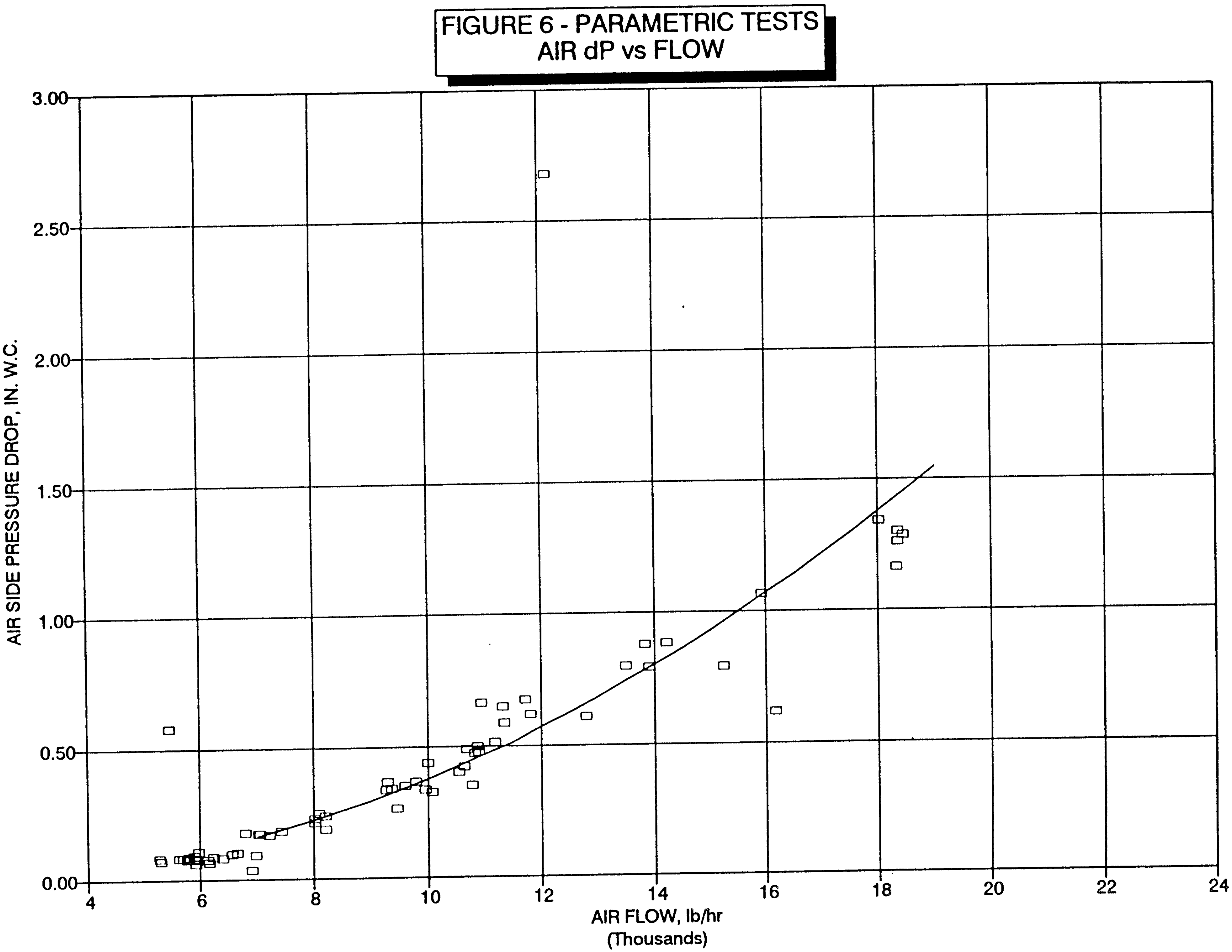


FIGURE 6 - PARAMETRIC TESTS
AIR dP vs FLOW
AIR SIDE PRESSURE DROP, IN. W.C.
3.00
2.50
2.00
1.50
1.00
0.50
0.00
4
6
8
10
12
14
16
18
20
22
24
AIR FLOW, lb/hr
(Thousands)

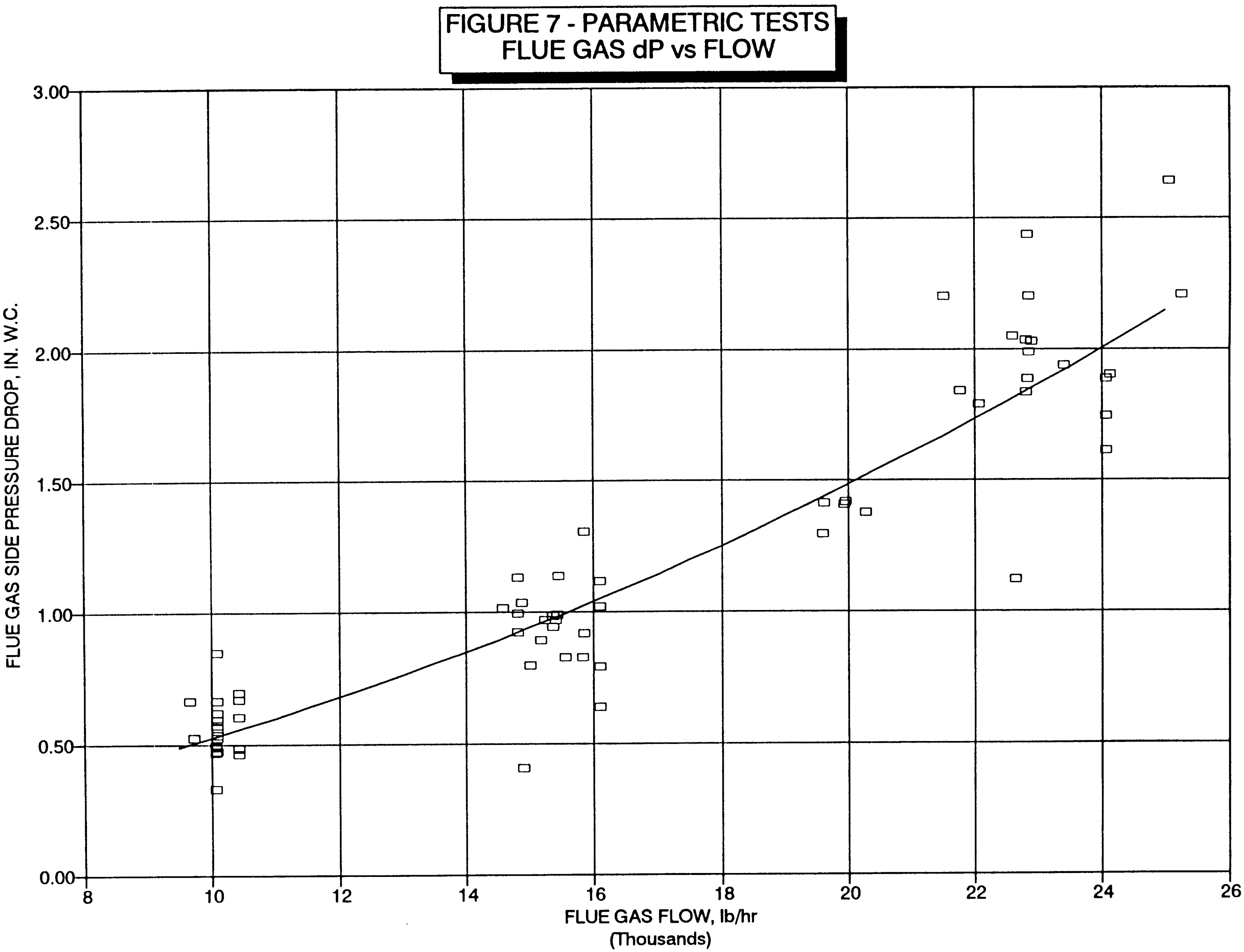


FIGURE 7 - PARAMETRIC TESTS
FLUE GAS dP vs FLOW
FLUE GAS SIDE PRESSURE DROP, IN. W.C.
3.00
2.50
2.00
1.50
1.00
0.50
0.00
8
10
12
14
16
18
20
22
24
26
FLUE GAS FLOW, lb/hr
(Thousands)

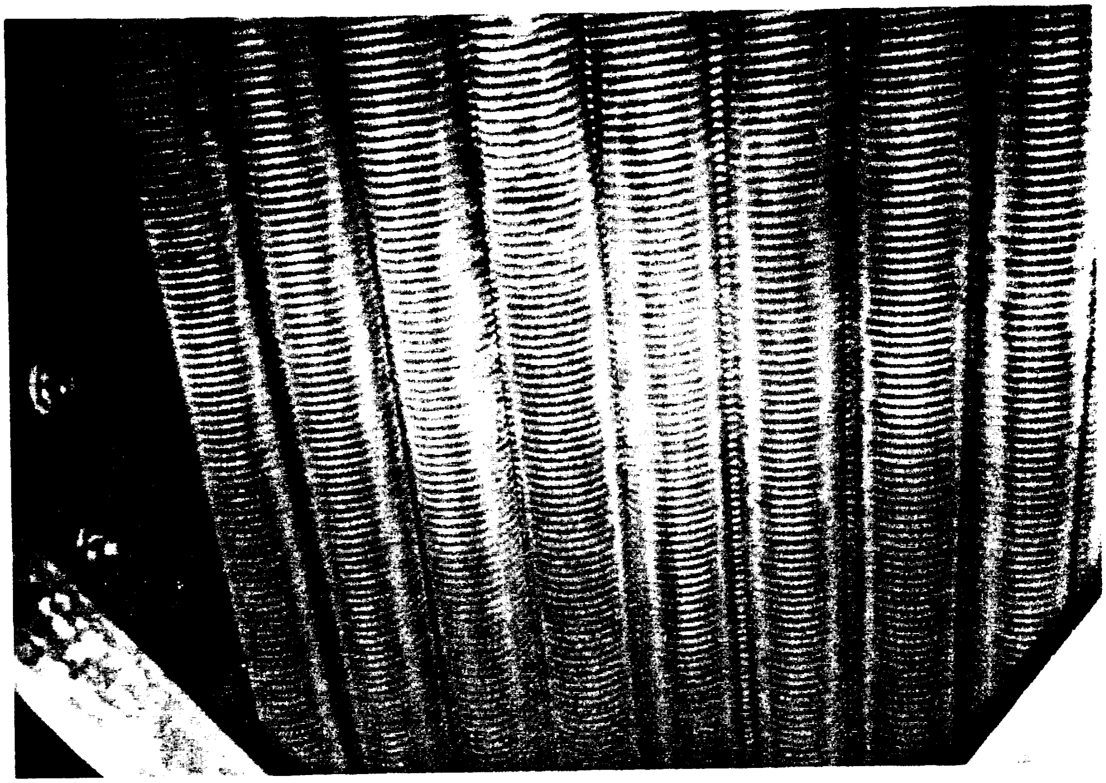


Figure 8a. Flue gas side cold-end outlet tubes before sootblowing (beginning of Phase I testing).

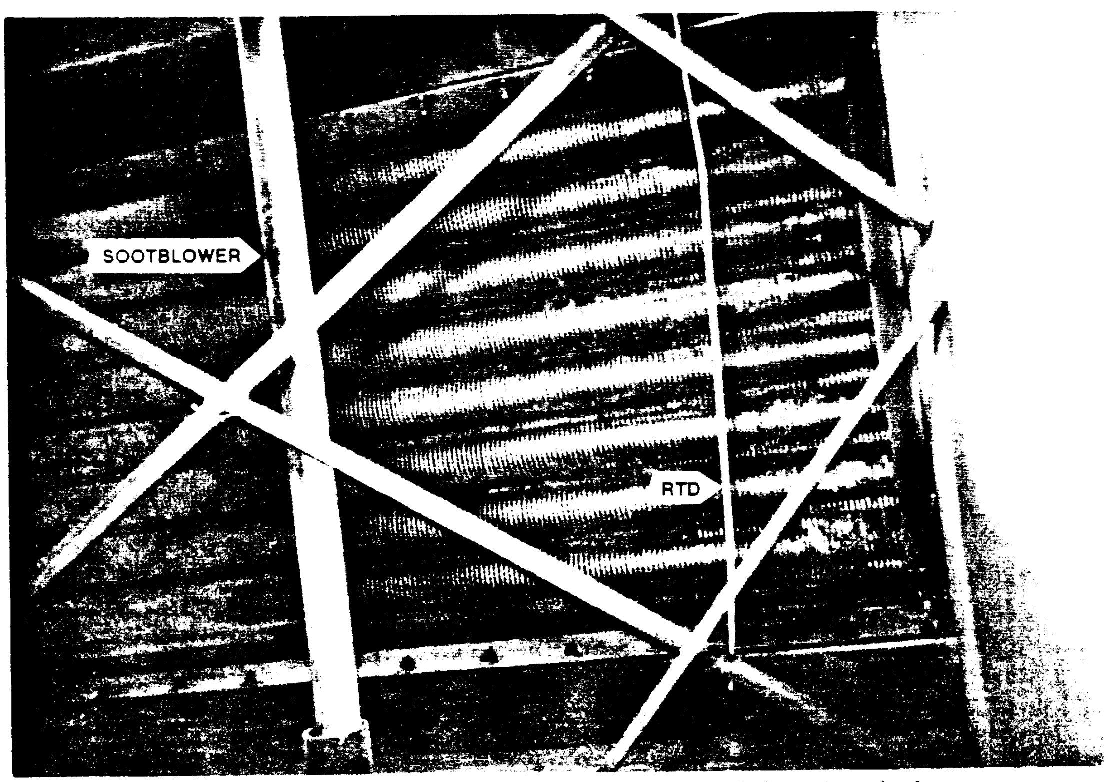


Figure 8b. Cold-end outlet tubes after a sootblow (beginning of Phase I testing).

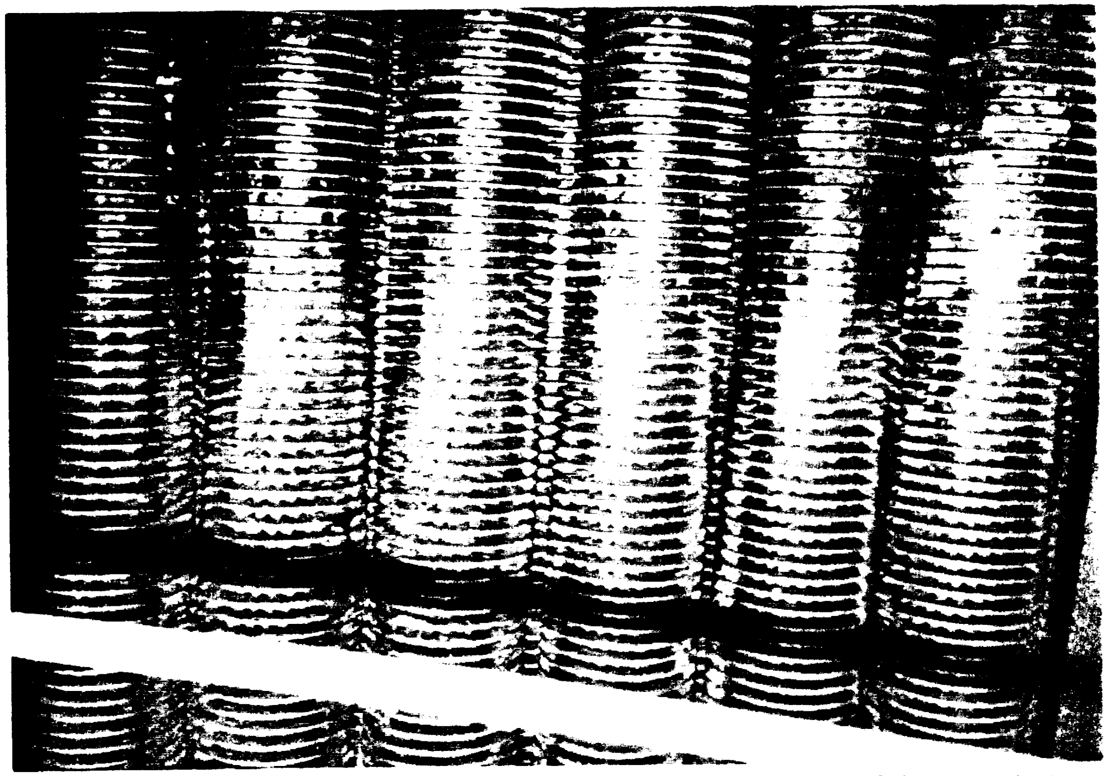


Figure 8c. Close-up view of cold-end outlet tubes after sootblow (beginning of Phase I testing). Tubes are essentially clean with only minor spotty surface deposits.

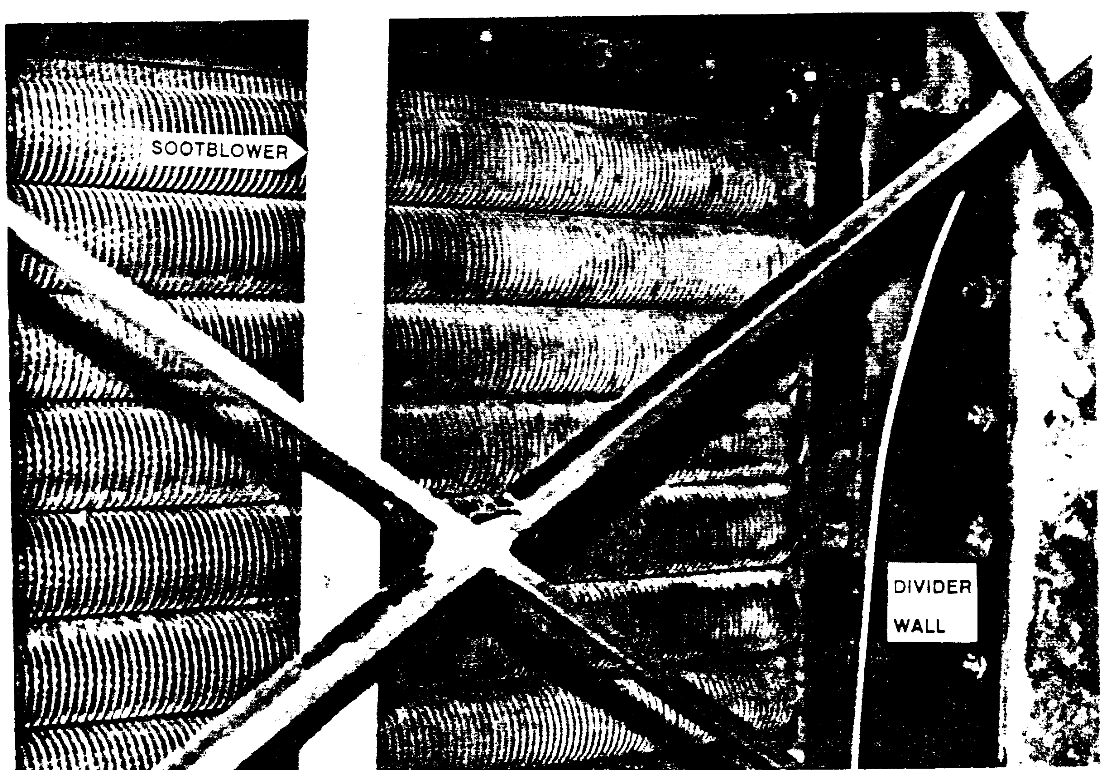


Figure 9a. South end view of cold-end outlet heat pipes after 500 hours of Phase I operations. Note tubes appear somewhat cleaner directly in front of sootblower.

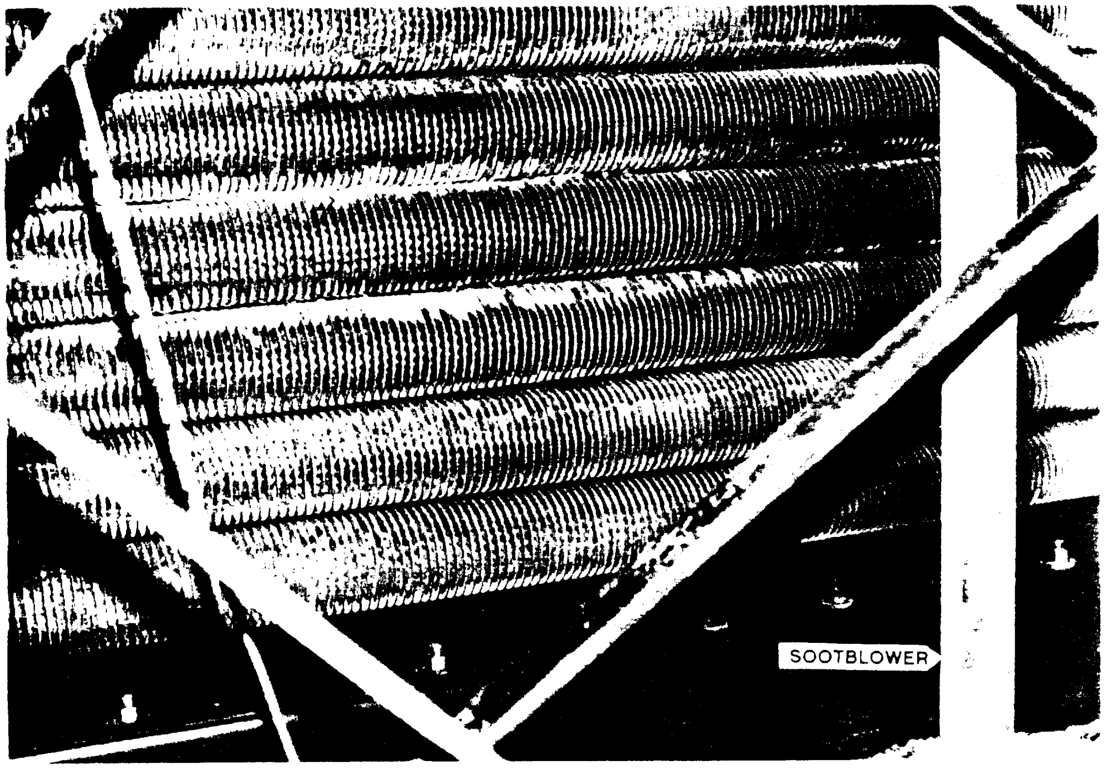


Figure 9b. Center view of cold-end outlet heat pipes after 500 hours of Phase I testing. View shows minor fouling by hard scale deposits on top side of last row fins.

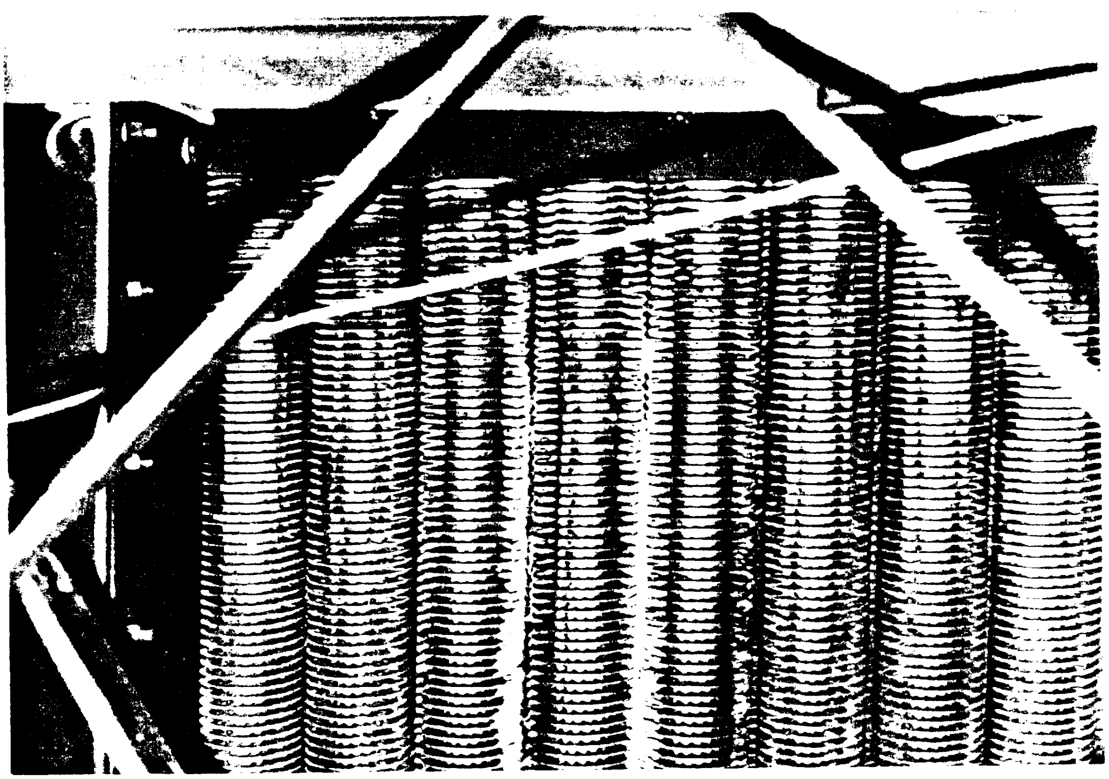


Figure 9c. North end view of cold-end outlet heat pipes after 500 hours of Phase I testing. Photograph shows some fouling on windward or top side of tubes and fins. Tubes in this area are furthest away from the sootblower. The fouling appeared to be about the same as at the beginning of the test.

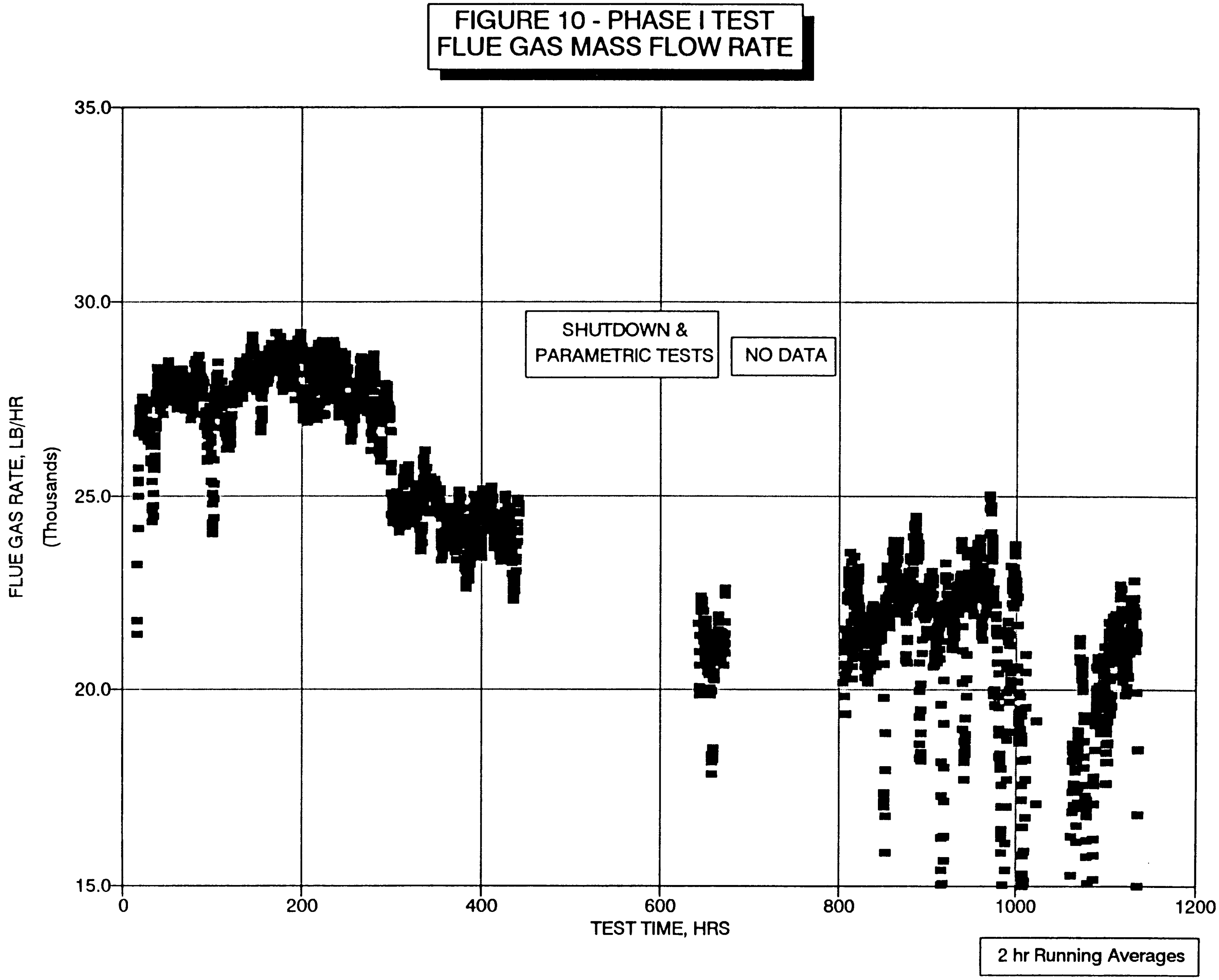


FIGURE 10 - PHASE I TEST
FLUE GAS MASS FLOW RATE
FLUE GAS RATE, LB/HR
(Thousands)
35.0
30.0
25.0
20.0
15.0
0
200
400
600
800
1000
1200
TEST TIME, HRS
SHUTDOWN &
PARAMETRIC TESTS
NO DATA
2 hr Running Averages

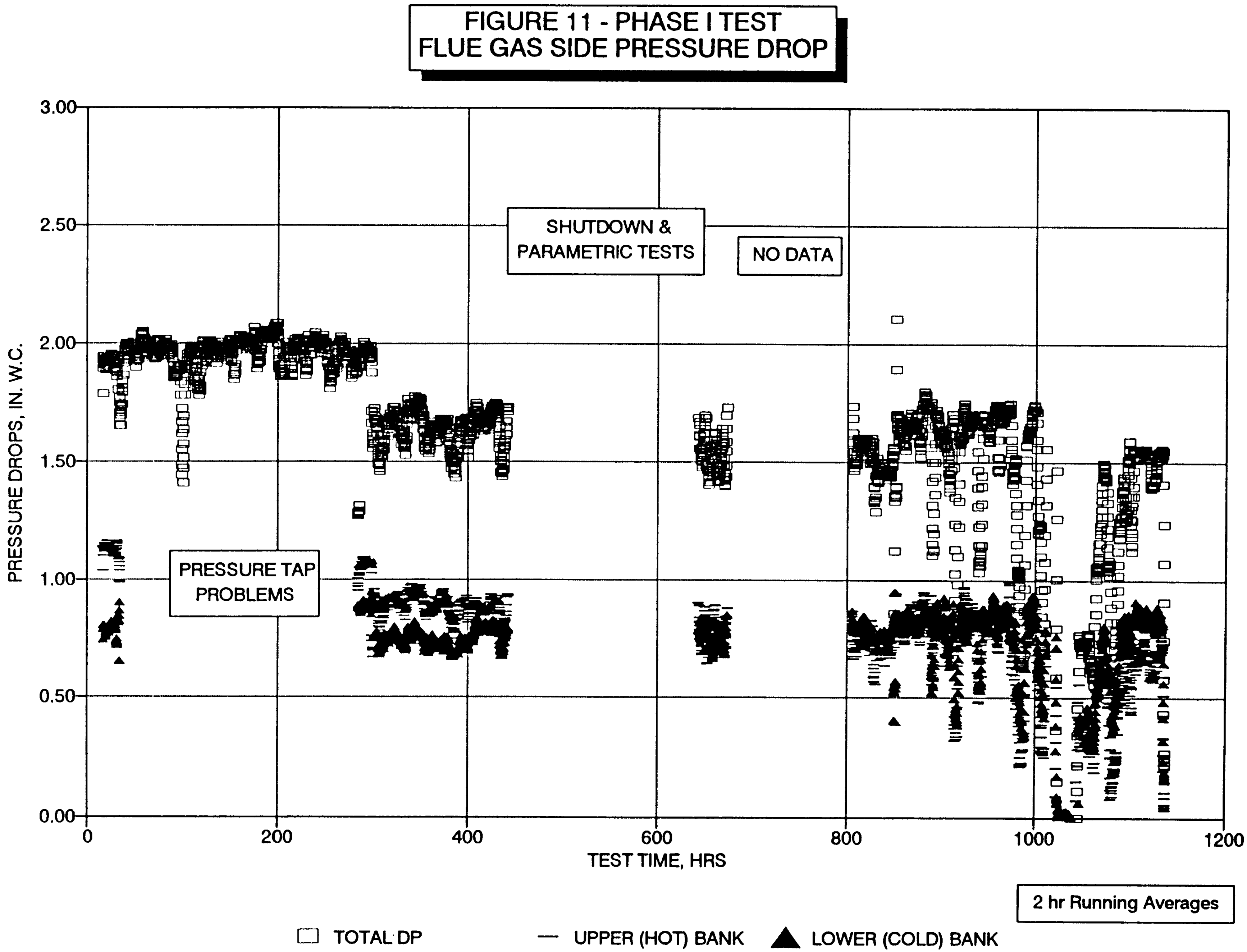


FIGURE 11 - PHASE I TEST
FLUE GAS SIDE PRESSURE DROP
SHUTDOWN &
PARAMETRIC TESTS
NO DATA
PRESSURE TAP
PROBLEMS
PRESSURE DROPS, IN. W.C.
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0
200
400
600
800
1000
1200
TEST TIME, HRS
2 hr Running Averages
TOTAL DP
UPPER (HOT) BANK
LOWER (COLD) BANK

FIGURE 12 - PHASE I TEST FLUE GAS SIDE PDFF RATIOS

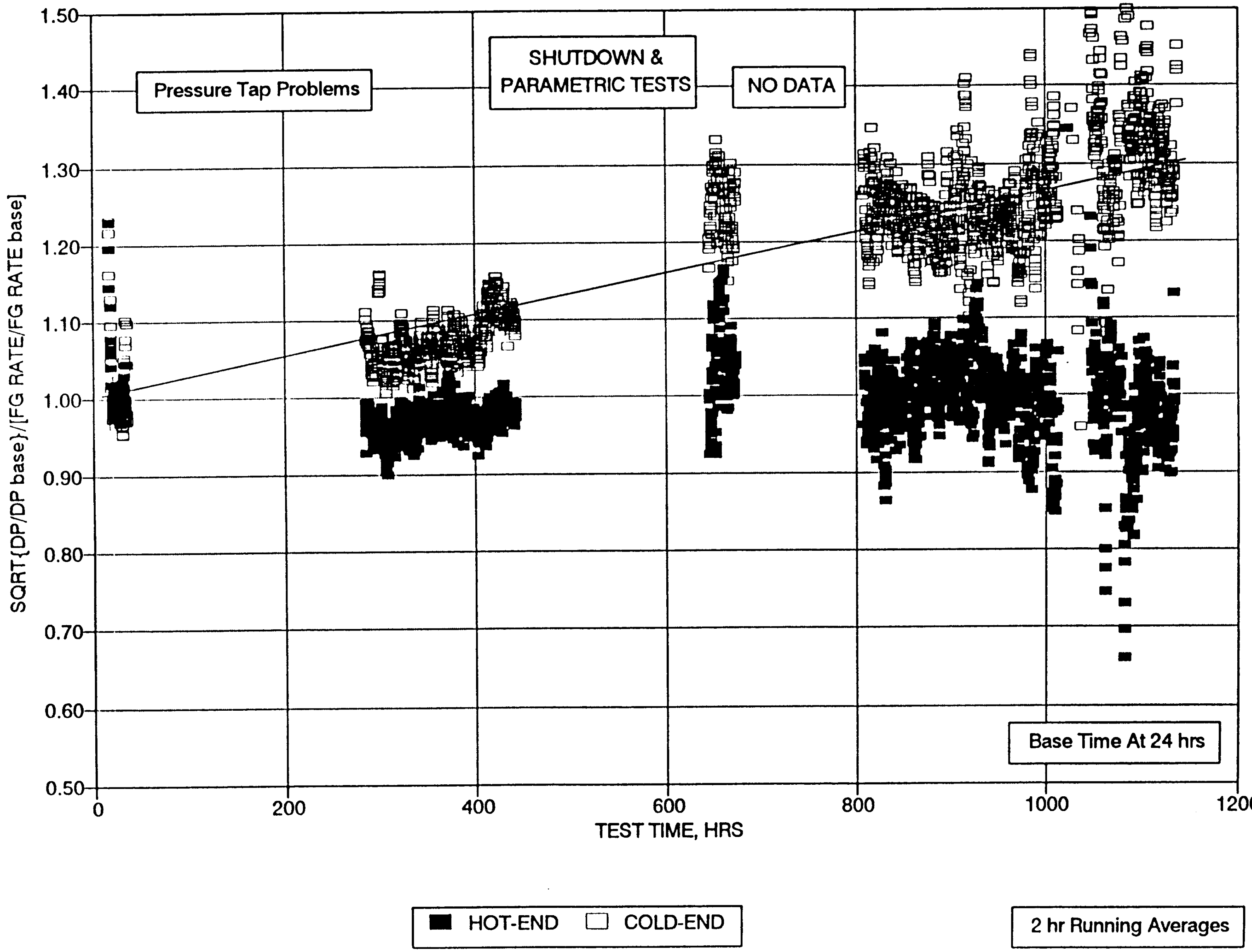


FIGURE 13 - PHASE I TESTS
COLD-END SKIN TEMPERATURE TC7

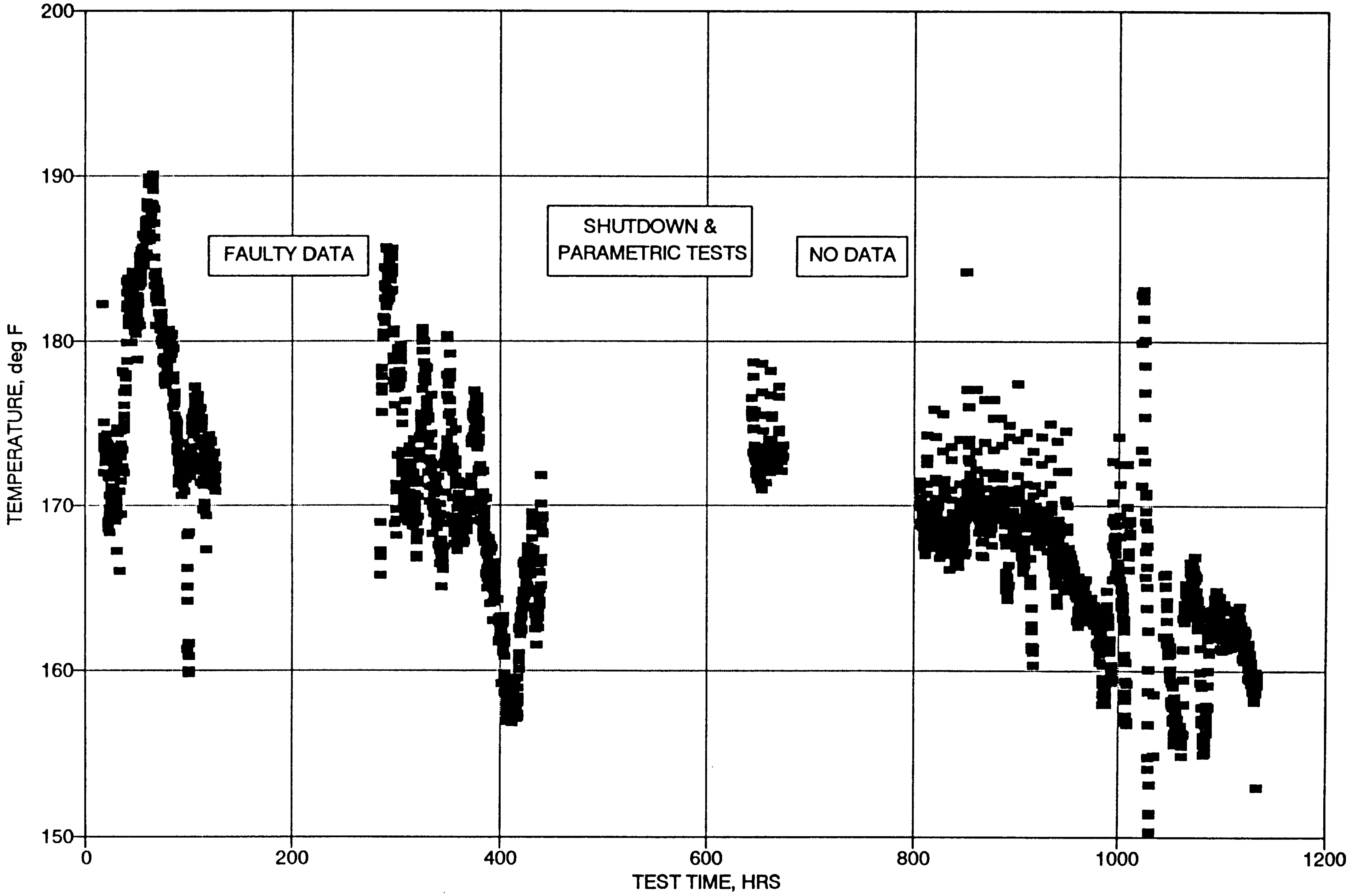


FIGURE 14 - PHASE I TEST
AIR SIDE EFFECTIVENESS RATIO

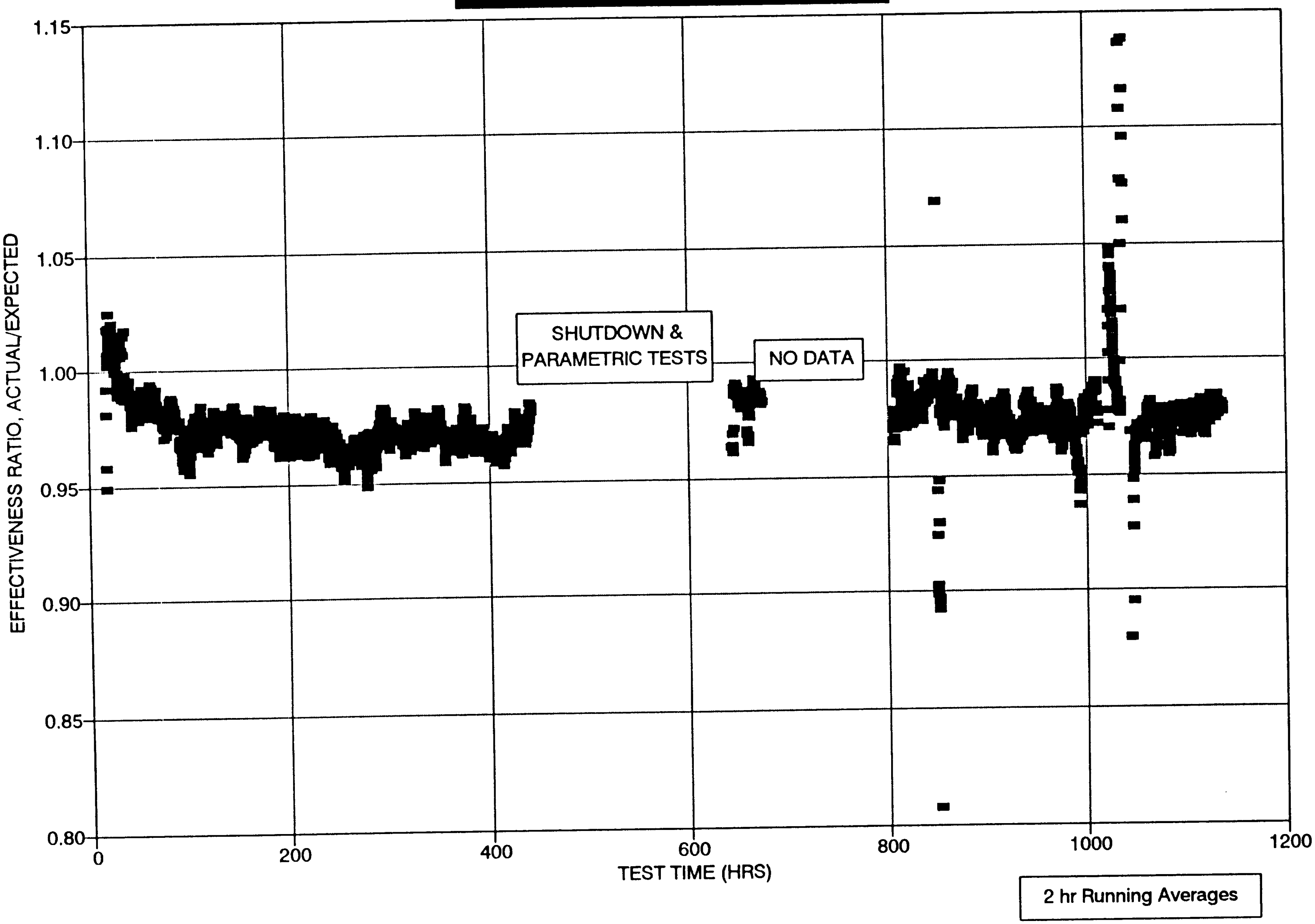
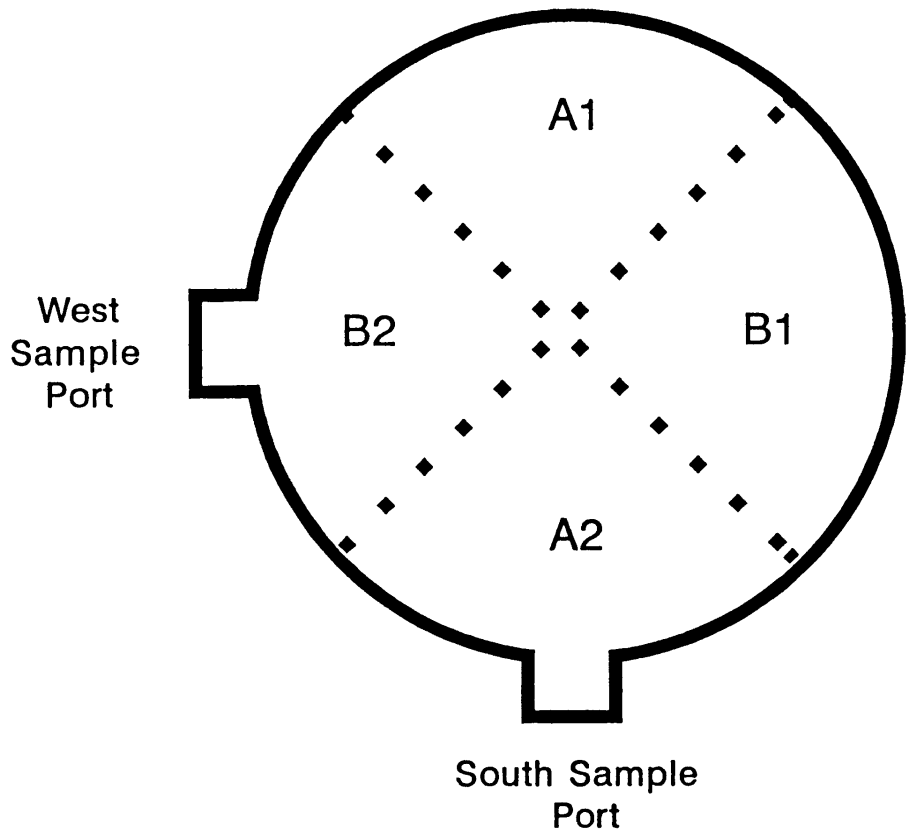


FIGURE 15

Sample Point Layout
Heat Pipe Inlet Duct



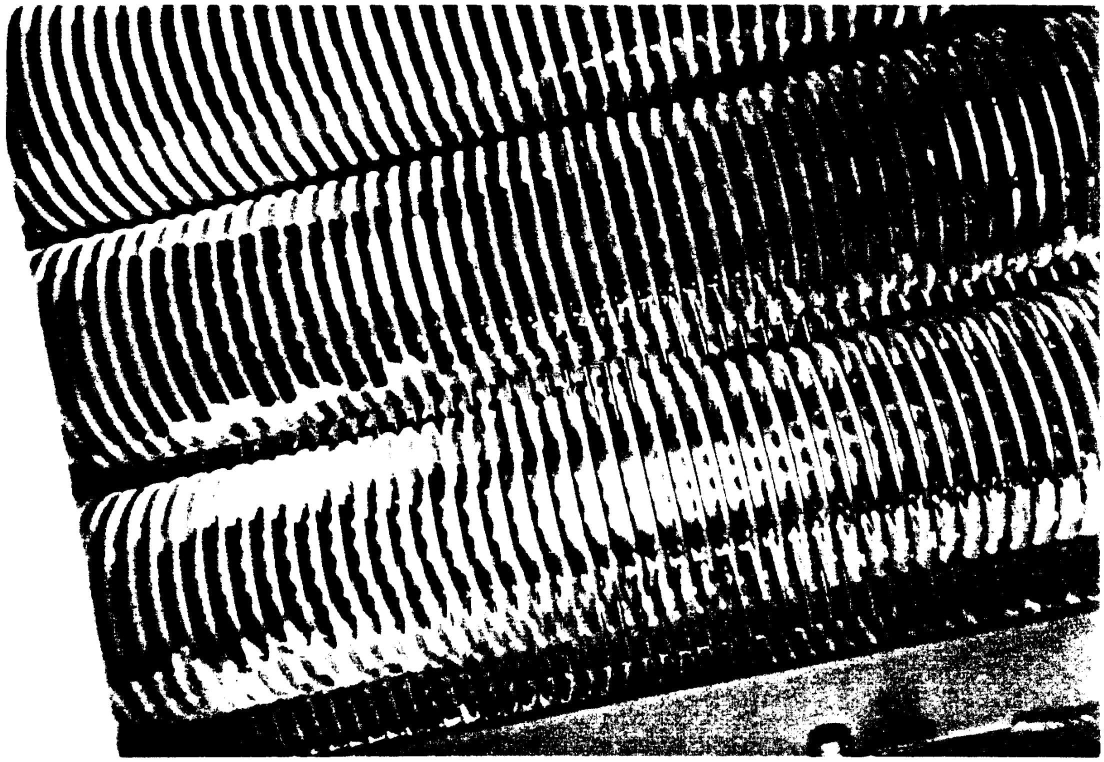


Figure 16. End of Phase II testing -- bottom side view of the hot-end tube bank outlet tubes. Tubes have a thin deposit coating on the windward side. Material on top of tube should have about the same consistency as material shown in Figure 17.

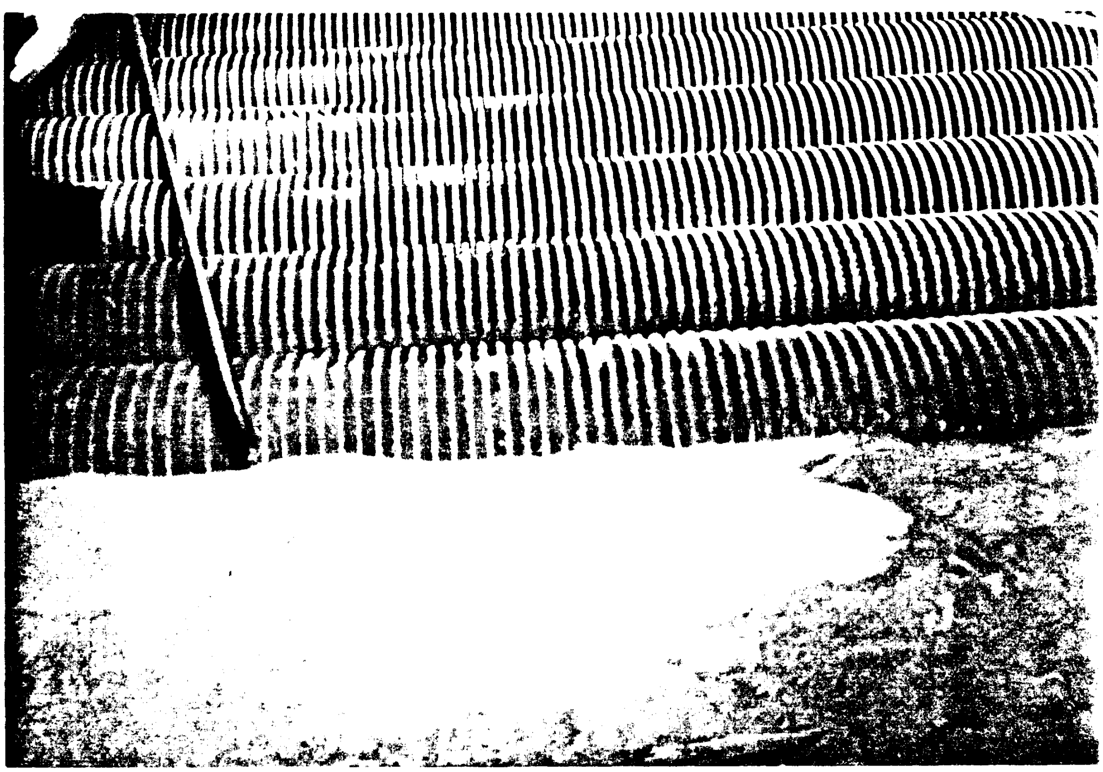


Figure 17. End of Phase II testing -- top side view of cold-end tube bank inlet tubes. Tops of tubes and fins are coated with a soft, slightly crusty sootblowable deposit.

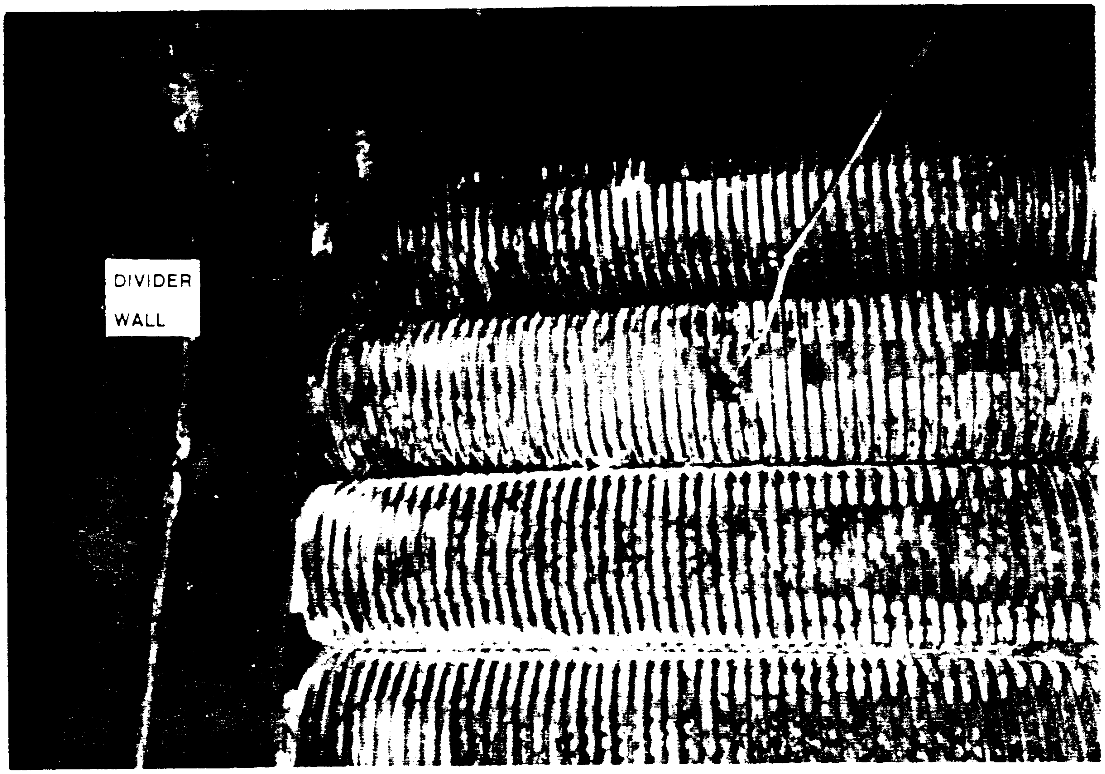


Figure 18a. End of Phase II testing -- Bottom (outlet) view of cold-end tube bank. View shows heat pipes at the divider wall between the flue gas and air sides. Heat pipes show somewhat more fouling than at the beginning or middle of the Phase I testing.

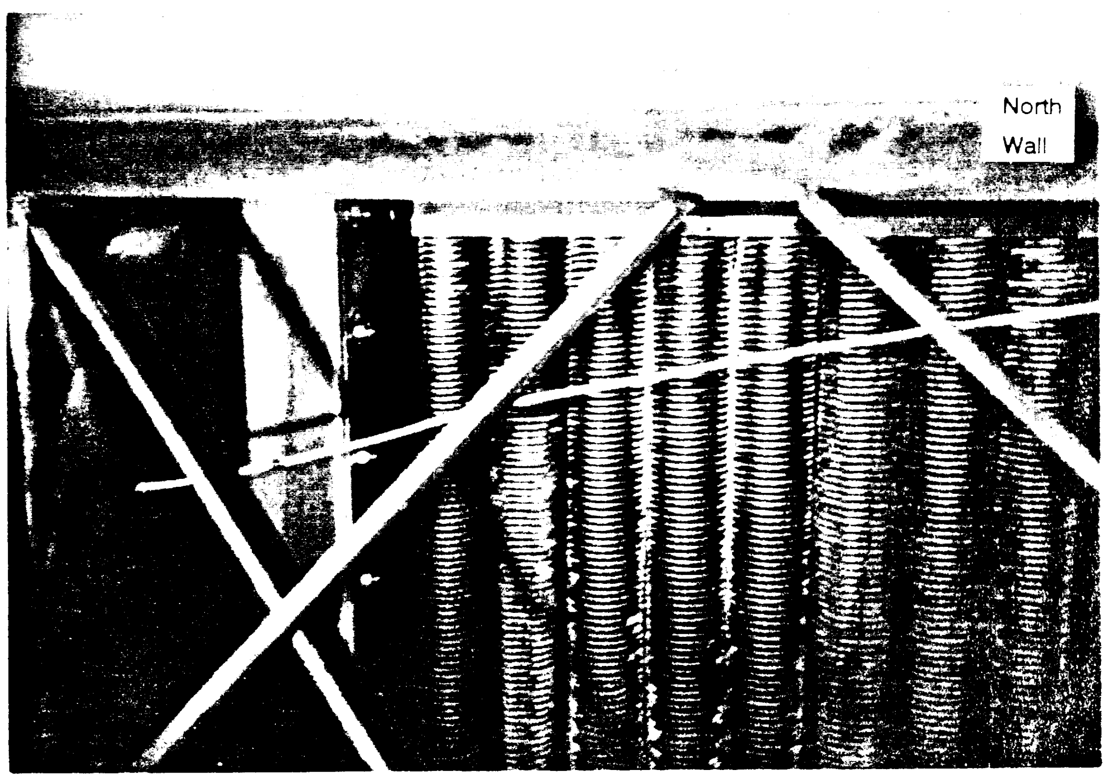


Figure 18b. End of Phase II testing -- Bottom side view of cold-end outlet heat pipes at outside (north) wall. Heat pipes show slightly more fouling than at the beginning or middle of the Phase I testing.

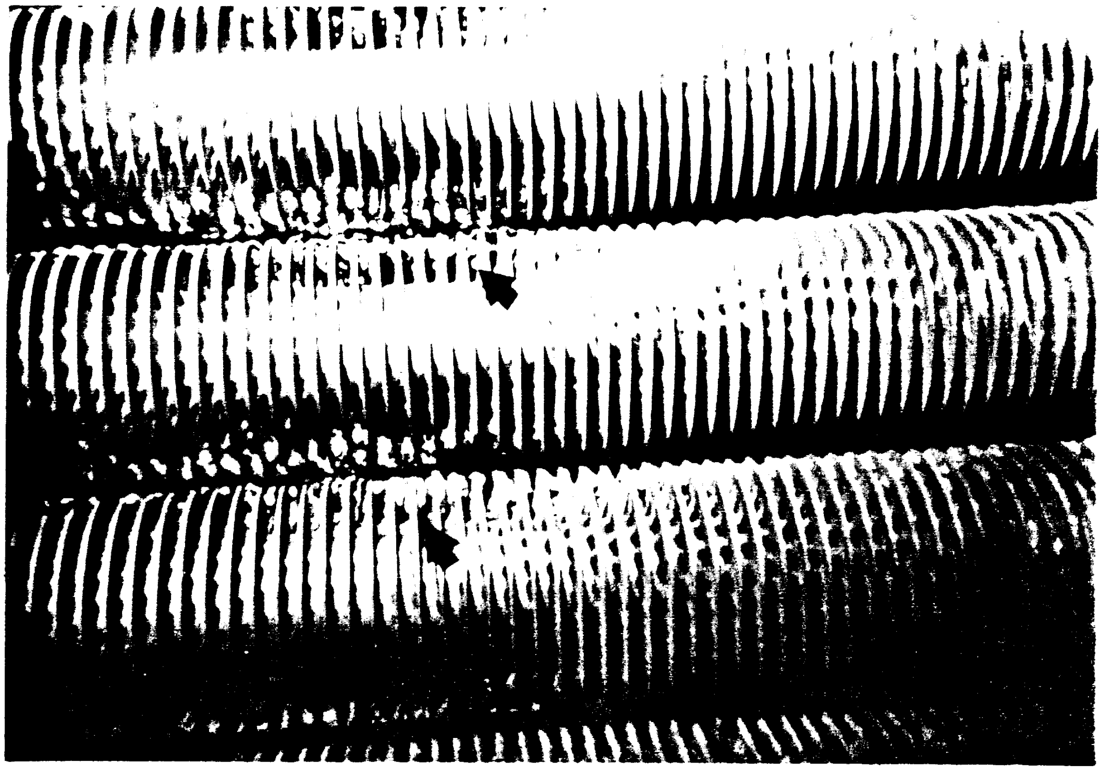
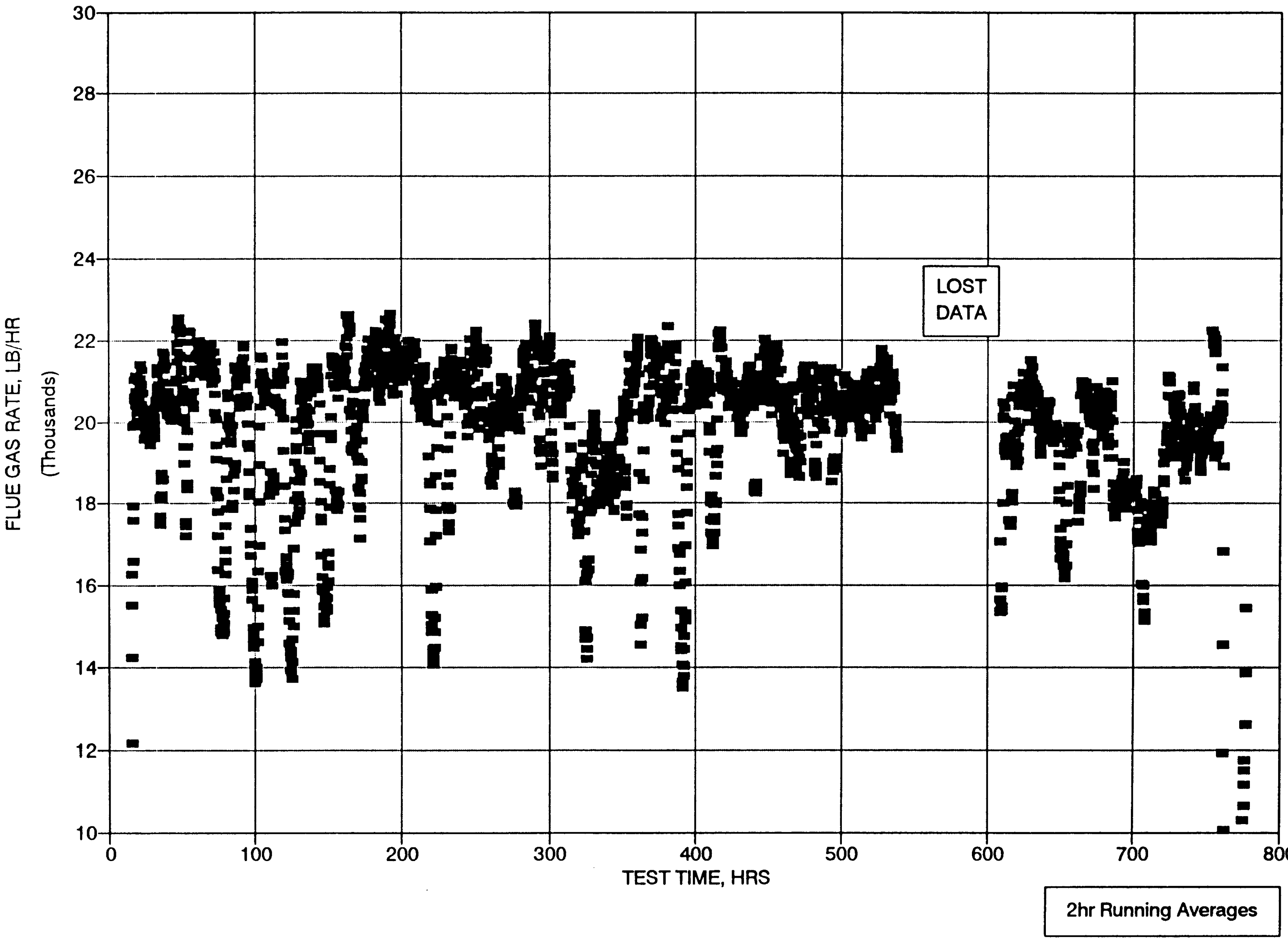


Figure 18c. End of Phase II testing -- close-up of hard deposits between fins on heat pipes at the outlet of the cold-end tube bank. Deposits contained very little NH_3 (23 ppmwt) and appear to be the result of sulfuric acid condensation.

FIGURE 19 - PHASE II
FLUE GAS MASS FLOW RATE



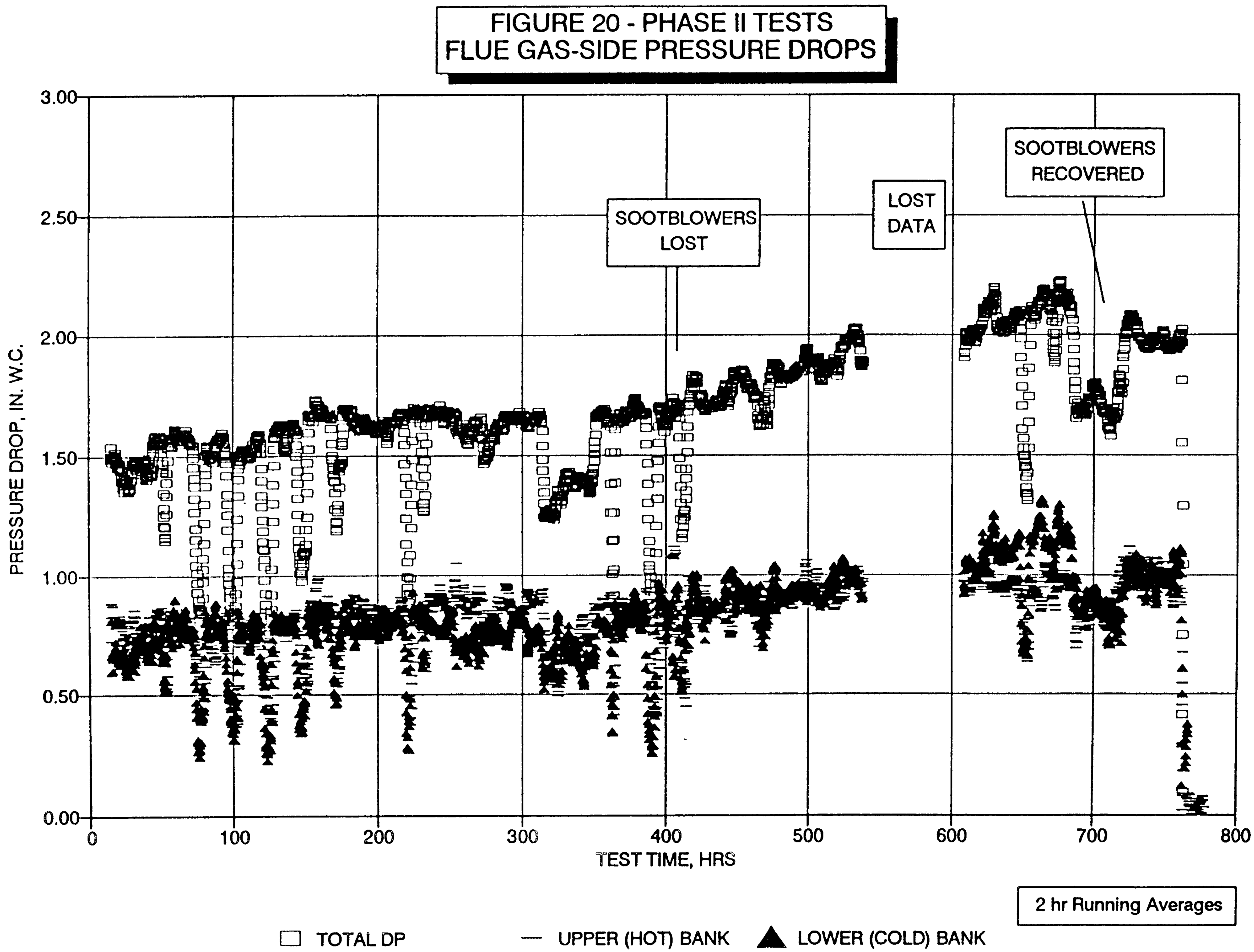


FIGURE 20 - PHASE II TESTS
FLUE GAS-SIDE PRESSURE DROPS
PRESSURE DROP, IN. W.C.
TEST TIME, HRS
SOOTBLOWERS LOST
LOST DATA
SOOTBLOWERS RECOVERED
2 hr Running Averages
TOTAL DP
UPPER (HOT) BANK
LOWER (COLD) BANK

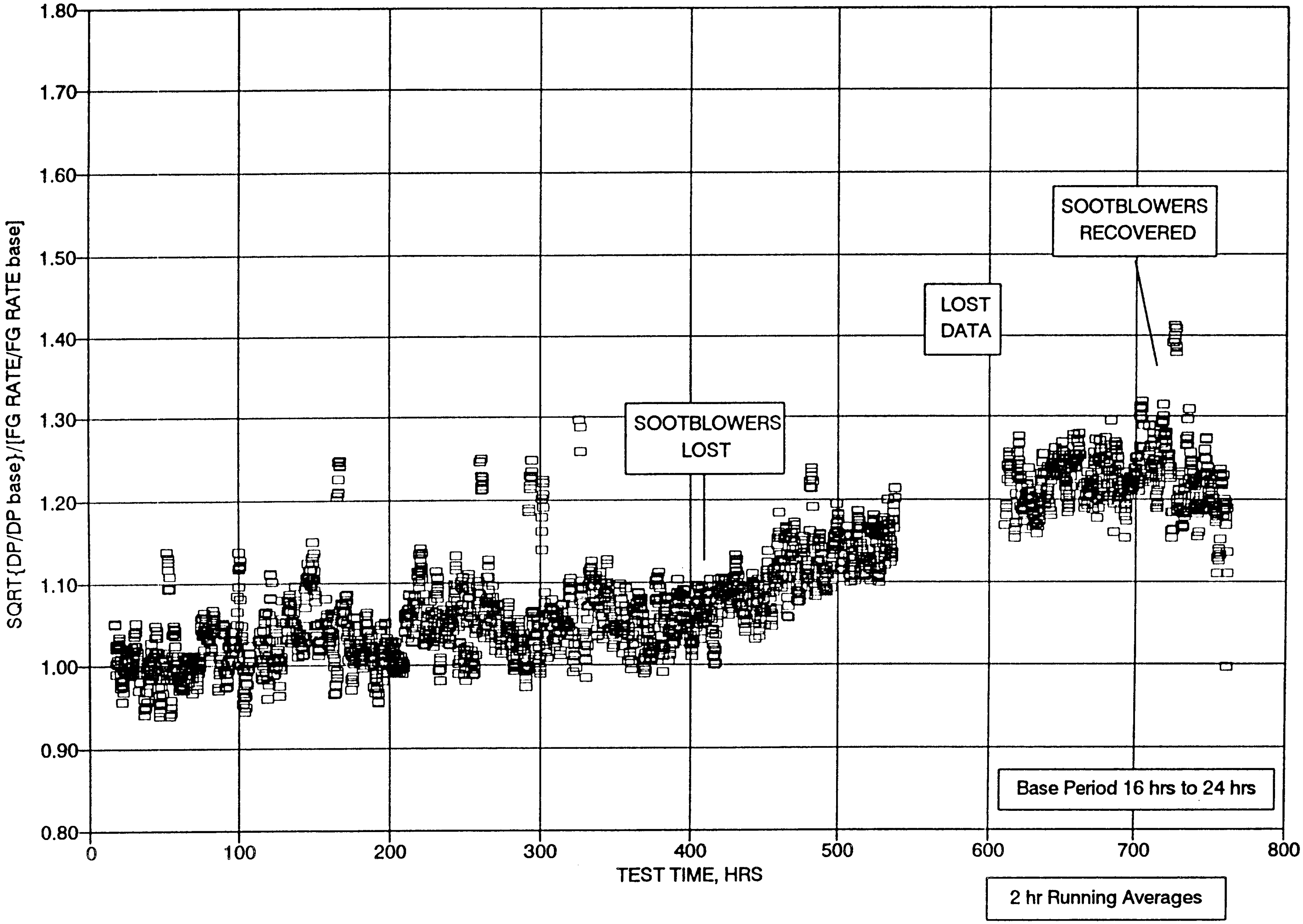


FIGURE 21 - PHASE II TESTS
TOTAL FLUE GAS SIDE PDFF

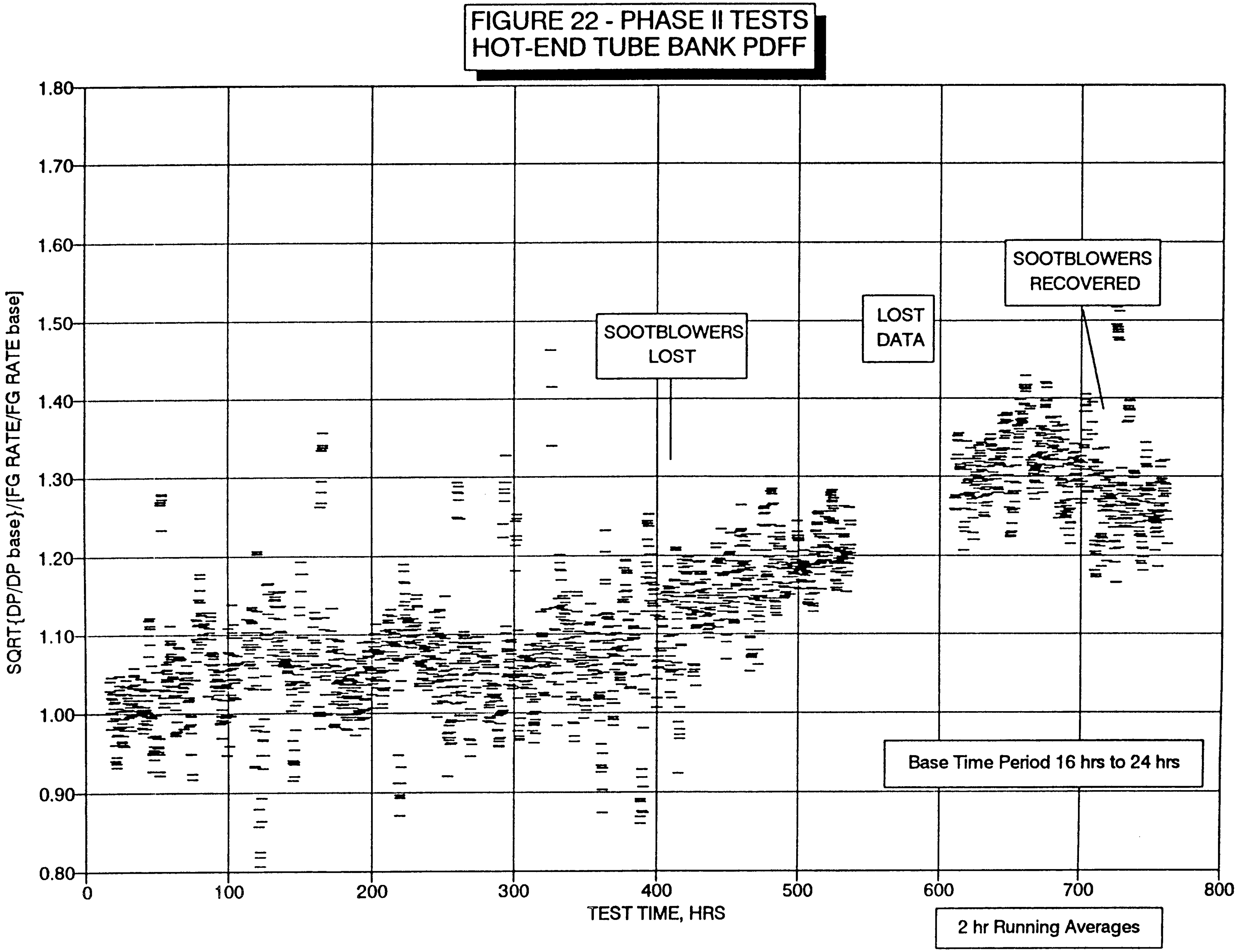


FIGURE 22 - PHASE II TESTS
HOT-END TUBE BANK PDFF
SQRT{DP/DP base}/[FG RATE/FG RATE base]
1.80
1.70
1.60
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0
100
200
300
400
500
600
700
800
TEST TIME, HRS
SOOTBLOWERS LOST
LOST DATA
SOOTBLOWERS RECOVERED
Base Time Period 16 hrs to 24 hrs
2 hr Running Averages

140

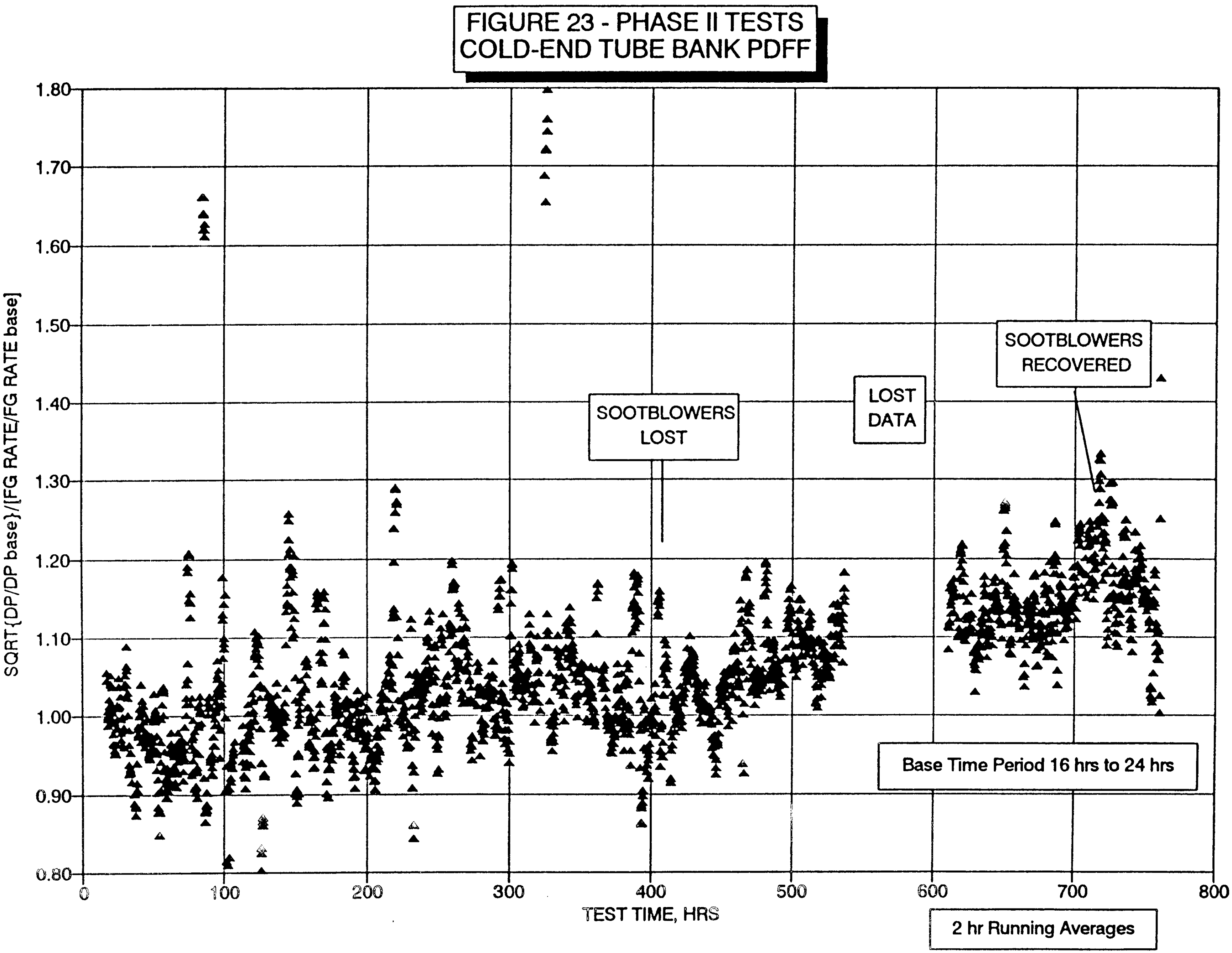
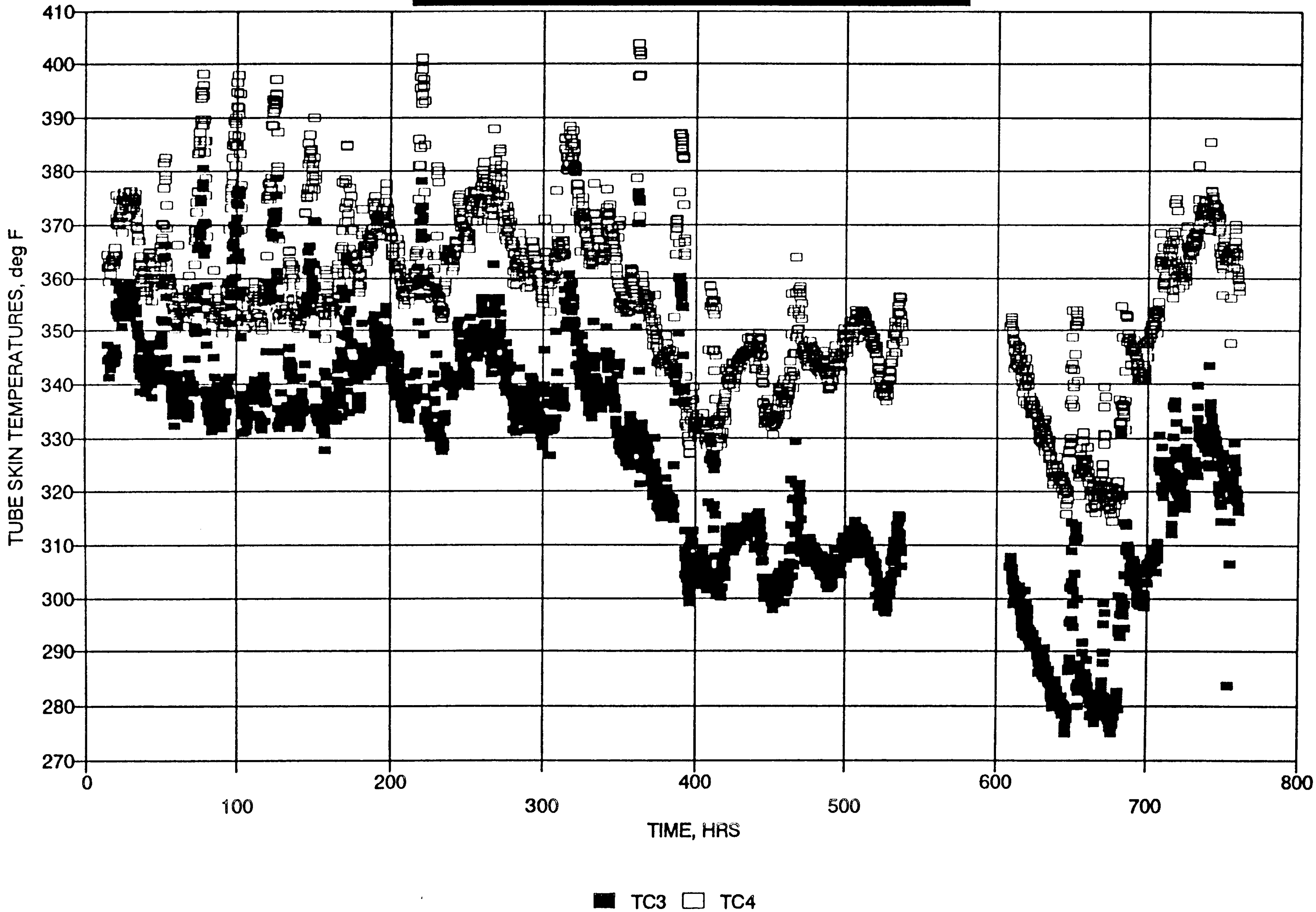


FIGURE 23 - PHASE II TESTS
COLD-END TUBE BANK PDFF
SQRT{DP/DP base}/[FG RATE/FG RATE base]
1.80
1.70
1.60
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0
100
200
300
400
500
600
700
800
TEST TIME, HRS
SOOTBLOWERS LOST
LOST DATA
SOOTBLOWERS RECOVERED
Base Time Period 16 hrs to 24 hrs
2 hr Running Averages

FIGURE 24 - PHASE II TESTS
HOT BANK OUTLET TUBE TEMPERATURES



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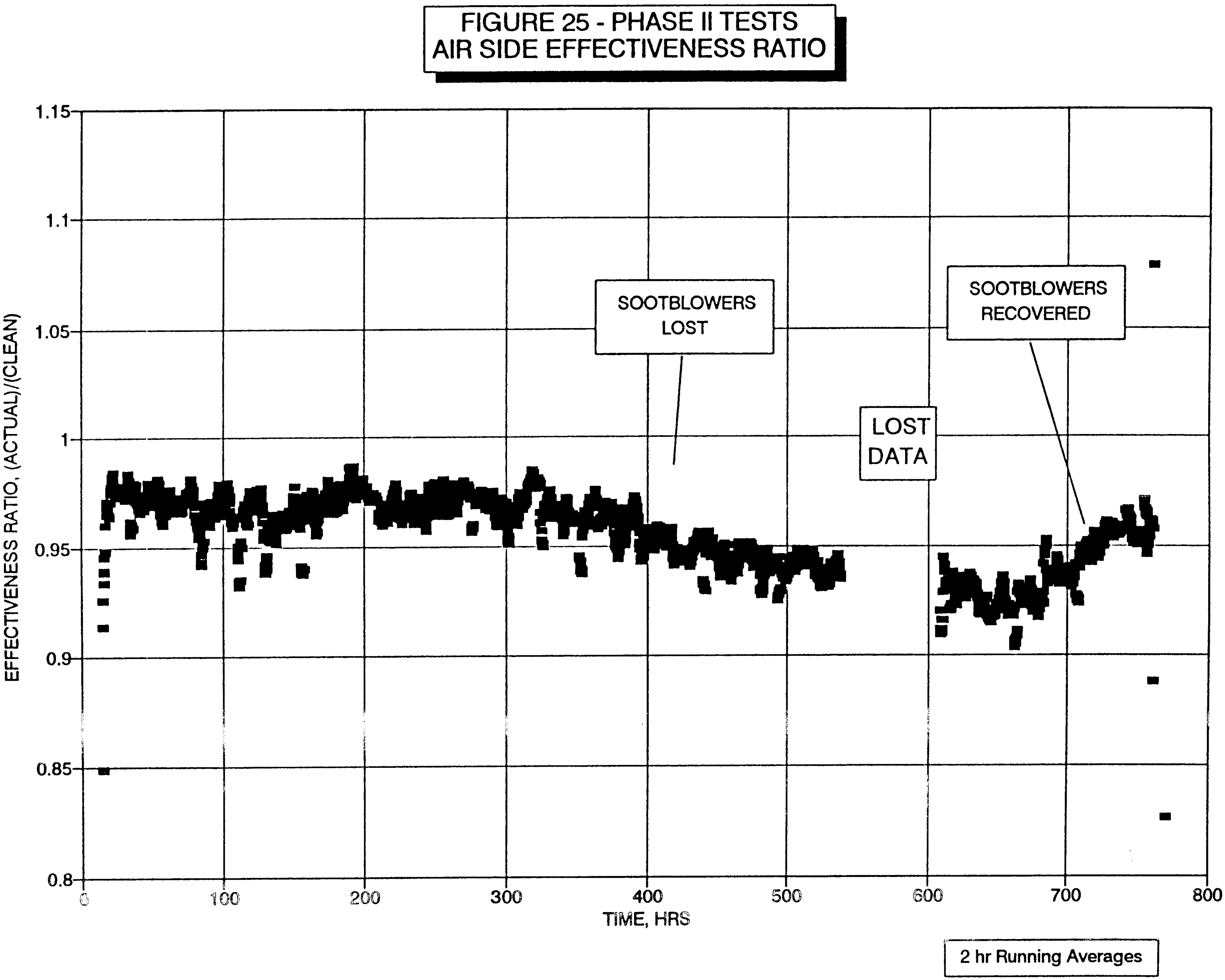
FIGURE 25 - PHASE II TESTS
AIR SIDE EFFECTIVENESS RATIO
SOOTBLOWERS LOST
SOOTBLOWERS RECOVERED
LOST DATA
EFFECTIVENESS RATIO, (ACTUAL)/(CLEAN)
TIME, HRS
2 hr Running Averages
1.15
1.1
1.05
1
0.95
0.9
0.85
0.8
0
100
200
300
400
500
600
700
800

1/13

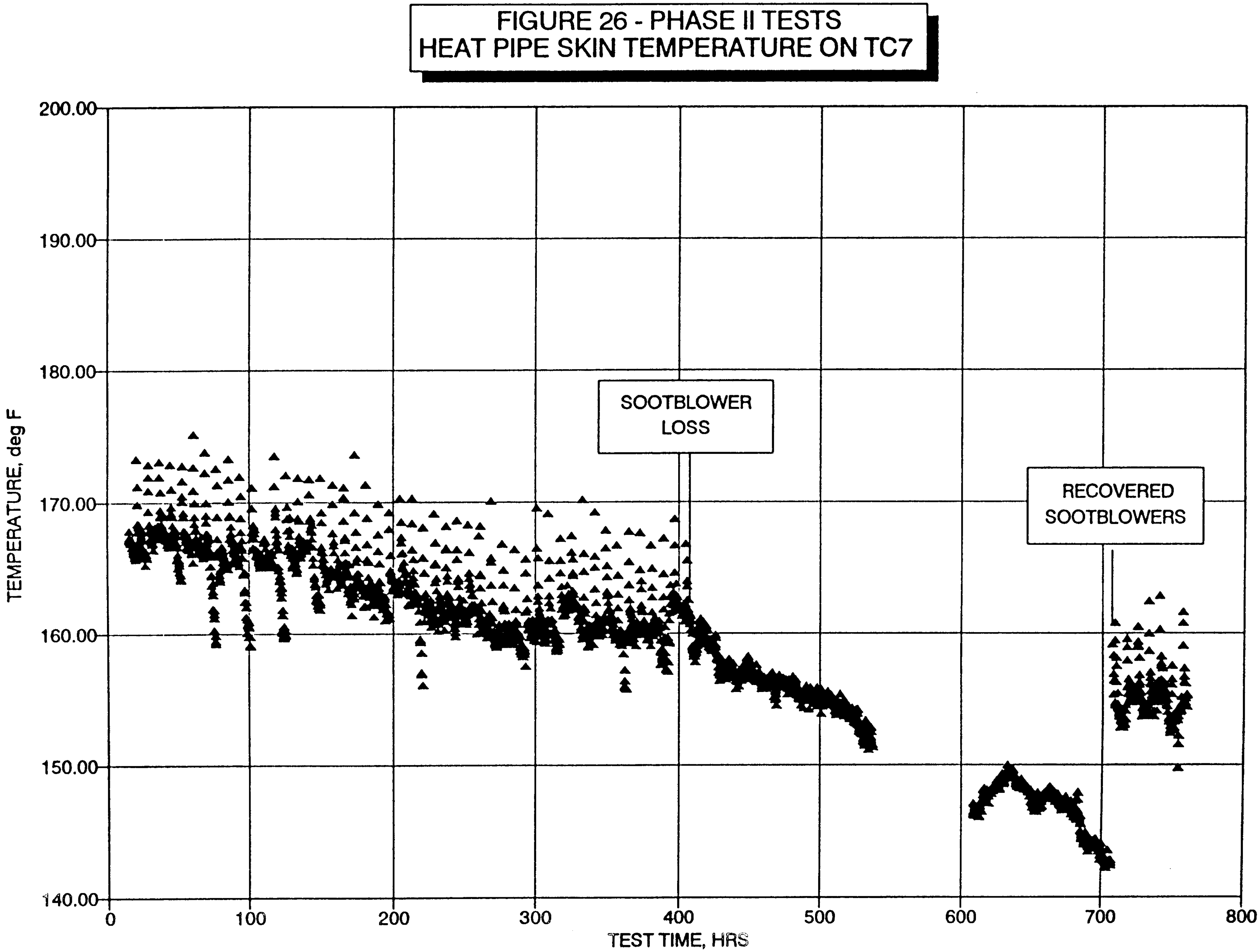

FIGURE 26 - PHASE II TESTS
HEAT PIPE SKIN TEMPERATURE ON TC7
200.00
190.00
180.00
170.00
160.00
150.00
140.00
TEMPERATURE, deg F
0
100
200
300
400
500
600
700
800
TEST TIME, HRS
SOOTBLOWER LOSS
RECOVERED SOOTBLOWERS

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FIGURE 27

Heat Pipe Outlet Duct Oxygen Levels
Milliken Station

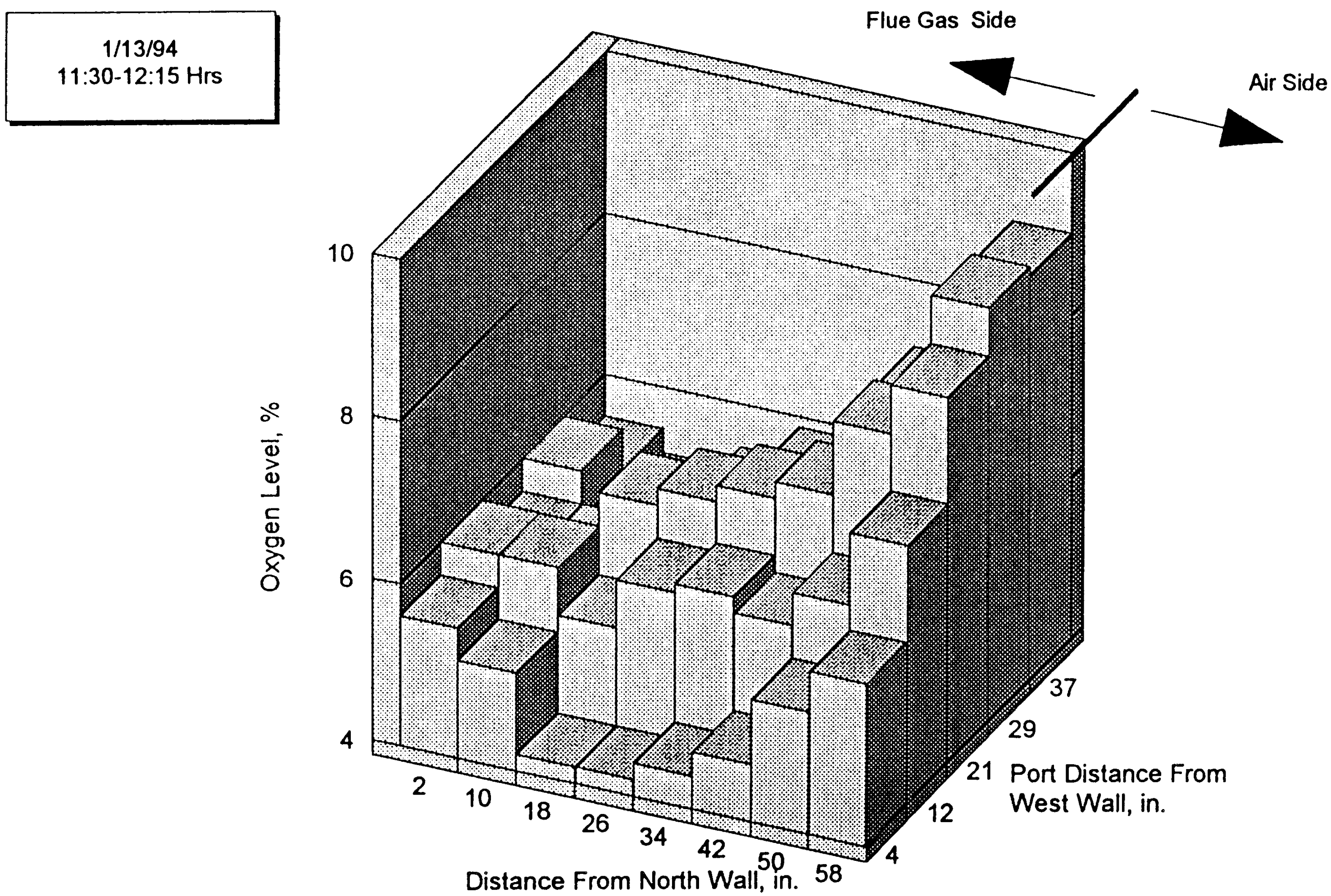
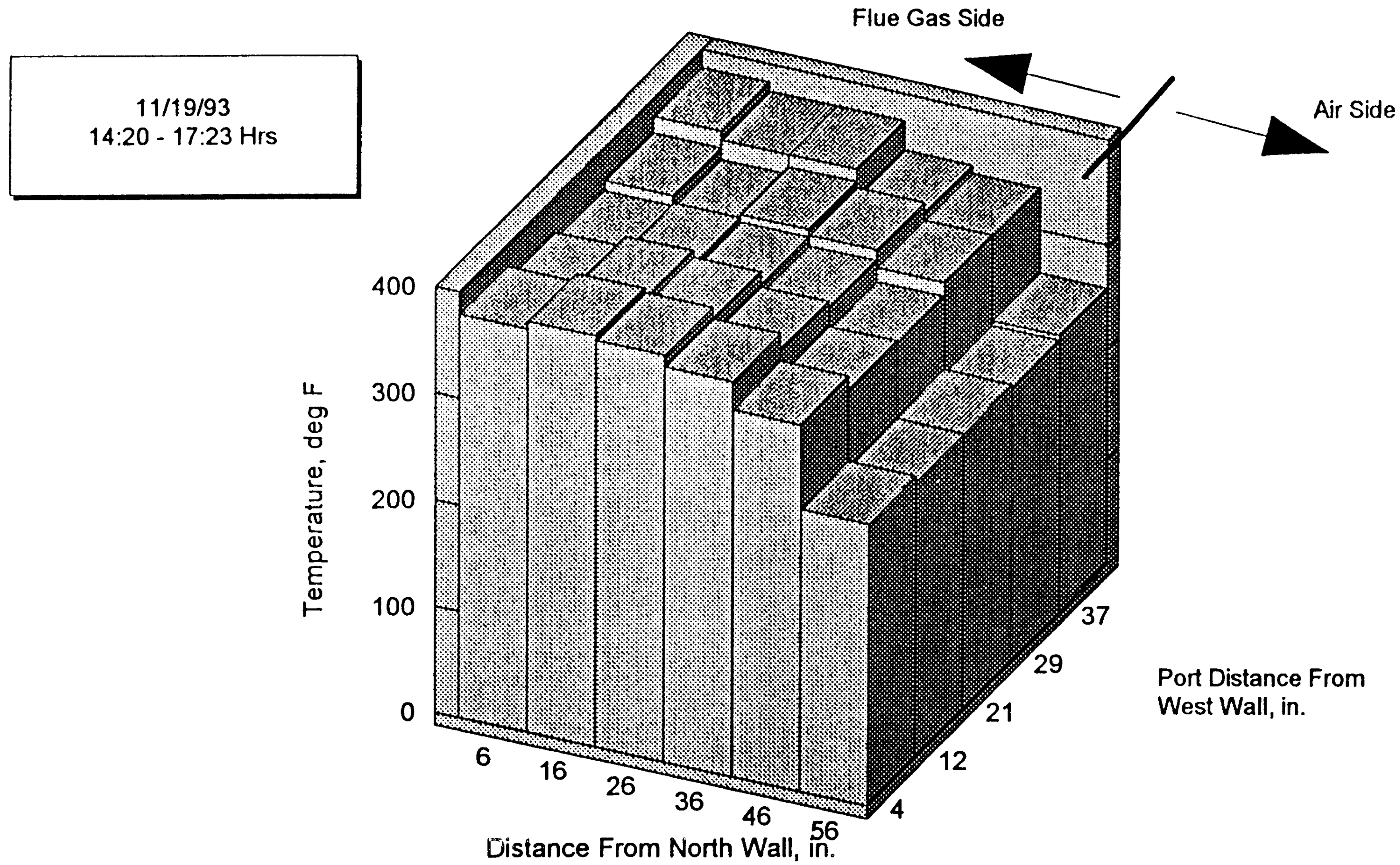


FIGURE 28

Heat Pipe Outlet Temperature Profile
Milliken Station



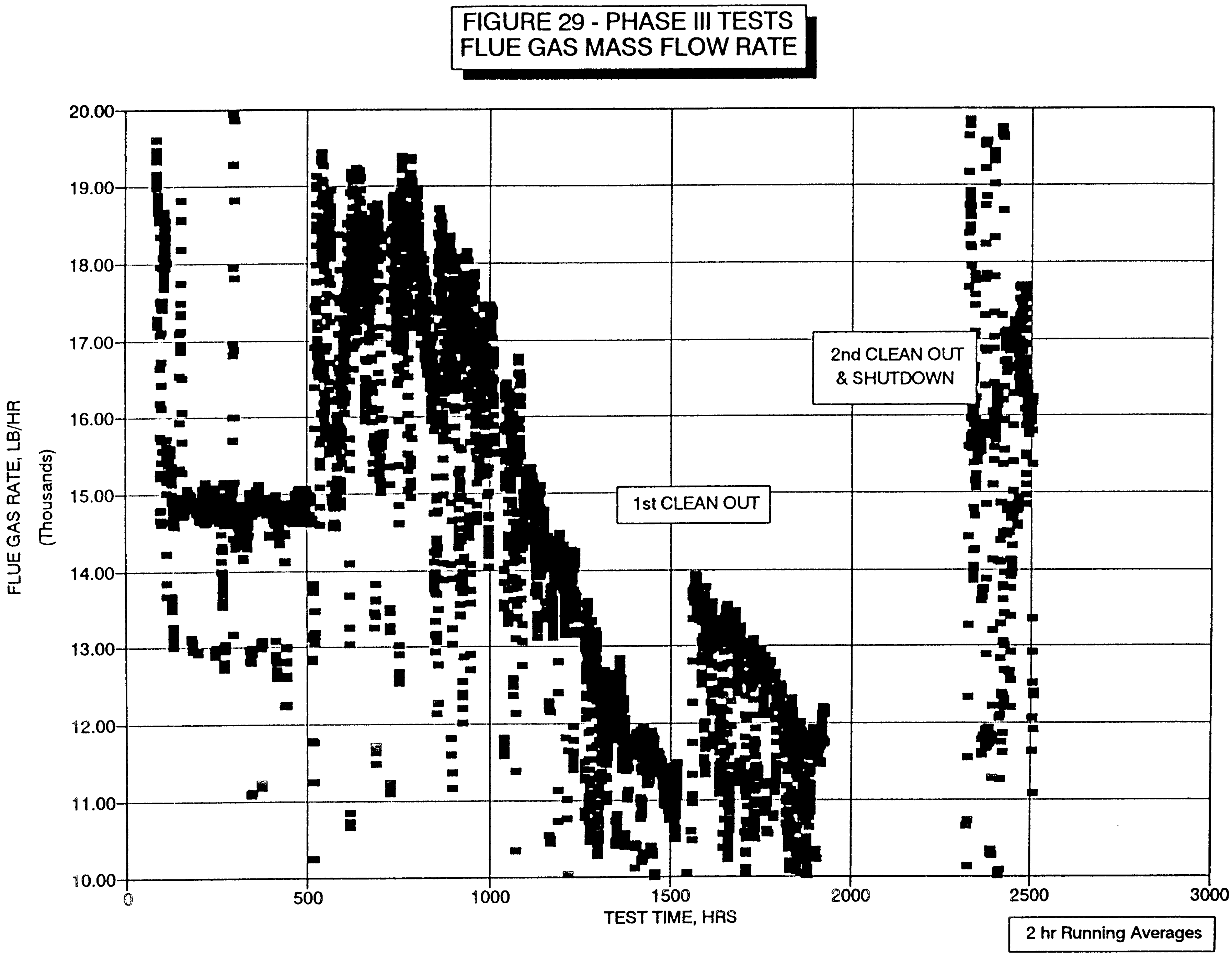


FIGURE 29 - PHASE III TESTS
FLUE GAS MASS FLOW RATE
FLUE GAS RATE, LB/HR
(Thousands)
20.00
19.00
18.00
17.00
16.00
15.00
14.00
13.00
12.00
11.00
10.00
0
500
1000
1500
2000
2500
3000
TEST TIME, HRS
1st CLEAN OUT
2nd CLEAN OUT
& SHUTDOWN
2 hr Running Averages

-54-

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FIGURE 30 - PHASE III TESTS
FLUE GAS SIDE TOTAL PRESSURE DROP

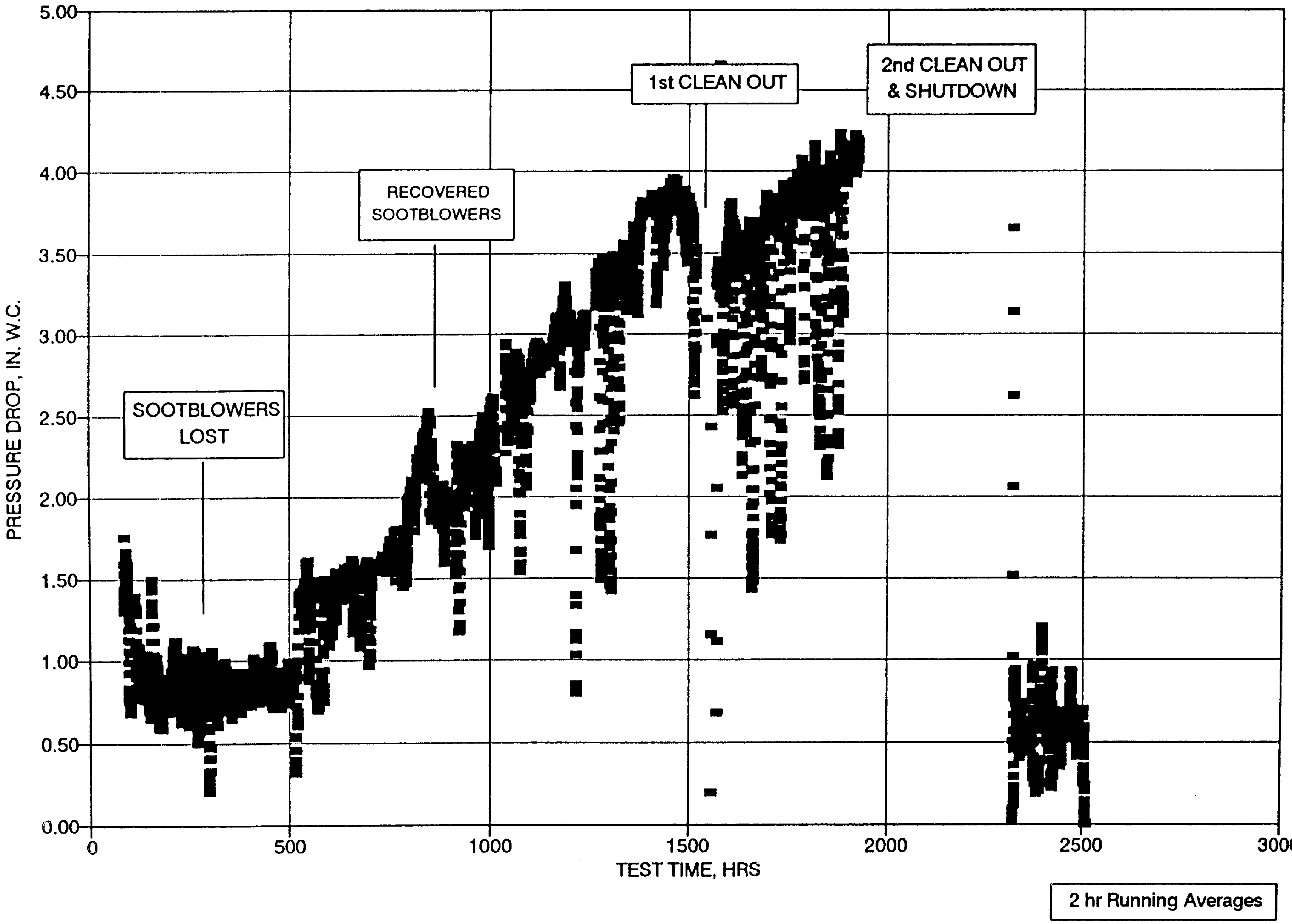

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FIGURE 31 - PHASE III TESTS
TOTAL FLUE GAS SIDE PDFF

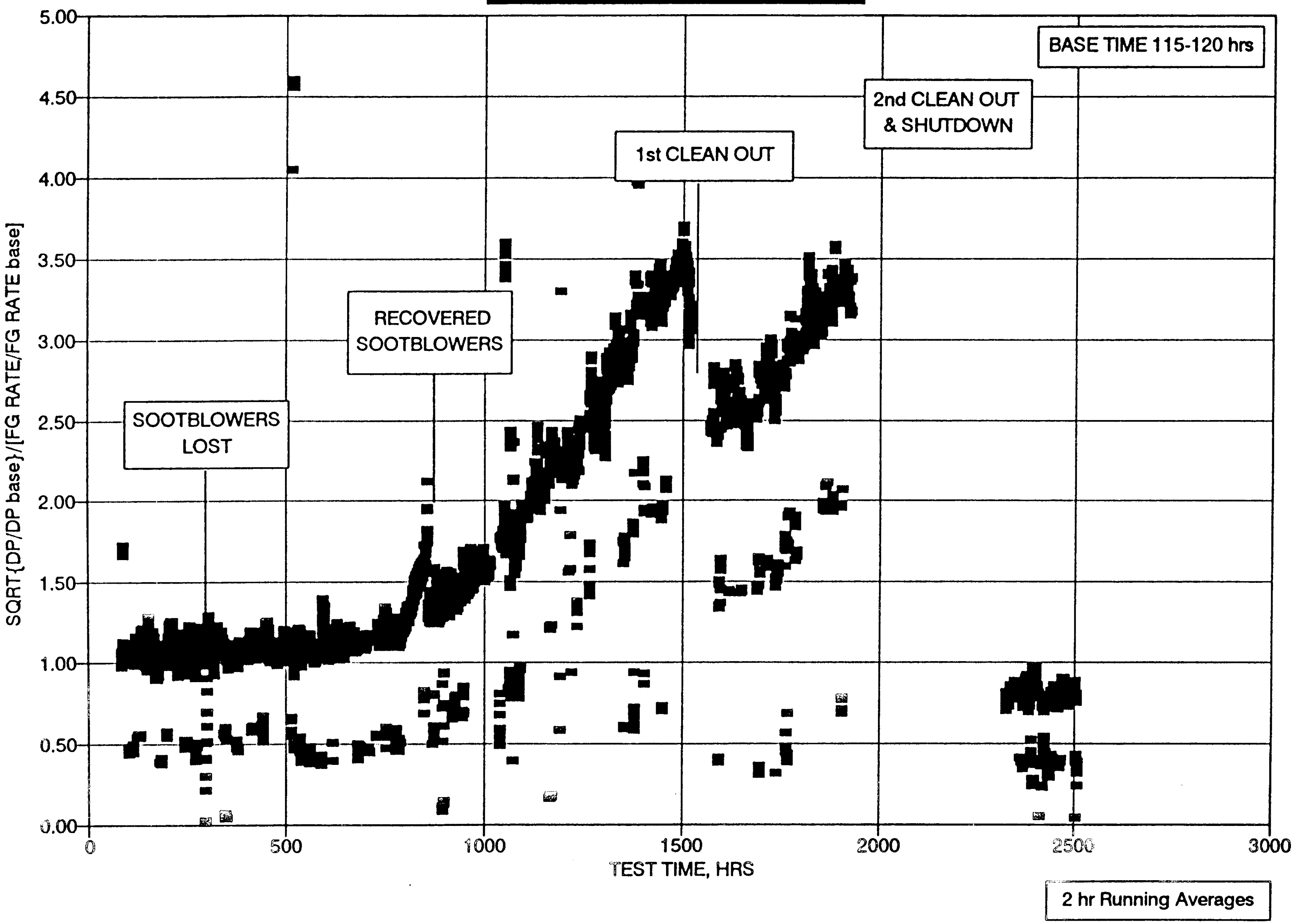

FIGURE 32 - PHASE III TESTS
HOT-END TUBE BANK PDFF

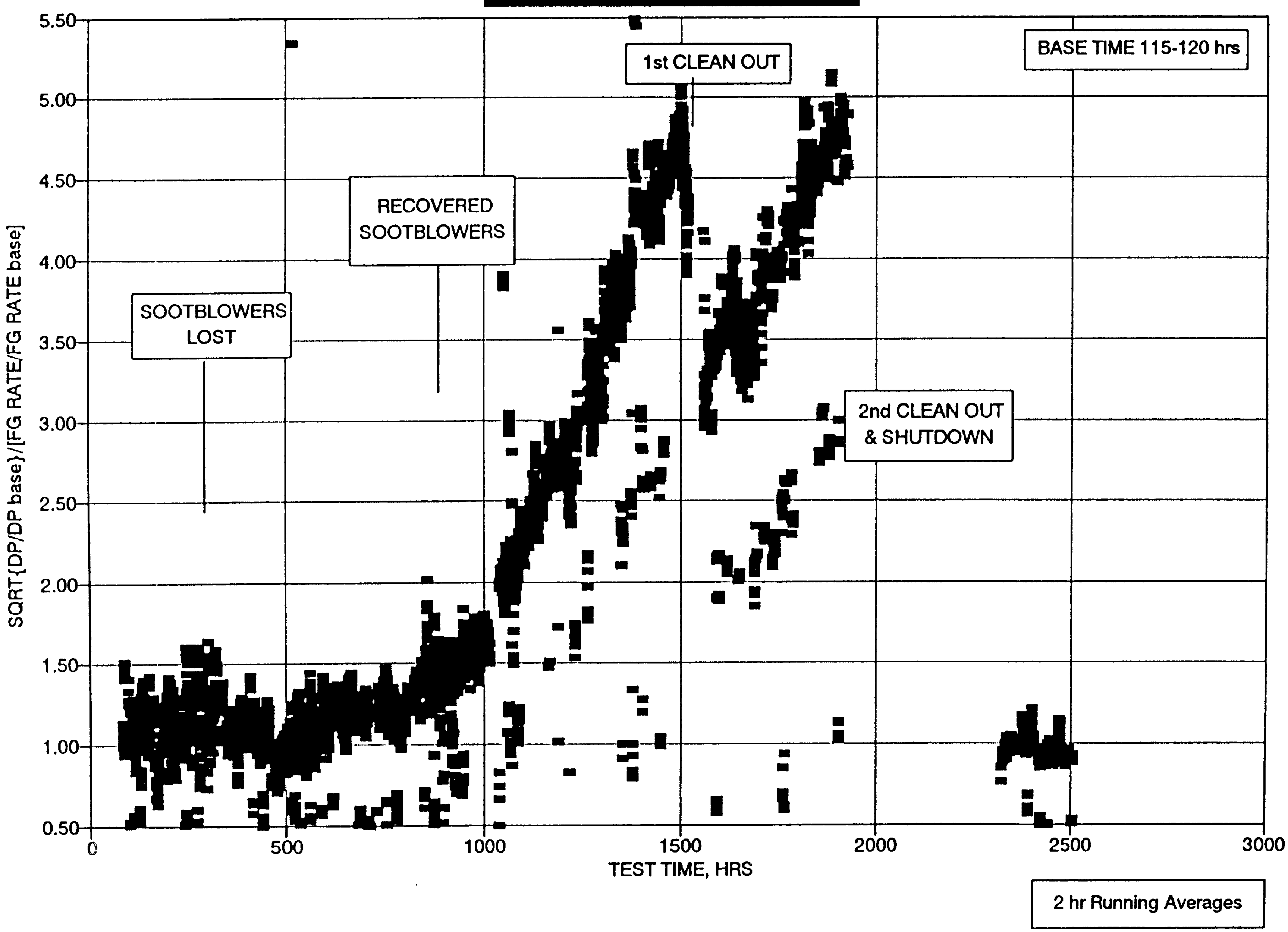

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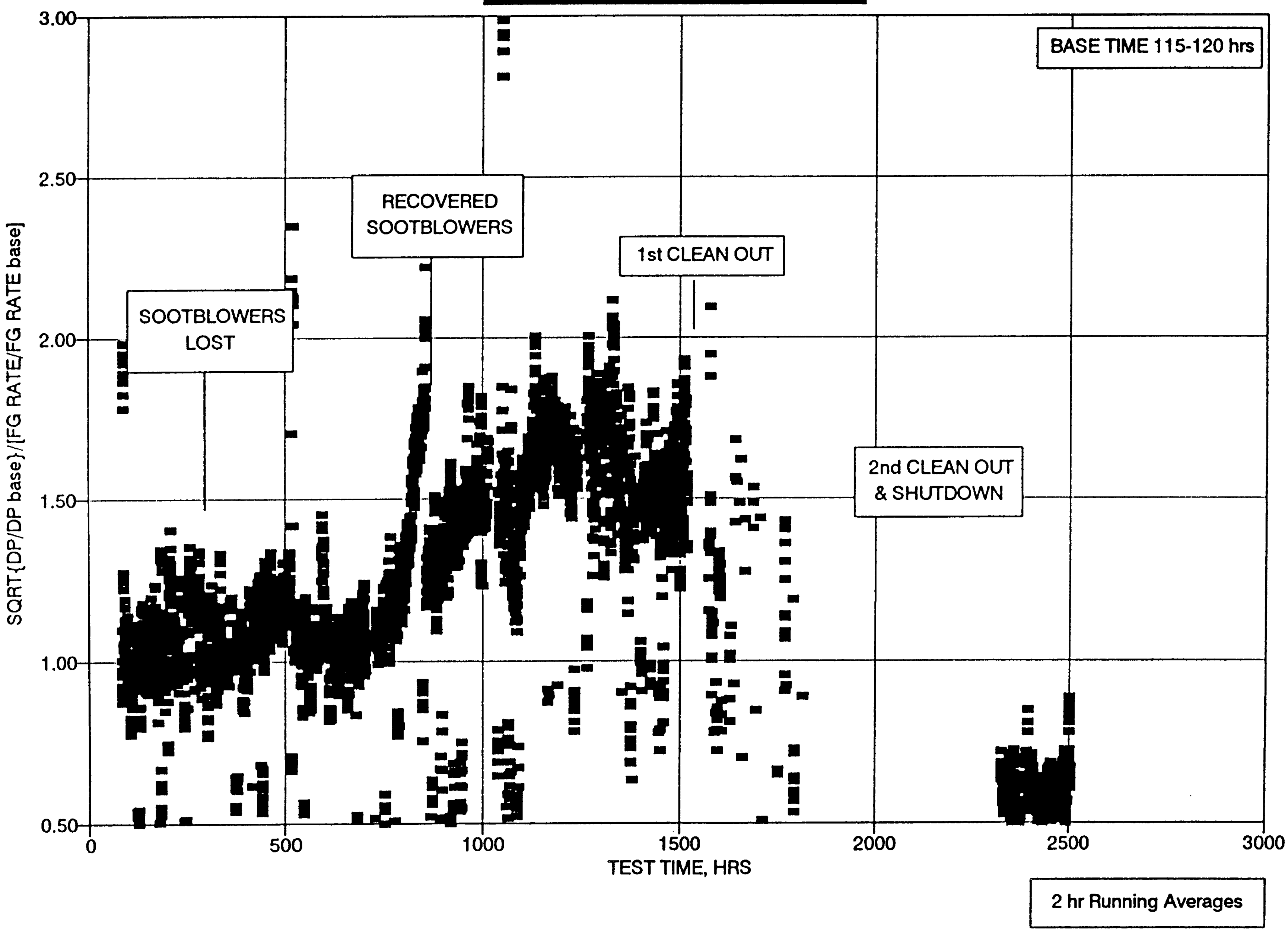
FIGURE 33 - PHASE III TESTS COLD-END TUBE BANK PDFF



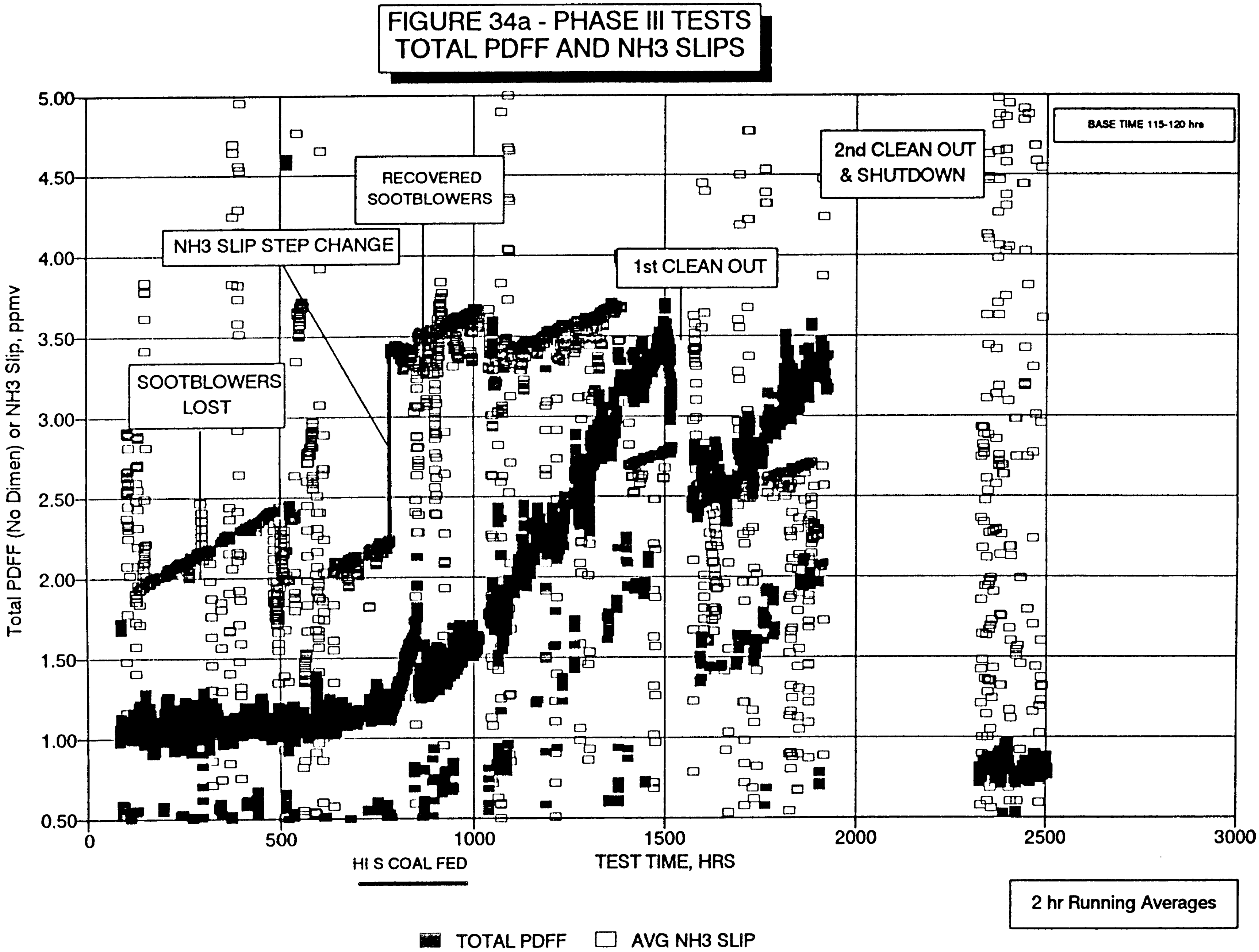


FIGURE 34a - PHASE III TESTS
TOTAL PDFF AND NH3 SLIPS
BASE TIME 115-120 hrs
2nd CLEAN OUT & SHUTDOWN
RECOVERED SOOTBLOWERS
NH3 SLIP STEP CHANGE
1st CLEAN OUT
SOOTBLOWERS LOST
Total PDFF (No Dimen) or NH3 Slip, ppmv
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0
500
1000
1500
2000
2500
3000
HI S COAL FED
TEST TIME, HRS
2 hr Running Averages
TOTAL PDFF
AVG NH3 SLIP

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FIGURE 34b - PHASE III TESTS
TOTAL PDFF AND NH3 SLIPS

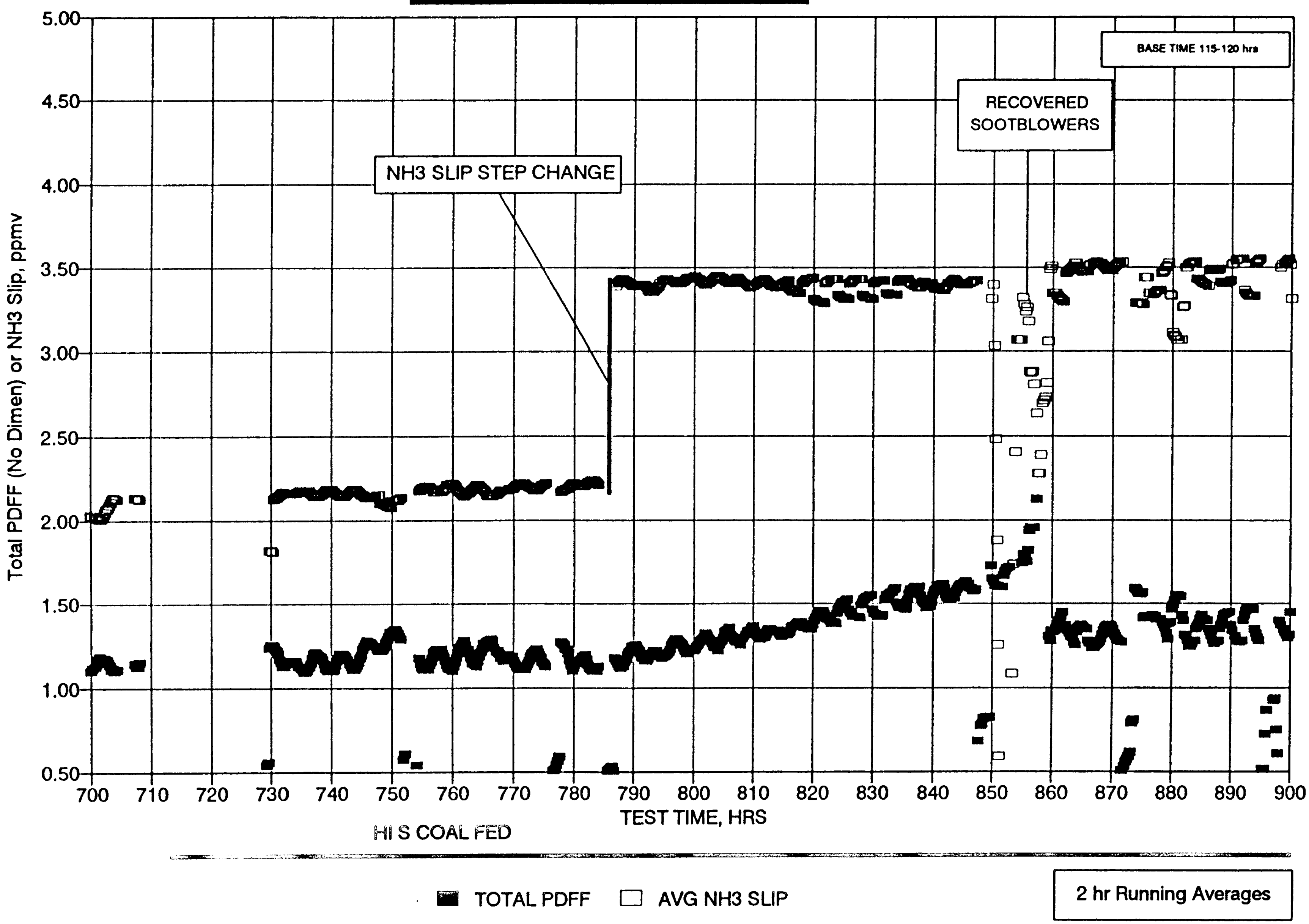

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FIGURE 35 - PHASE III TESTS
AIR EFFECTIVENESS RATIO

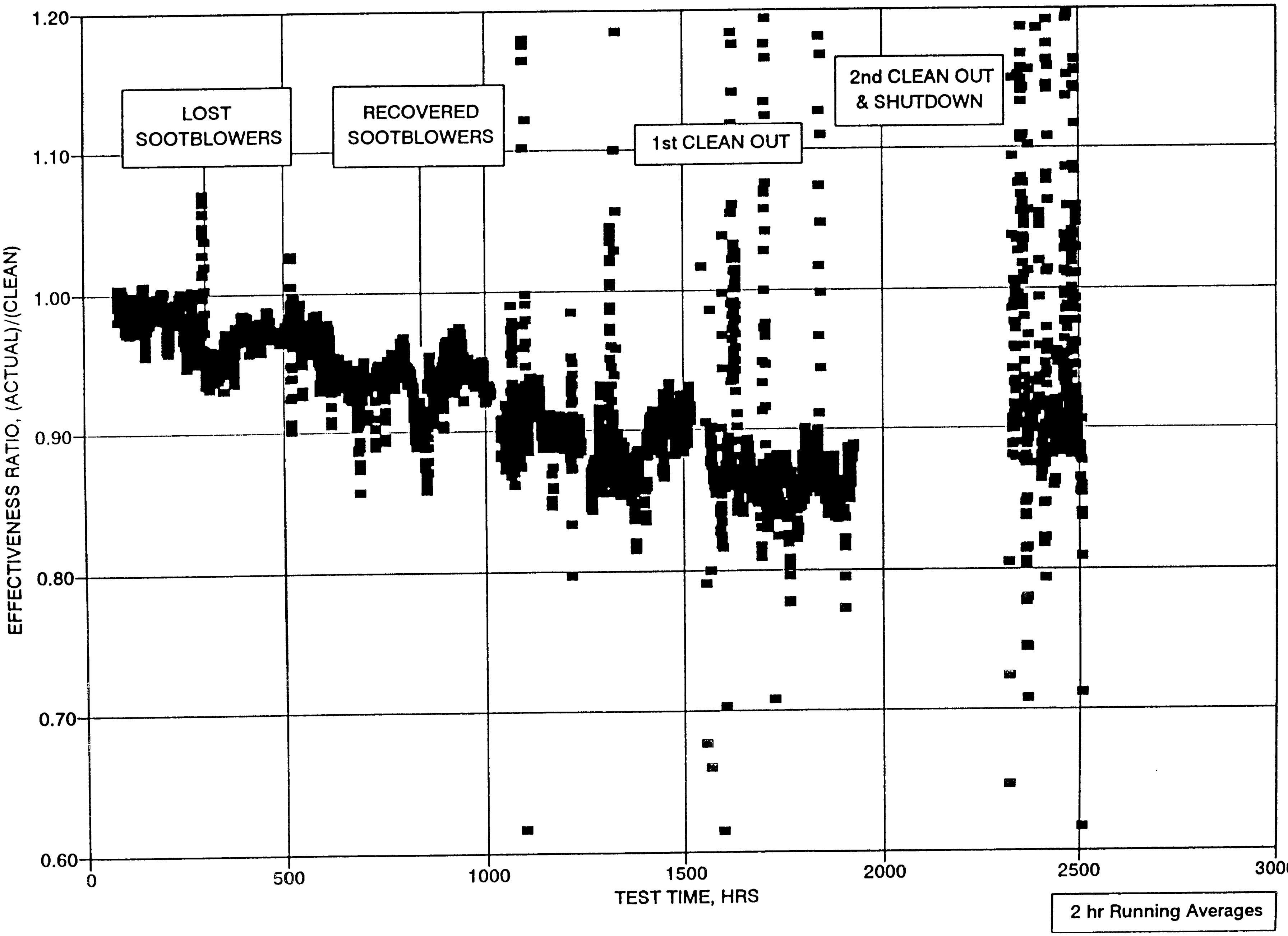
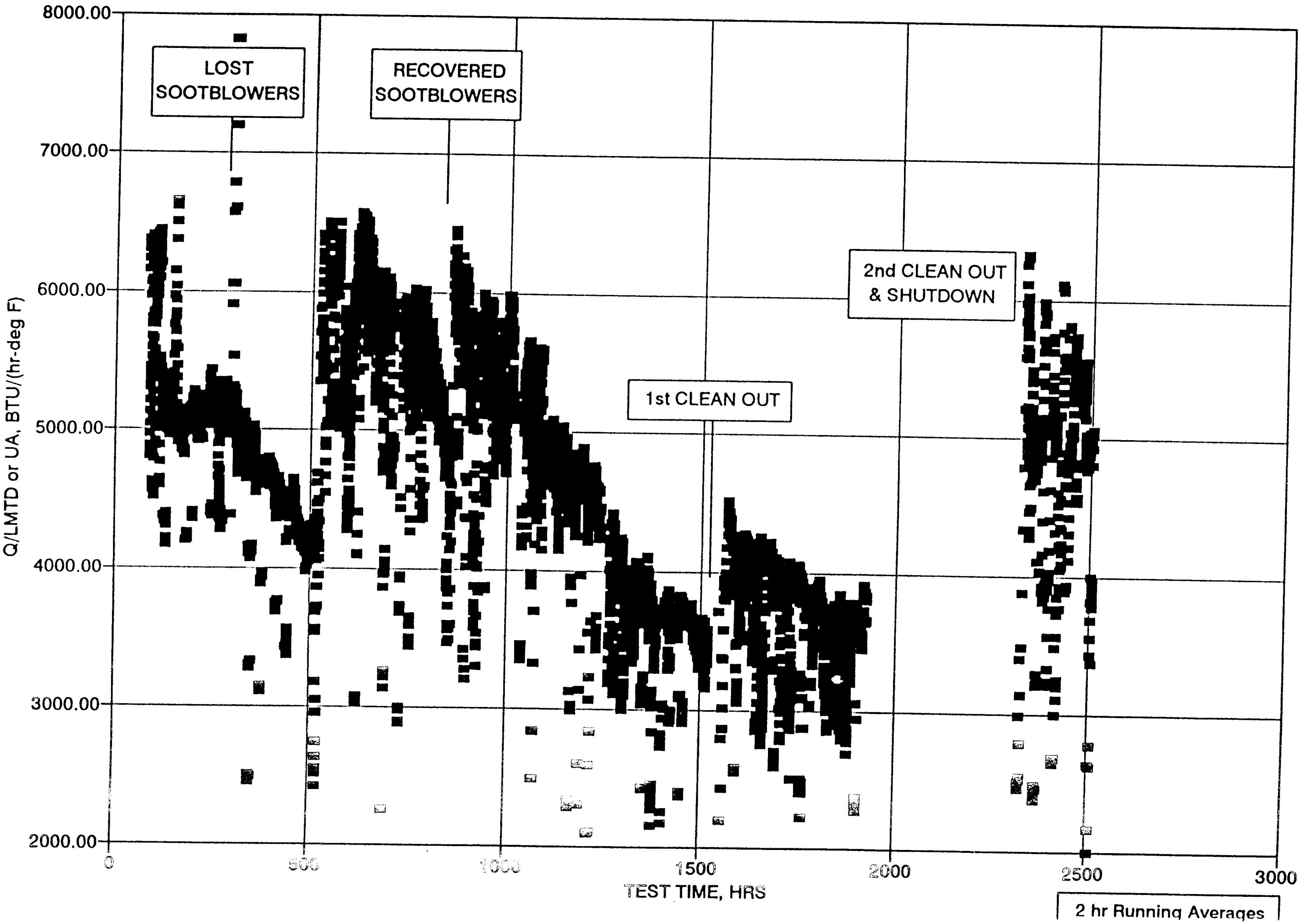


FIGURE 36 PHASE III TESTS HEAT PIPE Q/LMTD or UA



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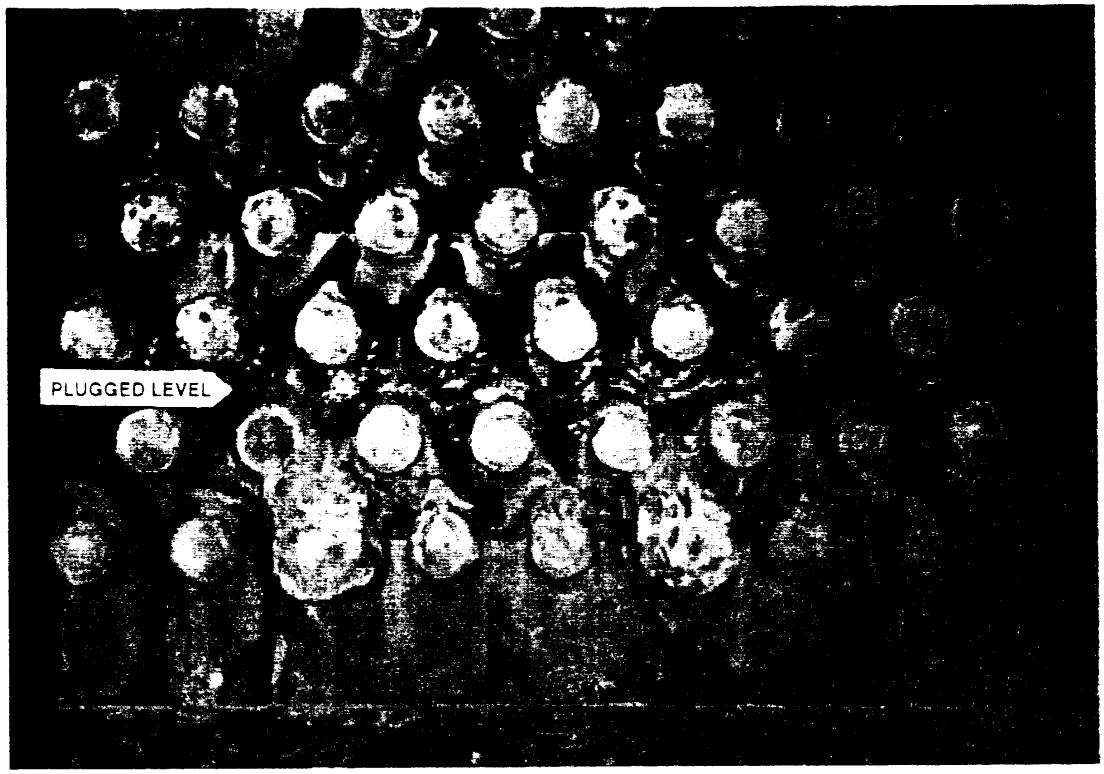

Figure 37. End view of bottom half of the hot-end tube bank showing main area where fouling occurred. Rows above row 3 from the bottom are mostly open.

Figure 38. Close up of plugged area between rows 2 and 3 from the bottom of the hot-end tube bank. Area between the tube rows is totally plugged.

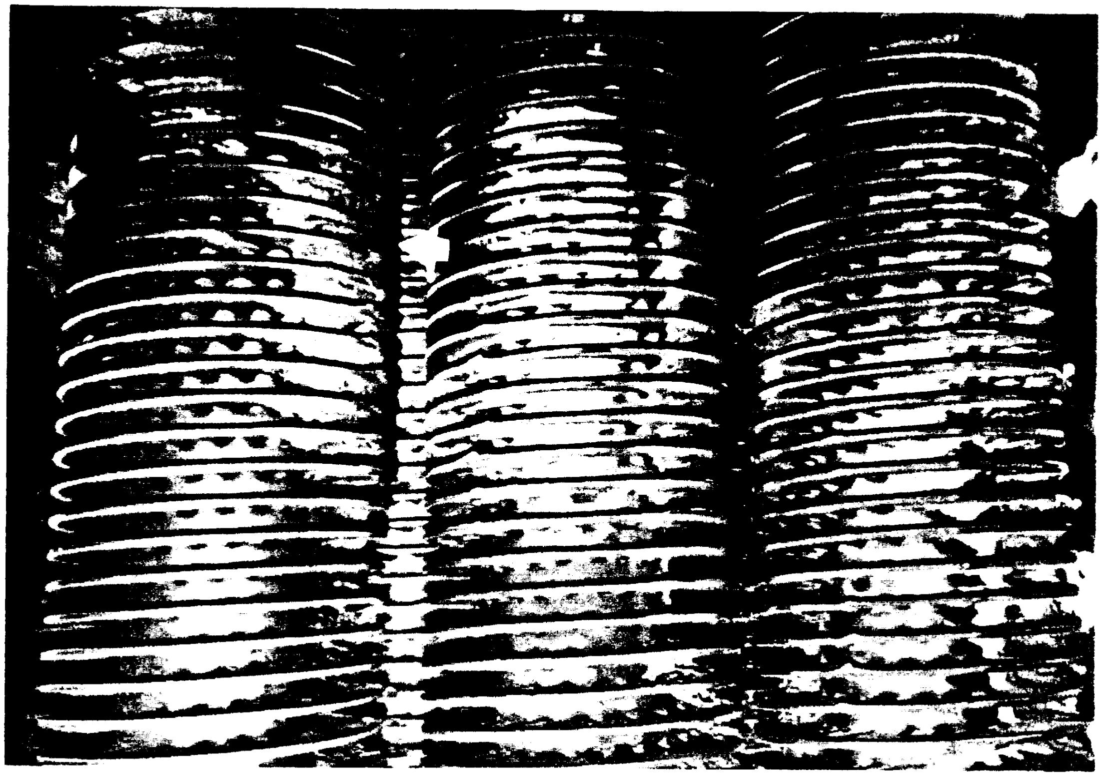

Figure 39. Bottom side view of row 1 (see Figures 37 and 38) showing hard deposits on top side of fins. Deposits collected during the April 12 inspection contained high ammonia levels (1.89 wt %).

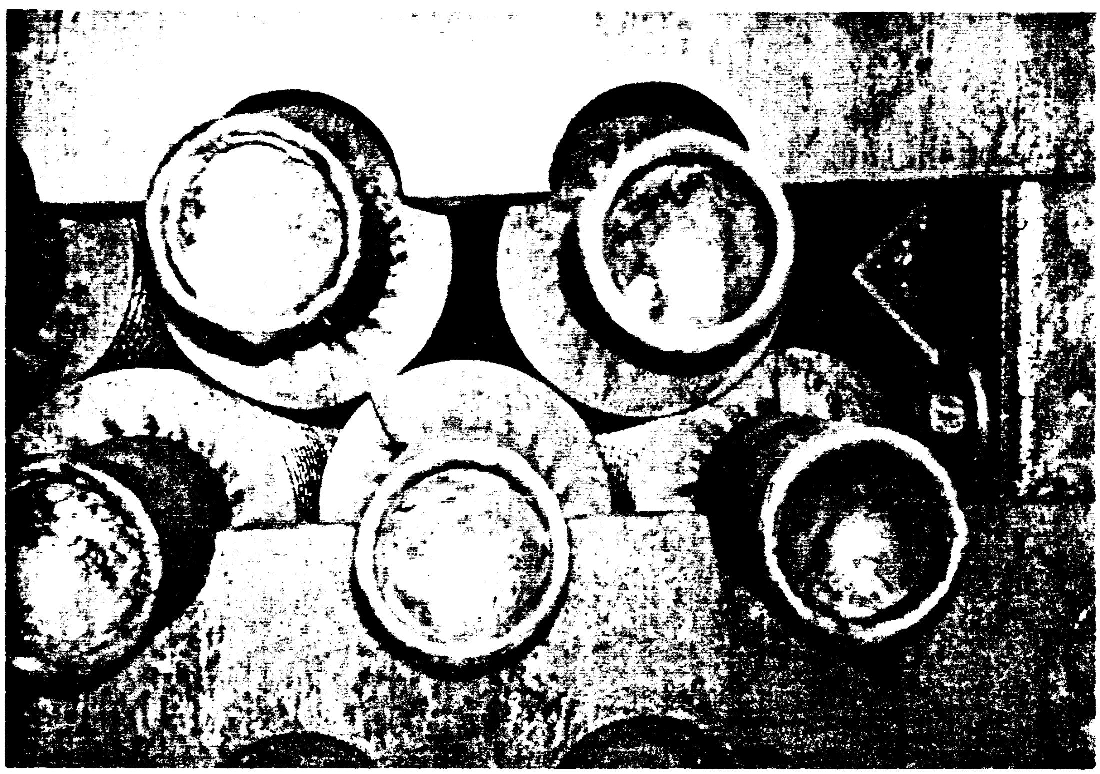

Figure 40. Close-up of heat pipe tubes after wash out showing complete removal of deposits.

APPENDIX

PARAMETRIC TEST PERIOD RAW DATA

NOVEMBER 19, 1993 TO NOVEMBER 21, 1993

RUN #	DATE	HOURS	AIR IN TEMP F	AIR MID TEMP F	AIR OUT TEMP F	GAS IN TEMP F	GAS MID TEMP F	GAS OUT TEMP F	TUBE SKIN TEMP TC7, F	TUBE SKIN TEMP TC8, F
RUN 1	nov-19	8.44	46	251	429	635	461	326	172	216
RUN 1	nov-19	9.45	46	258	433	634	462	326	172	217
RUN 1	nov-19	9.70	46	254	431	634	462	326	172	217
RUN 1	nov-19	9.95	46	255	432	634	463	327	172	216
RUN 2	nov-19	11.92	50	281	457	633	482	346	186	232
RUN 2	nov-19	12.17	49	282	457	634	482	346	186	232
RUN 2	nov-19	12.42	48	272	453	634	482	347	184	231
RUN 2	nov-19	12.67	50	280	449	633	475	342	185	231
RUN 2	nov-19	12.92	51	311	469	638	467	340	197	240
RUN 3	nov-19	15.68	52	317	482	632	494	353	198	241
RUN 3	nov-19	16.01	52	316	483	633	495	354	198	241
RUN 3	nov-19	16.26	54	318	484	633	496	354	198	242
RUN 3	nov-19	16.51	53	315	483	633	496	355	198	241
RUN 3	nov-19	16.76	53	314	482	634	495	354	198	241
RUN 3	nov-19	17.01	54	311	481	634	495	354	197	241
RUN 4	nov-19	18.51	55	363	511	633	522	383	222	264
RUN 4	nov-19	18.76	54	368	512	631	523	383	220	265
RUN 4	nov-19	19.01	56	361	511	631	521	382	219	265
RUN 4	nov-19	19.26	54	366	511	630	522	382	220	264
RUN 4	nov-19	19.51	55	359	511	631	521	382	220	265
RUN 4	nov-19	19.76	52	285	481	631	506	369	202	246
RUN 4	nov-19	20.01	51	290	451	624	461	317	175	216
RUN 5	nov-20	10.01	41	308	468	621	473	319	169	218
RUN 5	nov-20	10.26	42	308	467	621	472	318	168	218
RUN 5	nov-20	10.51	42	308	466	622	472	318	169	217
RUN 5	nov-20	10.76	39	324	474	622	480	324	170	222
RUN 6	nov-20	11.73	40	334	482	622	486	330	180	227
RUN 6	nov-20	11.98	41	334	482	622	488	329	183	228
RUN 6	nov-20	12.23	41	335	482	621	488	330	181	228
RUN 6	nov-20	12.48	41	334	481	620	487	330	180	227
RUN 6	nov-20	12.73	40	332	480	620	485	326	185	227
RUN 6	nov-20	12.98	42	333	481	620	488	329	183	228
RUN 6	nov-20	13.23	43	343	482	619	490	334	185	232
RUN 6	nov-20	13.48	40	357	487	619	498	341	188	238
RUN 7	nov-20	14.48	44	369	494	616	505	346	196	242
RUN 7	nov-20	14.73	41	370	494	616	504	346	195	242
RUN 7	nov-20	14.98	38	369	494	618	505	347	194	242
RUN 7	nov-20	15.23	39	378	497	618	510	352	197	247
RUN 7	nov-20	15.48	41	387	501	619	515	357	202	252
RUN 8	nov-20	16.48	41	402	509	620	524	365	210	260
RUN 8	nov-20	16.73	41	402	510	621	524	365	210	259
RUN 8	nov-20	16.98	41	403	510	621	525	366	210	259
RUN 8	nov-20	17.23	41	404	511	621	525	366	210	260
RUN 8	nov-20	17.48	42	403	511	621	525	367	210	260
RUN 9	nov-21	8.48	39	352	481	612	482	309	171	217
RUN 9	nov-21	8.73	39	349	480	612	480	308	168	217
RUN 9	nov-21	8.98	42	347	480	612	479	309	167	217
RUN 9	nov-21	9.23	42	350	480	612	479	309	167	217
RUN 9	nov-21	9.48	44	370	484	613	489	320	174	228
RUN 10	nov-21	10.73	44	380	493	613	498	326	185	232
RUN 10	nov-21	10.98	45	378	493	613	497	326	184	232
RUN 10	nov-21	11.23	45	377	493	613	497	326	183	232
RUN 10	nov-21	11.48	47	376	492	612	496	326	182	232
RUN 10	nov-21	11.73	47	387	492	610	500	331	187	238
RUN 11	nov-21	12.98	54	391	496	612	503	333	197	242
RUN 11	nov-21	13.23	54	391	497	612	504	333	196	242
RUN 11	nov-21	13.48	53	392	497	612	504	334	195	242
RUN 11	nov-21	13.73	53	392	495	609	503	333	195	242
RUN 11	nov-21	13.98	53	400	492	608	506	337	198	247
RUN 12	nov-21	14.98	55	409	497	610	513	344	205	252
RUN 12	nov-21	15.23	55	409	498	610	513	344	205	252
RUN 12	nov-21	15.48	55	409	499	611	513	344	204	252
RUN 12	nov-21	15.73	55	410	500	611	513	344	204	252
RUN 12	nov-21	15.98	53	364	502	623	513	357	202	248
RUN 13	nov-21	16.73	53	347	500	631	505	355	205	247
RUN 13	nov-21	16.98	55	346	500	632	505	356	205	247
RUN 13	nov-21	17.23	54	345	499	631	504	355	204	246
RUN 13	nov-21	17.48	54	344	500	633	504	356	204	247
RUN 13	nov-21	17.73	52	346	501	633	505	356	204	246

RUN #	HEAT PIPE AIR SIDE dP, IN W.C.	GAS SIDE dP, IN W.C.	FLUE GAS DUCT PRESS PSIA	AIR FLOW METER dP, IN W.C.	RECORDED AIR RATE LB/HR	RECORDED GAS RATE LB/HR	CORRECTED GAS RATE LB/HR	AVE CORR FLOW LB/HR	AIR AIR PR PSIA	MANUAL dP AVE IN W.C.
RUN 1	1.26	1.93	14.43	1.26	18,762	21,555	23,406		14.65	1.20
RUN 1			14.40	0.00	0	0	23,634		14.70	1.20
RUN 1	1.30	2.03	14.41	1.36	20,652	23,814	22,897		14.65	1.20
RUN 1	1.16	1.90	14.41	1.12	19,798	22,991	24,131	23,517	14.66	1.20
RUN 2			14.36	0.00	0	0	24,100		14.70	0.96
RUN 2	1.06	2.21	14.35	0.92	16,952	22,264	25,254		14.66	0.93
RUN 2	1.28	2.20	14.36	1.36	24,178	31,741	22,849		14.65	1.25
RUN 2	1.34	2.64	14.38	1.29	13,035	16,526	25,063		14.65	1.18
RUN 2	0.61	1.98	14.40	0.60	11,922	14,700	22,846	24,023	14.68	0.95
RUN 3	0.79	1.89	14.32	0.66	12,766	18,167	22,836		14.67	0.86
RUN 3			14.31	0.00	0	0	21,522		14.70	0.70
RUN 3	0.79	1.83	14.30	0.67	11,689	16,705	22,812		14.67	0.72
RUN 3	0.79	1.89	14.30	0.72	14,795	21,189	24,048		14.67	0.68
RUN 3	0.88	2.04	14.30	0.81	14,539	20,675	22,804		14.67	0.71
RUN 3	0.88	1.61	14.30	0.76	14,137	20,056	24,048	23,012	14.67	0.75
RUN 4	0.67	2.44	14.31	0.55	8,401	14,208	22,830		14.68	0.53
RUN 4	0.60	2.20	14.28	0.53	9,596	16,358	21,519		14.68	0.63
RUN 4	0.65	1.79	14.29	0.50	13,041	22,077	22,063		14.68	0.49
RUN 4	0.61	2.05	14.30	0.54	10,956	18,811	22,592		14.68	0.53
RUN 4	0.66	1.74	14.29	0.57	13,057	22,069	24,062		14.68	0.46
RUN 4	2.68	1.84	13.93	2.87	22,196	34,349	21,772		14.60	0.56
RUN 4	0.59	1.12	14.29	0.50	13,190	15,853	22,641	22,497	14.68	0.45
RUN 5	0.43	1.01	14.40	0.39	10,204	13,345	14,565		14.68	0.35
RUN 5	0.40	1.02	14.41	0.37	9,035	11,707	16,100		14.69	0.39
RUN 5	0.42	1.11	14.40	0.42	9,381	12,094	16,090		14.68	0.40
RUN 5	0.35	0.63	14.41	0.31	10,733	14,474	16,091	15,711	14.69	0.41
RUN 6	0.36	0.94	14.42	0.36	8,448	11,826	15,352		14.69	0.31
RUN 6	0.33	0.79	14.42	0.34	8,178	11,365	16,097		14.69	0.35
RUN 6	0.35	0.98	14.42	0.34	9,621	13,496	15,361		14.69	0.33
RUN 6	0.33	0.82	14.43	0.35	9,085	12,779	15,813		14.69	0.31
RUN 6	0.37	1.30	14.43	0.34	9,153	12,631	15,852		14.69	0.34
RUN 6	0.34	1.03	14.42	0.35	11,144	15,610	14,864		14.69	0.31
RUN 6	0.33	0.97	14.43	0.31	10,348	14,780	15,390		14.69	0.36
RUN 6	0.26	1.14	14.44	0.26	7,496	11,175	15,435	15,520	14.69	0.33
RUN 7	0.25	0.83	14.45	0.26	8,050	12,434	15,549		14.69	0.24
RUN 7	0.22	0.79	14.46	0.25	8,091	12,591	14,995		14.69	0.24
RUN 7	0.24	0.41	14.46	0.25	7,755	12,090	14,892		14.69	0.25
RUN 7	0.18	0.99	14.47	0.21	7,928	12,622	15,414		14.69	0.25
RUN 7	0.21	0.97	14.47	0.21	7,960	12,924	15,237	15,217	14.69	0.24
RUN 8	0.16	0.91	14.48	0.18	7,815	13,220	15,835		14.69	0.19
RUN 8	0.18	0.99	14.50	0.20	6,952	11,780	14,807		14.69	0.21
RUN 8	0.17	0.89	14.50	0.17	5,937	10,110	15,156		14.69	0.19
RUN 8	0.18	0.92	14.50	0.19	7,480	12,740	14,811		14.69	0.17
RUN 8	0.17	1.13	14.51	0.18	6,309	10,782	14,812	15,084	14.69	0.19
RUN 9	0.08	0.62	14.66	0.17	6,872	9,272	10,084		14.70	0.14
RUN 9	0.10	0.47	14.66	0.18	6,905	9,272	10,084		14.70	0.15
RUN 9	0.09	0.59	14.66	0.17	7,610	10,209	10,087		14.70	0.17
RUN 9	0.09	0.66	14.66	0.14	5,276	7,056	10,430		14.70	0.15
RUN 9	0.03	0.46	14.67	0.13	5,733	7,925	10,433	10,224	14.70	0.17
RUN 10	0.07	0.69	14.67	0.14	5,090	7,353	10,431		14.70	0.13
RUN 10	0.08	0.57	14.66	0.14	6,920	9,990	10,081		14.70	0.14
RUN 10	0.10	0.84	14.66	0.17	6,532	9,463	10,082		14.70	0.13
RUN 10	0.08	0.48	14.65	0.13	5,885	8,475	10,432		14.70	0.12
RUN 10	0.06	0.56	14.65	0.12	5,527	8,162	10,091	10,223	14.70	0.14
RUN 11	0.08	0.33	14.63	0.15	5,730	8,388	10,074		14.70	0.10
RUN 11	0.07	0.47	14.63	0.13	6,798	9,989	10,075		14.70	0.13
RUN 11	0.09	0.52	14.63	0.13	5,099	7,513	9,728		14.70	0.13
RUN 11	0.08	0.53	14.63	0.13	5,667	8,405	10,088		14.70	0.12
RUN 11	0.06	0.60	14.63	0.11	5,685	8,530	10,439	10,081	14.70	0.13
RUN 12	0.07	0.66	14.63	0.12	5,427	8,339	10,083		14.70	0.10
RUN 12	0.08	0.52	14.64	0.12	5,281	8,135	10,084		14.70	0.12
RUN 12	0.08	0.49	14.64	0.13	6,792	10,434	10,080		14.70	0.12
RUN 12	0.07	0.49	14.64	0.11	4,984	7,678	10,079		14.70	0.12
RUN 12	0.57	0.66	14.62	0.51	9,446	14,790	9,671	9,999	14.68	0.11
RUN 13	0.51	1.41	14.61	0.47	10,865	16,310	19,615		14.68	0.46
RUN 13	0.49	1.37	14.60	0.40	11,241	16,787	20,289		14.68	0.42
RUN 13	0.50	1.42	14.62	0.44	10,963	16,352	19,960		14.68	0.44
RUN 13	0.48	1.41	14.61	0.46	11,896	17,756	19,943		14.68	0.44
RUN 13	0.47	1.29	14.62	0.42	11,454	17,173	19,609	19,883	14.68	0.43

RUN #	CORR FLOW LB/HR	AVE CORR FLOW LB/HR	Xas	GAS EFF	AIR EFF	AVE Xas	AVE GAS EFF	AVE AIR EFF	FLUE GAS Cp BTU/MOL/F	FLUE GAS mCp BTU/F
RUN 1	18,345		0.806	0.525	0.651				7.77	6,118
RUN 1	18,366		0.796	0.524	0.658				7.77	6,178
RUN 1	18,341		0.801	0.524	0.654				7.77	5,985
RUN 1	18,335	18,347	0.797	0.523	0.656	0.800	0.524	0.655	7.77	6,308
RUN 2	16,174		0.705	0.492	0.697				7.78	6,309
RUN 2	15,913		0.705	0.492	0.698				7.78	6,611
RUN 2	18,448		0.710	0.491	0.691				7.78	5,981
RUN 2	18,012		0.730	0.499	0.684				7.77	6,558
RUN 2	16,169	16,943	0.712	0.507	0.712	0.712	0.496	0.696	7.78	5,980
RUN 3	15,249		0.650	0.482	0.741				7.78	5,980
RUN 3	13,810		0.647	0.480	0.742				7.78	5,636
RUN 3	13,922		0.648	0.481	0.743				7.78	5,974
RUN 3	13,520		0.647	0.480	0.742				7.78	6,299
RUN 3	13,858		0.651	0.481	0.739				7.78	5,973
RUN 3	14,236	14,099	0.653	0.482	0.738	0.649	0.481	0.741	7.78	6,299
RUN 4	11,734		0.548	0.432	0.790				7.80	5,992
RUN 4	12,817		0.541	0.430	0.795				7.80	5,647
RUN 4	11,333		0.547	0.433	0.792				7.80	5,789
RUN 4	11,820		0.540	0.429	0.795				7.80	5,928
RUN 4	10,953		0.547	0.433	0.791				7.80	6,314
RUN 4	12,160		0.612	0.453	0.740				7.79	5,708
RUN 4	11,351	11,738	0.769	0.536	0.697	0.586	0.450	0.771	7.75	5,910
RUN 5	9,999		0.708	0.521	0.737				7.75	3,801
RUN 5	10,543		0.715	0.524	0.733				7.75	4,202
RUN 5	10,649		0.718	0.525	0.732				7.75	4,199
RUN 5	10,791	10,496	0.685	0.511	0.746	0.706	0.520	0.737	7.76	4,202
RUN 6	9,292		0.660	0.501	0.759				7.76	4,011
RUN 6	9,950		0.664	0.504	0.759				7.76	4,205
RUN 6	9,605		0.659	0.501	0.760				7.76	4,012
RUN 6	9,280		0.658	0.500	0.760				7.76	4,130
RUN 6	9,794		0.668	0.507	0.759				7.76	4,139
RUN 6	9,366		0.661	0.503	0.760				7.76	3,882
RUN 6	10,064		0.648	0.494	0.762				7.76	4,021
RUN 6	9,457	9,601	0.621	0.479	0.772	0.655	0.499	0.761	7.77	4,035
RUN 7	8,081		0.599	0.472	0.787				7.77	4,065
RUN 7	8,018		0.595	0.469	0.788				7.77	3,920
RUN 7	8,209		0.593	0.466	0.787				7.77	3,894
RUN 7	8,207		0.581	0.460	0.791				7.77	4,032
RUN 7	8,013	8,106	0.569	0.452	0.795	0.587	0.464	0.790	7.78	3,988
RUN 8	7,208		0.546	0.441	0.808				7.78	4,147
RUN 8	7,443		0.545	0.441	0.808				7.78	3,878
RUN 8	7,058		0.543	0.440	0.809				7.78	3,969
RUN 8	6,795		0.542	0.439	0.810				7.78	3,879
RUN 8	7,036	7,108	0.542	0.439	0.810	0.544	0.440	0.809	7.78	3,880
RUN 9	6,385		0.685	0.528	0.770				7.74	2,628
RUN 9	6,650		0.689	0.530	0.769				7.74	2,628
RUN 9	6,976		0.691	0.531	0.769				7.74	2,629
RUN 9	6,549		0.692	0.531	0.768				7.74	2,719
RUN 9	6,907	6,694	0.666	0.515	0.774	0.685	0.527	0.770	7.75	2,721
RUN 10	5,946		0.641	0.505	0.789				7.75	2,722
RUN 10	6,217		0.640	0.505	0.789				7.75	2,631
RUN 10	5,965		0.641	0.505	0.789				7.75	2,631
RUN 10	5,920		0.642	0.506	0.789				7.75	2,722
RUN 10	6,148	6,039	0.627	0.496	0.790	0.638	0.504	0.789	7.75	2,634
RUN 11	5,293		0.631	0.500	0.793				7.76	2,630
RUN 11	6,123		0.630	0.500	0.793				7.76	2,631
RUN 11	5,907		0.628	0.498	0.794				7.76	2,540
RUN 11	5,812		0.624	0.496	0.794				7.76	2,633
RUN 11	5,915	5,810	0.617	0.488	0.791	0.626	0.496	0.793	7.76	2,726
RUN 12	5,301		0.602	0.479	0.796				7.76	2,634
RUN 12	5,641		0.601	0.479	0.798				7.76	2,635
RUN 12	5,701		0.601	0.480	0.798				7.76	2,634
RUN 12	5,782		0.600	0.480	0.799				7.76	2,634
RUN 12	5,471	5,579	0.594	0.467	0.787	0.600	0.477	0.796	7.78	2,532
RUN 13	11,171		0.617	0.477	0.774				7.78	5,137
RUN 13	10,696		0.620	0.479	0.772				7.78	5,314
RUN 13	10,876		0.619	0.478	0.771				7.78	5,227
RUN 13	10,908		0.621	0.479	0.771				7.78	5,224
RUN 13	10,818	10,894	0.617	0.477	0.773	0.619	0.478	0.772	7.78	5,136

RUN #	AIR Cp BTU/MOL/F	AIR mCp BTU/F
RUN 1	7.05	4,467
RUN 1	7.06	4,473
RUN 1	7.05	4,467
RUN 1	7.06	4,465
RUN 2	7.07	3,945
RUN 2	7.07	3,881
RUN 2	7.06	4,498
RUN 2	7.06	4,391
RUN 2	7.07	3,946
RUN 3	7.08	3,724
RUN 3	7.08	3,373
RUN 3	7.08	3,401
RUN 3	7.08	3,302
RUN 3	7.08	3,385
RUN 3	7.08	3,477
RUN 4	7.09	2,870
RUN 4	7.09	3,135
RUN 4	7.09	2,772
RUN 4	7.09	2,891
RUN 4	7.09	2,679
RUN 4	7.07	2,969
RUN 4	7.06	2,768
RUN 5	7.07	2,439
RUN 5	7.07	2,572
RUN 5	7.07	2,597
RUN 5	7.07	2,633
RUN 6	7.07	2,268
RUN 6	7.07	2,429
RUN 6	7.07	2,344
RUN 6	7.07	2,265
RUN 6	7.07	2,390
RUN 6	7.07	2,286
RUN 6	7.07	2,457
RUN 6	7.07	2,309
RUN 7	7.08	1,974
RUN 7	7.08	1,958
RUN 7	7.07	2,005
RUN 7	7.08	2,005
RUN 7	7.08	1,958
RUN 8	7.08	1,762
RUN 8	7.08	1,819
RUN 8	7.08	1,725
RUN 8	7.08	1,661
RUN 8	7.08	1,720
RUN 9	7.07	1,558
RUN 9	7.07	1,623
RUN 9	7.07	1,703
RUN 9	7.07	1,599
RUN 9	7.07	1,686
RUN 10	7.08	1,452
RUN 10	7.08	1,519
RUN 10	7.08	1,457
RUN 10	7.08	1,446
RUN 10	7.08	1,502
RUN 11	7.08	1,294
RUN 11	7.08	1,497
RUN 11	7.08	1,444
RUN 11	7.08	1,420
RUN 11	7.08	1,445
RUN 12	7.08	1,296
RUN 12	7.08	1,379
RUN 12	7.08	1,394
RUN 12	7.08	1,413
RUN 12	7.08	1,337
RUN 13	7.08	2,731
RUN 13	7.08	2,615
RUN 13	7.08	2,659
RUN 13	7.08	2,667
RUN 13	7.08	2,644