Second-Generation PFBC Systems R&D - Phase2 and 3

Annual Technical Report

Report Period: Start Date:10/01/1997 End Date: 09/30/1998

Author: A. Robertson

Report Date:11/20/1998

DE-AC21-86MC21023--66

Foster Wheeler Development Corp.
12 Peach Tree Hill Road
Livingston, NJ 07039

PRESSURIZED FLUDIZED BED COMBUSTION

SECOND-GENERATION SYSTEM RESEARCH AND DEVELOPMENT

TECHNICAL PROGRESS FOR PHASE 2
OCTOBER 1, 1997 THROUGH SEPTEMBER 1998

By:

A. Robertson	Foster Wheeler Development Corporation
D. Horazak	Siemens Westinghouse Power Corp.
R. Newby	Siemens Westinghouse Science & Technology Center
A. Rehmat	Institute of Gas Technology
J. White	Parsons Power/Gilbert-Commonwealth, Inc.

October 1998

Work Performed Under Contract: DE-AC21-86MC21023

For:

U.S. Department of Energy
Office of Fossil Energy
Federal Energy Technology Center
Morgantown, West Virginia

By:

Foster Wheeler Development Corporation
Livingston, New Jersey

TECHNICAL PROGRESS REPORT NUMBER 21023R20
FOR OCTOBER 1, 1997 THROUGH SEPTEMBER 1998

When DOE funds were exhausted in March 1995, all Phase 2 activities were placed on hold. In February 1996 a detailed cost estimate was submitted to the DOE for completing the two remaining Phase 2 Multi Annular Swirl Burner (MASB) topping combustor test burns; in August 1996 release was received from METC to proceed with these tests. The first test (Test Campaign No. 3) will be conducted to:

1. test the MASB at proposed demonstration plant full to minimum load operating conditions

2. identify the lower oxygen limit of the MASB

3. demonstrate natural gas to carbonizer fuel gas switching.

The 18 in. MASB was last tested in a high-oxygen configuration and must be redesigned/ modified for low oxygen operation. A second-generation PFB combustion plant incorporating an MASB based topping combustor will be constructed at the City of Lakeland's McIntosh Power Plant under the U.S. DOE Clean Coal V Demonstration Plant Program. This plant will require the MASB to operate at oxygen levels that are lower than those previously tested. Lakeland calculations aimed at defining the operating envelope of the demonstration plant MASB have been delayed pending finalization of the plant configuration (Greenfield vs. repowering) and gas turbine selection. Once this operating envelope is defined, the redesign, modification, and testing of the MASB will begin.

PRESSURIZED FLUIDIZED BED COMBUSTION

SECOND-GENERATION SYSTEM RESEARCH AND DEVELOPMENT

TECHNICAL PROGRESS FOR PHASE 3
OCTOBER 1, 1997 THROUGH SEPTEMBER 1998

By

A. Robertson	Foster Wheeler Development Corporation
D. Horazak	Siemens Westinghouse Power Corp.
R. Newby	Siemens Westinghouse Science & Technology Center
A. Rehmat	Institute of Gas Technology
J. White	Parsons Power/Gilbert-Commonwealth, Inc.

October 1998

Work Performed Under Contract: DE-AC21-86MC21023

For

U.S. Department of Energy
Office of Fossil Energy
Federal Energy Technology Center
Morgantown, West Virginia

By

Foster Wheeler Development Corporation
Livingston, New Jersey

TECHNICAL PROGRESS REPORT NUMBER 21023R21
FOR OCTOBER 1997 THROUGH SEPTEMBER 1998

Lakeland Carbonizer Test Run

The Livingston Phase 3 Pilot Plant was last operated under this contract (DE-AC21-86MC21023) in September 1995 for seven days in an integrated carbonizer-CPFBC configuration. In May, 1996, the pilot plant was transferred to Contract DE-AC22-95PC95143 to allow testing in support of the High Performance Power Systems (HIPPS) Program. The HIPPS Program required modifications to the pilot plant and the following changes were incorporated:

- Installation of a dense phase transport system for loading pulverized coal into the feed system lock hopper directly from a pneumatic transport truck.
- Removal of the char transfer pipe between the char collecting hopper and the CPFBC to allow carbonizer only operation.
- Installation of a lock hopper directly under the char collecting hopper to facilitate char removal from the process. The hopper vent gases exhaust to the carbonizer baghouse filter and the depressured char is transferred via nitrogen to the CPFBC baghouse for dumping into drums.
- Removal of the carbonizer cyclone and top of bed overflow drain line; all material elutriated from the carbonizer bed will thus be removed by the 22-element Westinghouse ceramic candle filter.
- Replacement of the carbonizer continuous bottom bed drain (screw feeder) with a batch-type drain removal system.
- Installation of a mass spectrometer that draws sample gas via a steam jacketed line from the refractory lined piping downstream of the candle filter.

In November 1997, the HIPPS program was interrupted to allow further testing under Contract DE-AC21-86MC21023. These tests were aimed at determining carbonizer operating characteristics with the Kentucky #9 coal and Florida limestone proposed for the Lakeland Clean Coal V Demonstration Plant. To conduct these tests the cyclone was reinstalled and its drain line brought to the char collecting hopper via the same piping arrangement used in Phase 3. The number of candles in the filter was reduced to 10 to allow operation with the same 5 feet per minute face velocity proposed for the Lakeland Clean Coal V carbonizer. Supplies of the 1.4% sulfur, highly caking, Kentucky coal and Florida limestone also proposed for Lakeland were obtained and the pilot plant was readied for operation at the Lakeland 1760^{o}F design point.

Test Run TR06

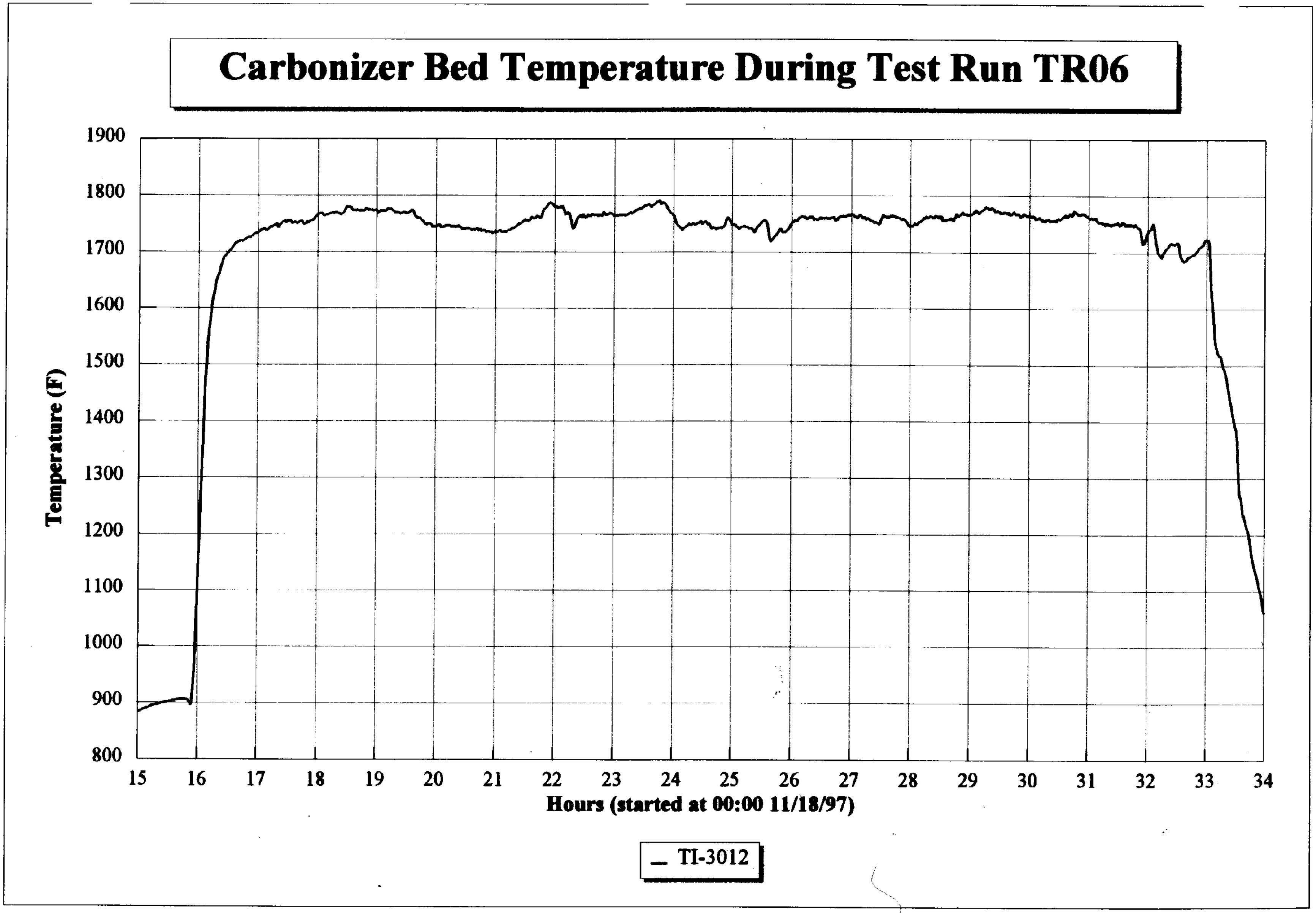
At about 16:00 hours on November 18, 1997, the carbonizer was ignited with coke and ramped to approximately 1760°F. After about 3 hours of operation, we began loading Kentucky coal into the feed system. The unit transitioned from coke to coal feed and, although it ran smoothly for the next 14 hours, as evidenced by the Figure 1 temperature plot, we eventually became unable to drain material from the unit. Since our experience from Phase 2 indicated this to be a precursor of a temperature upset that would eventually be caused by inadequate fluidization/ mixing at the feed point, we shut down the unit at about 09:00 hours on November 19th as a preemptive step after roughly 17 hours of operation. A post run inspection revealed the bottom 3 feet of the unit (10-inch diameter section) was filled with a solid agglomerate containing about a ¾ inch diameter rat hole that allowed coal, sorbent, and air to continue to be injected into the bed. In addition, the tip of the lowermost thermowell was found to have melted during the run.

The inability to drain material from the carbonizer occurred twice in Phase 2 when we searched to identify possible process operating limits. The first instance occurred when we reduced the bed temperature from 1600 to 1500°F with a highly caking coal and the second when we reduced the sorbent mass feed rate to about 0.1 pounds of sorbent per pound of highly caking coal at 1600°F. Later we demonstrated successful operation with the latter by raising the bed temperature to 1700°F and increasing the fluidized velocity from 3 to 3.3 ft/sec. Since the carbonizer was operating at about 1750°F and a 4 ft/sec velocity throughout the run, well above the latter, an analysis was begun to determine the cause of the problem.

Figure 2 plots the carbonizer's in-bed thermocouples. It is observed that the lowermost thermocouple (TI-3021 located 15½ inches above the top of the feed pipe) went off scale/burned out approximately 4 hours after we began loading coal into the system.

Figures 3 and 4 expand this time period and plot the air flow (FI-1055) to the unit along with the weight of the fuel (WI-2046) and sorbent (WI-1043) feed systems. The fuel and sorbent feed rates are determined by the loss of weight of their respective feed vessels and the figure shows all flows to the unit were stable prior to and following the loss of thermocouple TI 3021. Noting the unit is started up with coke, the minimum weight of the fuel feed system at 19:00 hours reflects our attempt to use up as much of the coke as possible; at this point in time, the increase in weight reflects our loading the highly caking Kentucky coal into the feed vessel. The thermocouple loss is noted to occur about 4 hours later.

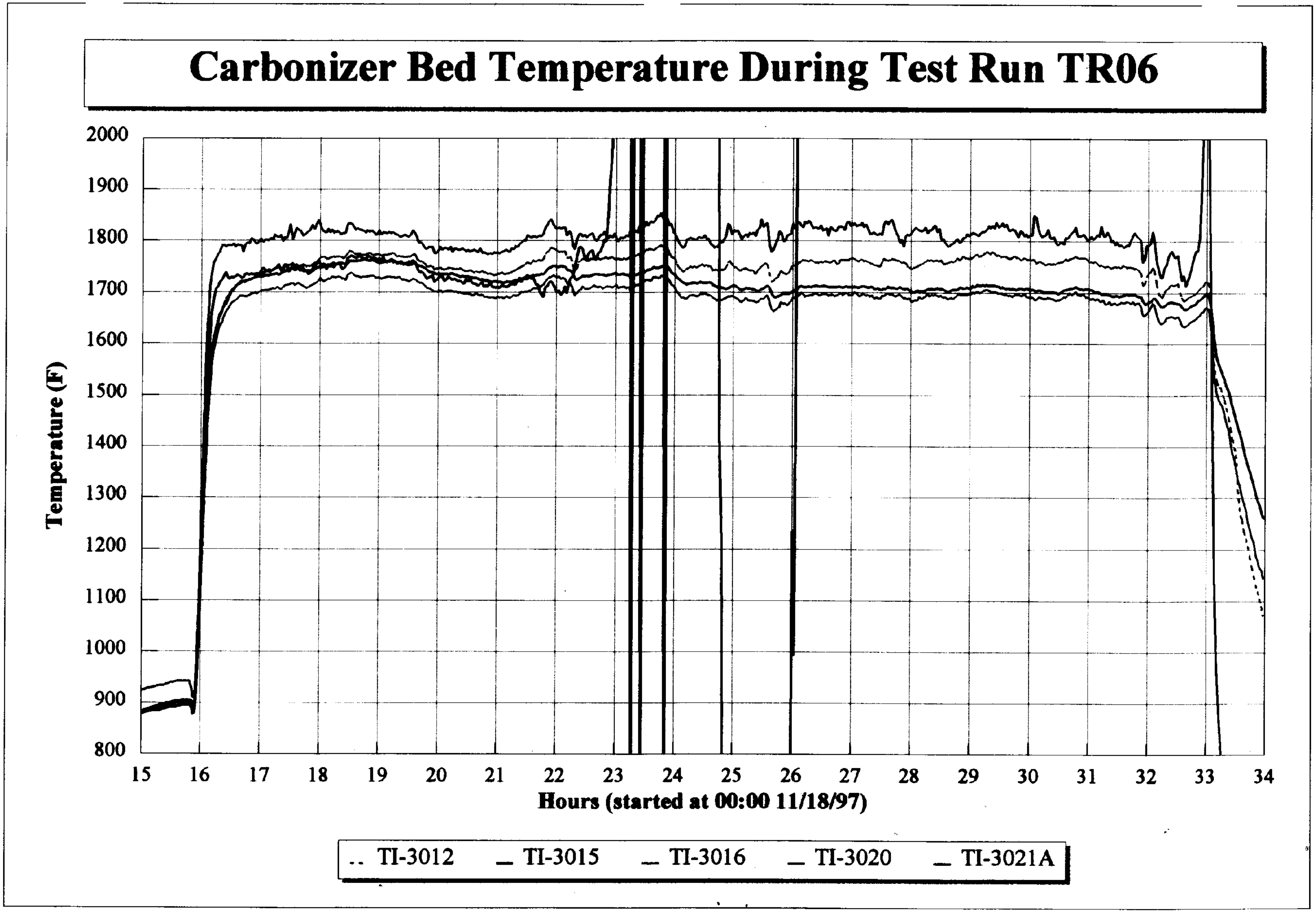
Figure 5 plots the nitrogen flow (FI-3028) to the bottom of the bed drain boot/cooling section along with the weight of the material being drained (WI-8071) from the unit in batches (material dumps into a drum setting on a platform scale –



Lu C:\Lakeland\9712Report\PLOTS.WK4

Figure 1

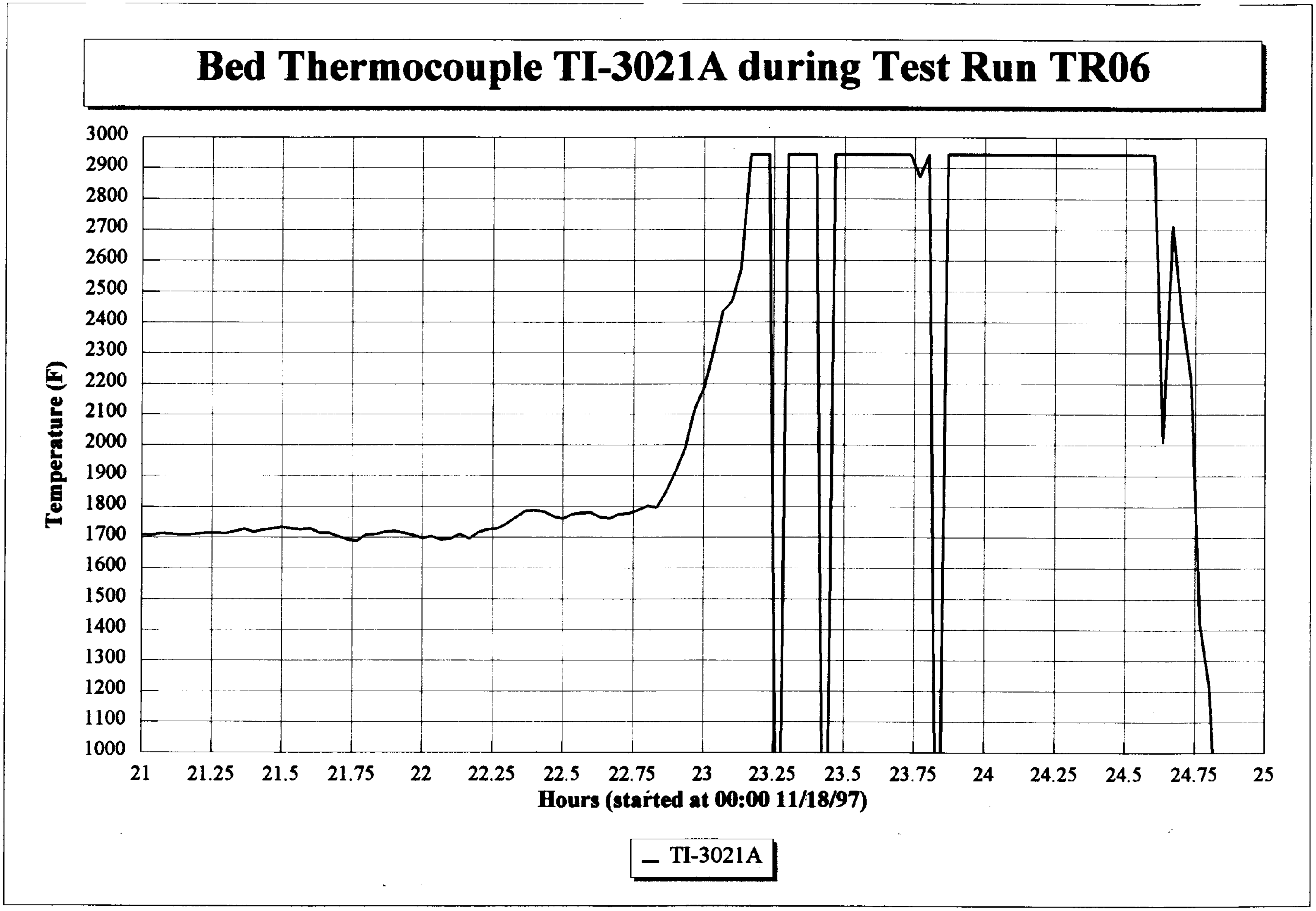
12:00 PM 12/23/97



Lu C:\Lakeland\9712Report\PLOTS.WK4

Figure 2

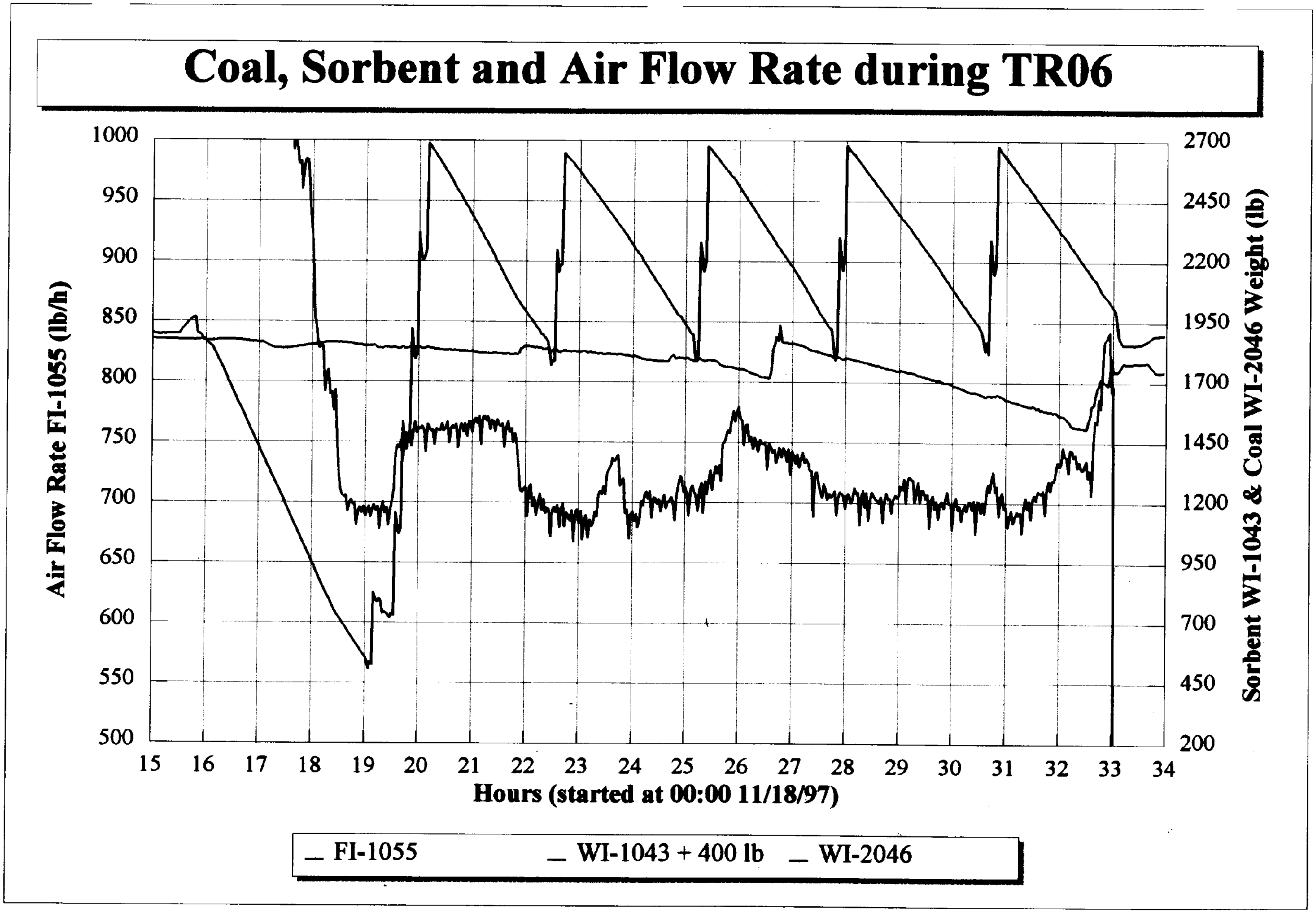
08:20 AM 12/24/97



Lu C:\Lakeland\9712Report\PLOTS.WK4

Figure 3

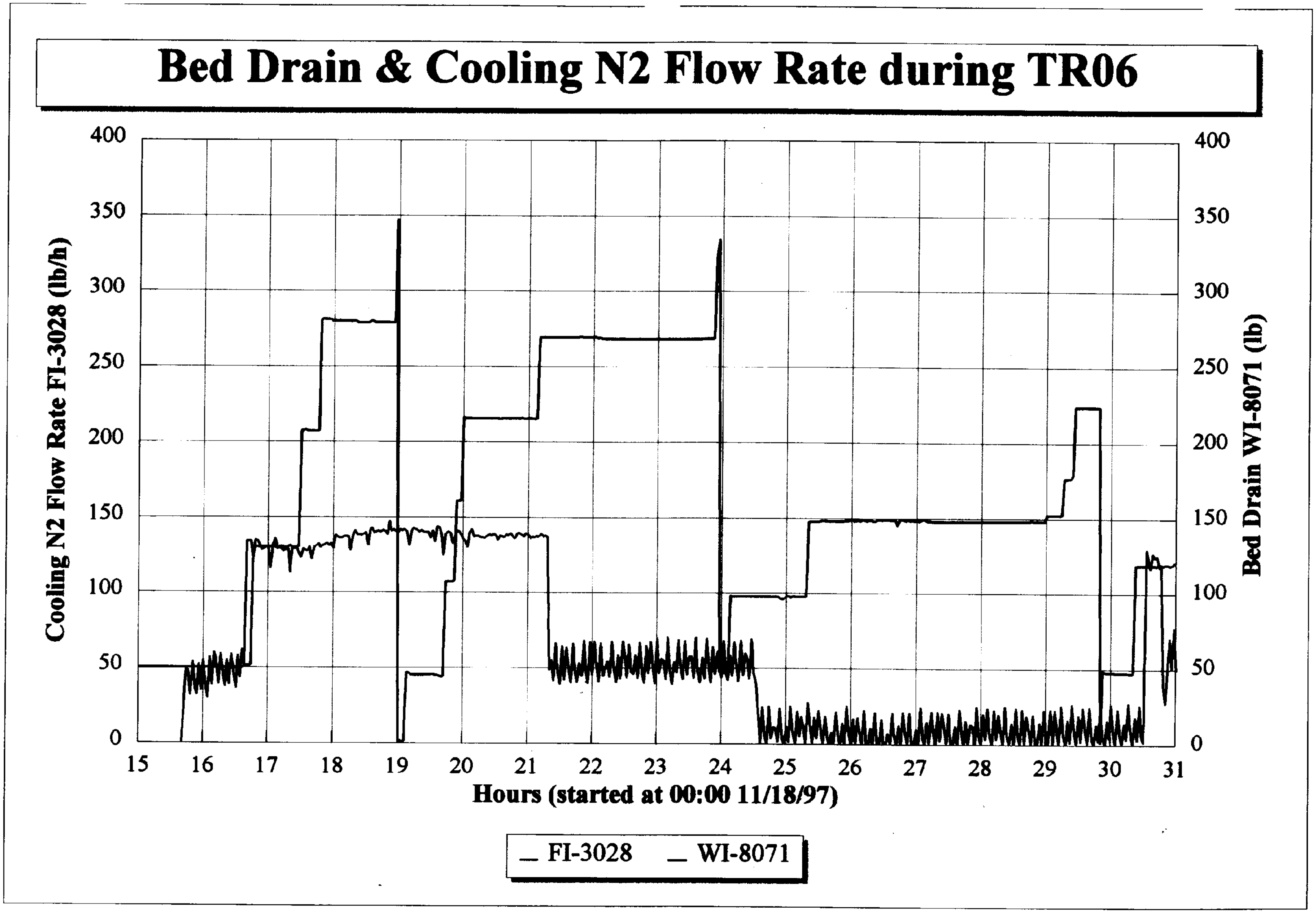
12:01 PM 12/23/97



Lu C:\Lakeland\9712Report\PLOTS.WK4

Figure 4

08:32 AM 12/24/97



Lu C:\Lakeland\9712Report\PLOTS.WK4

Figure 5

12:02 PM 12/23/97

the loss in weight reflects the emptying of the drum by our operators). The amount of material drained from the unit after the loss of thermocouple TI-3021 is the amount we estimate was contained in the drain cooler boot. As a result, we conclude the ability to drain material from the bed was lost at about the same time the thermocouple was lost.

The nitrogen injected into the drain cooler boot rises up and flows through the 1-7/8 inch wide drain annulus surrounding the central feed pipe. In Phase 2, this nitrogen flow yielded a 1.5 to 2 ft/s fluidizing velocity around the feed pipe. In this run, however, the nitrogen flow started at this value but then was purposely reduced in steps to a minimum (Figure 5). The first step reduction occurred about 2 hours after the start of coal feed and was in effect when thermocouple TI-3021 burned out. We were in this reduced flow condition to conserve nitrogen because a period of unusually high nitrogen usage during the night had drawn down our nitrogen tank level, and we were awaiting a truck delivery.

Based on the above, we believe the loss of drain ability/formation of the agglomerate was caused by inadequate fluidization around the feed pipe. Although we cannot tell what minimum value is acceptable, since the 1.5 ft/sec Phase 2 value has yielded successful operation in the past, we will use it in future runs and are adding this velocity to the control room operating screens.

During the 17 hours of operation, the 10-element candle filter system operated without any problems, even though we did lose the N_2 booster compressor for several hours and had to pulse clean with low pressure (350 psig) nitrogen. Figure 6 presents filter performance data for the last 8 hours of operation with coal. The filter pulse tank pressures (PI-3604 and 3605) were set at about 550 psig, 400 psi above process pressure (carbonizer freeboard PI-3007). PI-3638 is the pressure differential across the tube sheet and the trigger pulse cleaning pressure differential PDI-3005 (inlet to outlet nozzle) set at about 90" H_2O. The filter pulse cleaned at about 10 minute intervals, and the oscillations in thermocouple TI-3109, located in the filter drain nozzle, reflect the passage of the filter cake blown off during pulse cleaning. Recognizing that the operating period was short, there appeared to be little change in the filter after-cleaning pressure drop. Post run inspections with the laboratory remote camera (boroscope) revealed all candles to be in place with no signs of bridging being visible.

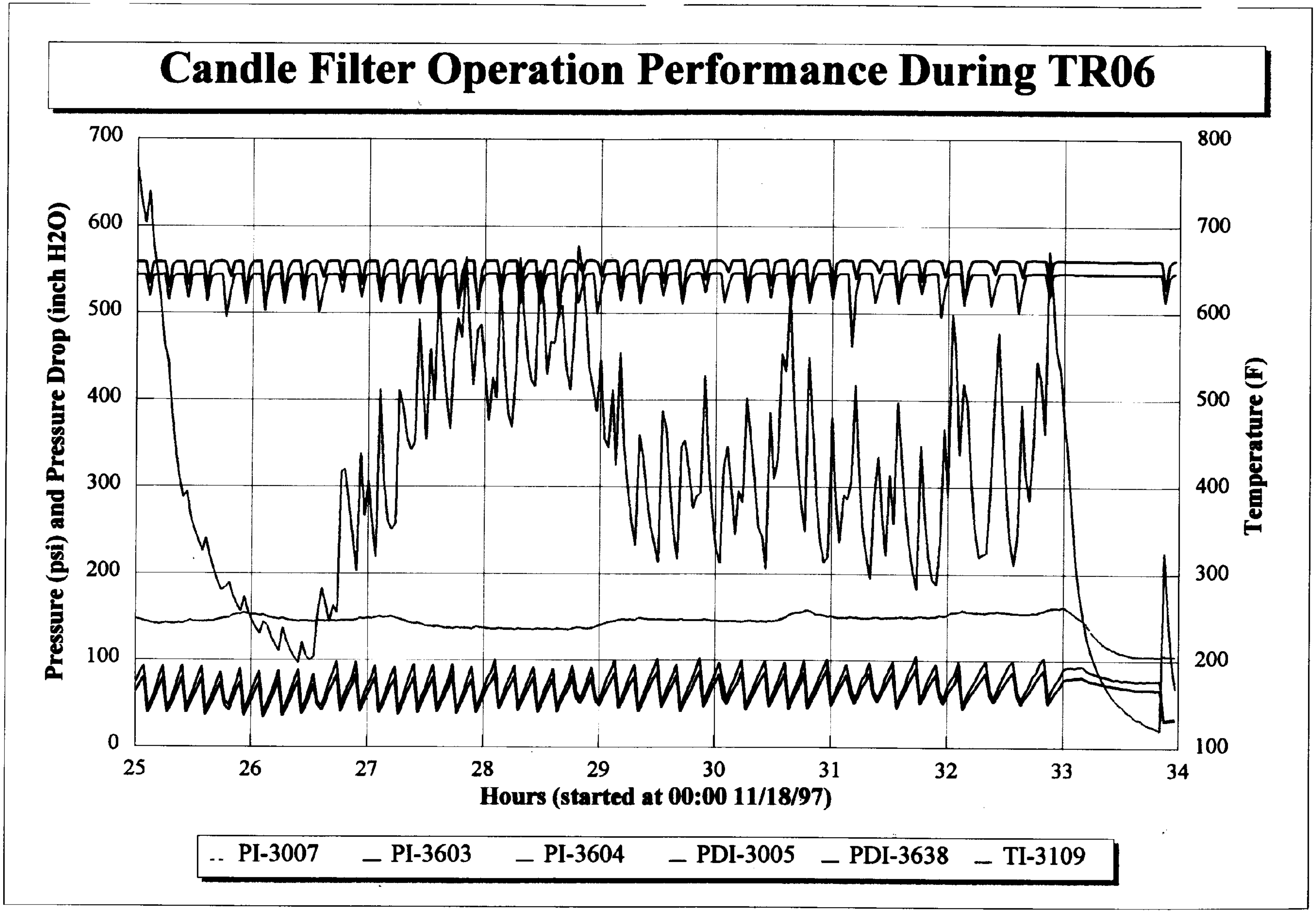


Figure 6

Lu C:\Lakeland\9712Report\PLOTS.WK4

12:04 PM 12/23/97

Test Run TR07

On December 9, 1997 we attempted another carbonizer run, but this time the annulus fluidizing velocity was set at a minimum value of 1.5 ft/sec and the sorbent-to-coal mass feed ratio was set at 0.16 lb per lb. Because of the relatively low sulfur content of the coal and the use of limestone, this equated to a calcium-to-sulfur molar feed ratio of 3.5. To maximize the sorbent content of the bed, without further increasing the calcium-to-sulfur molar feed ratio, the sorbent was double screened to a 6 x 50 mesh size to remove the fines from the feed that were expected to be immediately blown out of the bed.

The carbonizer was ignited at 00:15 hours on Wednesday, December 10, 1997 (Test Run TR07), and the unit ran smoothly for approximately 19 hours until a high baghouse back pressure forced us to shut down. The high back pressure was caused by a gradual plugging of the two flame arrestors located downstream of the baghouse; they are located at the inlet of the incinerator used to burn the carbonizer generated fuel gas. A post run inspection of the two flame arrestors revealed that their fine gas passages were becoming blocked by particulate matter escaping through the baghouse filter. The fact that particulate were reaching the baghouse was of concern. The fuel gas generated by the carbonizer and the gases vented from both the bed drain and the char collecting lock hoppers (the latter collects the drains from the cyclone and the candle filter) all exhaust to the baghouse. Each of the gas streams, however, must first pass through dust filtering candles before reaching the baghouse. The lock hopper vent gases are cleaned by porous metal filters whereas the carbonizer gas is cleaned by the Westinghouse ceramic candle filter. Post-run inspections of the porous metal filters and the Westinghouse candle filter, the latter by remote camera, revealed no obvious problems/breaks. Although the candle filter was not disassembled to permit a detailed inspection (testing funds had been exhausted), it is suspected a dust seal(s) developed a leak when the pressure drop across the filter grew to about 8 psi during the one hour the filter was not pulse cleaned.

With agglomeration having caused the termination of the previous carbonizer run, each batch of material drained from the bottom of the carbonizer bed was screened for oversize material as soon as it was removed from the process. About 5 hours after transitioning to coal, pieces of a deposit were drained from the unit which, when assembled (see Figure 7), formed a doughnut shape. The inside diameter of the doughnut matched the feed pipe outside diameter, and this is the first time a deposit of this shape has been observed in the entire carbonizer development program. Figure 8 shows a sample of the balance of the oversize material found in the drains. Unlike the doughnut, they could be easily broken by hand and are considered acceptable. A total of 1.9 pounds of this oversize material was generated from the 2,500 pounds of high caking coal fed to the unit – again, a value that is deemed acceptable.

Figure 9 plots the carbonizer bed temperature (TI-3012) during the run which was conducted for the most part with about a 160 psig freeboard pressure. The 50^{o}F temperature spike at hour 30 occurs at the transition between start up coke and coal and

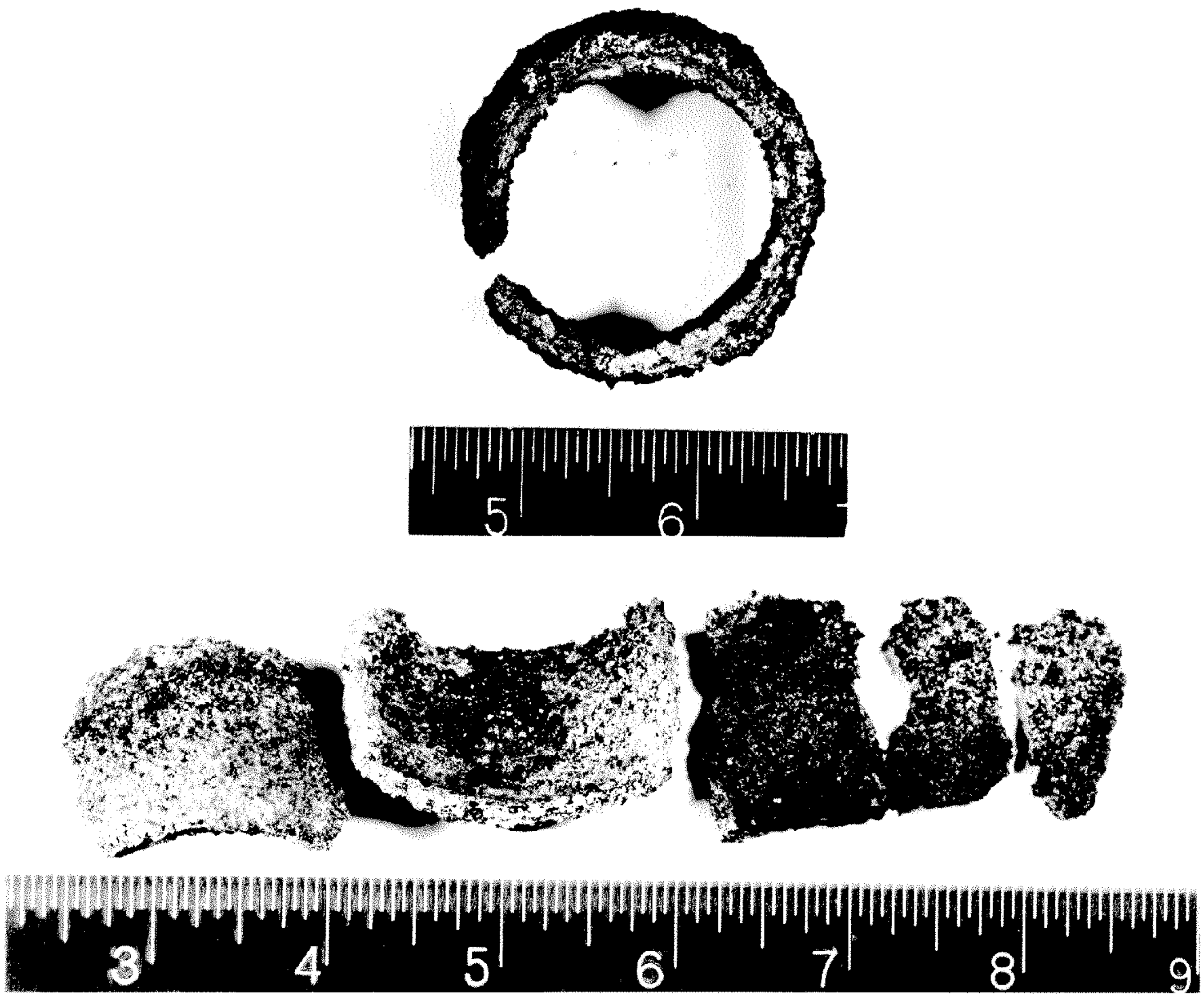


Figure 7 Doughnut Shaped Deposit Found in Carbonizer Test Run TR07

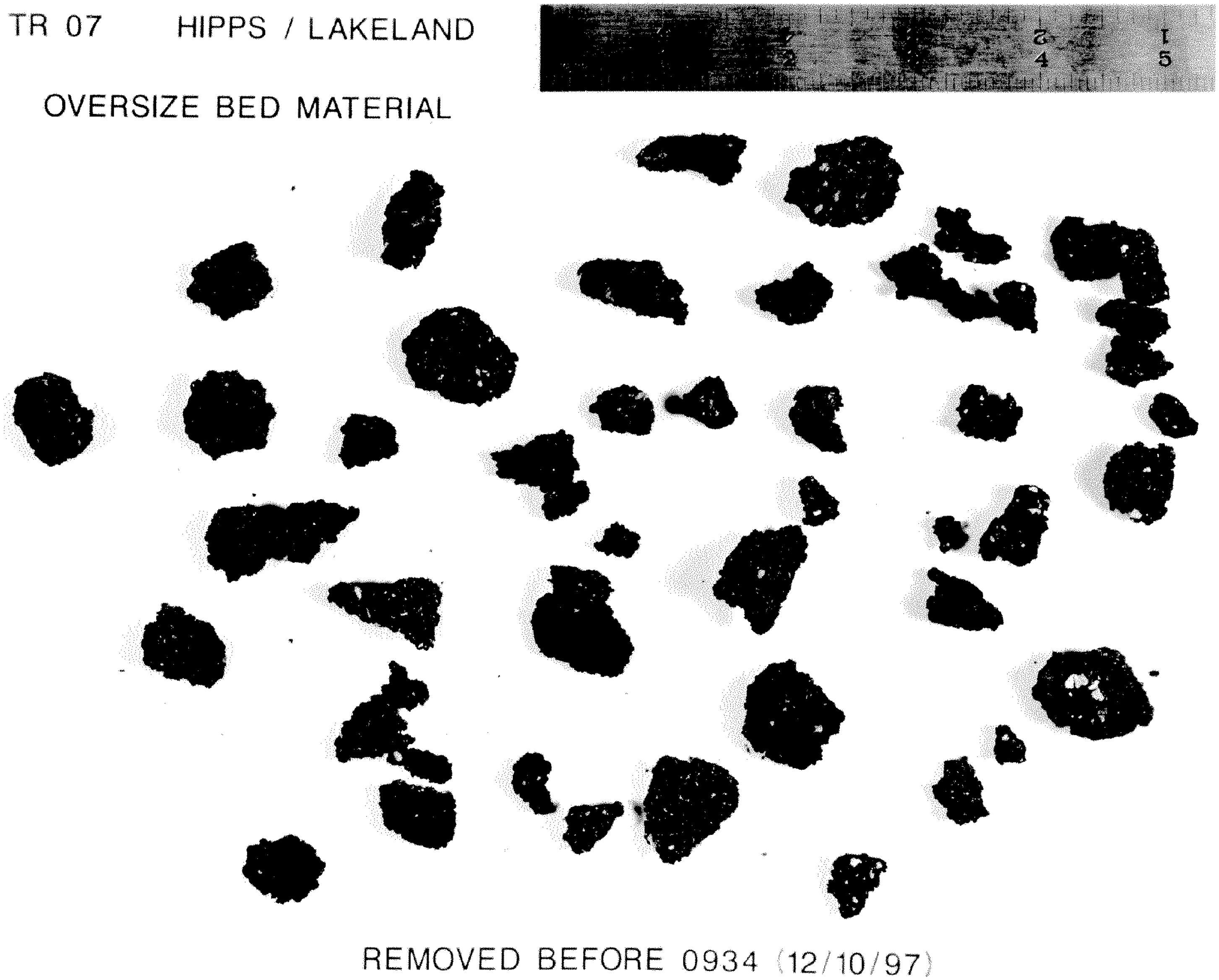


Figure 8 Typical Oversize Bed Drain Material from Carbonizer Test Run TR07

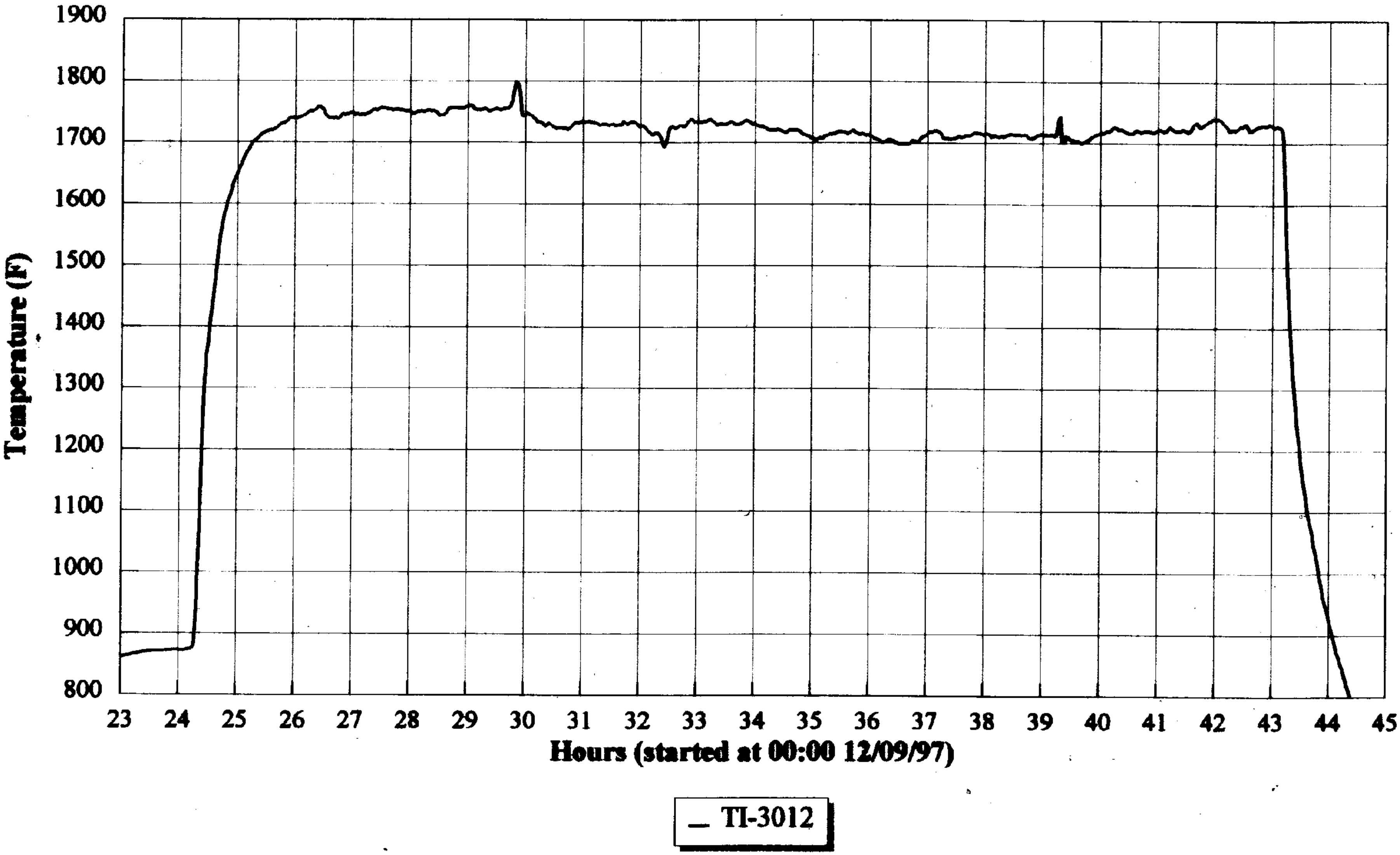


Figure 9 Carbonizer Bed Temperature During Test Run TR07

is the result of an increase in the temperature of the air entering the carbonizer (air heater was turned on to raise the inlet temperature from approximately 165°F to 635°F). The spike near hour 39 represents an upset caused by the injection of steam into the inlet of the candle filter. Figure 10 identifies gas temperatures at several plant locations as follows: TI-3012 – carbonizer bed, TI-3003 – carbonizer gas outlet, TI-3049 – cyclone gas outlet/candle filter inlet, TI-3001 – candle filter gas outlet, and TI-3108 – inlet to choked flow orifice. From Figure 10 it is seen the candle filter operated with about a 1450^{o}F inlet temperature and about a 300^{o}F inlet to outlet temperature drop during most of the run. The temperatures at different bed elevations are shown in Figure 11 (see Figure 12 for thermocouple locations) and, aside from the thermocouple closest to the feed pipe, there is generally about a 50^oF bottom to top difference in the unit. Figure 13 plots the weight of the coal (WI-2046) and limestone (WI-1043) feed systems and the carbonizer air flow rates (FI-1055). The minimum in the weight of the coal feed system at hour 30 marks our attempt to use up as much of the start up coke as practical before loading coal into the feed lock hopper; this minimizes the amount of time both fuels are in the feed system and expedites stabilizing the system with coal for test purposes. The coal was loaded at about 06:00 hours on December 10, 1997, and the fuel transition occurs shortly thereafter. Figure 14 plots the pressure differentials along the bed height (see Figure 15 for locations) and shows the change in bed density with type of fuel fed. In the time period from hour 24 to 27, the unit transitions from a limestone to a coke-limestone bed and from hour 30 to hour 34 to a coal-limestone bed. As seen from these plots, it takes about 3 to 4 hours for the bed density to transition to steady state values.

Figure 16 plots typical candle filter data, and it is seen that with the carbonizer operating at about 160 psig (PI-3007), the candle filter pulse tank pressures (PI-3603 and 3604) operated about 500 psi higher. PDI 3638 and 3005 are the pressure differentials across the filter tube sheet and gas inlet to outlet nozzle respectively. TI-3109 is located in the filter ash drain line and responds to the temperature of the ash cake blown off the candles during pulse cleaning. For clarity, Figure 17 is a blow-up of a three-hour time period and shows the typical rise and fall of the filter pressure differentials. With the trigger pressure set at about 40 inches H_2O, the filter pulse cleaning frequency was 9 times per hour. Aside from relatively frequent pulse cleaning, which will be slowed in the next run by raising the trigger pressure, the filter behaved normally. A computer program automatically pulse cleans the candle filter. Samples of carbonizer gas are extracted downstream of the filter for mass spectrometer analysis. Starting at hour 38, the pulse cleaning program was turned off to allow gas samples to be taken without distortion from the nitrogen pulse gas. During the one-hour period it was turned off, the filter pressure drop rose to about 210 inches of H_2O (see Figures 18 and 19). Upon reactivation the cleaning trigger pressure was raised to about 60 inches H_2O and the pulse pressure reduced by about 50 psi. The higher trigger pressure reduced the cleaning frequency to 7 per hour, and operation proceeded normally, albeit with a slightly higher post cleaning/baseline pressure.

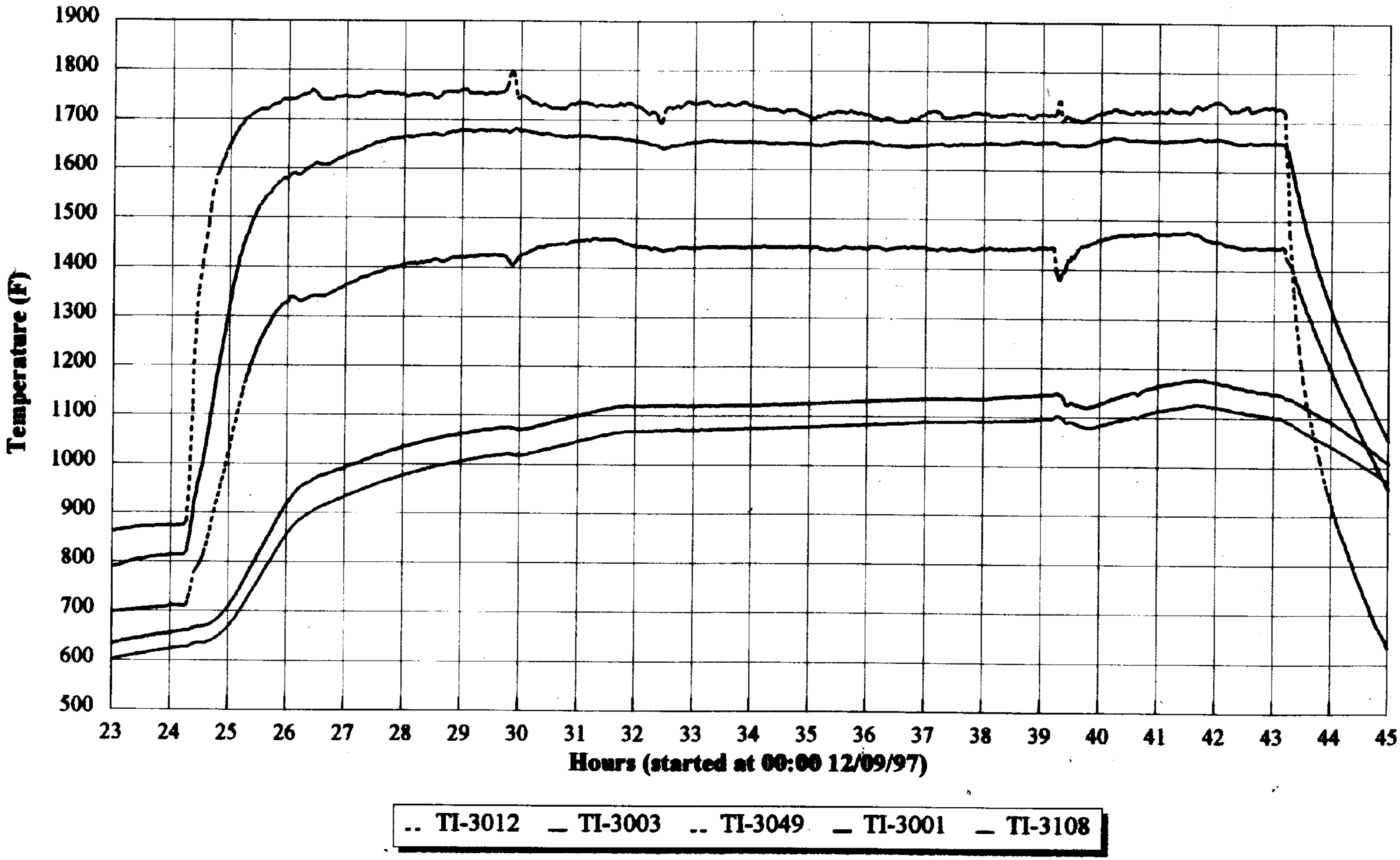


Figure 10 Plant Gas Temperatures During Test Run TR07

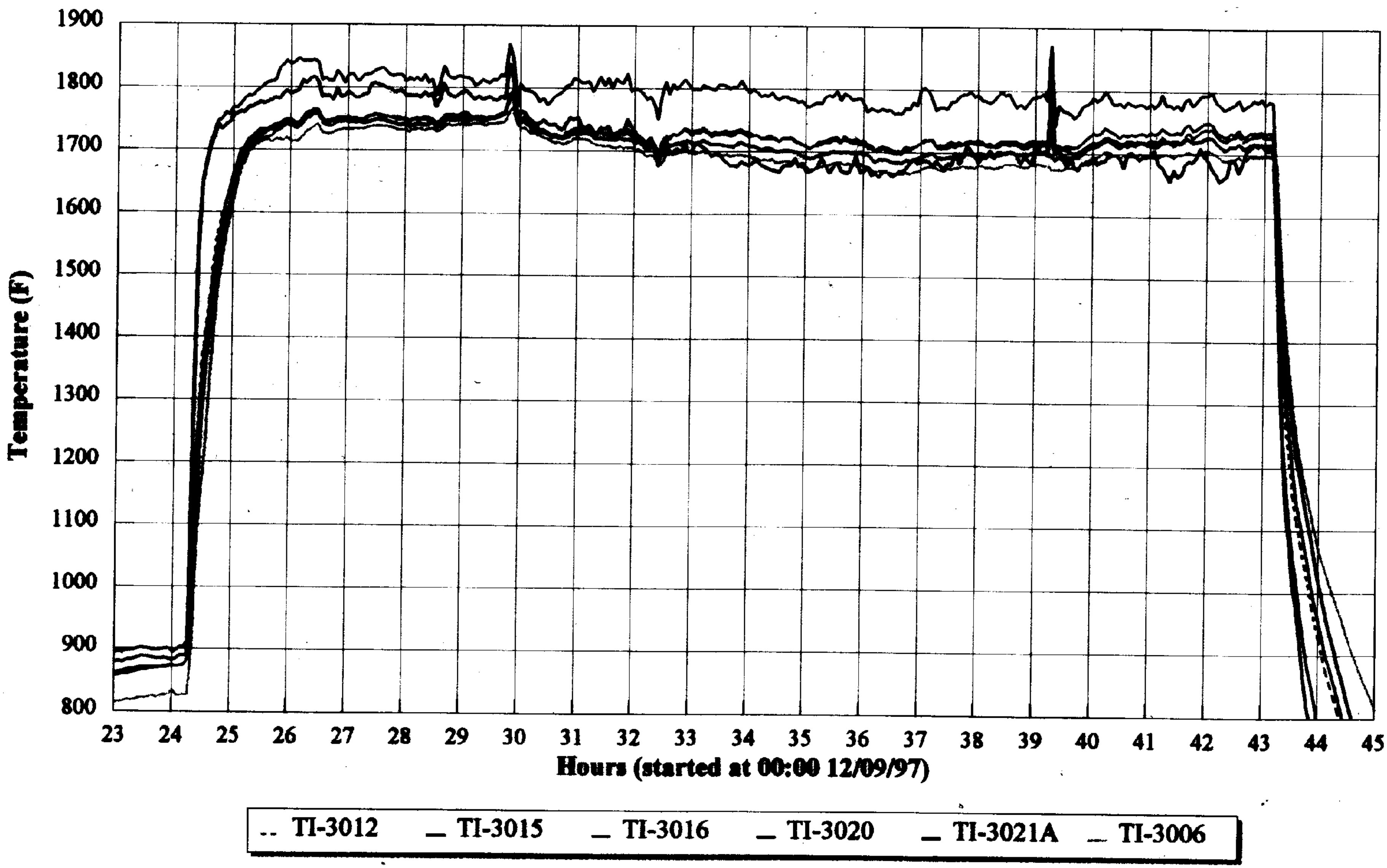


Figure 11 Bed Temperatures During Carbonizer Test Run TR07

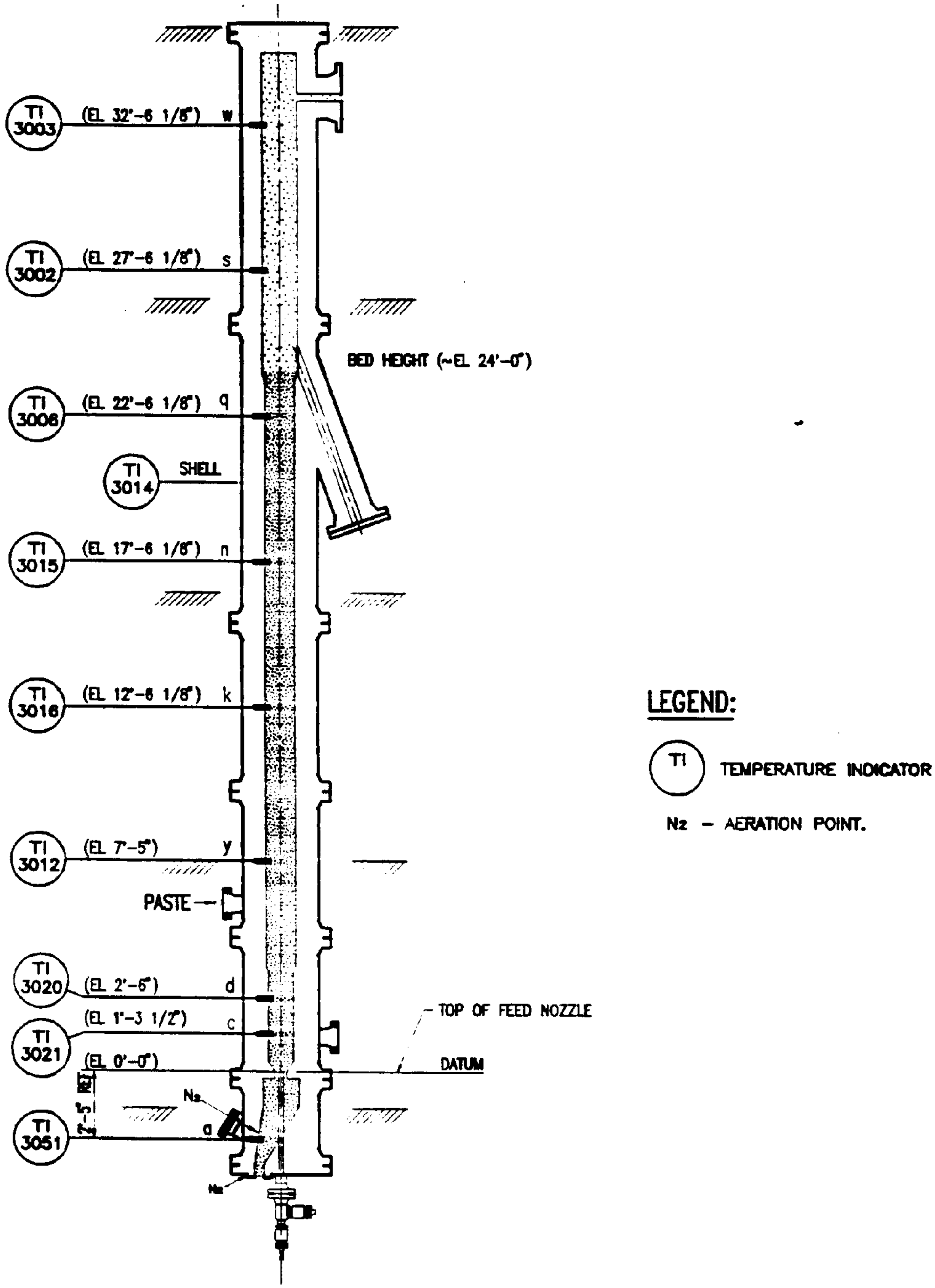


Figure 12 Location of Carbonizer Bed Thermocouples

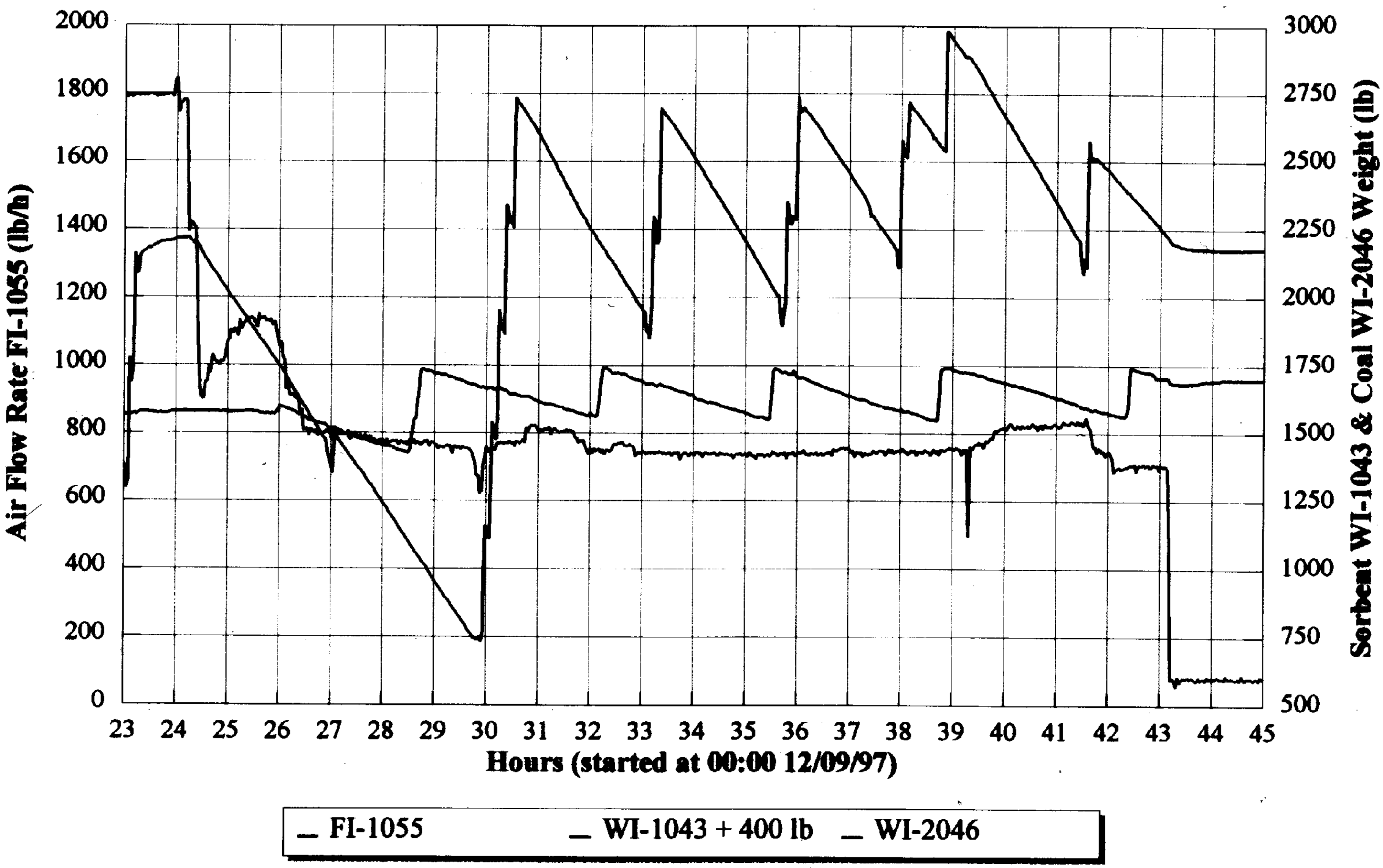


Figure 13 Coal, Sorbent and Air Flow Rates During TR07

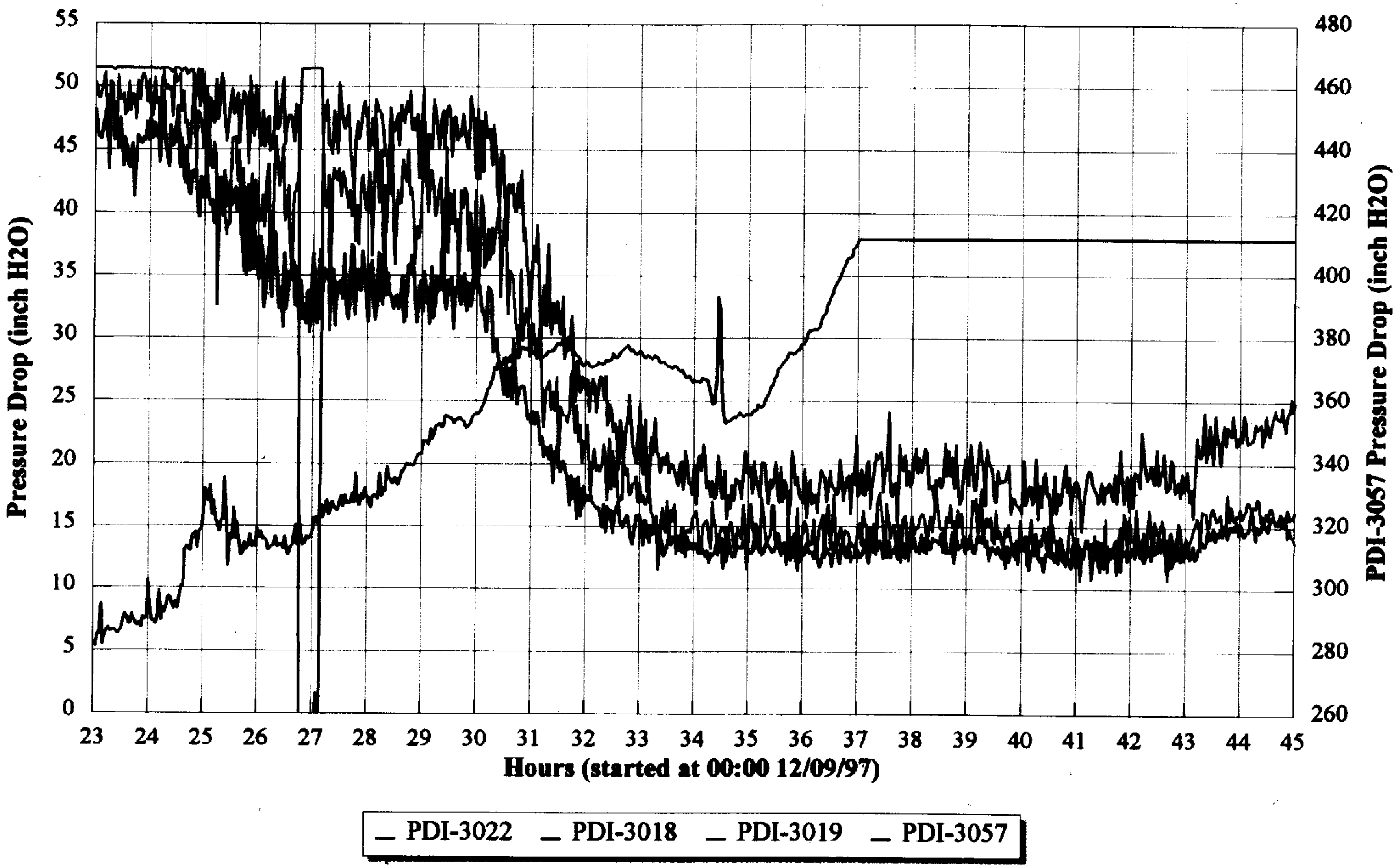


Figure 14 Carbonizer Pressure Differentials

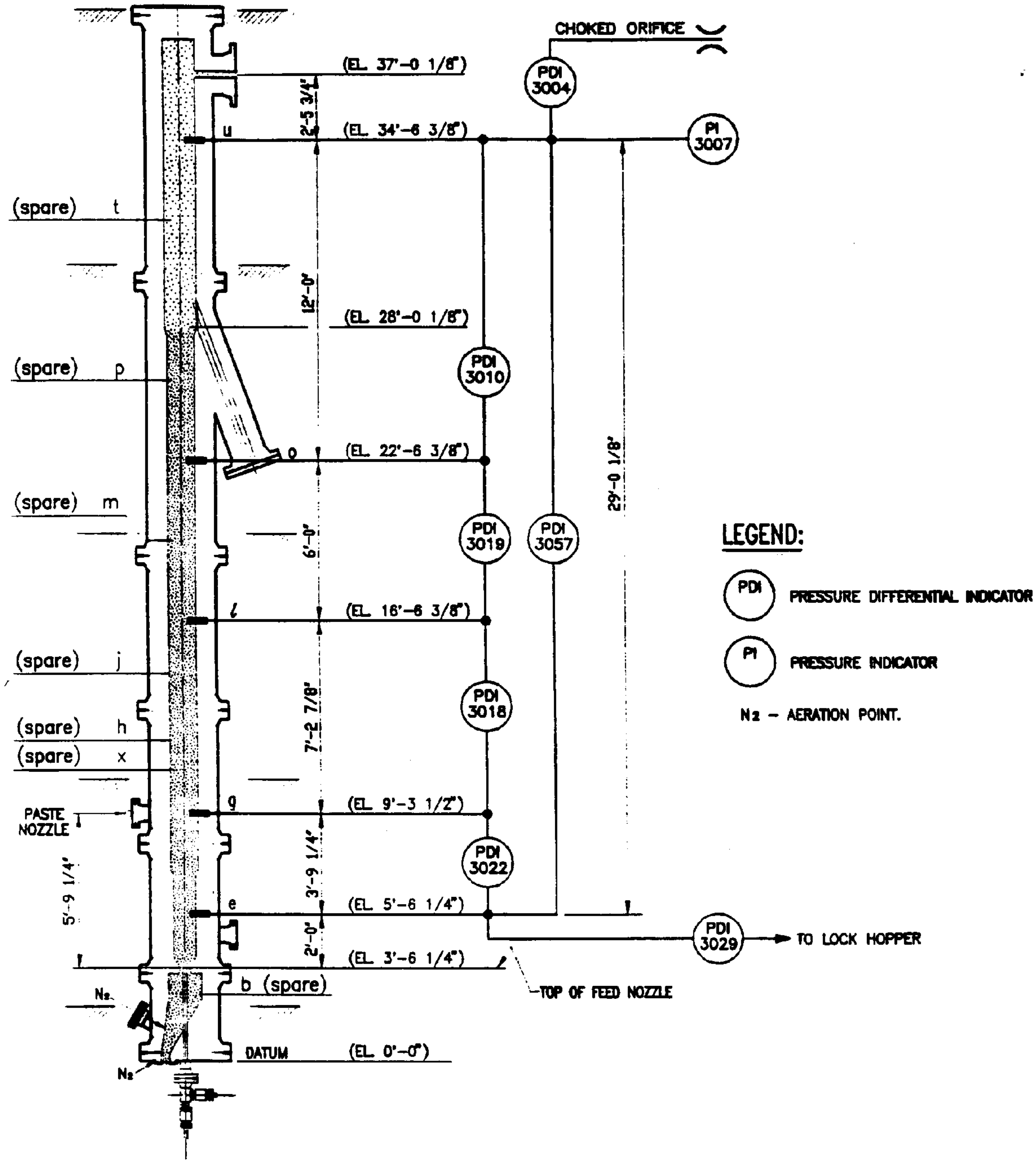


Figure 15 Carbonizer Pressure Tap Locations

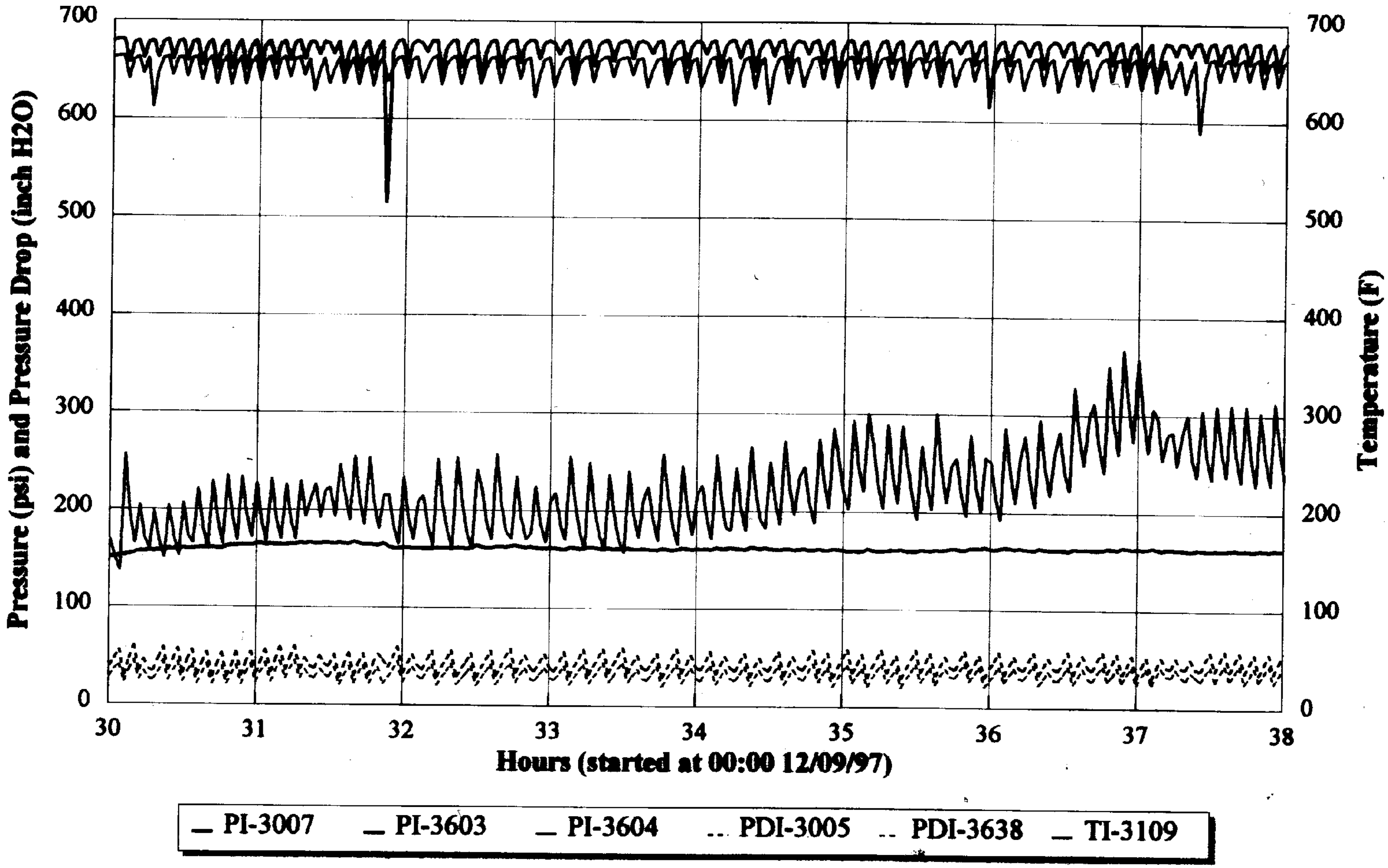


Figure 16 Typical Candle Filter Performance During TR07

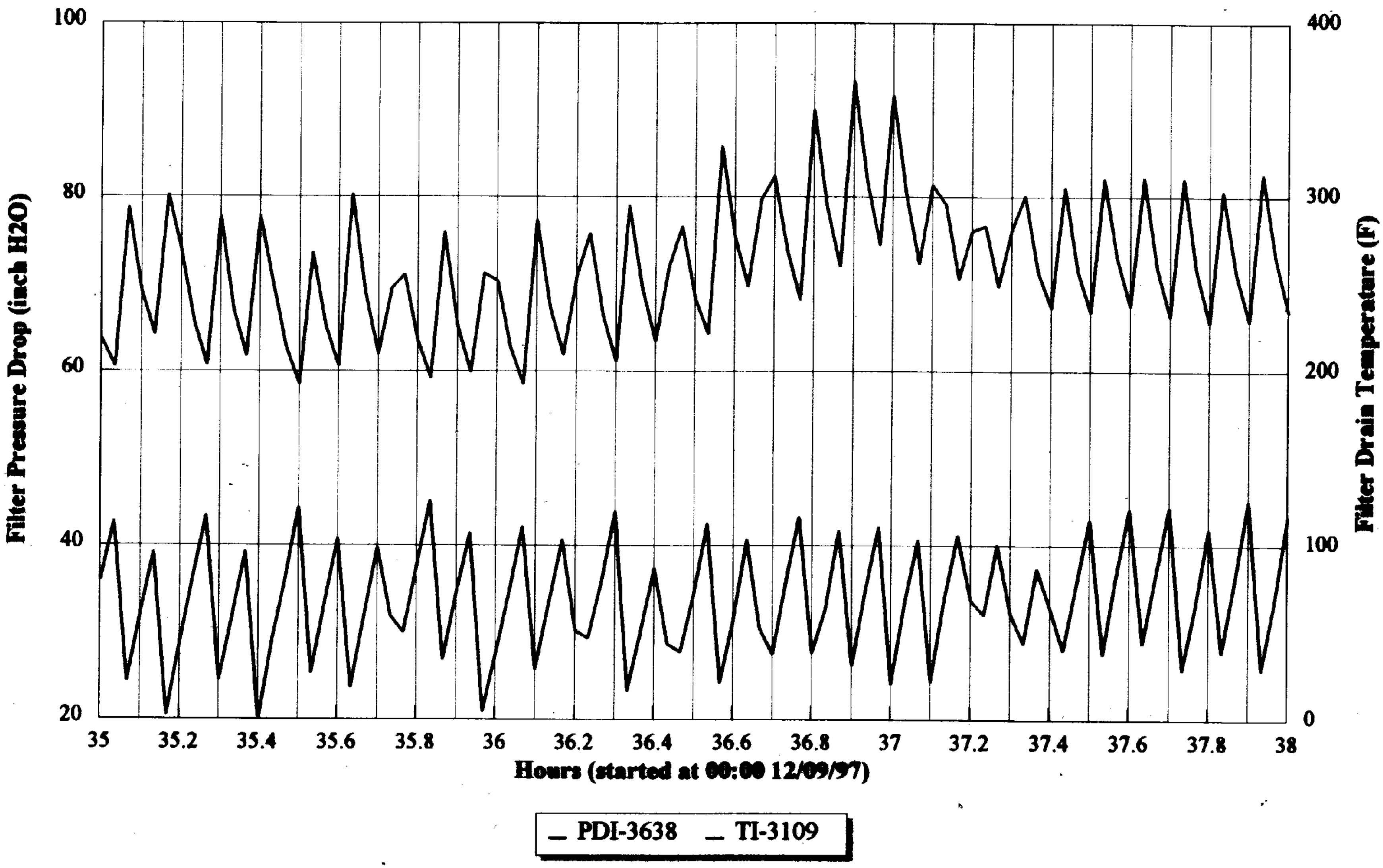


Figure 17 Typical Filter Pressure Drops During Carbonizer Test Run TR07

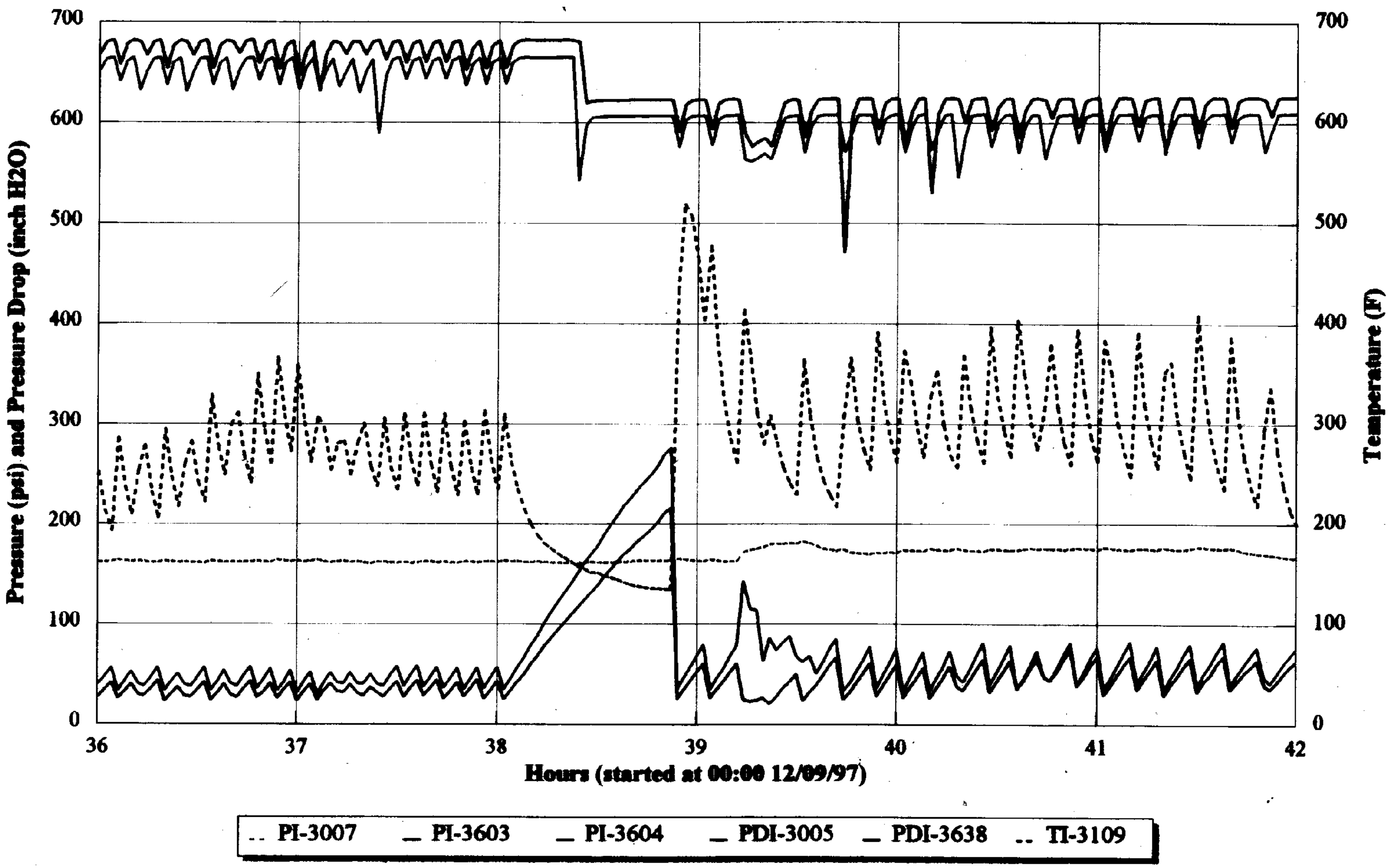


Figure 18 Filter Performance During Non-Cleaning Time Period

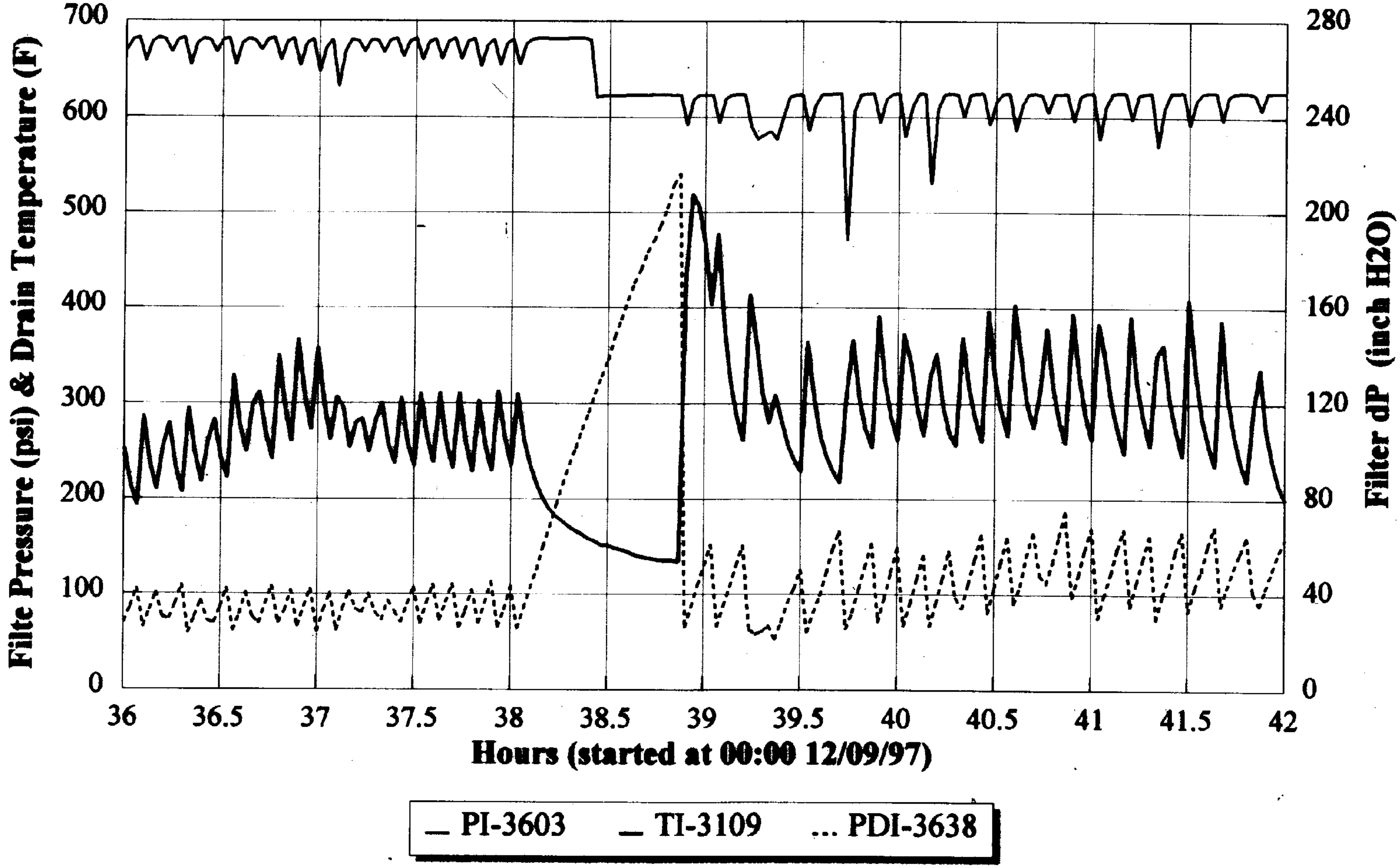


Figure 19 Filter Pressures During one Hour Non-Cleaning Time Period

Figure 20 plots the baghouse filter gas flow rate (FI-4552) and outlet temperature (TI-4548) along with the candle filter tube sheet (PDI-3638) and flame arrestor (PDI-4603 and 4604) pressure differentials. The flame arrestor pressure loss steadily increased during the run and accelerated after the candle filter was not pulse cleaned for one hour. Based on the above, it is suspected a dust seal(s) leak developed in the candle filter during the cessation of pulse cleaning. This leak(s) released ash to the baghouse, which in turn passed through a leaking bag(s) and gradually blocked the flame arrestors. Because of the rise in baghouse pressure, the unit was shut down at about 19:10 hours on December 10, 1997.

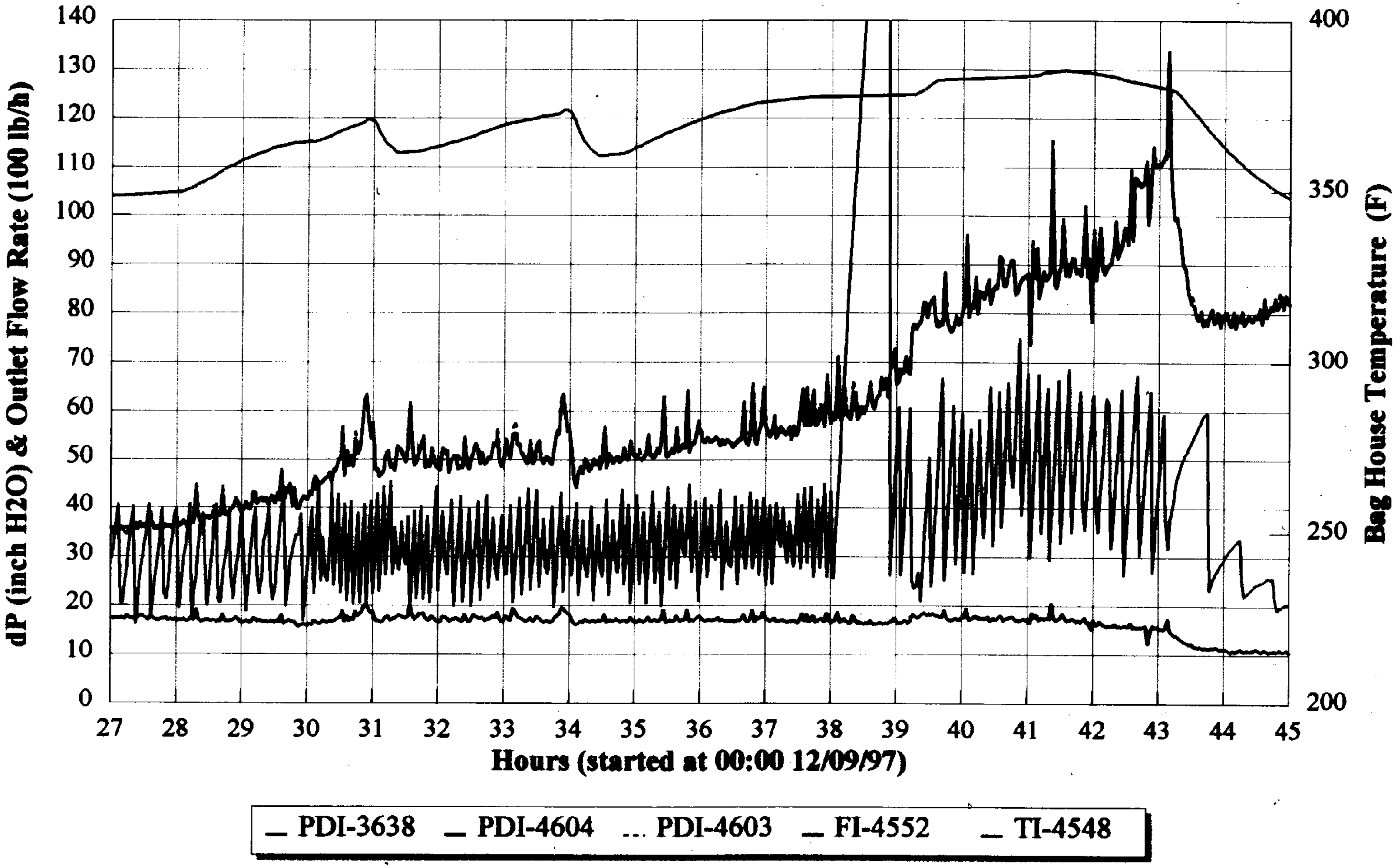


Figure 20 Baghouse and Flame Arrestor Performance During Carbonizer Test Run TR07

Data Analyses

As discussed above, agglomerates formed in the carbonizer in Test Run TR06 and blocked the bed drain about 4 hours after coal was loaded into the feed system, the cause of agglomeration being attributed to inadequate fluidization around the feed pipe. With the carbonizer operating in a compromised condition early in the run, no set points were completed in Test Run TR06. In Test Run TR07 the carbonizer ran smoothly, but the run was terminated after approximately 18 hours of operation because of a high baghouse back pressure. The carbonizer is started with a 100% limestone bed, ignited with petroleum coke, and switched to coal. Recognizing that time must be allowed for transitions to occur and the bed composition to steady out, the amount of steady state operating data is rather limited. Despite this, two set points/test points can be squeezed from the run. The first set point, TR07-01, is approximately 2½ hours long and involved operation with 4.1% sulfur petroleum coke. The second set point, TR07-02, is approximately 6 hours long and involved operation with the 1.4% sulfur Kentucky coal planned for use in the Lakeland Clean Coal V Demonstration Plant Project. Tables 1 through 3 present analysis of the coke, coal, and limestone during these set points.

As shown in Table 4, during the run the carbonizer operated at freeboard pressures of 160 and 165 psig, bed temperatures of 1752°F and 1718°F, bed depths of 23.5 and 26 feet, and a 2.8 ft/sec superficial gas velocity. Analyses indicate the carbonizer's sorbent, which was fed in a 1.4 to 1 calcium to sulfur molar feed ratio, captured 98.7% of the sulfur released by the high sulfur coke. Although the Kentucky coal is relatively low in sulfur content, it is a highly caking coal; and to preclude agglomeration risks (sorbent acts as a dilutent), the carbonizer was operated at a calcium-to-sulfur molar feed rate of 3.4. A sulfur capture efficiency of 95.1% was achieved with this low sulfur coal. Carbon conversion efficiencies were 35.6 and 41.4 percent and Table 5 presents the carbonizer fuel gas compositions. The latter include all nitrogen pressure tap purge and drain cooler flows and their elimination result in gas higher heating values of 111 and 132 Btu/SCF. Hydrogen sulfide and ammonia levels as determined by gas chromatograph analyses of bag samples were 36 and 87 ppm and 283 and 713 ppm respectively. Despite the fact that TR07-01 was of very short duration, the results appear consistent with Phase 2 test results.

Table 1

Typical Petroleum Coke Analysis for Test Point TR07-01

Proximate Analysis, wt %		**Ultimate Analysis, wt %**	
Fixed Carbon	86.82	C	87.90
Volatile Matter	10.87	H	3.94
Ash	1.87	O	0.27
Moisture	0.44	N	1.56
		S	4.02
		Ash	1.87
		Moisture	0.44

Table 2

Typical Kentucky #9 Coal Analysis for Test Point TR07-02

Proximate Analysis, wt %		Ultimate Analysis, wt %		Ash Analysis, wt % (element as oxide)	
Fixed Carbon	54.48	C	74.99	S_1O_2	53.2
Volatile Matter	33.64	H	5.3	Al_2O_3	29.0
Ash	10.18	O	4.71	T_1O_2	1.5
Moisture	1.70	N	1.63	Fe_2O_3	10.0
		S	1.49	CaO	1.3
		Ash	10.18	MgO	1.0
		Moisture	1.70	Na_2O	<0.1
				K_2O	2.4
				SO_3	0.4
				P_2O_5	0.4
				N_1O	0.2

Table 3

Typical Florida Limestone Analysis for Test Points TR07-01 and TR07-02

Ash Analysis, wt % (element as oxide)	
S_1O_2	19.5
Al_2O_3	4.8
T_1O_2	0.2
Fe_2O_3	1.9
CaO	69.4
MgO	0.9
Na_2O	<0.1
K_2O	1.0
SO_3	0.3
P_2O_5	0.1

Table 4

Carbonizer Test Run TR07 (Lakeland) Test Results

Set Point	Fuel			Sorbent		Carbonizer					
	Type	Sulfur (%)	Flow (lb/h)	Type	Ca/S (mole/ mole)	Freeboard Pressure (psig)	Bed			Sulfur Capture Efficiency (%)	Carbon Conversion (%)
							Temp.∆ (°F)	Height (ft)	Velocity∇ (ft/s)		
TR07-1	coke	4.1	281	limestone*	1.40	160	1752	23.5	2.8	98.7	35.6
TR07-2	bit. coal*	1.4	304	limestone*	3.4	165	1718	26.0	2.7	95.1	41.4

* Lakeland Kentucky coal and Florida limestone.
∆ TI 3016 located 12.5 ft. above feed pipe.
∇ In 12-inch diameter section.

Table 5

Carbonizer Fuel Gas

Gas Composition (dry basis)	Test Point	
	TR07-1	TR07-2
H2, %v	4.67	5.55
CO, %v	6.40	7.46
CH4, %v	0.27	1.30
C'2, %v	0.00	0.00
CO2, %v	5.48	5.04
N2, %v	82.76	80.23
Ar, %v	0.42	0.42
H2S, ppmv	36	87
NH3, ppmv	283	713
Gas HHV*, Btu/SCF	111	132

*after elimination of pressure tap and drain cooler nitrogen flows

During Test Point TR07-02, a mass spectrometer continuously analyzed for about 3½ hours samples of carbonizer syngas extracted from the outlet of the ceramic candle filter. In the previous Phase 2 and Phase 3 test programs, bag samples of carbonizer generated syngas were taken in pairs after the gas had been depressured to atmosphere pressure and spray quenched to 350°F. Since the bag samples would not be analyzed by a gas chromatograph for several hours and possibly days, compounds were injected into the bags to convert hydrogen sulfide and ammonia into species that would not be lost during this time period. Sodium hydroxide was injected in the first bag (converts hydrogen sulfide to sodium sulfide or sodium hydrosulfide) and hydrochloric acid was injected in the second bag (converts ammonia to ammonium chloride). Typically only about four pairs of gas samples were taken during a test point and the gas mass spectrometer with its continuous sampling now enables us to more accurately observe variations in gas quality/composition with time.

In attached Figure 21, we plot for the 3½ hour low sulfur coal period the carbonizer:

1. bed temperature at approximately 7 feet above the feed pipe
2. coal flow rate (loss in weight of the feed lock and injector hoppers)
3. air flow rate
4. syngas CO content wet vol %
5. syngas H_2 content wet vol %
6. syngas CH_4 content wet vol %

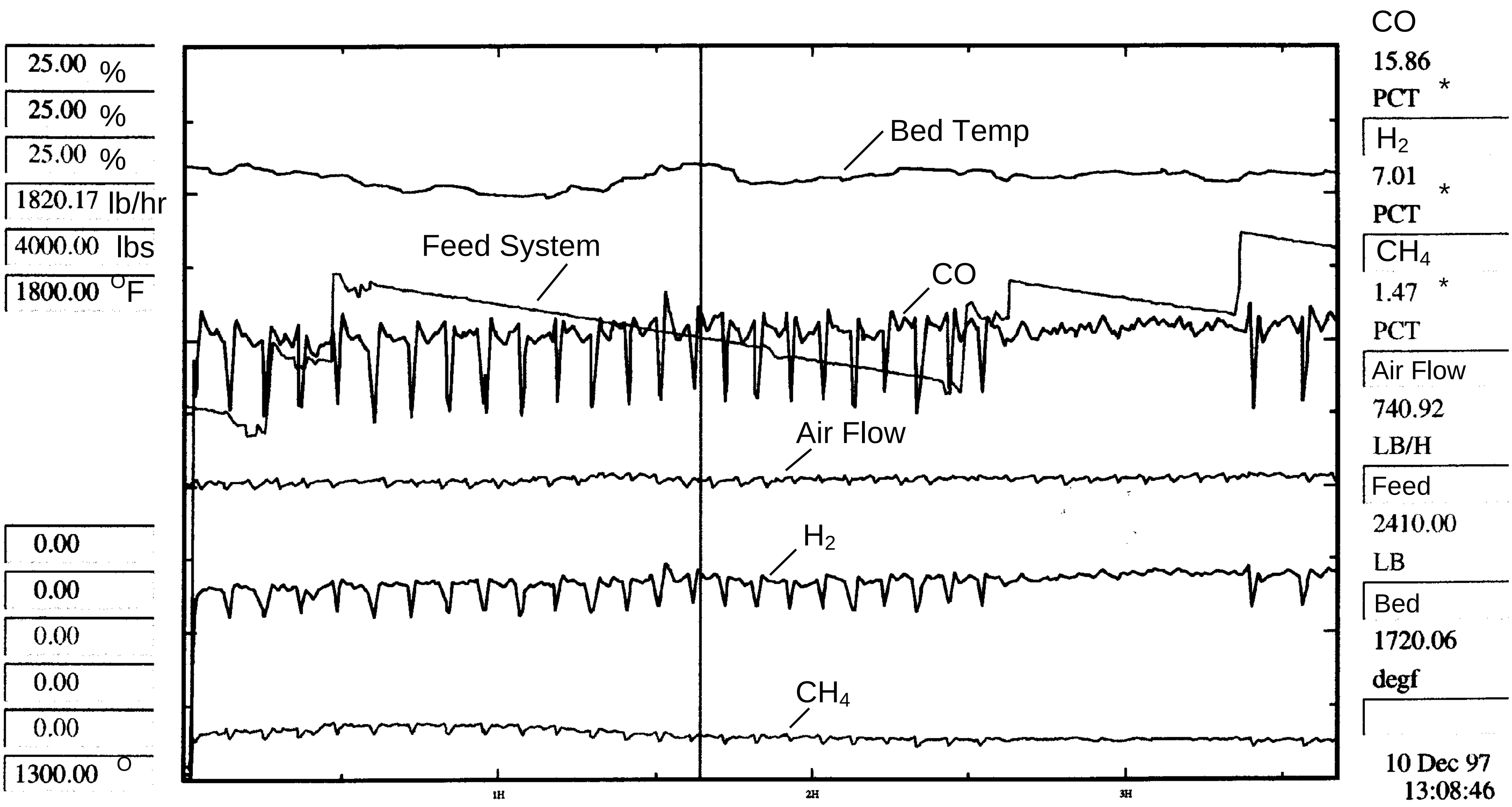


Figure 21 - TR07.2 Syn Gas Composition and Carbonizer Flow Rates
Time Period: 11:30 to 15:10

* % wet volume

AR98061

The figure confirms the steadiness of the coal and air flows to the unit and the ≈1715°F bed temperature. The carbon monoxide, hydrogen, and methane levels plotted as wet volume percent, are observed to be relatively constant except for perturbations caused by the pulse cleaning of the candle filter (approximately once every 6 minutes). For about a one-hour period the candle filter pulse cleaning was shut down to facilitate gas alkali measurements. The two-hour period immediately before this shut down is expanded in Figure 22 and the non-cleaning period is expanded in Figure 23. The expanded figures still show steady values especially the pulse free Figure 23 where carbon monoxide, hydrogen, and methane wet volume percentages are 15.5, 7.0, and 1.3 percent respectively.

During the December 1997 test run the carbonizer filter operated with 10 candles which were cleaned in groups of 5. Since each cleaning pulse represented a significant fraction of the carbonizer syn gas flow rate, the perturbations in gas composition caused by the cleaning pulses are much larger than would be experienced in a commercial size system possessing numerous cleaning sections. In addition, commercial scale systems would probably be pulse cleaned with recycled syn gas (our pilot plant used nitrogen), and hence the gas composition changes due to pulse cleaning would be minimal if any at all. Based on the above, it is seen the carbonizer can produce a syn gas with a relatively constant composition/heating value which should facilitate stable topping combustor operation.

A second-generation PFB plant may require the carbonizer gas to be cooled to the 1200°F to 1400°F temperature range to ease design requirements for downstream gas turbine valves. A relatively inexpensive way to achieve this cooling would be to spray a small amount of water into the gas between the cyclone and candle filter. Previous tests, however, have demonstrated that steam injection into the carbonizer bed will result in a loss of sulfur capture efficiency (moisture raises the equilibrium partial pressure of hydrogen sulfide over calcium oxide/calcium carbonate). Since spray cooling would involve the introduction of moisture between the cyclone and candle filter where the gas is relatively particulate-free, an investigation was made to determine if there would be a similar effect. Because the pilot plant cyclone outlet bolts directly to the candle filter inlet, steam rather than water was injected into the carbonizer gas. Realizing that the gas produced in the carbonizer is depressured via an orifice rather than a pressure control valve, steam injection will tend to increase the carbonizer pressure and can affect air and coal flows to the unit. Unfortunately, when the injection test was performed, the steam was not introduced slowly and it resulted in an upset condition in the carbonizer. Figure 24 plots the steam injection rate (FI 1057) along with the carbonizer freeboard pressure (PI 3007), air flow rate (FI 1055), coal feeder speed (FI 203), and bed temperature (TI 3021) 15 inches above the feedpipe; the upset caused by the sudden steam injection results in approximately a 20 psi increase in the carbonizer freeboard pressure and a 130°F increase in lower bed temperature.

Figure 25 plots the hydrogen sulfide level (AI 0608) measured by the mass spectrometer located downstream of the candle filter along with the steam flow rate (FI 1057), lower bed temperature (TI 3021), and candle filter clean gas/outlet plenum temperature (TI

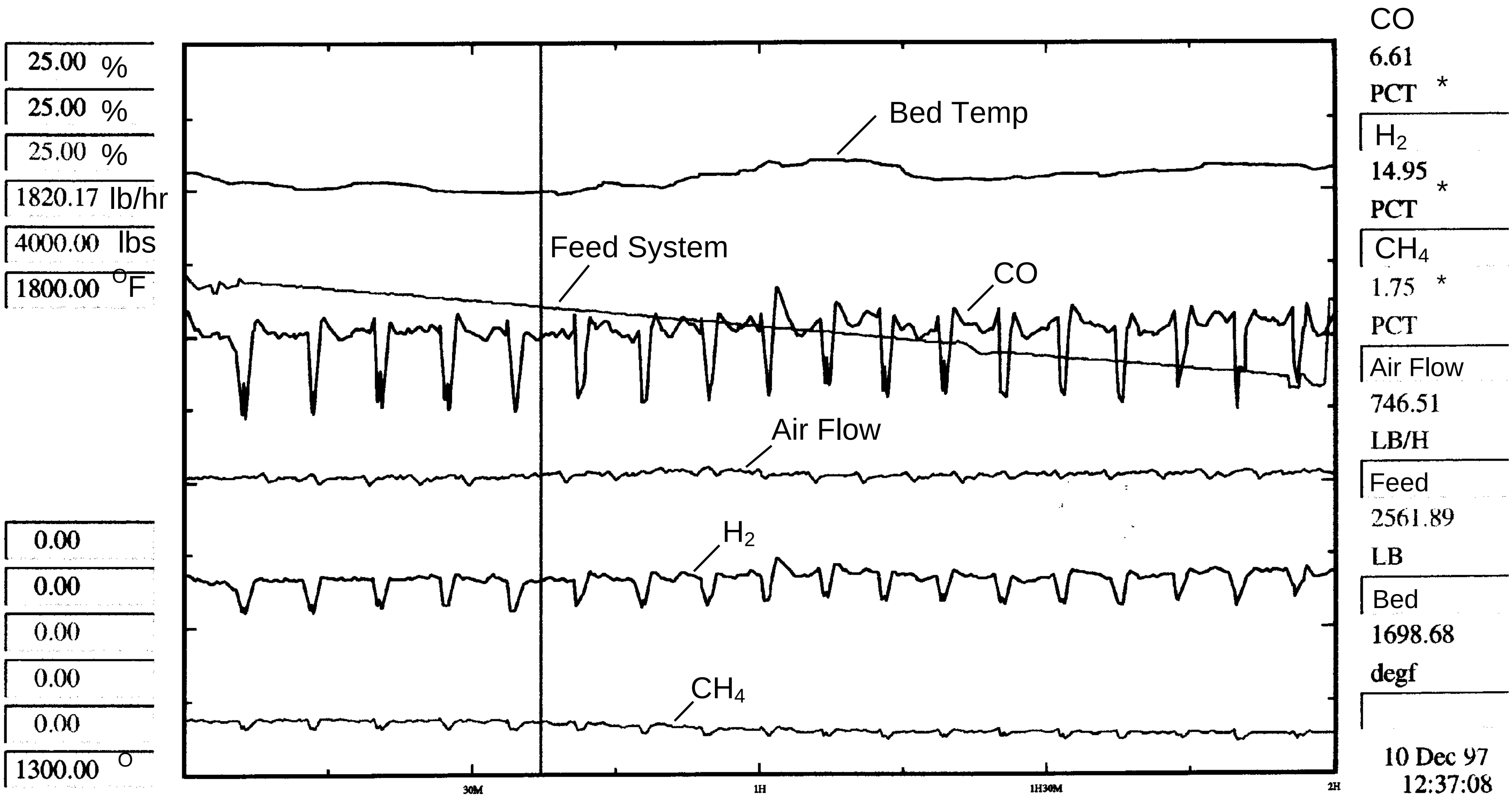


Figure 22 - TR07.2 Syn Gas Composition and Carbonizer Flow Rates
Time Period: 12:00 to 14:00

* % wet volume

AR98061

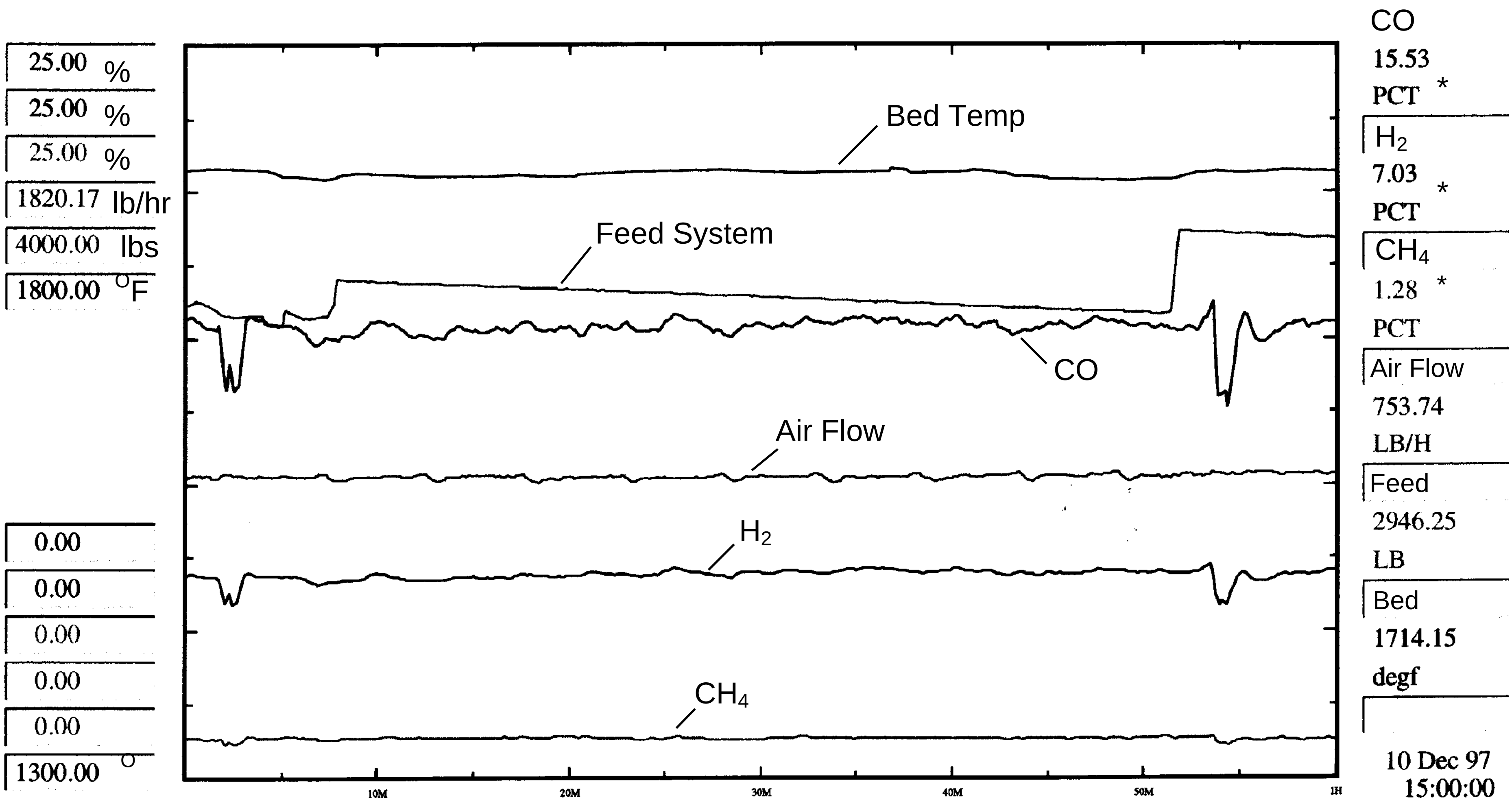


Figure 23 - TR07.2 Syn Gas Composition and Carbonizer Flow Rates
Time Period: 14:00 to 15:00

* % wet volume

AR98061

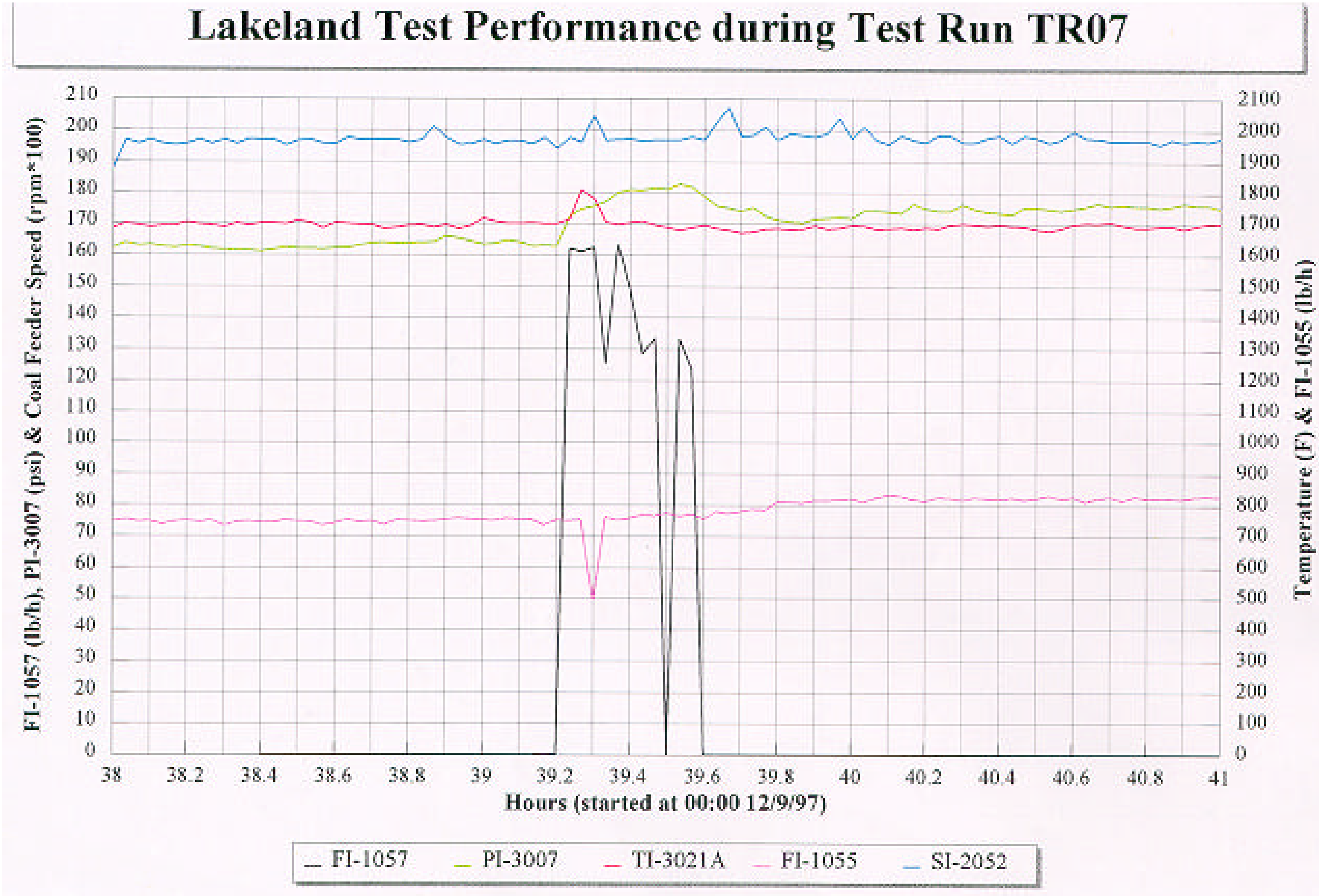


Figure 24 Carbonizer Upset Caused by Sudden Steam Injection

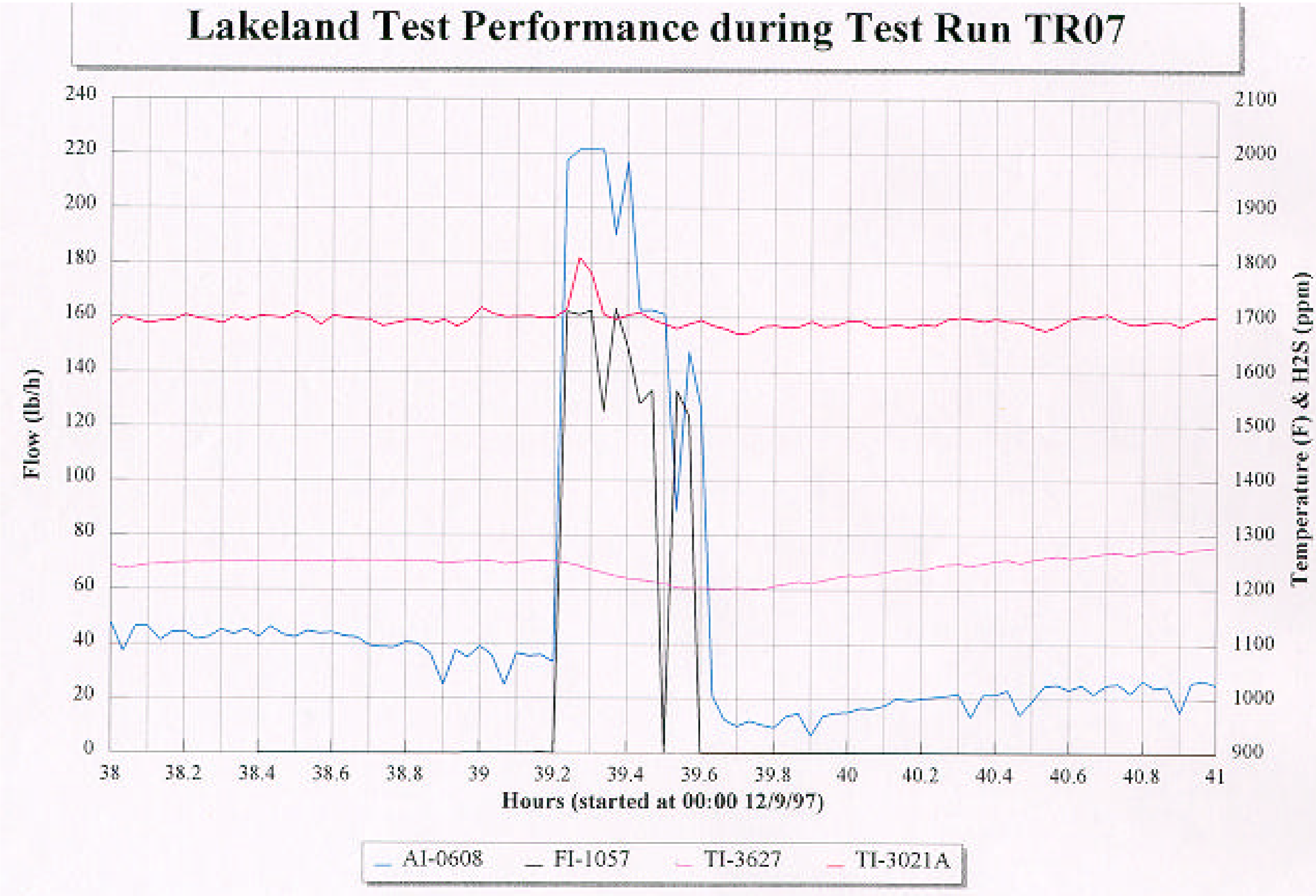


Figure 25 H2S Increase Caused by Steam Injection at Filter Inlet

3627). Starting at about hour 37, candle filter pulse cleaning was stopped and the two spikes in H2S at about hour 38 mark the restart of pulse cleaning. Figure 19 confirms (PDI 3638) re-establishment of a normal thickness of filter cake and steam injection is observed to double the level of H2S in the gas exiting the filter. Because the Figure 25 data is marred by an upset, we cannot quantify the loss in sulfur capture efficiency without additional testing; additional testing, however, was prevented by the forced shutdown of the plant by the baghouse dust leak. Despite this , it appears a water spray cooling approach must be done with caution as it appears the resulting increase in gas moisture will cause the partial release of sulfur from the calcium sulfide in the particulate entering and contained in the downstream candle filter cake.

Commercial Plant Design Update

The Second-Generation PFB Combustion Plant conceptual design prepared in 1987 is being updated to reflect the benefit of pilot plant test data and the latest advances in gas turbine technology. The updated plant is being designed to operate with 95 percent sulfur capture and a single Westinghouse 501G gas turbine. Our 1987 study investigated two coal feeding arrangements, e.g., dry and paste feed. Paste feeding resulted in a higher plant efficiency and a lower cost of electricity. Paste, however, increases the water content of the carbonizer generated syn gas; this increases the equilibrium partial pressure of hydrogen sulfide gas over calcium oxide/calcium carbonate and thereby reduces the carbonizer sulfur capture efficiency. Recognizing that the carbonizer and the CPFBC work together to control the plant overall sulfur capture efficiency, the higher CPFBC efficiency can compensate for the carbonizer's lower sulfur capture efficiency depending upon the amount of coal and/or char being fed to each unit. Since the latter are determined by the overall plant heat and material, we prepared a balance for each feed case to enable selection of the plant coal feed system.

Figures 26 and 27 present preliminary carbonizer performance data prepared by FW for the paste and dry feed cases. The paste fed carbonizer operates with a 94.3% sulfur capture efficiency and produces a 118 Btu/SCF (Lower Heating Value) syn gas. The dry fed carbonizer in contrast operates with a 96.5% sulfur capture efficiency and produces a 139 Btu/SCF syn gas. The topping combustor and gas turbine cooling air flow rates and distributions are considered proprietary Siemens-Westinghouse data. Using the Figure 26 and 27 performance data and assuming topping combustor and gas turbine cooling air flow rates, Parsons prepared preliminary heat and material balances for both cases and forwarded them to Westinghouse for their comments. As the reporting period ended, the balances were undergoing analyses by Siemens-Westinghouse.

Product Gas

	Lb/hr	Mol%
CO	51.793	16.708
CO2	43.960	9.026
H2	3.307	14.823
H2O	19.692	9.877
CH4	3.198	1.801
NH3	.417	.221
H2S	.114	.030
N2	145.521	46.940
Ar	2.529	.572
Sum	270.532	100.000

HHV(Btu/Lb)= 1867.
LHV(Btu/Lb)= 1723.
HHV(Btu/scf)= 127.
LHV(Btu/scf)= 118.

Char-Sorbent

	Lb/hr		Lb/hr
C	21.578	CaCO3	7.136
H	.136	MgCO3	.000
O	.000	CaO	.000
N	.377	MgO	4.857
S	.432	CaS	4.036
Ash	8.033	Inert	.398
Sum	30.557	Sum	16.427

HHV(Btu/Lb Char)=10603.
LHV(Btu/Lb Char)=10563.

HHV(Btu/Lb Sorb)= 1085.
(on CaCO3-MgCO3 base)

QPFB(LHV:Btu/Lb Avg)= 7292.

CARBONIZER

P(psia)=294.
T(F)=1700.

Purge 77.F ----------> ; Steam 415.F <---------

Purge

	Lb/hr
N2	.000

Steam

Lb/hr
.000

Coal 70.F ; Sorbent 70.F ; Air 600.F

Coal

	Lb/hr
C	56.060
H	3.656
O	4.940
N	.980
S	2.333
Ash	8.033
Moist	24.000
Sum	100.003

HHV(Btu/Lb MF)=13250.

Sorbent

	Lb/hr
CaCO3	12.735
MgCO3	10.160
Moist	.117
Inert	.398
Sum	23.410

Ca/S= 1.750

Air

	Lb/hr
O2	44.736
N2	145.261
Ar	2.529
H2O	1.577
CO2	.000
Sum	194.103

Stoi% 25.399

Note: HHV & LHV - Fuel heating value as it burns out @ STD.

Phase 3 Paste Feed Carbonizer Balance 6/4/98

Figure 26

```
     Product Gas                                Char-Sorbent

       Lb/hr       Mol%                     Lb/hr            Lb/hr
CO    63.127     19.848             C      34.428   CaCO3    9.397
CO2   36.759      7.356             H        .217   MgCO3     .000
H2     3.868     16.898             O        .000   CaO       .000
H2O   15.802      7.725             N        .602   MgO      6.231
CH4    4.102      2.252             S        .689   CaS      5.001
NH3     .459       .237             Ash    10.306   Inert     .510
H2S     .086       .022             ----------      ------------
N2   143.492     45.111             Sum    46.242   Sum     21.140
Ar     2.493       .550
-----------   -------               HHV(Btu/Lb Char)=11179.
Sum 270.189   100.000               LHV(Btu/Lb Char)=11137.

HHV(Btu/Lb)=  2260.                 HHV(Btu/Lb Sorb)= 1050.
LHV(Btu/Lb)=  2088.                 (on CaCO3-MgCO3 base)
HHV(Btu/scf)=  150.
LHV(Btu/scf)=  139.                 QPFB(LHV:Btu/Lb Avg)= 8016.
              \                             /
               \                           /
                \                         /
                 \                       /
                  \                     /
                   FWFWFWFWFWFWFWFWFWFWFW
             77.F  F                    W     415.F
    Purge ---------->F    CARBONIZER      W <-------- Steam
                   F                    W
        Lb/hr      F    P(psia)=294.    W           Lb/hr
 N2      .000      F    T(F)=1700.      W           16.180
                   F                    W
                   FWFWFWFWFWFWFWFWFWFWFW
                  /          |           \
                 /           |            \
                /            |             \
          70.F/        70.F  |      600.F\
             /               |             \
            /                |              \
     Coal                Sorbent              Air

           Lb/hr                 Lb/hr                    Lb/hr
C         71.912     CaCO3     16.336         O2         44.105
H          4.690     MgCO3     13.033         N2        143.213
O          6.337     Moist       .150         Ar          2.493
N          1.258     Inert       .510         H2O         1.555
S          2.993     ------------             CO2          .000
Ash       10.306     Sum       30.029         ------------
Moist      2.500                              Sum       191.367
------------         Ca/S=     1.750
Sum       99.996                              Stoi%      19.521

HHV(Btu/Lb MF)=13250.

Note: HHV & LHV - Fuel heating value as it burns out @ STD.
```

Phase 3 Dry Feed Carbonizer Balance   6/4/98

Figure 27

Char-Sorbent Disposal

As of September 1, 1997, approximately 290,000 lbs. of char-sorbent-ash residue from the Phase 2 and Phase 3 carbonizer-CPFBC test programs were stored in 757 drums at Foster Wheeler's research laboratory in Livingston, New Jersey. In September 1997 Foster Wheeler received release from FETC to proceed with the disposal of this material. During the October-December 1997 time period each drum was opened, inspected, and when not full was topped off with char from other drums, thereby reducing the number of drums to 612. All 612 drums were shipped off site for chemical treatment/processing as a hazardous waste (reactive calcium sulfide) and disposal. Approximately 200 drums containing char-sorbent residue from the recently completed Test Runs TR06 and TR07 remain to be processed.