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UTILIZATION OF COAL-WATER FUELS IN FIRE-TUBE BOILERS

Final Report for the Period October 1990–August 1994

By
Todd Sommer
Todd Melick
Donald Morrison

Work Performed Under Contract No. AC22-90PC90165

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UTILIZATION OF COAL-WATER FUELS IN FIRE-TUBE BOILERS

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FINAL REPORT

Period Covered By Report
October 1990 to August 1994

Submitted by:

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EXECUTIVE SUMMARY

The objective of this DOE sponsored project was to successfully fire coal-water slurry in a fire-tube boiler that was designed for oil/gas firing and establish a data base that will be relevant to a large number of existing installations. Firing slurry in a fire-tube configuration is a very demanding application because of the extremely high heat release rates and the correspondingly low furnace volume where combustion can be completed. Recognizing that combustion efficiency is the major obstacle when firing slurry in a fire-tube boiler, the program was focused on innovative approaches for improving carbon burnout without major modifications to the boiler.

The boiler system was successfully designed and operated to fire coal-water slurry for extended periods of time with few slurry related operational problems. The host facility was a 3.8 million Btu/hr Cleaver-Brooks fire-tube boiler located on the University of Alabama Campus. A slurry atomizer was designed that provided outstanding atomization and was not susceptible to pluggage. The boiler was operated for over 1000 hours and 12 shipments of slurry were delivered. Two University boiler operators and one graduate student were trained to operate the boiler in addition to four EER employees.

The new equipment engineered for the coal water slurry system consisted of the following:

- Combustion Air and Slurry Heaters
- Cyclone
- Baghouse
- Fly Ash Reinjection System
- New Control System
- Air Compressor
- CWS/Gas Burner and Gas Valve Train
- Storage Tank and Slurry Handling System

TABLE 1

Specific performance goals and achievements are as follows:

GOALS	ACHIEVEMENTS
Coal water slurry as the primary fuel	Yes
Natural gas or petroleum fuels as secondary fuel	Yes
Fully automatic start-up with system purge and ignition verification	Yes
Turndown ratio of 3:1	Yes
Comparable reliability/safety to oil-fired commercial boilers	Yes
Thermal efficiency greater than 80%	77.5%
Combustion efficiency greater than 99%	95%
Routine Operating/Maintenance Labor less than one dedicated man-hour per day and an additional two man-hours per week	Less than 13 hours per week estimated
Dust free and automatic or semiautomatic ash removal	Yes
Scheduled Maintenance less than twice a year	Yes
Service Life of the overall system greater than 20 years	Yes
Emissions lb/MMBtu 1.2 SO_2 0.3 NO_x 0.03 Particulate	 1.1 SO_2 0.7 NO_x NA

The economics of converting an oil or gas fired boiler to coal water slurry was evaluated in order to identify which parameters are necessary to create an attractive payback period. The parameters used were boiler capacity, capacity factor, and fuel cost differential. Also considered was whether the slurry system was being retrofitted to an existing boiler, installed on one (1) new boiler, or being installed on a new boiler in large quantities. The result is that boilers smaller than 4,000 lb/hr steam are not good candidates for conversion unless they are shop assembled in large quantities (greater than 10). Boilers in the 4,000 to 10,000 lb/hr range become attractive for retrofit if they are subject to high fuel cost differentials and capacity factors. Most boilers larger than 10,000 lb/hr steam have short payback periods and are excellent candidates for conversion to coal water slurry.

1.0 INTRODUCTION

In the industrial and commercial markets, fire-tube boilers represent the major portion, about 70 percent, of small oil- and gas-fired boilers. Annually, these boilers consume about two quads or approximately ten percent of the total energy used in the combined industrial and commercial market sectors. Thus, replacing the premium fuels now used in these markets with coal-based fuels would accomplish a significant reduction in oil and gas consumption.

To demonstrate the feasibility of converting this commonly used boiler to coal-fired operation, the Energy Department's Pittsburgh Energy Technology Center funded EER to retrofit a 3.8 million Btu/hr Cleaver-Brooks fire-tube boiler at the University of Alabama (UA) to burn coal-water slurry. The project team also included the Mining Division of Jim Walter Resources Inc. (JWRI), which prepared and delivered the fuel to the University Campus.

Water-tube boilers dominate large industrial and utility applications and, as the name implies, are designed differently than fire-tube boilers. In water-tube units, the combustion gases flow outside and around tubes filled with water that are heated to produce steam. In fire-tubes (see Figure 1-1), however, heat is transferred from hot combustion gases flowing inside tubes to water contained in a shell that surrounds the tubes. Because the shell of a fire-tube boiler must withstand the pressure of the steam produced, high pressures and large boiler sizes (i.e., large shell diameters) would require extremely thick shell walls. Thus, fire-tube boilers usually have smaller capacities than water-tube units.

These two types of designs result in different gas flow patterns, velocities, and temperatures, which lead to differences in heat transfer and durability. Testing of a water-tube boiler was also conducted in parallel with this fire-tube program. The results from each program when combined together, provide a broad data base that can be applied to virtually all commercial and industrial-scale boilers.

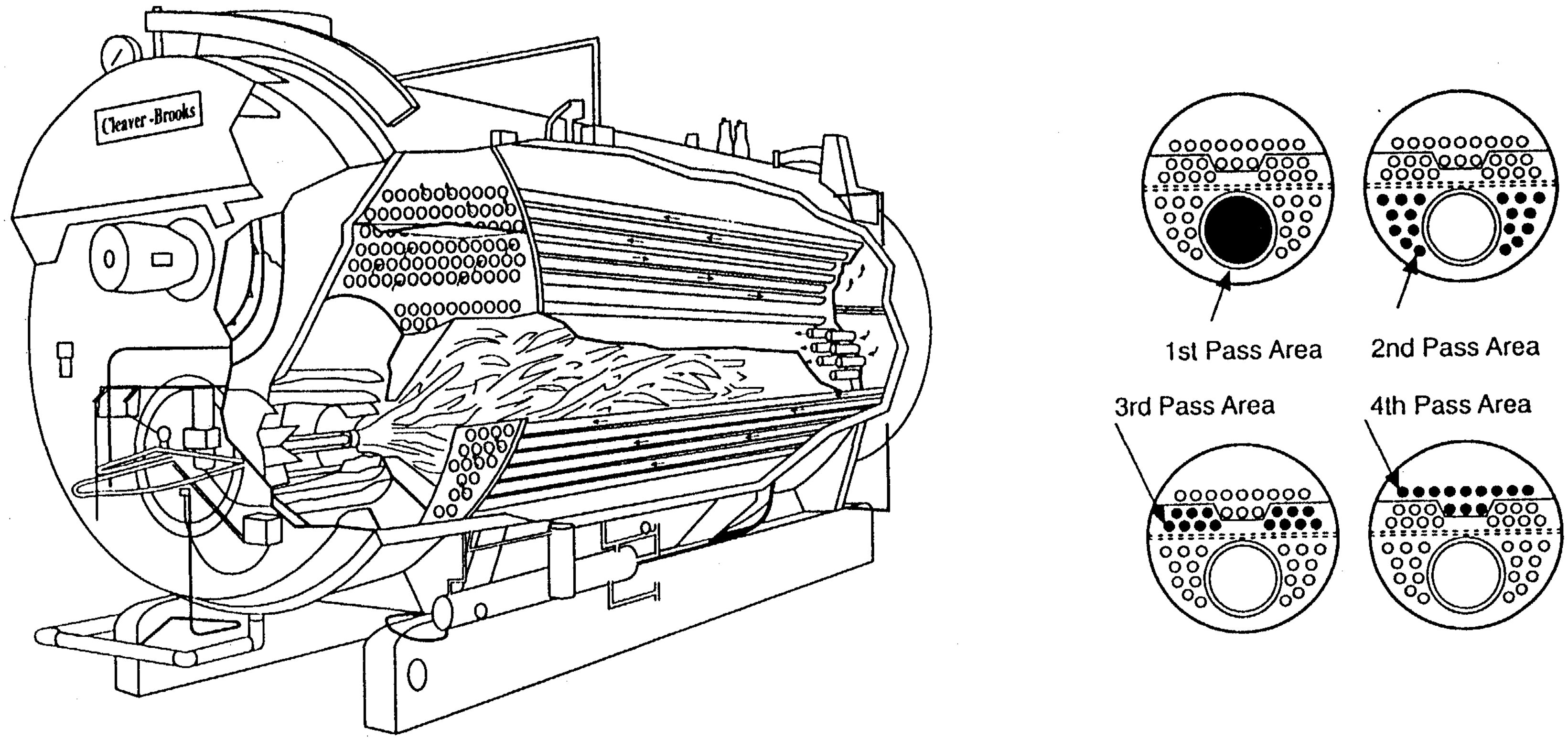


Figure 1-1. Typical four-pass fire-tube boiler (Cleaver-Brooks).

1.1 Program

The Program was divided into the following five tasks:

Task 1 Establish Test Site; Acquire and Integrate Components

Task 2 Perform Preliminary System Tests

Task 3 Perform Proof-of-Concept System Tests

Task 4 Evaluate Economics

Task 5 Decommission Test Facility

Task 1 provided the design and installation of the slurry firing equipment on the host boiler located at the University of Alabama Tuscaloosa Campus. Task 2 was a series of optimization tests to determine the effects of adjustable parameters on boiler performance and to document short term performance. Task 3 was long term continuous boiler operation. Task 4 provided a comprehensive review of the test data in order to evaluate the economics of slurry conversions. Task 5 would have provided for the renovation of the host boiler to the previous gas firing configuration if required.

1.2 Background Information

This program was focused on boilers in the 1-10 million Btu/hr (1,000-10,000 lb/hr steam equivalent) size range. Of the U.S. boilers in this size range, 3.8 million Btu/hr is the average size. Only a small fraction of the boilers by units and combined firing capacity are coal fired. The reason for this poor market penetration by coal is cost. Coal-fired equipment has not been cost competitive in this small size range.

The fire-tube boiler, based on the original Scotch design, is a self-contained "packaged boiler" wherein combustion takes place in a long narrow cylindrical furnace -- the "fire-tube". The fire-tube shown in Figure 1-1 is a four-pass boiler, meaning that the combustion gases make four passes through the boiler prior to exiting the stack.

From the point of combustion, the most important feature of these boilers is the fire-tube itself. Oil and gas are fired in these units at very high volummetric heat release rates. Heat extraction rates from these intense flames are also very high because of the relatively large surface-to-volume ratio of the long, narrow combustion chamber, and the fact that no refractory is used on the inside surface of the fire-tube.

1.3 Retrofit Equipment

As mentioned previously, the key technical hurdle was acceptable carbon conversion efficiency. Two lesser concerns were coal ash effects and ignition stability. In order to improve the carbon conversion the following modifications or techniques were selected:

Micronized Slurry The slurry was ground fine in order to enhance carbon burnout, but not so fine as to increase slurry viscosities that would reduce the ability to atomize the particles into fine droplets.

Fire-tube Refractory Refractory was added to the fire-tube just downstream of the burner throat to increase the initial combustion temperature which improved flame stability and carbon burnout.

Air Preheat Flue gas from the second pass of the boiler was diverted to an air heater. The level of combustion air preheat had a noticeable impact on flame stability and the added surface of the air heater helped to offset the loss of boiler efficiency due to the water content of the slurry.

2.0 PROCESS DESIGN

2.1 Host Site Characteristics

The host boiler was located at the University of Alabama Campus in Tuscaloosa, Alabama. It is a Cleaver-Brooks Model LF-211X-8, 4-pass, 80hp fire-tube boiler rated at 2816 #/hr of steam at 150 psig. It was installed in 1950, and has 352 square feet of heating surface. The boiler was designed to be fired with either fuel oil or natural gas but has only fired natural gas. The boiler is connected to the University's steam supply system. The boiler is of the dry-back variety, indicating that the rear wall is not water-cooled.

At it's rated capacity , the gas firing rate is approximately 3.8 million Btu/hr. The inside diameter of the fire-tube is 18.5 inches and the length is 9 feet. This fire-tube configuration results in a volumetric heat release of about 200,000 Btu per cubic foot per hr which is typical of the general population of fire-tube boilers. Also in keeping with the standard design, the fire-tube is not refractory lined except in the region of the burner itself.

In addition to the fire-tube, the boiler is equipped with 56 tubes split between the remaining three gas passes of this 4-pass boiler. These tubes have an inside diameter of 2.375 inches, and are 10 feet long. The number of tubes in each pass decreases (24 in second, 18 in third, 14 in fourth)as the gases move towards the exit of the boiler to maintain a uniform gas velocity throughout the boiler. The flue gas velocity is approximately 60 ft/sec when firing natural gas at full load. The tubes in the boiler were recently replaced and all asbestos containing insulation was removed. Since the boiler was designed to fire only natural gas or oil, it is not equipped with particulate removal equipment, sootblowers, air compressor, or an air heater.

The boiler is located in a 16' x 25' brick building adjacent to the mechanical engineering building. There is a large fenced area behind the building that provided sufficient space for the slurry storage tank , baghouse, and other miscellaneous equipment.

2.2 Heat Transfer Modeling

Firing an oil- or gas-fired boiler on a coal-water slurry (CWS) will influence the thermal performance and operation of the boiler and, hence, requires the implementation of design modifications, such as the addition of a refractory lining to the fire tube and preheating the combustion air and fuel, to allow proper combustion of the fuel. The use of numerical combustion and heat transfer models allows prediction of the boiler thermal characteristics as functions of various input and operational variables, and consequently can provide information needed to optimize the design modifications to the boiler.

The primary problems in firing coal-water slurries in fire-tube boilers designed for gas- or oil-firing, from a design standpoint, are the extremely short residence times and low gas temperatures in the combustion zone, which make ignition and complete combustion of coal-based fuels difficult. Industrial fire-tube boilers are designed with a long and narrow combustion chamber with water-cooled walls resulting in a high intensity combustion zone followed by rapid cooling of the combustion products. These conditions are not favorable for the combustion of coal-water slurries. Conventional slurry-firing experience, which has been obtained with larger systems designed with lower combustion intensities and longer residence times, is not directly applicable to fire-tube boilers. In this study, a thermal performance model was developed and applied to a 3.8 million Btu/hr fire-tube boiler to simulate the combustion and heat transfer processes in order to optimize the design and operational conditions for converting the boiler to fire a coal-water slurry. The slurry, which contains sixty-five weight percent coal, was produced from a medium volatile (27%) bituminous Alabama coal and was supplied by Jim Walter Resources.

Since combustion efficiency is a key concern when firing slurries in fire-tube boilers, the analysis approach was focused on evaluating methods for improving carbon burnout without major modifications to the boiler. The results of the analysis assisted with selecting: (1) the length and thickness of refractory lining necessary to stabilize the flame, avoid ash slagging (ash initial deformation temperature of 2700°F) and maximize the carbon conversion, (2) the equipment needed to enhance carbon utilization by fly ash recycling, air preheating, natural gas co-firing, and load control, (3) the optimum location for flue gas extraction and the required quantity of flue gas needed to preheat the combustion air to 600°F, and (4) the strategy to provide optimum steam generation. The thermal characteristics evaluated in this study include gas temperature profiles throughout the four-pass boiler, surface temperatures of refractory linings, unburned carbon in the fly ash, air preheat, steam generation and ASME heat loss efficiency. The temperature profiles were required to design an air preheater and to select the location for flue gas extraction.

The following section presents a brief description of the heat transfer models used in the study, followed by initial model calibration results. Subsequent sections of the report discuss the analysis approach for the design of CWS retrofit, model parametric results and perform boiler performance predictions. This report concludes with a comparison of model results to field data for a wide range of operating conditions, and a summary of the study conclusions.

THERMAL PERFORMANCE MODEL

To permit a wide range of design and operating changes to be examined efficiently and economically, the modeling approach adopted for this study employed a series of coupled thermal analysis models of varying complexity. In the radiation-dominated first pass of the boiler, a two-dimensional combustion and heat transfer computer model (2D code) was used, while a one-dimensional convective heat transfer model was applied to the convection-dominated second, third and fourth passes of the boiler. A simple gray body radiant heat transfer model was also coupled with the convective heat transfer model for the second pass heat transfer calculation.

The first pass of the boiler was divided into a two-dimensional computational grid configured to model an axisymmetric cylinder. Figure 2-1 shows a sectional view of the fire tube and illustrates how the tube was divided into sixteen layers in an axisymmetric cylindrical grid. This grid was used for the two-dimensional model calculations in the initial parametric study. The key sub-models of the two-dimensional heat transfer code include a semi-stochastic radiation model for calculating the radiative exchange between all volume and surface zones, and combustion models to describe volatile combustion and char burnout. For these calculations, it was assumed that the water content in the slurry was vaporized immediately adjacent to the burner zone, allowing separation of spray evaporization and coal particle combustion processes. This assumption is considered reasonable given that the CWS atomizer was optimized to generate droplet Sauter mean diameters between 20 to 30 microns. In the model, coal particles are divided into ten different size classifications, and are devolatilized according to a one-step Arrhenius rate law incorporating an empirical user-specified statistical lifetime. Char oxidation is determined by a global rate equation which is a function of diffusion, chemical reaction rates, and local oxygen concentrations. The activation energy and frequency factor of apparent kinetic rate constants for char combustion were specified based on compiled literature data. The flow field is not calculated in the model, but is prescribed based on experience in modeling boilers of similar design.

The convective passage code used to simulate the second, third and fourth passages consists of a simple circular-tube convection heat transfer model with constant wall surface temperatures and correlations for evaluating flue gas thermal properties (viscosity, conductivity, heat capacity and density) at film temperatures in the tube. A simple air preheater model was developed to calculate flue gas extraction required to heat the combustion air from 77°F to 600°F. The amount of flue gas extracted for the air preheater is determined by the combustion air flow rates, air heater efficiency and flue gas temperature difference across the air heater (the last two parameters are obtained from the manufacturer's design curves) and the flue gas exit temperature of the second pass.

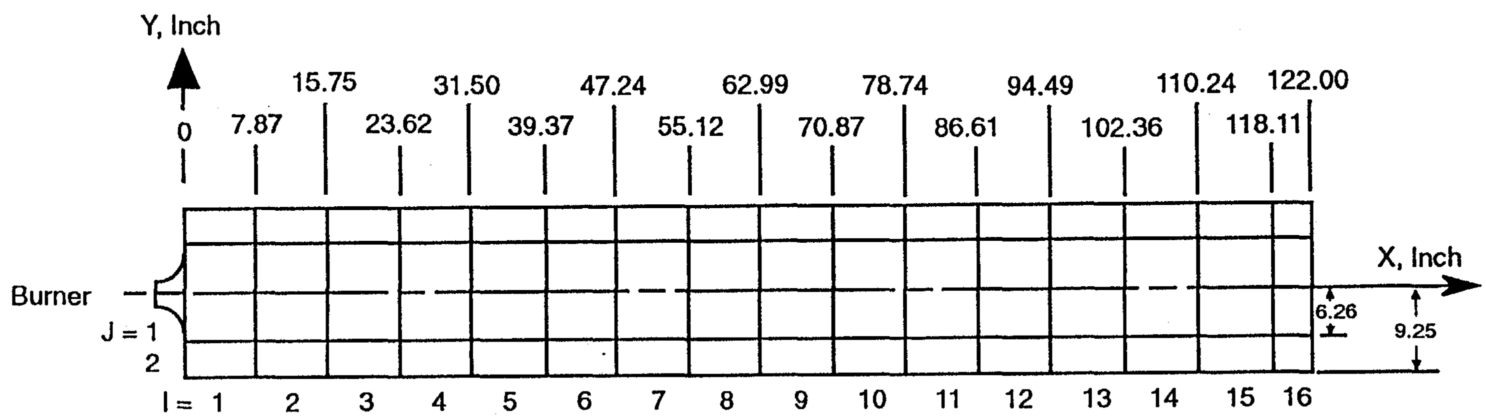


Figure 2-1. Sectional view of actual fire-tube geometry and 2D computational grid for initial parametric study.

MODEL CALIBRATION

The performance models were initially calibrated using field data to verify that they were properly simulating the boiler performance for baseline gas-fired operating conditions at a thermal input of 2.84 million Btu/hr. The major model parameter adjusted for the calibration case was the fuel heat release rate. The rate was determined using an empirical database, where the rate is a function of burner thermal load. Figure 2-2 shows that the predicted gas temperature at the exit of the fire tube agrees with mean measured data for the baseline case. The flue gas temperatures throughout the second, third and fourth passes which were calculated by the performance models are compared with available measurement data in Table 2-1. The calibration of the performance models was considered adequate since the differences between the measured and predicted temperatures were within five percent. A parametric study was then performed to select the optimum design modifications and operational conditions to a fire-tube boiler retrofitted with CWS.

RETROFIT DESIGN STUDY

A critical factor governing the conversion of the boiler to firing CWS is the combustion performance achievable in the fire-tube; therefore, the two-dimensional model was used to assess the impacts of design parameters and operating conditions on combustion performance of the first pass. An initial parametric model study was performed to evaluate the thermal performance impacts caused by the key design parameters and operating conditions: the length and thickness of the refractory lining, refractory conductivity, burner swirl, air preheat, fly ash recycle, natural gas co-firing, overall excess air level and thermal load variation. The thermal performance impact analyses included mean gas temperatures, refractory surface temperatures, unburned fixed carbon in ash, and cumulative fuel heat releases. The results of these simulations provided information needed to design modifications for converting the boiler to fire CWS.

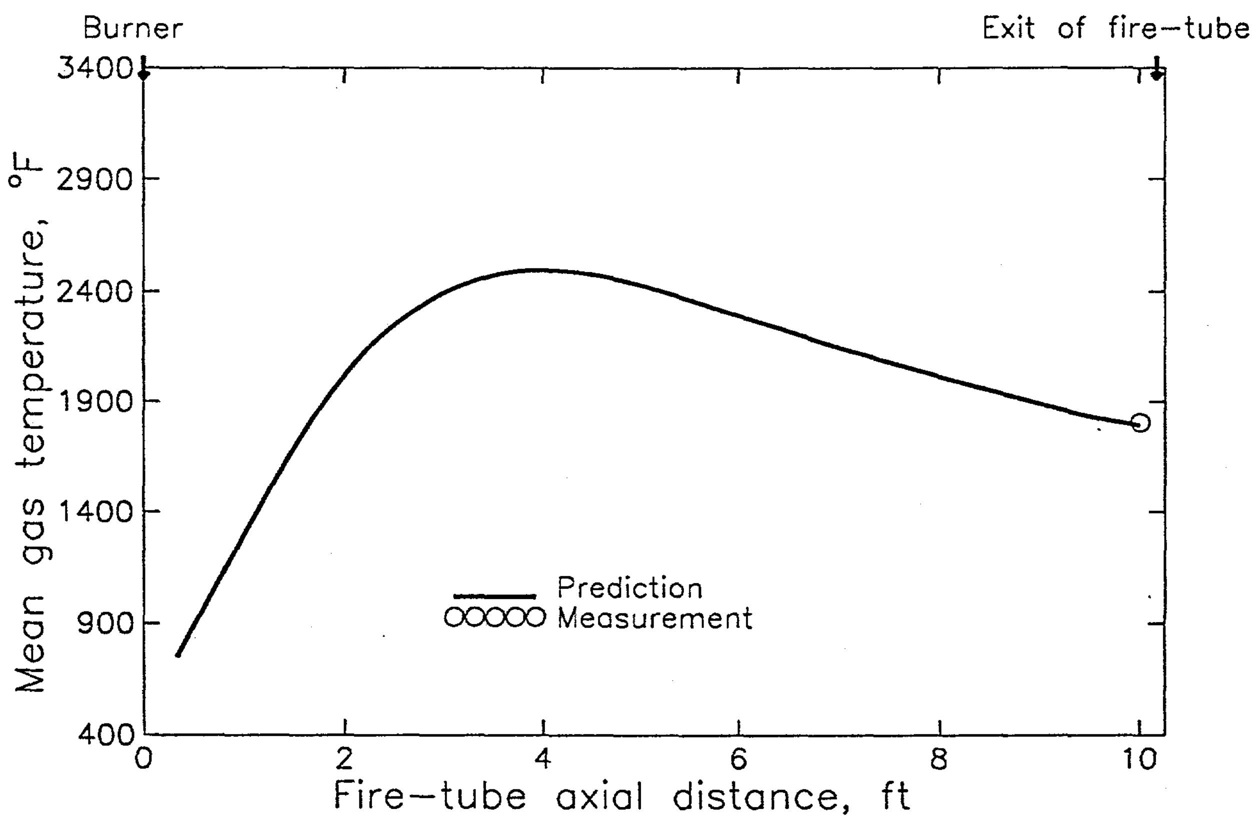


Figure 2-2. Mean gas temperature distribution for the gas-firing calibration case.

TABLE 2-1. COMPARISON OF GAS EXIT TEMPERATURES FOR CALIBRATION CASE.

Description		Prediction	Measurement
Gas Exit Temperature (F)			
of	Fire Tube	1,794	1,805
	2nd Pass	728	-----
	3rd Pass	464	-----
	4th Pass	368	381

TABLE 2-2. REPRESENTATIVE FUEL ANALYSES AND HIGHER HEATING VALUES.

Fuel	Coal Water Slurry	
Proximate Analysis (lbs/100lb,wet)		
	Fixed Carbon	43.35
	Volatile	17.42
	Moisture	35
	Ash	4.23
	Total	100
Ultimate Analysis (lbs/100lb,dry)		
	Carbon	82.45
	Hydrogen	4.97
	Nitrogen	1.58
	Oxygen	3.78
	Sulfur	0.71
	Ash	6.51
	Total	100
High Heating Values (Btu/lb), As recieved:		9510
Fuel	Natural Gas	
Composition (Volume%)		
	CH4	90
	C2H6	5
	N2	5
	Total	100
Specific Gravity		0.6
Higher Heating Value (Btu/scf)		1000

Table 2-2 lists fuel analyses and higher heating values used in this study. The coal particle size distribution used in the 2D code was based on the design specification. Figure 2-3 compares the specified coal particle distribution with some preliminary measurement data. Char reactivity parameters (activation energy and frequency factor) for the char combustion model were specified based on the rank of the coal. The flow field similar to the calibration case was applied to the parametric study cases.

The parametric study results were used to assist with the optimization of the retrofit design and selection of the optimum operating conditions. A detailed thermal characteristics impact analysis for the initial parametric study is summarized in Appendix A. Key model results from the initial study are presented in Figures 2-4, 2-5, 2-6, 2-7, and 2-8, showing respectively the impacts of refractory lining length, ash recycle, air preheat, gas co-firing and load variation on mean gas temperatures and carbon burnout. In the model, the refractory lining is composed of two segments: the burner refractory lining (typical 15 inches long) followed by the refractory sleeve covering the fire tube. The refractory lining reduces the amount of heat extracted from the CWS flame, and improves carbon utilization and flame stability. As the length of the refractory sleeve increases, the potential to cause ash slagging in the fire tube becomes higher. To control gas temperatures below the ash initial deformation temperature in the combustion chamber at nominal operating conditions, it was determined that a one-third refractory lining was required. Preheating the combustion air, recycling ash particles, and reducing the thermal load to the boiler can improve the carbon burnout, while the model predicts gas co-firing up to thirty percent of total heat input has no significant improvement on the carbon combustion efficiency.

The optimum refractory configuration selected consisted of one inch of a rammable plastic refractory on the inside surface for wear due to the coal particle abrasion and one quarter inch of a ceramic paper between the refractory and the steel fire tube for insulation purposes. The thickness of the total lining was minimized to prevent a significant reduction in the volume of the fire tube. The thermal conductivity of plastic refractory was at a constant of 14.4 Btu-in/hr-ft^2-^{o}F for the refractory service temperature ranging from 800 to 2000^{o}F, while the thermal

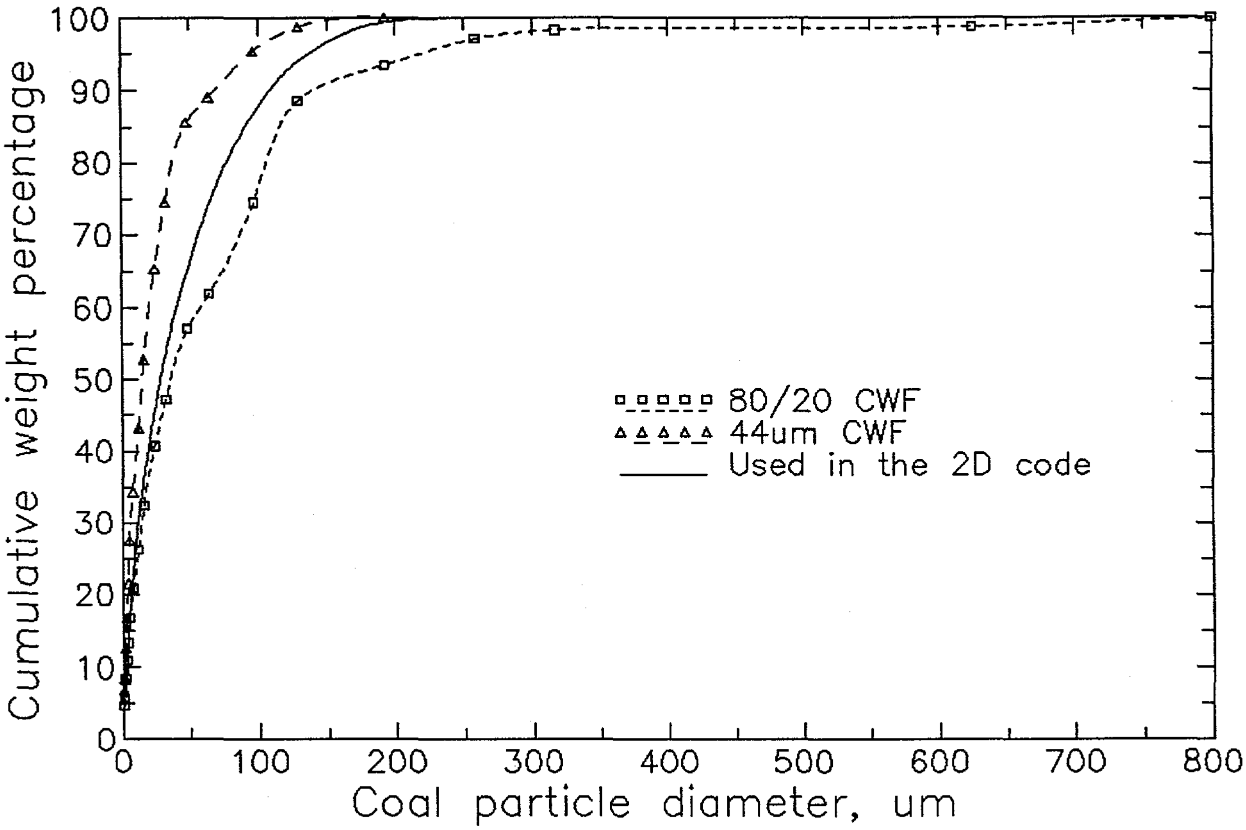


Figure 2–3. Comparison of coal particle size distribution used in the 2D code with preliminary measurement data.

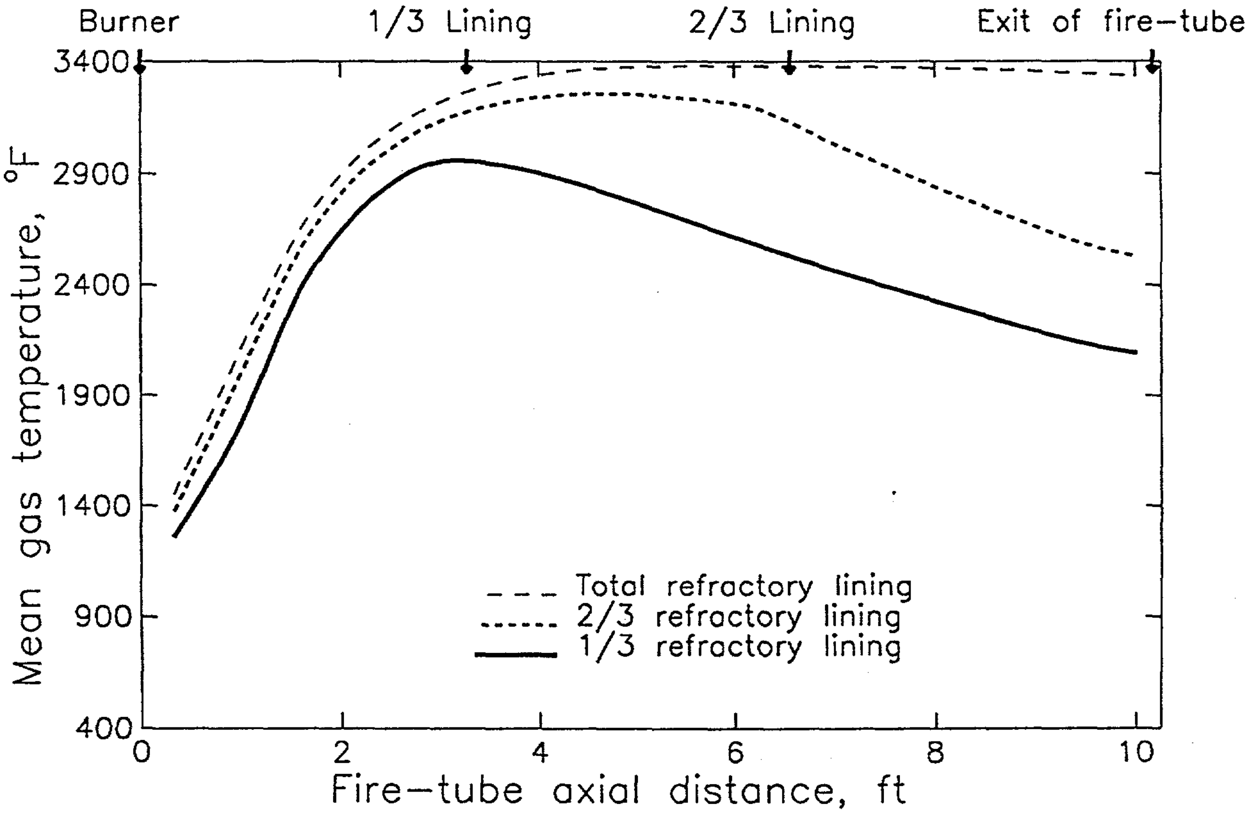


Figure 2-4. Impacts of length of refractory lining on mean gas temperatures.

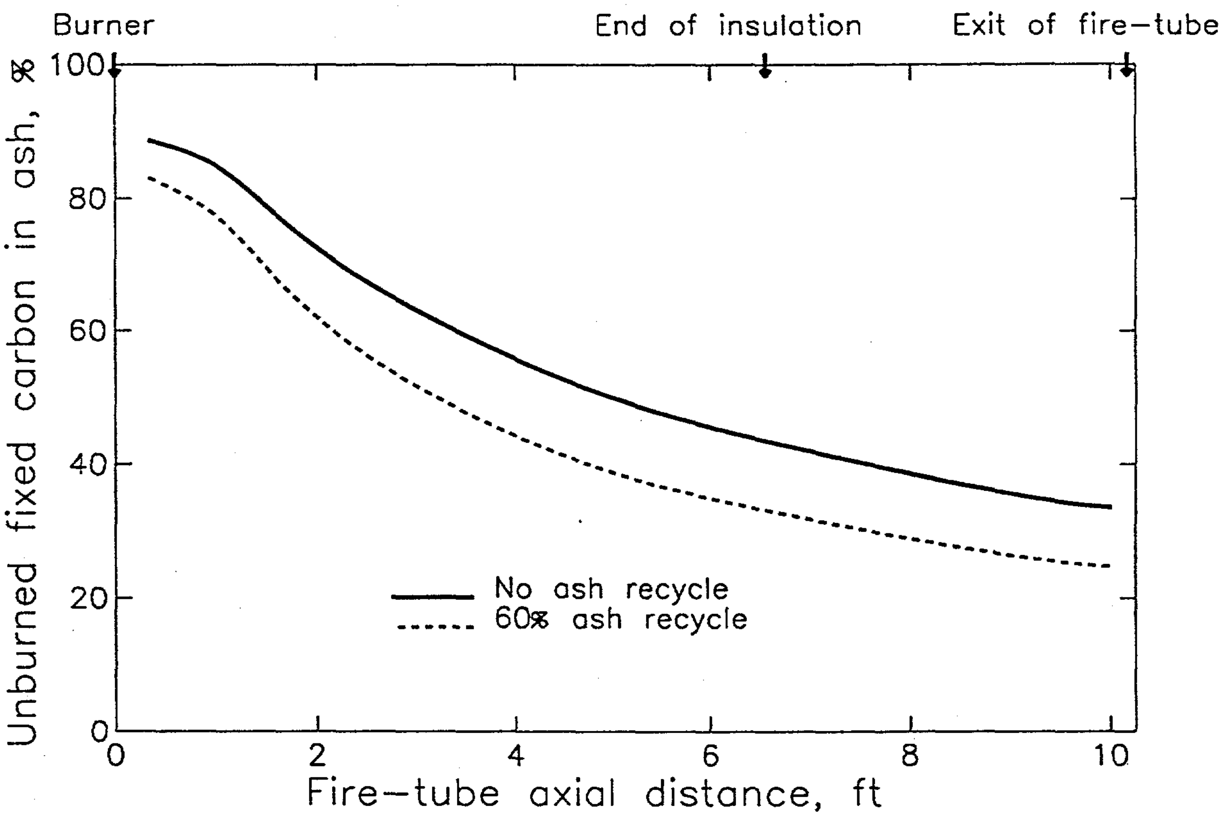


Figure 2−5. Impacts of ash recycle on unburned fixed carbon in ash.

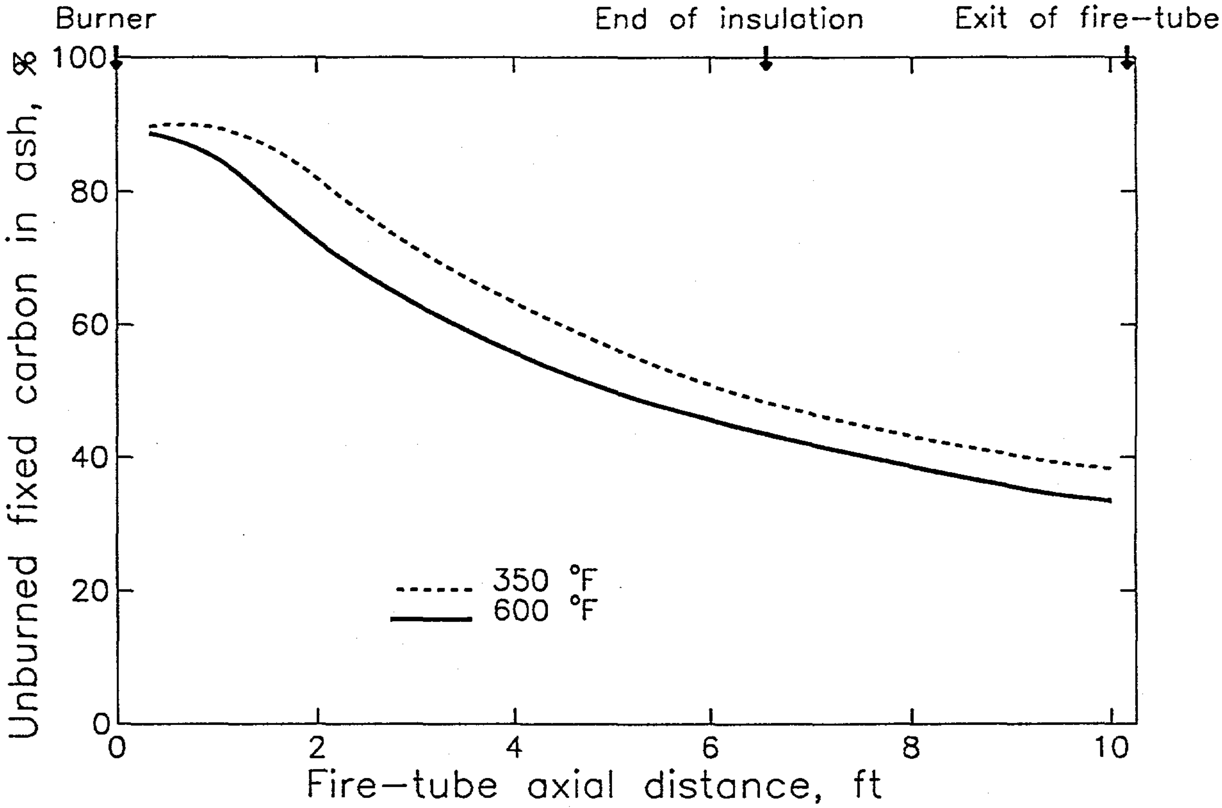


Figure 2–6. Impacts of air preheat temperature on unburned fixed carbon in ash.

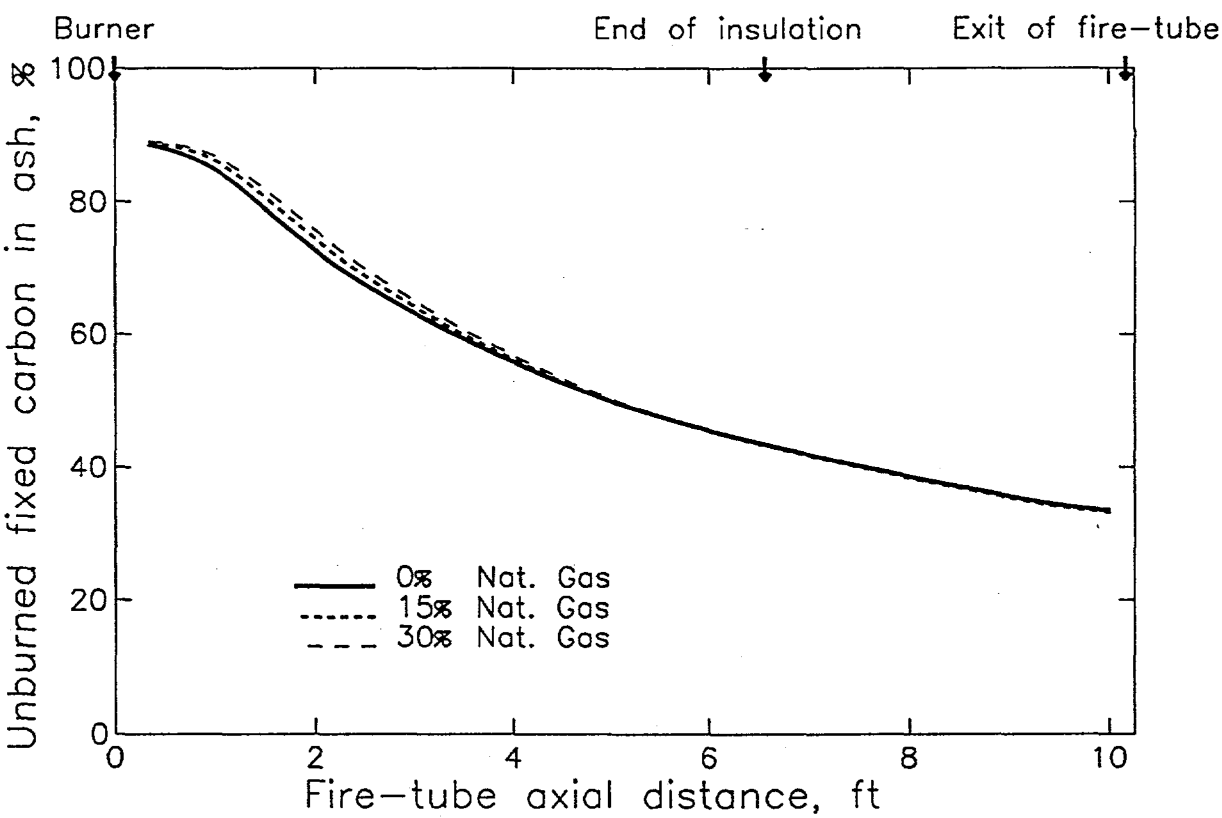


Figure 2−7. Impacts of gas co−firing on unburned fixed carbon in ash.

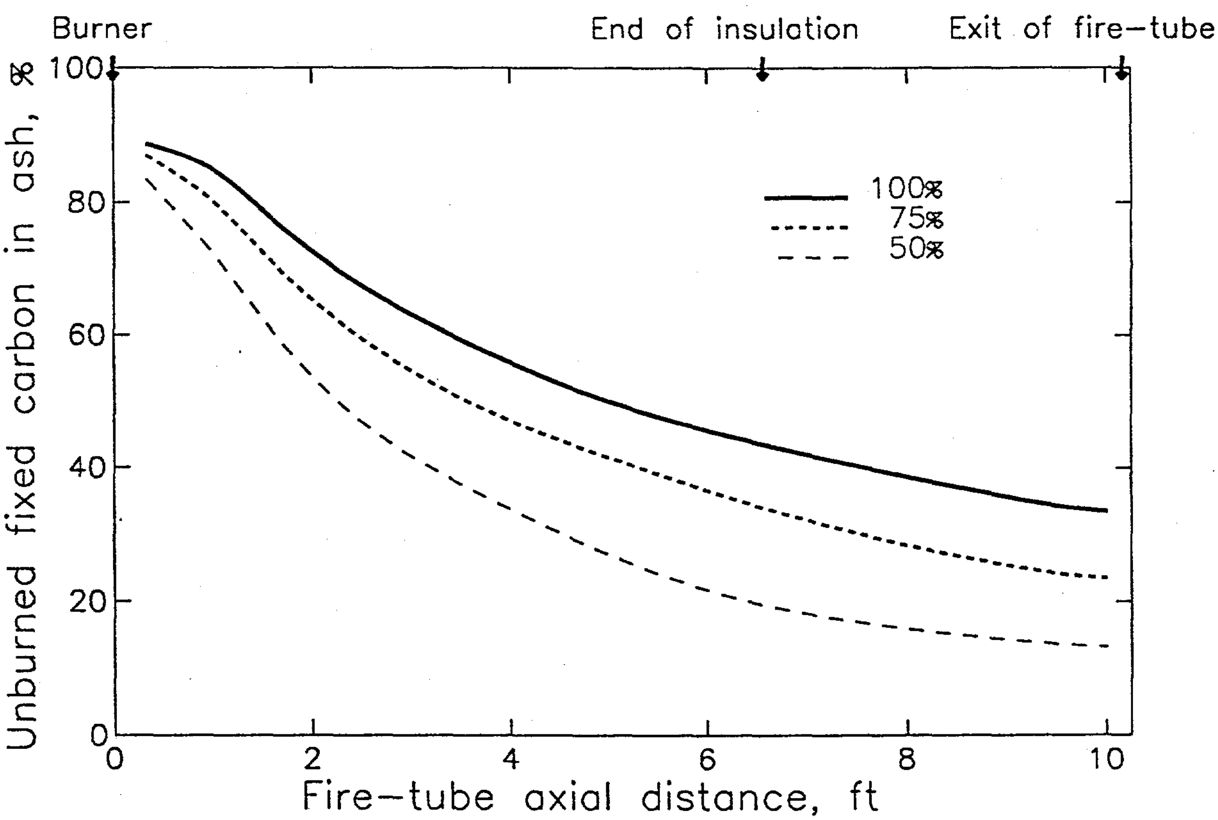


Figure 2-8. Impacts of thermal load on unburned fixed carbon in ash.

conductivity of ceramic paper was less than 1.5 Btu-in/hr-ft^2-^{o}F for the service temperature below 2500^{o}F. Figure 2-9 shows the thermal conductivity of ceramic paper as a function of refractory service temperature. Figure 2-10 shows the schematic of the CWS fire-tube boiler system used in the study. Diverting the flue gas from the exit of the second pass rather than from the exit of first pass was preferred due to the anticipated lower flue gas temperatures exiting the second pass which allow the use of a less expensive air heater material. The amount of ash recycle was maintained at a constant value of sixty percent, based on the hardware specification of the ash reinjection cyclone.

MODEL PERFORMANCE ANALYSIS

After the design modifications were selected based on the analysis from the initial parametric study results, six cases were simulated to assess the impacts of fuel and load variations on thermal characteristics, boiler performance, and boiler efficiency. Figure 2-11 shows the two-dimensional computational grid used for the performance analysis. The installation of refractory lining reduces the fire-tube combustion volume slightly. Table 2-3 summarizes the key parameters, mass flow rates and carbon burnout characteristics for the cases studied. Several parameters were held constant in the analyses: the refractory lining (39 inches), excess air (20 percent), recycled ash particles (60 percent), and quantity of gas co-fired (15 percent) when gas co-firing is applied. The fuel flow rate is calculated based on the dry lower heating value. The thermal load percentage was relative to the nominal fuel load of 3.74 million Btu/hr (100% MCR). The chemical heat carried by the carbon in the recycled fly ash was considered as additional fuel heat input. The modified CWS analyses and heating values used in the 2D code are summarized in Table 2-4, where the recycled ash and carbon contents and heat contents carried by the recycled ash are included.

Figures 2-12, 2-13, and 2-14 present the impacts of fuel and load variations on mean gas temperatures, refractory surface temperatures, and carbon in ash. Table 2-5 summarizes the impacts of these parameters on boiler performance and the ASME heat loss efficiency. The ASME heat loss method, as described in "ASME Test Form for Abbreviated Test" (PTC 4.1-a

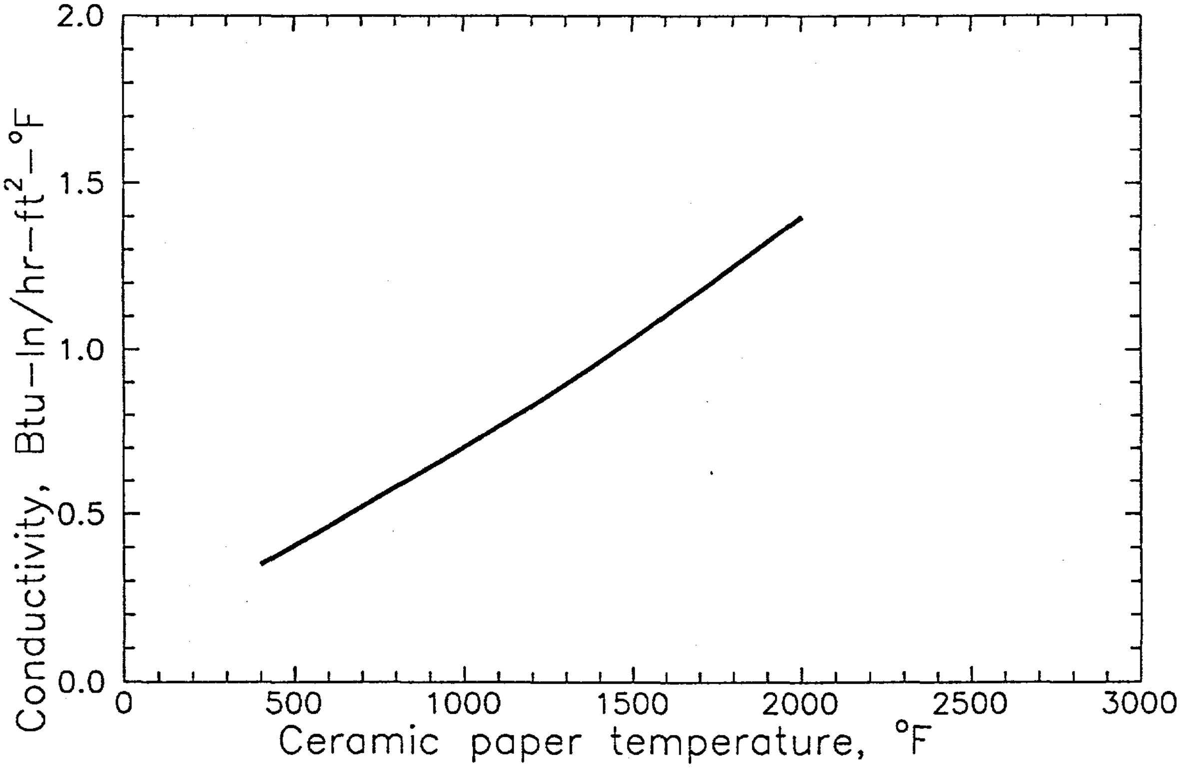


Figure 2–9. Thermal conductivity of ceramic paper as a function of temperature.

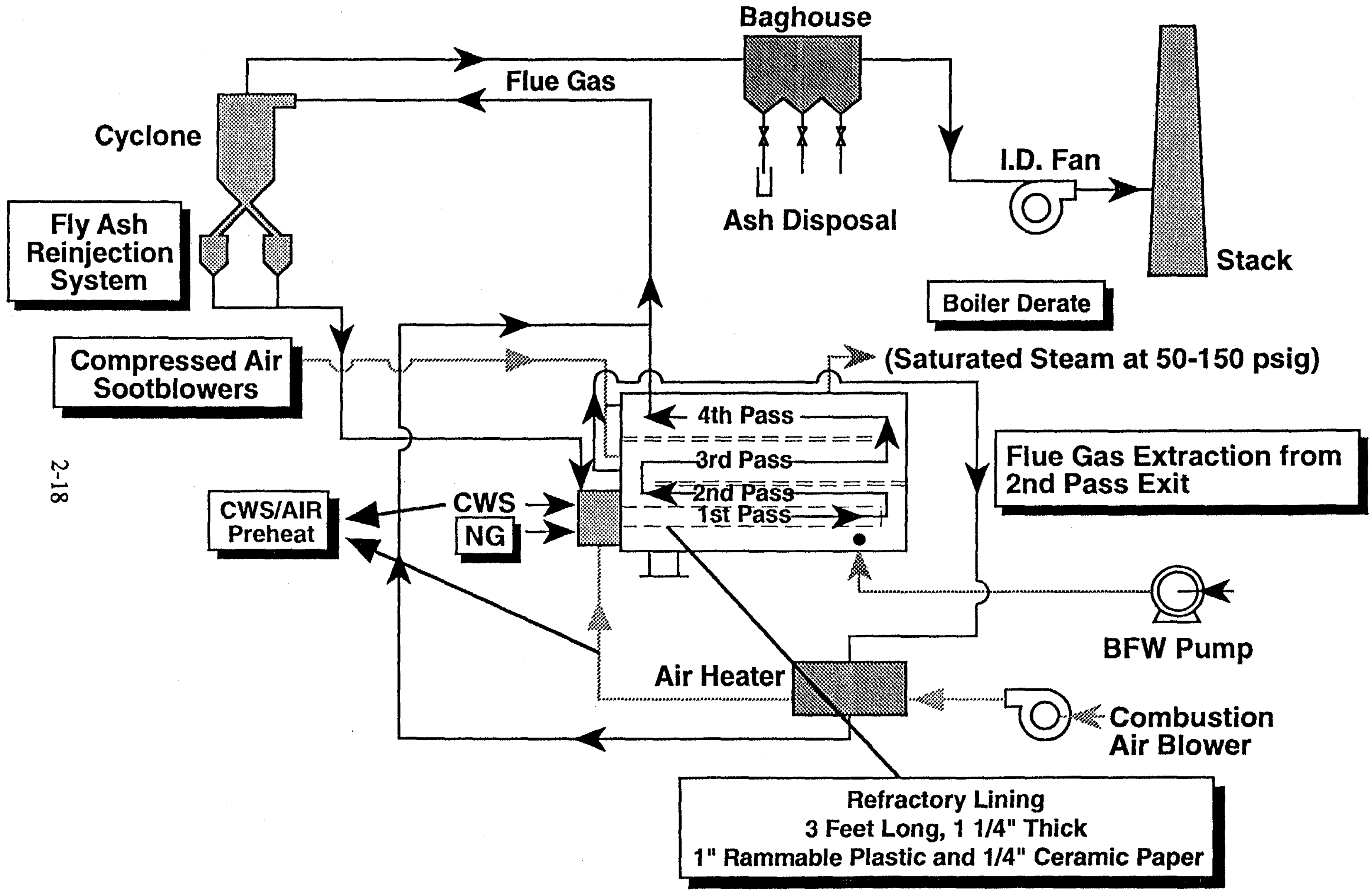


Figure 2-10. Schematic of the CWS fire-tube boiler system with design modifications high-lighted by shadowed boxes.

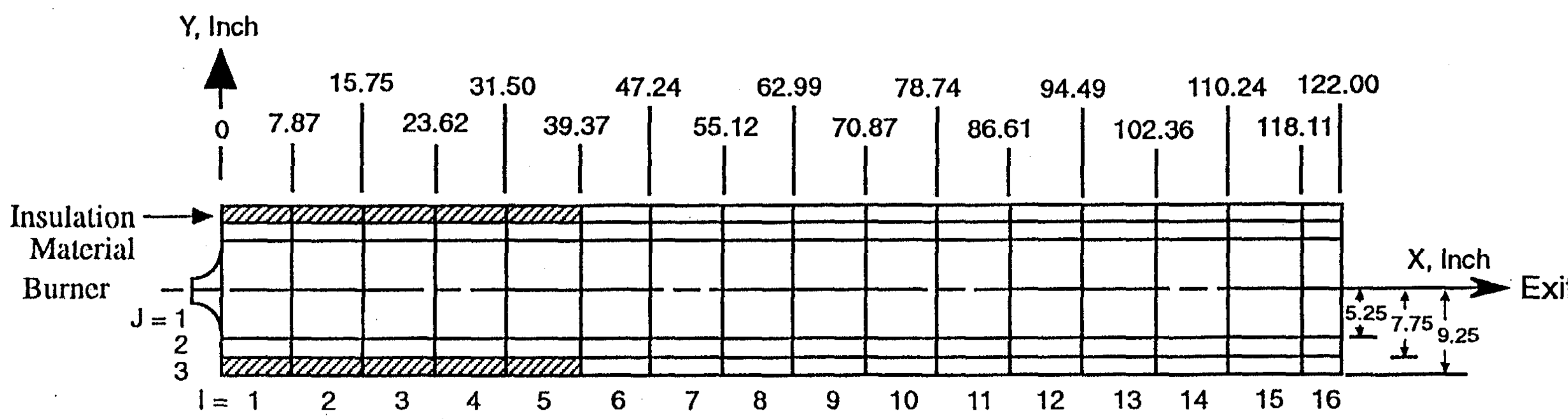


Figure 2-11. Sectional view of actual fire-tube geometry with refractory lining and 2D computational grid for initial parametric study.

TABLE 2-3. SUMMARY OF KEY PARAMETERS, MASS FLOWS, AND BURNOUT CHARACTERISTICS OF PERFORMANCE IMPACT STUDY CASES.

Description	Case 1	Case 1a	Case 2	Case 3	Case 4	Case 5
KEY PARAMETERS						
Load (%)	91	91	91	91	68	100
Fuel Type	Natural Gas	Natural Gas	CWS	85%CWS+ 15%Nat. Gas	85%CWS+ 15%Nat. Gas	CWS
60% Ash Recycled	N/A	N/A	Yes	Yes	Yes	Yes
Fuel CWS Temperature (F)	N/A	N/A	250	250	250	250
Fuel Nat. Gas Temperature (F)	77	77	N/A	77	77	N/A
Secondary Air Temperature (F)	600	77	600	600	600	600
Net Fuel Heat Input (MBtu/hr)	3.40	3.40	3.40	3.40	2.55	3.74
Unburned Fixed Carbon Heat Input (MBtu/hr)	N/A	N/A	0.08	0.06	0.03	0.10
Net Fuel Total Heat Input including Recycled Fixed Carbon (MBtu/hr)	3.4	3.4	3.48	3.46	2.58	3.84
Air Sensible Heat Input (MBtu/hr)	0.42	0.00	0.41	0.42	0.31	0.46
Fuel Sensible Heat Input (MBtu/hr)	0.00	0.00	0.02	0.02	0.01	0.02
MASS FLOWS						
Fuel CWS Flow (lbs/hr)	N/A	N/A	369	314	235	406
Fuel Nat. Gas Flow (lbs/hr)	172	172	N/A	25	19	N/A
Recycled Ash (lbs/hr)	N/A	N/A	9.4	8.0	6.0	10.3
Recycled Unburned Fixed Carbon (lbs/hr)	N/A	N/A	5.2	4.3	2.3	6.8
Total Recycled Mass (lbs/hr)	N/A	N/A	14.6	12.3	8.2	17.1
Total Air Flow (lbs/hr)	3248	3248	3268	3258	2427	3607
Total Mass Input (lbs/hr)	3421	3421	3652	3610	2692	4030
Flue Gas Extraction at the Exit of 2nd Pass (lbs/hr)	2163	N/A	2295	2263	1911	2438
Flue Gas Extraction (% of Total Mass Input)	63	N/A	63	63	71	60
Flue Gas through 3rd and 4th Pass (lbs/hr)	1258	N/A	1357	1347	782	1592
BURNOUT CHARACTERISTICS						
Unburned Fixed Carbon in Ash (%)	N/A	N/A	35.74	35.25	27.59	39.77
Unburned Fixed Carbon (% of Total Fixed Carbon Input)	N/A	N/A	8.41	8.24	5.82	9.93

TABLE 2-4. MODIFIED PROXIMATE, ULTIMATE ANALYSES AND HEATING VALUES OF CWS USED IN ASH RECYCLE CASES (2 THROUGH 5).

Case Number		Case 2	Case 3	Case 4	Case 5
Load (%)		91	91	68	100
Fuel Type		CWS	85%CWS+ 15%Nat. Gas	85%CWS+ 15%Nat. Gas	CWS
60% Ash Recycled		Yes	Yes	Yes	Yes
Proximate Analysis(lbs/100lb,wet)					
	Fixed Carbon	43.06	43.05	42.82	43.21
	Volatile	16.76	16.76	16.83	16.72
	Moisture	33.67	33.68	33.81	33.58
	Ash	6.51	6.51	6.54	6.49
	Total	100	100	100	100
Ultimate Analysis(lbs/100lb,dry)					
	Carbon	79.77	79.76	79.64	79.85
	Hydrogen	4.69	4.69	4.72	4.67
	Nitrogen	1.49	1.49	1.5	1.48
	Oxygen	3.56	3.57	3.59	3.55
	Sulfur	0.67	0.67	0.67	0.67
	Ash	9.82	9.82	9.88	9.78
	Total	100	100	100	100
High Heating Values(Btu/lb)		9347	9345	9324	9360

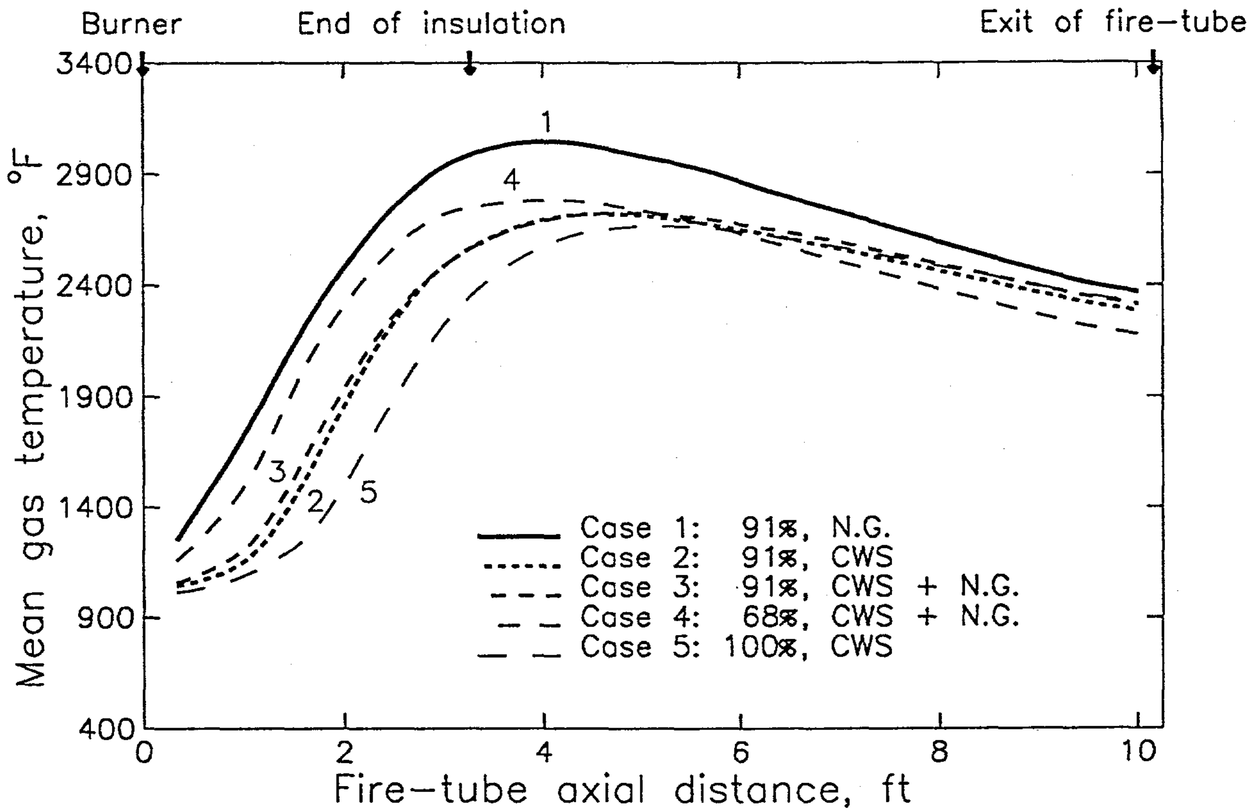


Figure 2–12. Impacts of fuel and load variations on mean gas temperatures.

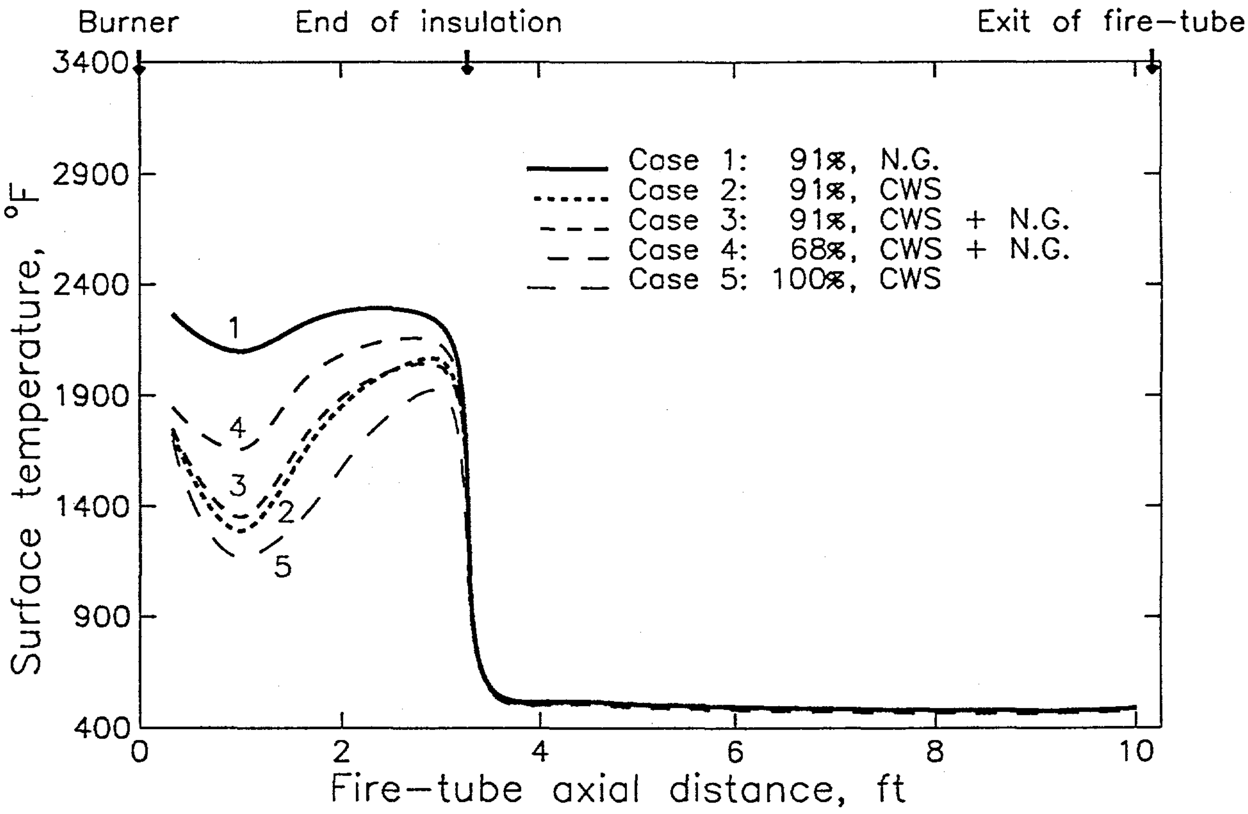


Figure 2-13. Impacts of fuel and load variations on surface temperatures.

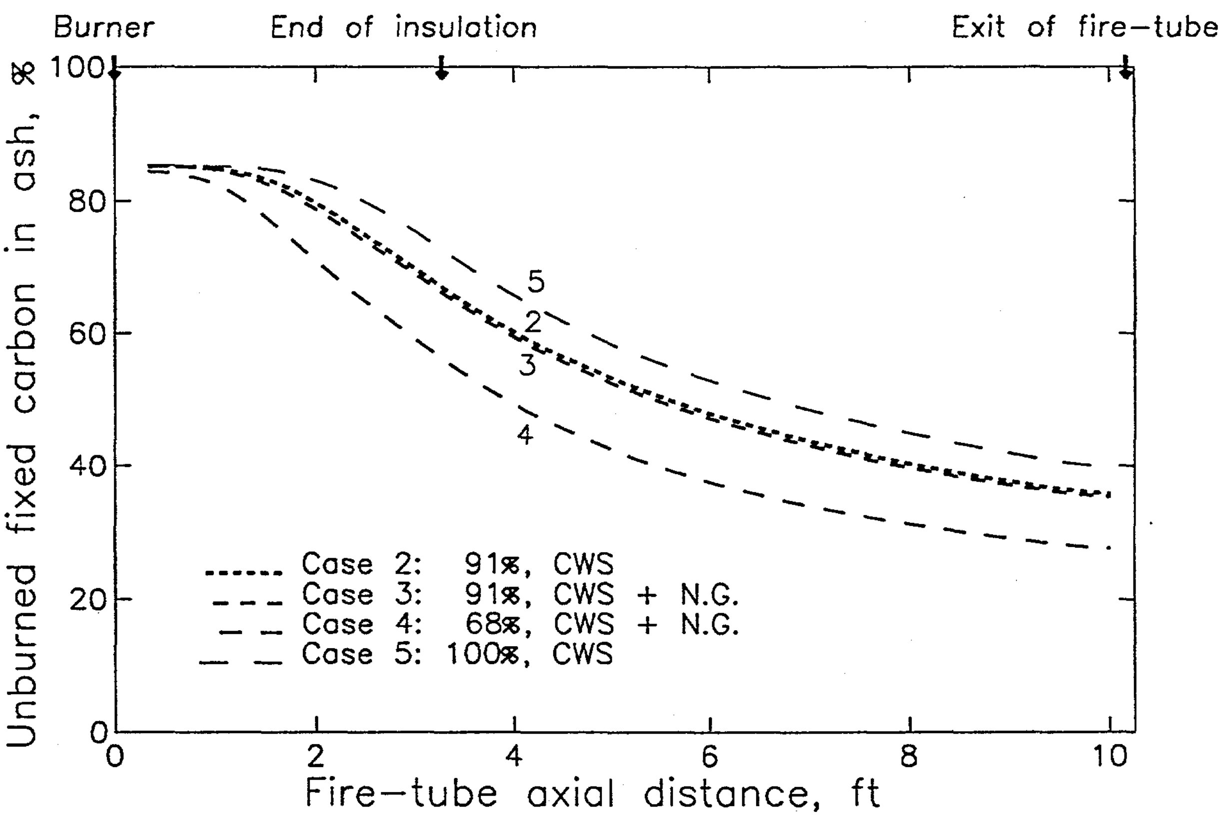


Figure 2−14. Impacts of fuel and load variations on unburned fixed carbon in ash.

TABLE 2-5. IMPACTS OF FUEL AND LOAD VARIATIONS ON BOILER PERFORMANCE AND ASME HEAT LOSS EFFICIENCY.

Description	Case Number					
	Case 1	Case 1a	Case 2	Case 3	Case 4	Case 5
Load (%)	91	91	91	91	68	100
Case Description	Nat. Gas W/ Air Preheat	Nat. Gas W/O Air Preheat	CWS	CWS + Nat. Gas	CWS + Nat. Gas	CWS
BOILER PERFORMANCE						
Amount of Flue Gas Diverted to Air Heater (wt.% of total flue gas)	63%	N/A	63%	63%	71%	60%
Exit Gas Temperature (F) of						
Fire Tube	2,368	2,183	2,286	2,313	2,178	2,323
2nd Pass	999	948	988	999	893	1,020
3rd Pass	611	634	615	615	566	632
4th Pass	489	513	494	494	469	503
Baghouse Gas Inlet Temperature (F)	354	513	358	358	323	371
Heat Absorption (MBtu/hr)						
Fire Tube	1.44	1.24	1.35	1.34	1.15	1.41
2nd Pass	1.50	1.34	1.46	1.48	1.06	1.63
3rd Pass	0.15	0.31	0.14	0.15	0.08	0.18
4th Pass	0.05	0.12	0.05	0.05	0.02	0.06
Steam Heat Absorption (MBtu/hr)	3.13	3.00	3.01	3.02	2.31	3.27
Mean Gas Velocity (ft/s)						
Fire Tube	------	------	------	------	------	------
2nd Pass	51.20	49.20	50.80	50.90	36.50	56.70
3rd Pass	17.80	48.10	18.10	18.10	10.20	21.50
4th Pass	20.10	55.50	20.60	20.60	11.70	24.30
Saturated Steam Flow Rate(lb/hr)	2,713	2,606	2,608	2,617	2,005	2,836
ASME H. L. EFFICIENCY (%)						
Heat Loss due to Dry Gas	5.35	8.44	6.32	6.18	5.40	6.60
Heat Loss due to Moisture in Fuel	0.00	0.00	4.25	3.59	3.56	4.25
Heat Loss due to H2O from Combustion of H2	10.94	11.63	3.53	4.68	4.64	3.53
Heat Loss due to Combustion in Refuse	0.00	0.00	5.65	4.68	3.29	6.68
Unmeasured Losses*	0.75	0.75	0.75	0.75	0.75	0.75
Total Heat Losses (%)	17.30	21.07	20.75	20.12	17.89	22.05
Boiler Efficiency (%)	82.70	78.93	79.25	79.88	82.11	77.95

* Typical design values of a similar sized boiler.

and 4.1-b), considers six categories of heat losses: heat loss due to dry gas, moisture in fuel, water vapor generated by combustion of hydrogen in fuel, combustible matter in refuse, radiation, and unmeasured. Water vapor in flue gas is formed by both vaporization of moisture and combustion of hydrogen in the fuel. As long as the flue gas leaving the boiler carries the moisture in the vapor form, the latent heat of flue gas moisture normally becomes a loss to the unit. Heat exchange through the air heater is considered in the efficiency calculation. Heat losses were calculated based on the two-dimensional model results and flue gas temperatures entering the baghouse. The radiation and unmeasured heat losses were assumed to be typical values used for similarly sized boilers.

Impacts of fuel variation (Cases 1, 2 and 3)

Firing the boiler with natural gas produces the highest mean gas temperatures along the fire tube due to its highest fuel heat release (see Figure 2-12). Consequently, surface temperatures of the refractory wall were also higher for this case. The results also show that the mean gas temperatures in the entire tube length do not exceed the ash initial deformation temperature of 2700°F while the CWS is fired. Furthermore, refractory surface temperatures of all three cases were maintained below the maximum continuous-use limit of the refractory (3000°F).

The performance impact of natural gas co-firing was negligible. The boiler efficiency with CWS firing is approximately 3.5% lower than with only gas-firing since the heat loss increase due to dry gas, moisture in fuel and combustible in refuse is greater than the reduction of heat loss due to H_2O from combustion of H_2. The boiler efficiency is improved by approximately 0.6% when 15 percent of the total heat input was contributed by natural gas.

Impacts of load changes without natural gas co-firing (Cases 2 and 5)

Case 2: 91% load, 100% CWS

Case 5: 100% load, 100% CWS

Increasing the boiler load from 91 to 100 percent when firing CWS reduced the mean gas temperatures in the refractory zone due to delay of fuel chemical heat release. Carbon burnout was also reduced at the high load due to lower gas temperatures and residence times in the flame zone.

The steam generation at 100 percent load was increased to 2,836 lbs/hr, which is close to the originally-designed steam production. The drop of efficiency for 100 percent load is due to an increase of heat losses due to dry gas and unburned fixed carbon in ash.

Impacts of load changes with natural gas co-firing (Cases 3 and 4)

Case 3: 91% load, 85% CWS/15%NG

Case 4: 68% load, 85% CWS/15%NG

The general trends predicted for co-firing natural gas with CWS were similar to those for the predicted cases without co-firing. However, the magnitude of the impact was increased for Cases 3 and 4 in comparison to Cases 2 and 5 due to the increase of load difference.

Impacts of air preheat and flue gas diversion

Case 1: 91% load, 100%NG

The flue gas temperature entering the baghouse was controlled by mixing the gas leaving the fourth pass with the exhausted flue gas from the air heater. The mixing temperatures were targeted to be below the baghouse material allowable maximum of 400°F.

Firing the natural gas with preheated combustion air (Case 1), in comparison to the case without air preheat (Case 1a), improved boiler efficiency by approximately 3.8%, and increased steam generation. Without air preheat, the flue gas temperature entering the baghouse exceeded the allowable limit. This occurred due to a reduction of residence time in the third and fourth passes, when no flue gas was extracted.

Independent of the fuel burned in the boiler at 91 percent load, 63 percent of the total flue gas mass flow was diverted to the air heater at the exit of the second pass to heat the combustion air to 600°F. Table 2-5 also shows that the increase in the boiler load reduced the quantity of flue gas diverted through the air preheater. The flue gas temperature entering the baghouse was increased as the load increased due to the higher flue gas temperatures at the fourth pass exit for higher load.

MODEL VALIDATION

The design modifications and operational conditions were optimized based on the model performance analysis and were implemented in the field. Due to some unexpected operational problems (fuel transportation, ash slagging, and fouling on air heater), the design modifications were fine-tuned to resolve these initial obstacles. In this section, fine-tuned modifications are discussed first, followed by comparison of model predictions to field data, which were collected for a wide range of operational conditions after the boiler was retrofitted with final design modifications.

Fine-Tuned Modifications

The CWS was not preheated for the final retrofit, since preheating the CWS made the viscosity increase to unacceptable levels. Since the coal ash caused air heater fouling the amount of flue gas extracted from the exit of 2nd pass was higher than originally-designed and the preheated combustion air temperatures were 150°F to 200°F lower than the targeted value of 600°F. The boiler was originally fitted with three feet of refractory sleeve and 15 inches of burner refractory lining. Based on this configuration, ash slagged around the refractory zone. Therefore, two feet of the refractory sleeve was removed for the final test runs. Figure 2-15(a) shows the sectional view of the fire-tube geometry with a one foot long refractory sleeve in the

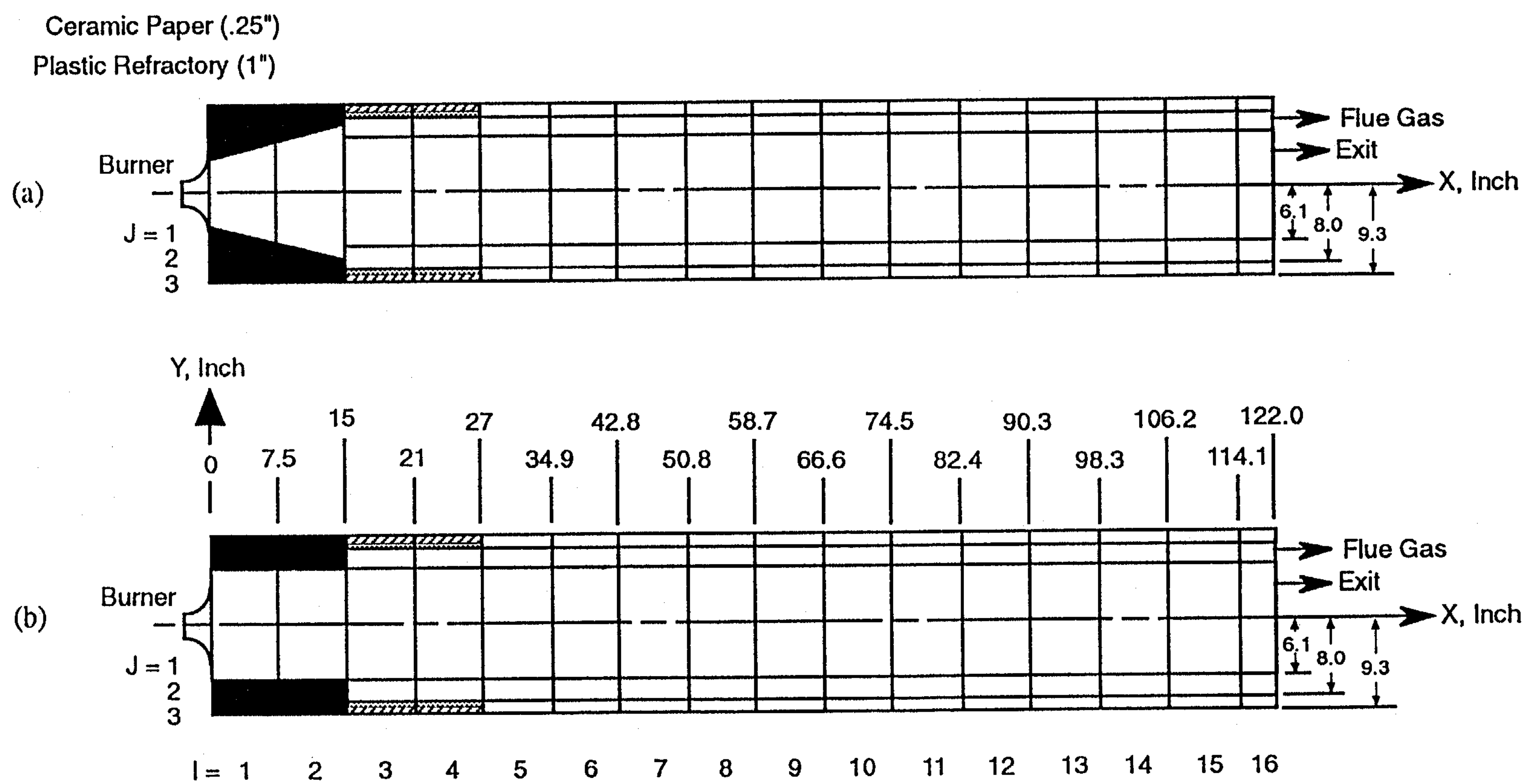


Figure 2-15. Fire-tube retrofit used for the final test runs:
(a) Sectional view of the actual fire-tube geometry showing division into zones.
(b) 2D computational grid.

fire-tube and a fifteen inch long cone-shaped burner throat configuration with insulation materials around the cone. Figure 2-15(b) shows the two-dimensional computational grid used in the final retrofit.

Field Test Results

After the boiler was retrofitted with the CWS firing system, coal reactivity and fouling factors for the 2nd pass were adjusted in the model to correctly simulate post-retrofit boiler performance. Table 2-6 lists the representative fuel analysis and higher heating value of the CWS, which were sampled during the final test runs. Table 2-7 summarizes the key parameters of ten model validation cases. The field tests, ranging from 39 to 71% MCR, were basically conducted by varying natural gas flows with a constant CWS flow rate for the first four pairs of tests. The last two tests were performed to evaluate the carbon conversion impact caused by the ash recycle. The amount of flue gas extraction was calculated based on the energy balance around the air heater, where air flow rates, air and flue gas temperatures were all field data, assuming that there was no heat loss to ambient due to the heavy insulation around the air heater. The modified CWS analyses and heating values used in the 2D code for the final test runs are summarized in Table 2-8. Table 2-9 summarizes the comparison of measured data to model predictions for the ten model validation cases. In Table 2-9, the predicted and measured carbon-in-ash values are compared at the entrance of the ash cyclone(i.e., after merging the flue gas streams from the exit of the 4th pass with the stream exhausted from the air heater). Table 2-9 also reports the actual carbon-in-ash from the baghouse and exit of the cyclone. The measured carbon-in-ash in Table 2-9 is calculated from the actual carbon-in-ash at the cyclone outlet and baghouse and the mass ratio of ash flow from each.

Figure 2-16 shows that the comparison of measured data to predicted flue gas temperatures at locations of each pass exit, entering the baghouse, and leaving the air heater for various operating conditions. The predicted gas temperatures were basically in good agreement with the field data except for the locations at the first pass exit and the baghouse entrance. The gas temperatures at the baghouse entrance were predicted higher than the measured values

TABLE 2-6. CWS FUEL ANALYSES AND HIGHER HEATING VALUE USED IN MODEL VALIDATION CASES.

Fuel		Coal Water Slurry
Proximate Analysis (lbs/100lb,wet)		
	Fixed Carbon	40.55
	Volatile	16.41
	Moisture	37
	Ash	6.04
	Total	100
Ultimate Analysis (lbs/100lb,dry)		
	Carbon	78.41
	Hydrogen	4.75
	Nitrogen	1.43
	Oxygen	5.02
	Sulfur	0.81
	Ash	9.58
	Total	100
High Heating Values (Btu/lb), Slurry:		8891

TABLE 2-7. SUMMARY OF KEY PARAMETERS AND MASS FLOWS OF MODEL VALIDATION STUDY CASES.

Description	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15
KEY PARAMETERS										
Load (%MCR)	50	63	61	71	39	51	44	54	62	62
% of Heat Input from Natural Gas	30	44	26	35	40	54	36	47	27	30
CWS*	70	56	74	65	60	46	64	53	73	70
60% Ash Recycled	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
Excess O2, vol.% dry	5.6	5.4	5.4	5.8	8.2	5.3	6.5	5.2	5.7	5.2
Fuel CWS Temperature (F)	63	70	58	68	60	69	64	69	57	57
Fuel Nat. Gas Temperature (F)	77	77	77	77	77	77	77	77	77	77
Secondary Air Temperature (F)	416	453	418	394	392	437	442	447	414	412
Net Fuel Heat Input (MBtu/hr)	1.87	2.36	2.28	2.64	1.46	1.91	1.66	2.02	2.32	2.32
Unburned Fixed Carbon Heat Input (MBtu/hr)	0.21	0.18	0.19	0.18	0.13	0.09	0.11	0.09	0.21	N/A
Net Fuel Total Heat Input including Recycled Fixed Carbon (MBtu/hr)	2.08	2.54	2.47	2.82	1.58	1.99	1.77	2.11	2.54	2.32
Air Sensible Heat Input (MBtu/hr)	0.18	0.25	0.22	0.24	0.16	0.18	0.18	0.20	0.22	0.20
Fuel Sensible Heat Input (MBtu/hr)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MASS FLOWS										
Fuel CWS Flow (lbs/hr)	150	150	200	200	100	100	125	125	200	200
Fuel Nat. Gas Flow (lbs/hr)	32	57	32	50	32	55	32	50	34	34
Recycled Ash (lbs/hr)	5.4	5.4	7.2	7.2	3.6	3.6	4.5	4.5	7.2	N/A
Recycled Unburned Fixed Carbon (lbs/hr)	14.7	12.1	13.5	12.4	8.9	6.0	8.1	6.3	10.9	N/A
Total Recycled Mass (lbs/hr)	20.1	17.5	20.7	19.6	12.5	9.6	12.6	10.9	18.1	N/A
Total Air Flow (lbs/hr)	2240	2700	2637	3078	2037	2100	2030	2213	2760	2448
Total Mass Input (lbs/hr)	2441	2925	2889	3348	2181	2264	2199	2398	3017	2682
Flue Gas Extraction at the Exit of 2nd Pass (lbs/hr)	1682	1844	1970	1442	1674	1693	1617	1809	2201	1973
Flue Gas Extraction (% of Total Mass Input)	69	63	68	43	77	75	74	75	73	74
Flue Gas through 3rd and 4th Pass (lbs/hr)	759	1081	918	1905	507	572	583	589	816	708

* Percentages of heat input from natural gas and CWS are added up 100%.

TABLE 2-8. MODIFIED CWS FUEL ANALYSES AND HEATING VALUES USED IN MODEL VALIDATION STUDY CASES 6 THROUGH 14.

Description	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
Load (%MCR)	50	63	61	71	39	51	44	54	62
% of Heat Input from Natural Gas	30	44	26	35	40	54	36	47	27
CWS*	70	56	74	65	60	46	64	53	73
60% Ash Recycled	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Proximate Analysis(lbs/100lb,wet)									
Fixed Carbon	44.39	43.53	42.84	42.57	43.95	42.45	42.69	41.97	43.16
Volatile	14.47	14.69	14.87	14.94	14.58	14.97	14.91	15.1	14.79
Moisture	32.62	33.13	33.53	33.69	32.88	33.76	33.62	34.04	33.34
Ash	8.52	8.65	8.76	8.8	8.59	8.82	8.78	8.89	8.71
Total	100	100	100	100	100	100	100	100	100
Ultimate Analysis(lbs/100lb,dry)									
Carbon	77.45	76.94	76.51	76.35	77.19	76.27	76.42	75.98	76.72
Hydrogen	3.92	4.01	4.08	4.11	3.96	4.12	4.1	4.17	4.04
Nitrogen	1.18	1.21	1.23	1.24	1.19	1.24	1.23	1.26	1.22
Oxygen	4.14	4.23	4.31	4.34	4.19	4.36	4.33	4.41	4.27
Sulfur	0.67	0.68	0.7	0.7	0.68	0.7	0.7	0.71	0.69
Ash	12.64	12.93	13.17	13.26	12.79	13.31	13.22	13.47	13.06
Total	100	100	100	100	100	100	100	100	100
High Heating Values(Btu/lb)	9098	9013	8946	8919	9056	8907	8931	8860	8978

* Percentages of heat input from natural gas and CWS are added up 100%.

TABLE 2-9. COMPARISON OF MODEL PREDICTIONS TO FIELD TEST DATA OF CARBON IN ASH AND GAS TEMPERATURES, AFTER THE BOILER IS RETROFITTED WITH CWS SYSTEM.

Case number	Load (%MCR)	Carbon in ash (%)*			Exit gas temperatures (deg. F)										Total heat abs. (MBtu/hr)	
		Pred.	Msd.		1st pass		2nd pass		3rd pass		4th pass		Baghouse			
		4th Pass	Cycl.	Bag.	Pred.	Msd.	Pred.	Msd.	Pred.	Msd.	Pred.	Msd.	Pred.	Msd.	Pred.	Msd.
6	50	53	73	58.5	1856	1405	868	806	531	502	431	397	450	386	1.67	1.60
7	63	47.3	69	58	1971	1600	927	935	562	529	448	420	444	431	2.11	2.08
8	61	62.9	65	51.6	1862	1583	898	850	546	540	438	416	459	408	1.76	1.70
9	71	55.3	63	45.9	1915	1616	936	958	587	581	464	476	411	421	2.20	2.19
10	39	55.8	71	56.8	1667	1483	811	738	502	532	416	409	437	365	1.27	1.20
11	51	38.7	62.5	45.2	1912	1624	866	833	517	532	421	414	452	414	1.73	1.68
12	44	46.7	64.3	48.6	1798	1785	837	847	512	500	420	407	416	411	1.45	1.42
13	54	40.2	58	40.9	1922	1541	881	844	524	544	426	421	463	424	1.80	1.76
14	62	57	60	54	1841	1584	902	822	547	566	440	424	485	409	1.79	1.70
15	62	60	-	69	1897	1707	891	794	530	543	427	414	479	390	1.84	1.76

* The carbon-in-ash values were predicted at the exit of the 4th pass,
while the carbon burnouts were measured at the ash cyclones and the baghouse.

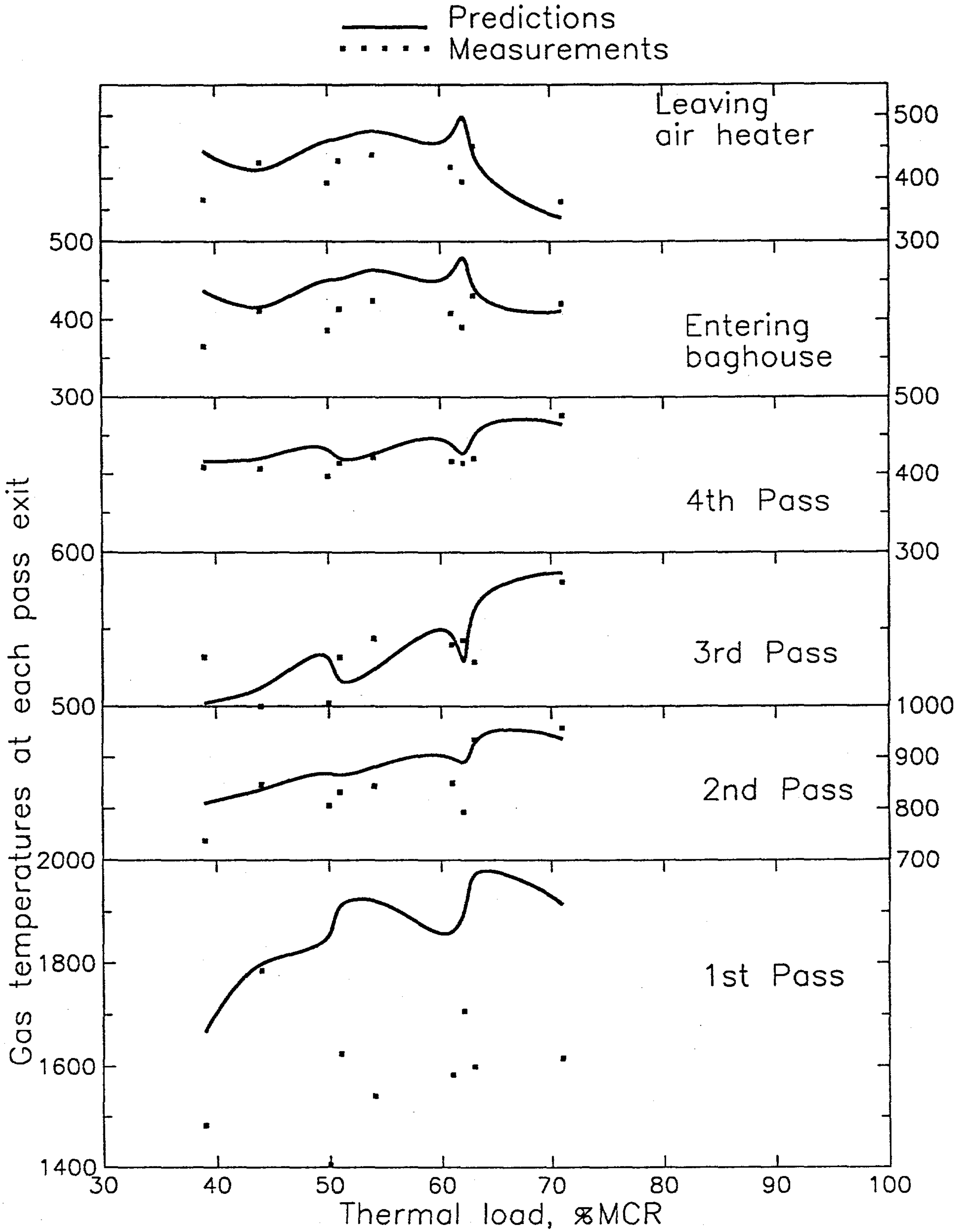


Figure 2–16. Comparison of predicted gas temperatures at pass exit with measured data at various operating conditions.

mainly due to the higher gas temperatures at the exit of the air heater, which is caused by the uncertainty of the fouling factor in the 2nd pass and air heater. The gas temperatures at the exit of the 1st pass were predicted 150 to 300°F higher than the measured values. However, the predicted results for the validation cases are in line with the gas temperatures listed in Table 2-5, where the impacts of fuel and load variations were studied.

In spite of the discrepancy between predicted and measured intermediate gas temperatures inside the boiler passes, Figure 2-17 shows that the overall heat absorptions predicted by the performance models agree reasonably well with the measurement data. This implies that the overall heat transfer is strongly driven by the temperature difference between the tube wall and gas temperature. Higher gas temperatures at the first pass exit predicted by the performance models, providing a higher heat transfer driving force from gas to wall in the 2nd pass, consequently result in higher heat absorptions there. The predicted gas temperatures at the 2nd pass exit therefore were in better agreement with field data than the agreement for the first pass. The dips on the fitted curve in the figure were mainly caused by the variation of the percentage distributions between gas and CWS heat inputs.

Figure 2-18 compares the overall carbon-in-ash prediction to field data at the location before entering the ash cyclone. The agreement is reasonably good for the higher loads (>60%MCR), while the model under-predicts the carbon burnout for the lower loads (<60%MCR). The discrepancy for the lower loads may be caused by the variation of the coal particle size distributions during the test runs. Since no ash samples were collected at the entrance of the ash cyclone, the carbon-in-ash values measured at the baghouse and ash cyclone were used to calculate the corresponding values at this location. Also the total input ash is assumed distributed between the cyclone and baghouse at a constant mass ratio of 0.6:1.0, which is based on the manufacturer's design specification of the cyclone. Figure 2-19 shows the impact of thermal load on carbon in ash and shows the comparison of model predictions to field data. The thermal loads were adjusted by varying the CWS flow rates while natural gas flow rates were maintained constants. Generally speaking, both the prediction and field data indicate

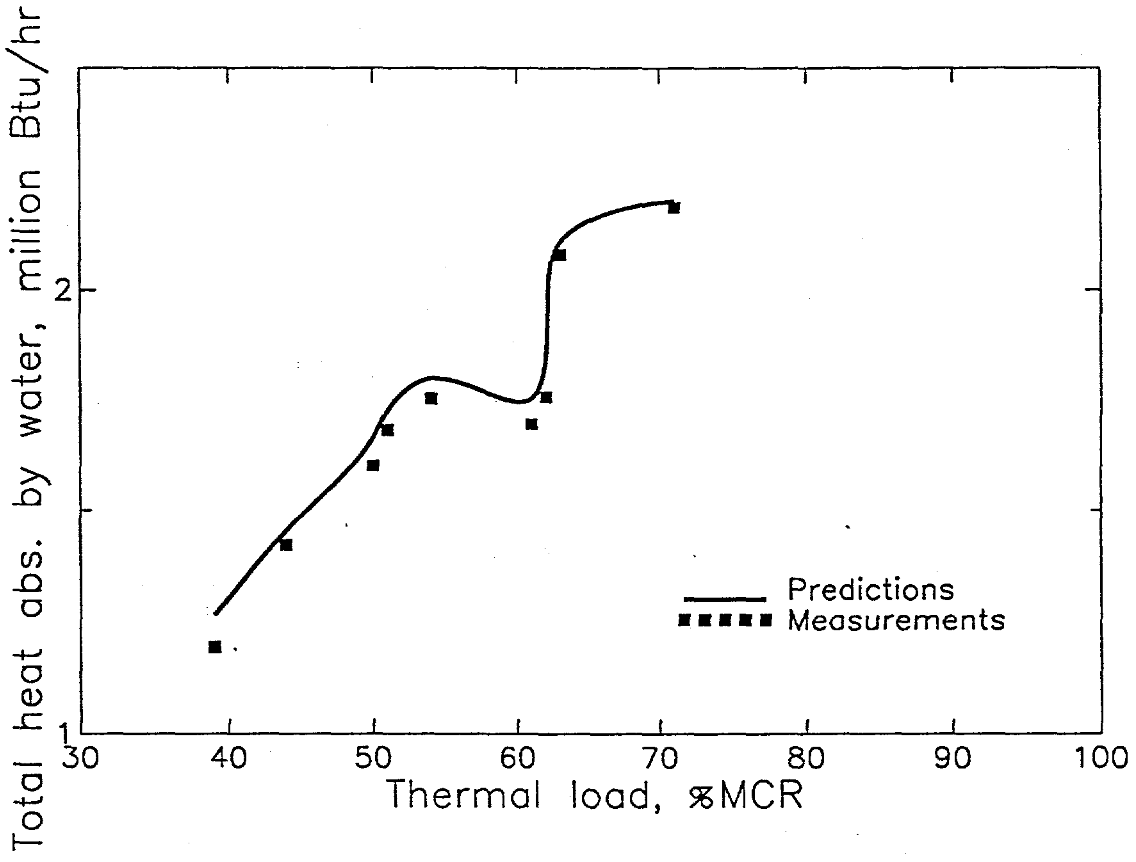


Figure 2–17. Comparison of total heat absorptions by water with measured data at various operating conditions.

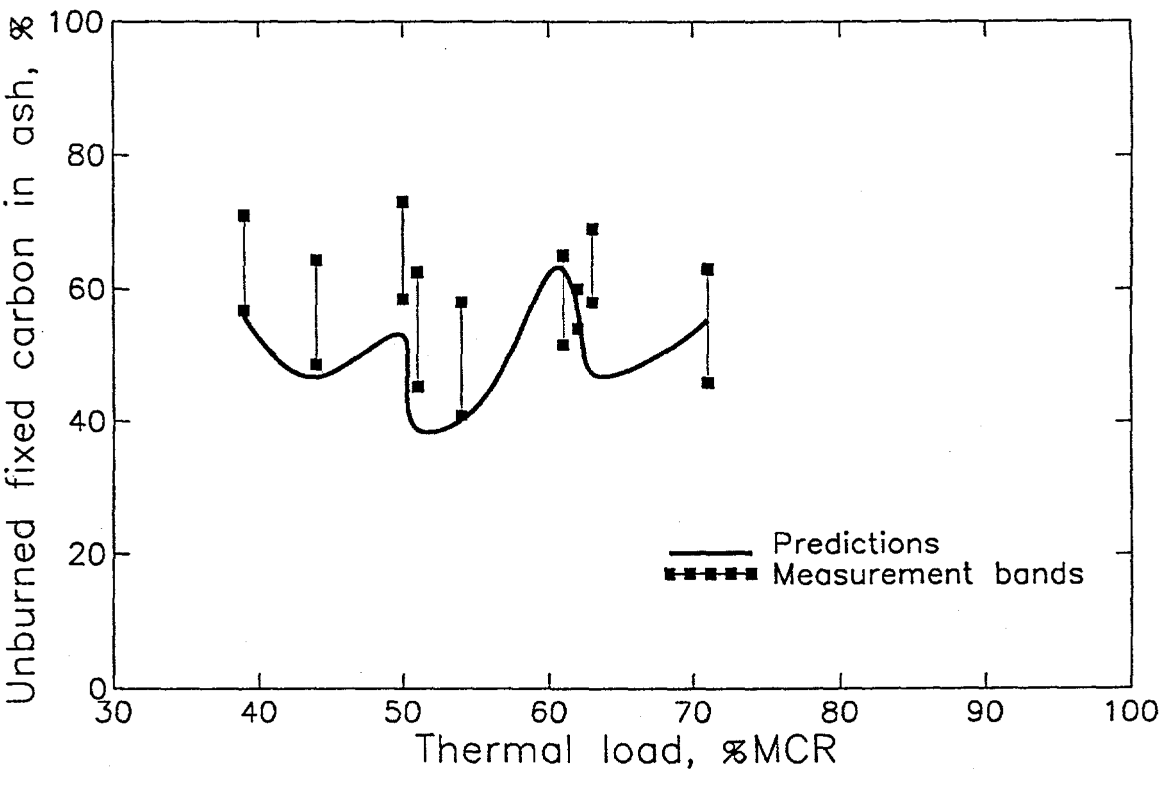


Figure 2-18. Comparison of predicted carbon-in-ash values with measured data at various operating conditions.

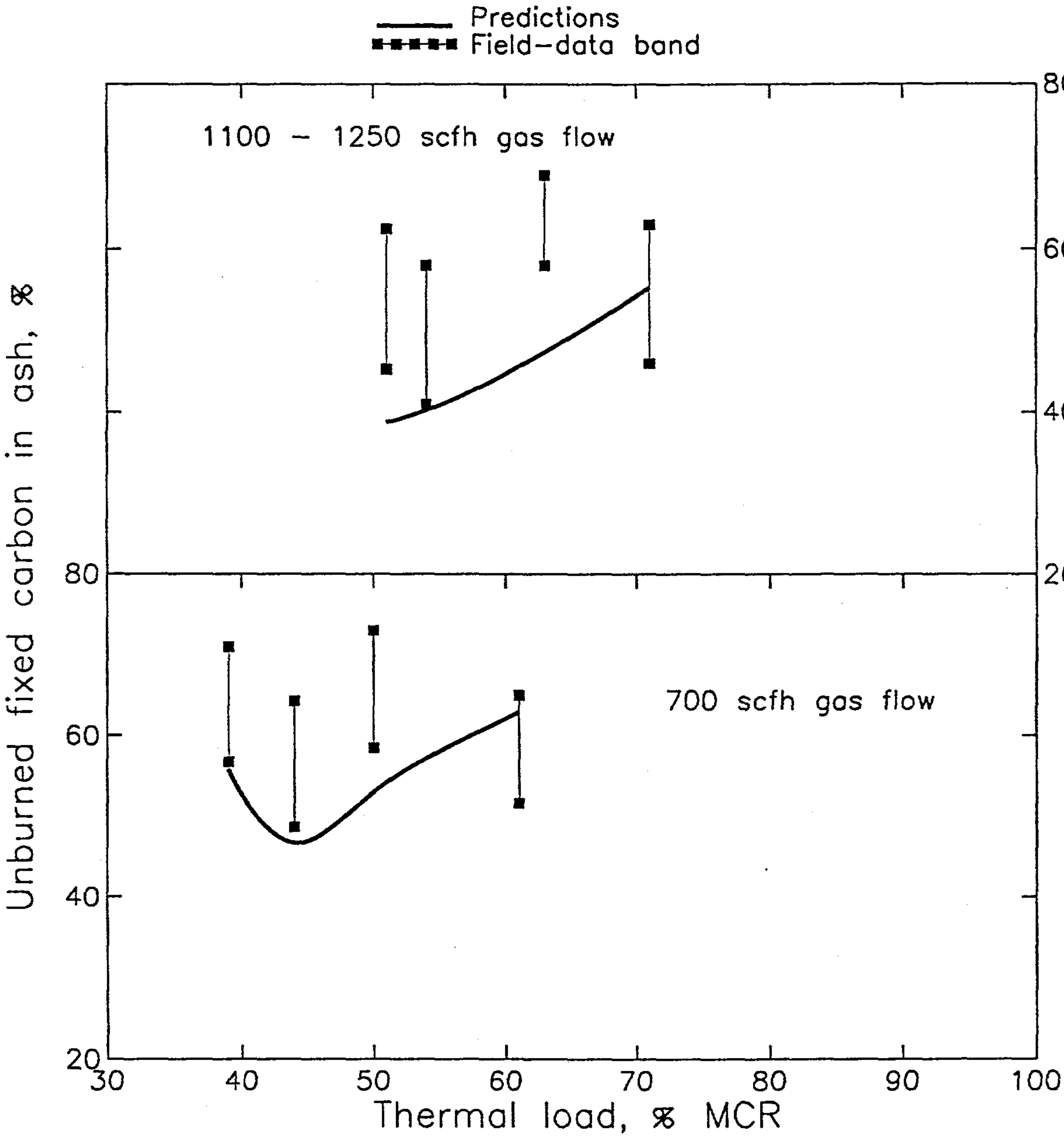


Figure 2-19. Impact of thermal load on carbon in ash and comparison of of model predictions to field data with constant gas flows.

that derating the boiler increases the carbon burnout due to the increase of flue gas residence-time in the fire tube, even though the model under predicts the carbon-in-ash values.

Figure 2-20 shows the impact of natural gas co-firing on carbon-in-ash profiles and shows the comparison of model predictions to field data. Four pairs of predicted and measured carbon-in-ash values were plotted in the figure for four constant CWS flows with various natural gas heat input percentages. The results indicate that increasing the heat input percentage by natural gas (mostly exceeding thirty percent) reduces the carbon loss from the fly ash. However, the earlier predictions indicated that there would be no significant impact on carbon conversion, when up to thirty percent of the total heat input is contributed by natural gas. The results also show that agreement between measurement and prediction was better for the high CWS flow cases than for the low CWS flow cases.

Table 2-9 illustrates, the impact of ash recycle on carbon conversion for Cases 14 and 15. The measured carbon-in-ash improvement due to ash recycle is supported by the model predictions, even though the predicted magnitude of change is 6% less than the measured one.

The impact of thermal load on the flue gas amount required to preheat the combustion air is shown in Figure 2-21. The amount of flue gas extracted from the exit of the 2nd pass decreases as the load increases mainly due to the higher gas temperatures entering the air heater for the higher load cases. The results show that the trend of field data is in line with the trend earlier predicted by the models.

CONCLUSIONS

Thermal performance models were developed and applied to provide design information for the conversion of a gas- and oil- fired industrial fire-tube boiler to firing a coal-water slurry. Initially, models were calibrated against the boiler data for nominal gas-firing operating conditions. A parametric model study was then performed to provide information needed to optimize the design modifications and to select optimum operational conditions for a fire-tube

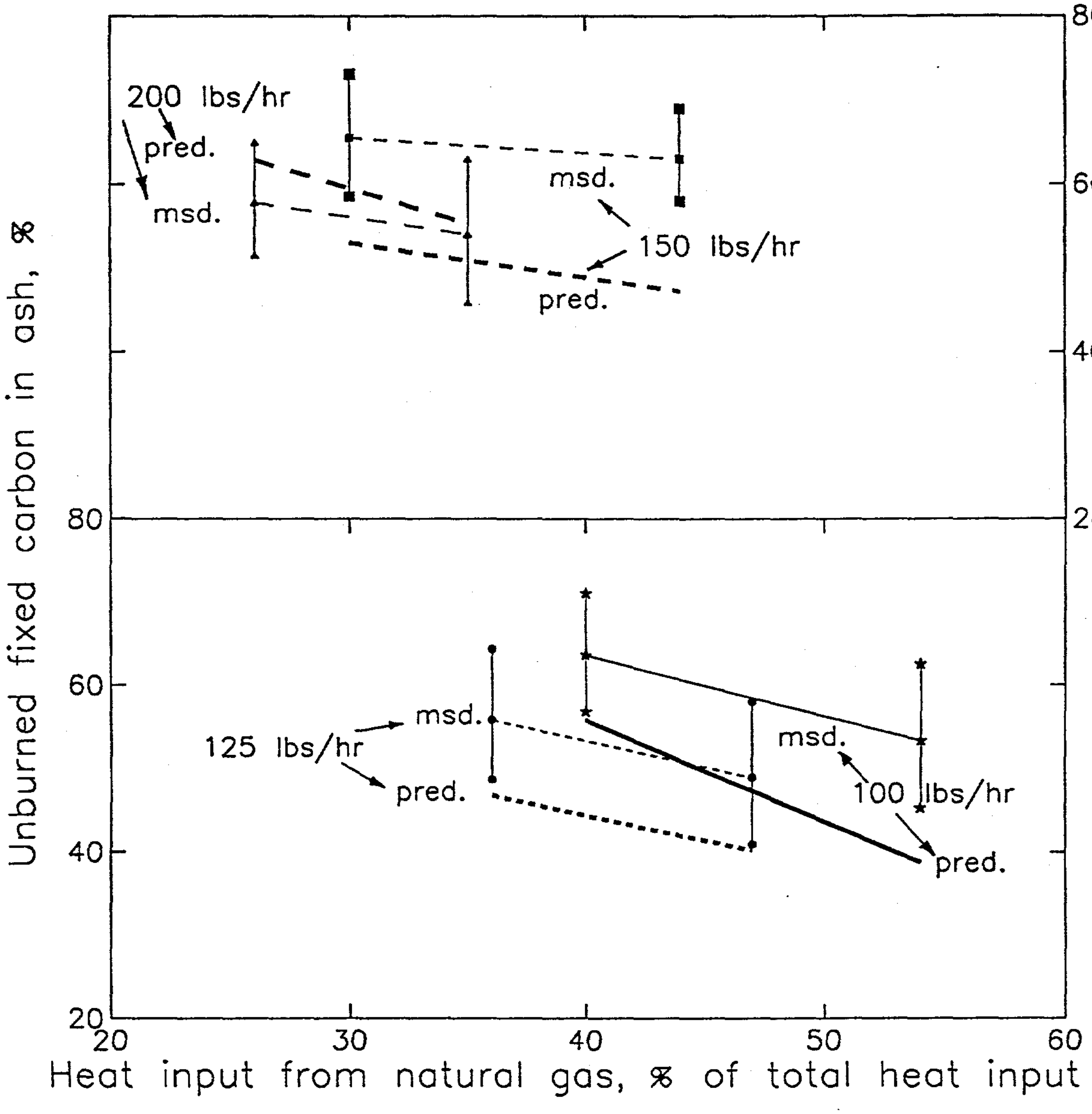


Figure 2-20. Impact of natural gas co-firing on carbon-in-ash values, and comparison of model predictions to field data.

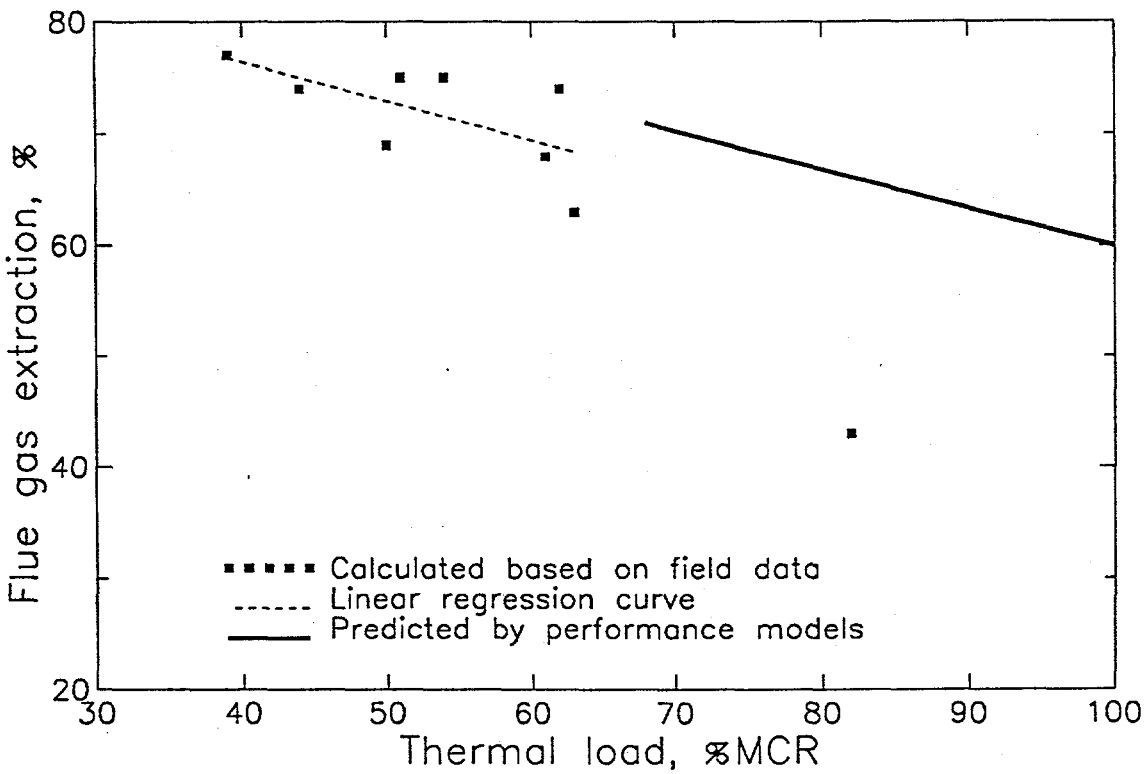


Figure 2–21. Impact of thermal load on flue gas extraction amount in percent of total mass input.

boiler retrofitted with coal-water slurry fuels. The model predictions assisted with the selection of the refractory lining length and thickness, maximization of carbon burnout efficiency, and evaluation of the impacts of various operating conditions within design limits imposed by the ash deformation temperature and the continuous-use limit of the refractory. The coal reactivity and 2nd pass fouling factor were fine-tuned in the model to correctly simulate post-retrofit boiler performance. Model results were then compared with field data at a wide range of operating conditions. Overall model predictions agreed reasonably well with field results from the retrofit boiler.

Retrofitting a fire-tube boiler with the CWS firing system will influence the thermal performance and operation of the boiler and, hence, requires the implementation of design modifications. In general, the study results indicate that converting the primary fuel from natural gas or oil to coal water slurry in an oil- and gas- fired fire-tube boiler requires:

- Retrofitting the boiler with a refractory lining to stabilize the high moisture flame, and enhance carbon conversion,
- Selecting an optimum length and configuration for the refractory material to avoid initiating slag formation in the tube and to resist abrasion from coal particles,
- Derating the boiler to improve the carbon burnout,
- Utilization of air preheat, ash recycle, and natural gas co-firing, to enhance combustion efficiency,
- Diverting the flue gas from the exit of the 2nd pass rather than the first pass to reduce the cost of the air heater.

In addition, the study results showed that:

- Compared to gas firing, firing an oil- or gas-fired fire-tube boiler on a coal water slurry decreases the boiler efficiency by approximately 3.5% at full load mainly due to the water content in the slurry fuel, unburned carbon in ash, and higher gas temperatures leaving the boiler.

- The boiler efficiency is improved by natural gas co-firing due to the reduced water content and lower carbon loss in the fly ash. Carbon conversion is increased for natural-gas heat inputs exceeding thirty percent of total heat input to the boiler, while natural gas co-firing below thirty percent of total heat input does not have a significant impact on carbon burnout.

- The amount of flue gas extracted from the exit of the 2nd pass decreases as the load increases mainly due to the higher gas temperatures entering the air heater for the higher load cases.

- Air preheating with gas-firing only increases the boiler efficiency by approximately 3.8 percent in comparison to gas-firing without air preheat.

2.3 System Design

This section discusses the design engineering of the various sub-systems that were integrated into the coal water slurry conversion.

2.3.1 Coal Water Slurry

The Coal water slurry was formulated at Jim Walters Resources #4 mine located in Brookwood, Alabama. During the fire-tube retrofit test 21,295 gallons were burned. There were eleven different slurries burned in the boiler. Ten were prepared by JWRI and one was prepared by Pennsylvania Electric Company. The CWS was manufactured from medium volatile southern bituminous Alabama coal. The coal fines that were made into CWS was from the cleaning facility filter cake. Table 2-6 had previously listed a typical ultimate and proximate analysis of the CWS. Table 2-10 presents the characteristics of the slurries used in the boiler testing. Figures 2-22, 2-23, and 2-24 report the particle size distribution. Figures 2-25, 2-26, and 2-27 report the particle size distribution on a cumulative basis. Figure 2-28 is the apparent viscosity vs. shear rate for the various slurries combusted during the performance testing. It is evident from the tables and figures that the properties for JWRI slurry numbers 2 and 4 were vastly different than all the remaining batches. Slurry number one was created by directing all of the coal fines through the wet stirred ball mill to produce a very fine slurry with a resulting high viscosity. In order to increase the production rate on slurry numbers 2 and 4, JWRI attempted to divert only a portion of the coal fines through the ball mill. The result was a better bi-modal distribution with a lower viscosity, however the ability to burn the larger particles with such a short residence time was not successful. Unburned carbon in the flyash increased and slagging was more apparent(firing occurred with the 15 inch refractory burner quarl and 3 foot refractory section in the fire-tube). As a result of this testing JWRI was instructed to continue producing slurry similar to slurry number one for the remainder of the program.

2.3.2 CWS Supply System

The CWS was delivered to the site by a tank truck. Slurry unloading was accomplished by an air operated diaphragm pump into the top of the 4500 gallon CWS storage tank. The tank could also be unloaded by the air-operated diaphragm pump if required. The CWS storage tank was equipped with a 2 HP mixer that operates for 6 minutes every hour, and a containment wall with a capacity of 110% of the CWS storage tank. The tank has a 120 degree cone on the bottom to promote continuous feed of the CWS.

Slurry flows from the CWS storage tank to the slurry pump which increases the slurry pressure to 150 psig. The slurry pump is a Moyno four stage progressive cavity type with a capacity of .07 to .7 gpm. Since the slurry pump can be damaged by high back pressure, the

Table 2-10 **Properties of CWF's Burned in the Fire-Tube Boiler**

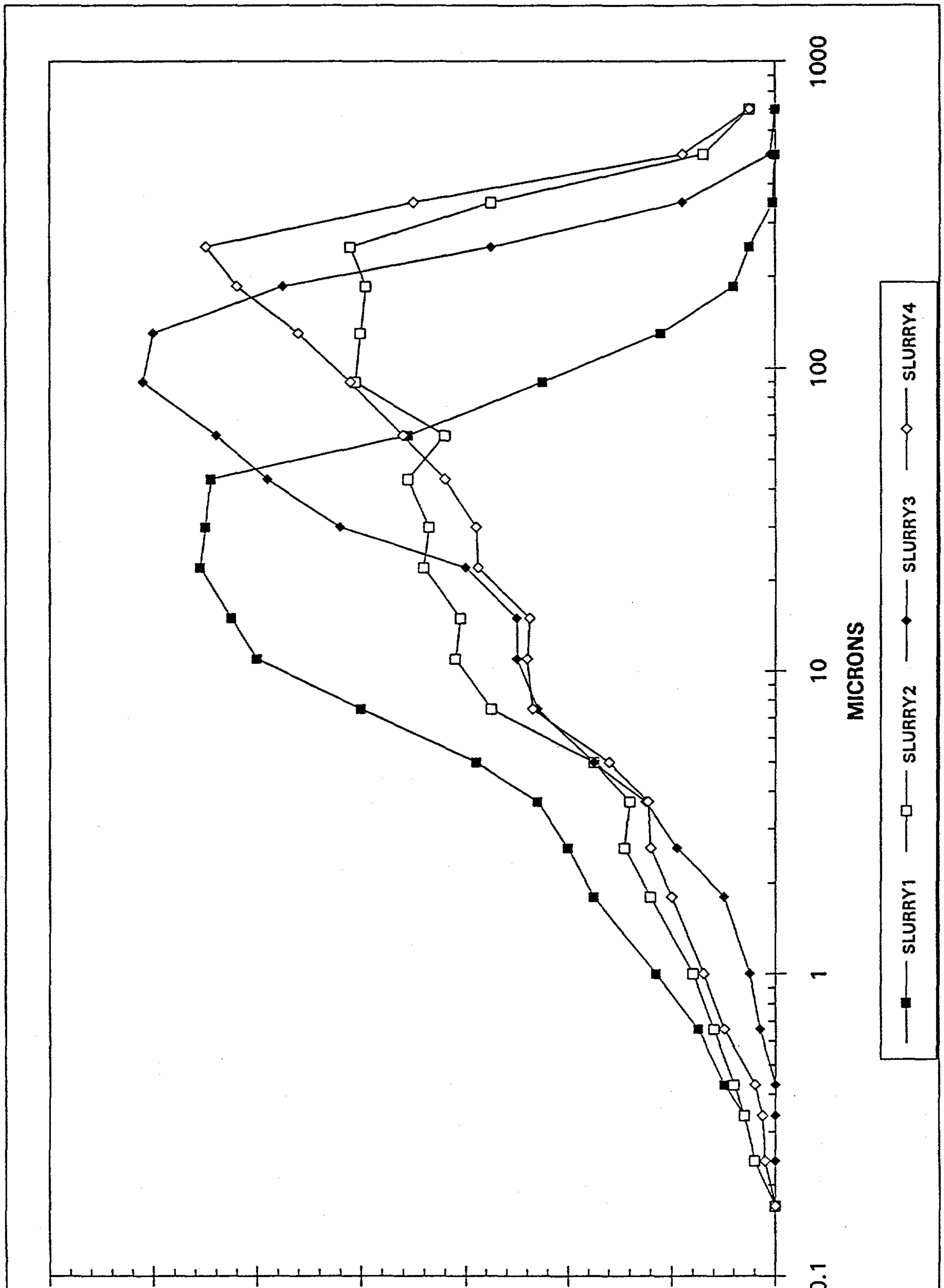
					Particle Size in Microns			Rheology	
Slurry Number	JWRI Shipment Date	UA Sampling Date	Solids	Ash (Dry)	10%	MW**	90%	Viscosity*** Cp	CWF **** Type
1	8/27/92	9/2/92	63.44	7.52	2	24	55	930	Rheopectic
2	9/28/92	9/30/92	65.00	7.94	3	79	226	109	Thixotropic
3	*	10/6/92	48.00		5	65	159	<100	Thixotropic
4	10/7/92	10/7/92	69.00	9.3	4	95	250	238	Thixotropic
5	10/13/92	10/13/92	63.00		2	26	55	398	Rheopectic
6	10/19/92	10/19/92	63.1	9.23	3	37	90	326	Rheopectic
7	10/22/92	10/23/92	62.8		3	31	71	518	Rheopectic
8	10/29/92	10/29/92	64.6		3	29	60	577	Rheopectic
9	11/13/92	11/16/92	64.00		2	27	60	658	Rheopectic
10	12/2/92	12/2/92	63.75		2	26	62	689	Rheopectic
11	1/13/93	1/18/93	63.5	7.8	2	25	60	458	Rheopectic

* The slurry was made by Penelec
** MV = Mean Volume Diameter
*** Apparent Viscosity in Centipoise @ 400 1/sec

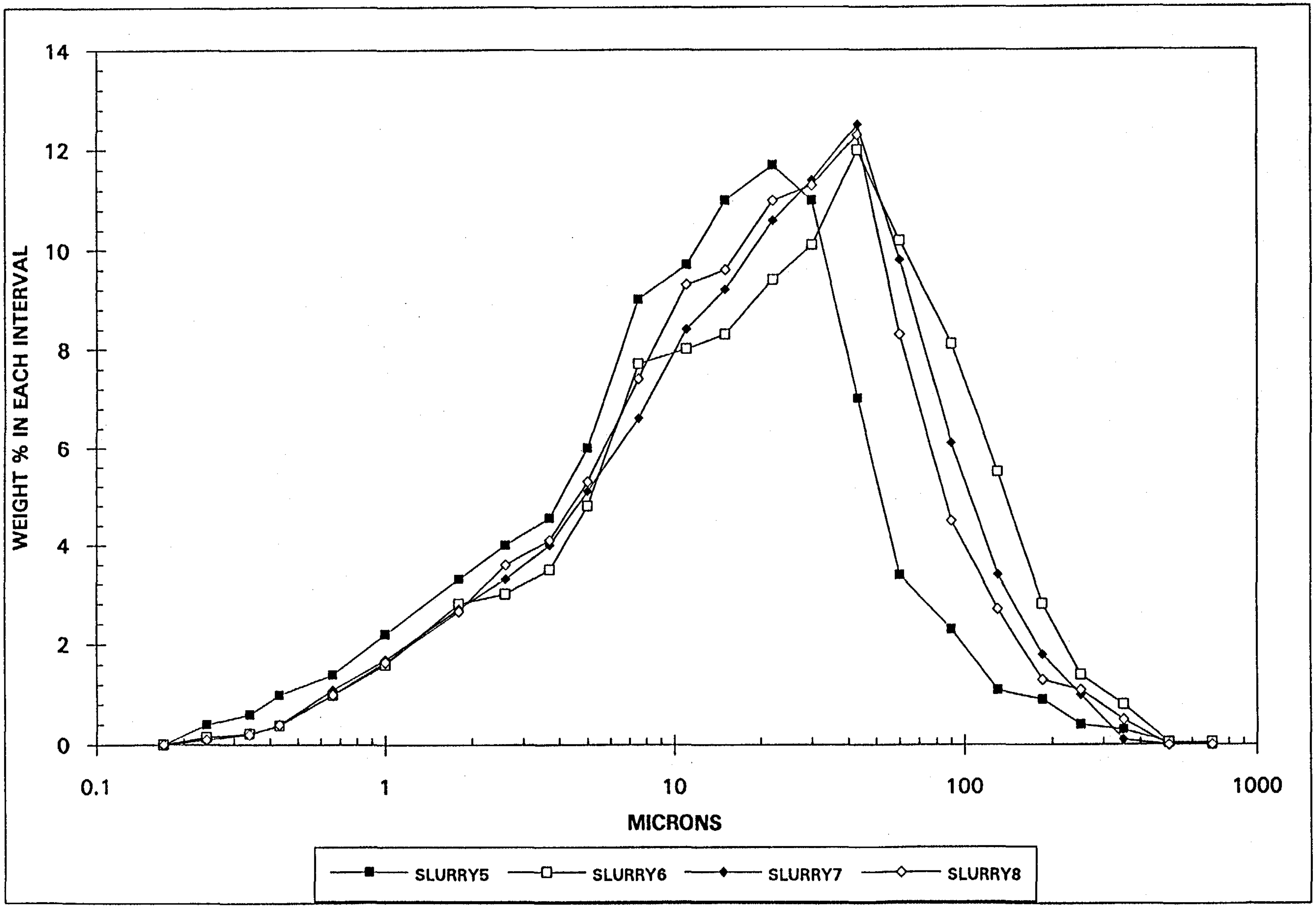
**** Definitions

Rheopectic - A fluid that shows an increase in apparent viscosity with time while under constant shear stress is Rheopectic

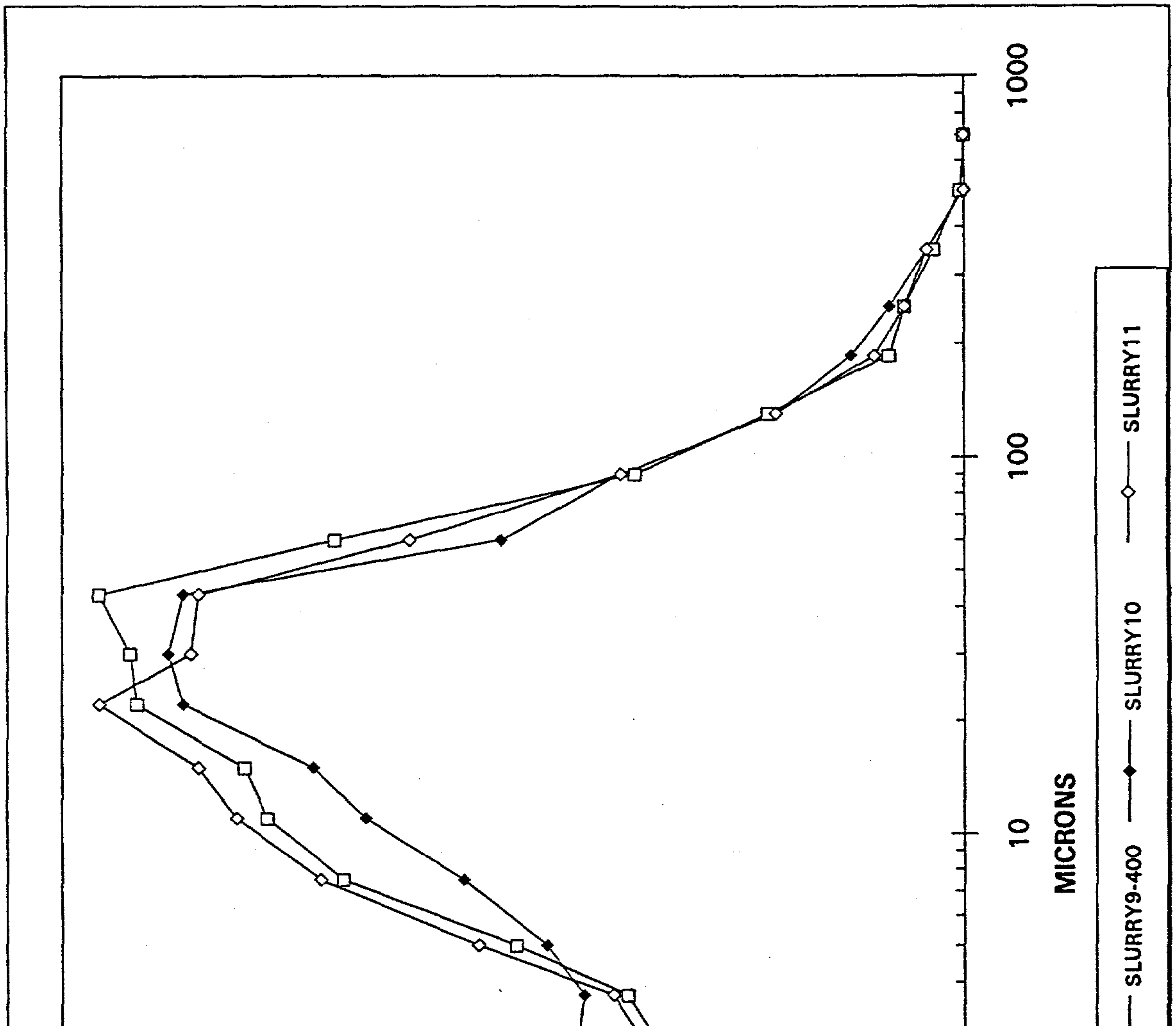
Thixotropic - A fluid that shows a decrease in apparent viscosity with time while under constant shear stress is Thixotropic



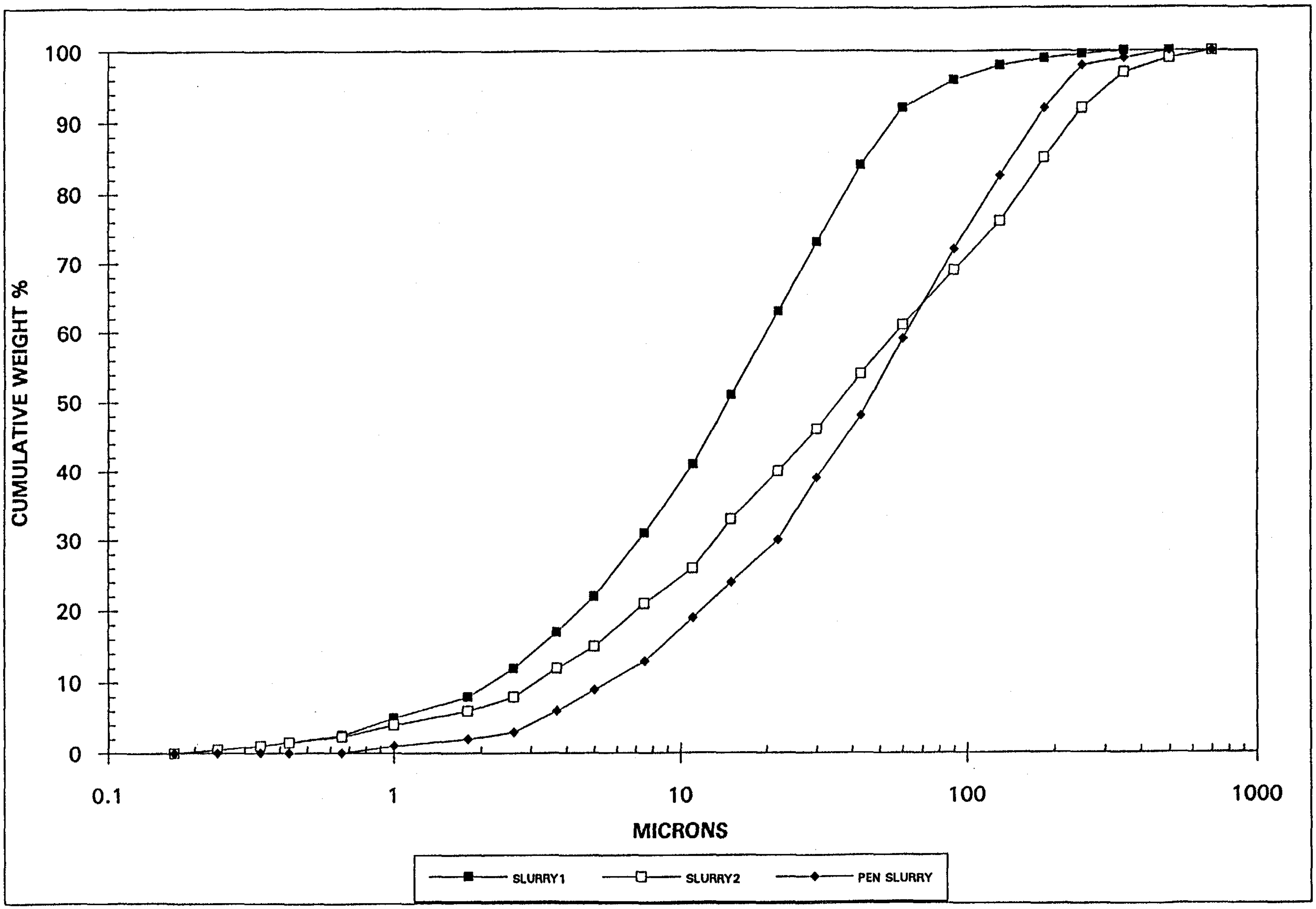
PARTICLE SIZE DISTRIBUTION
Fig. 2-22



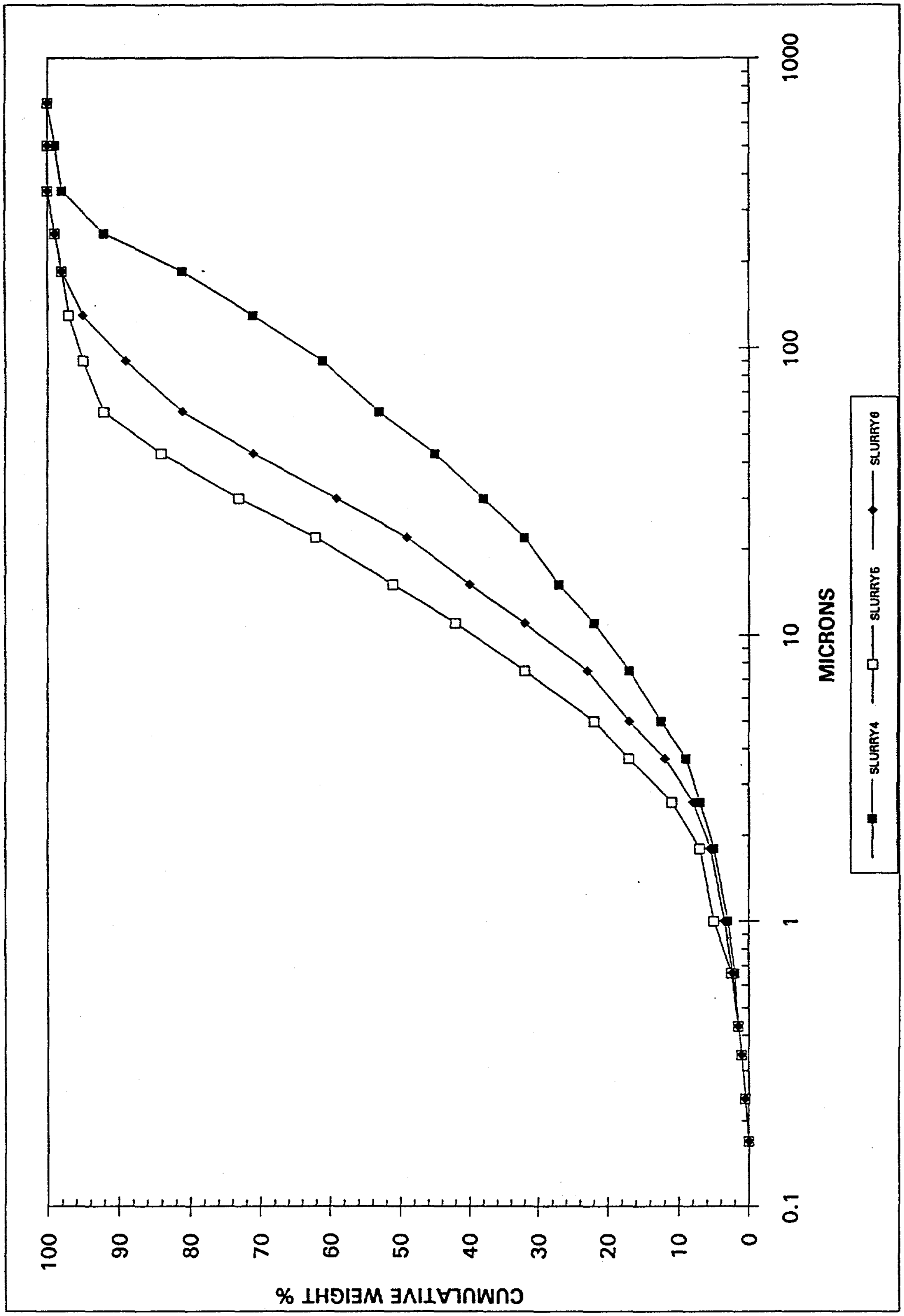
PARTICLE SIZE DISTRIBUTION
Fig. 2-23



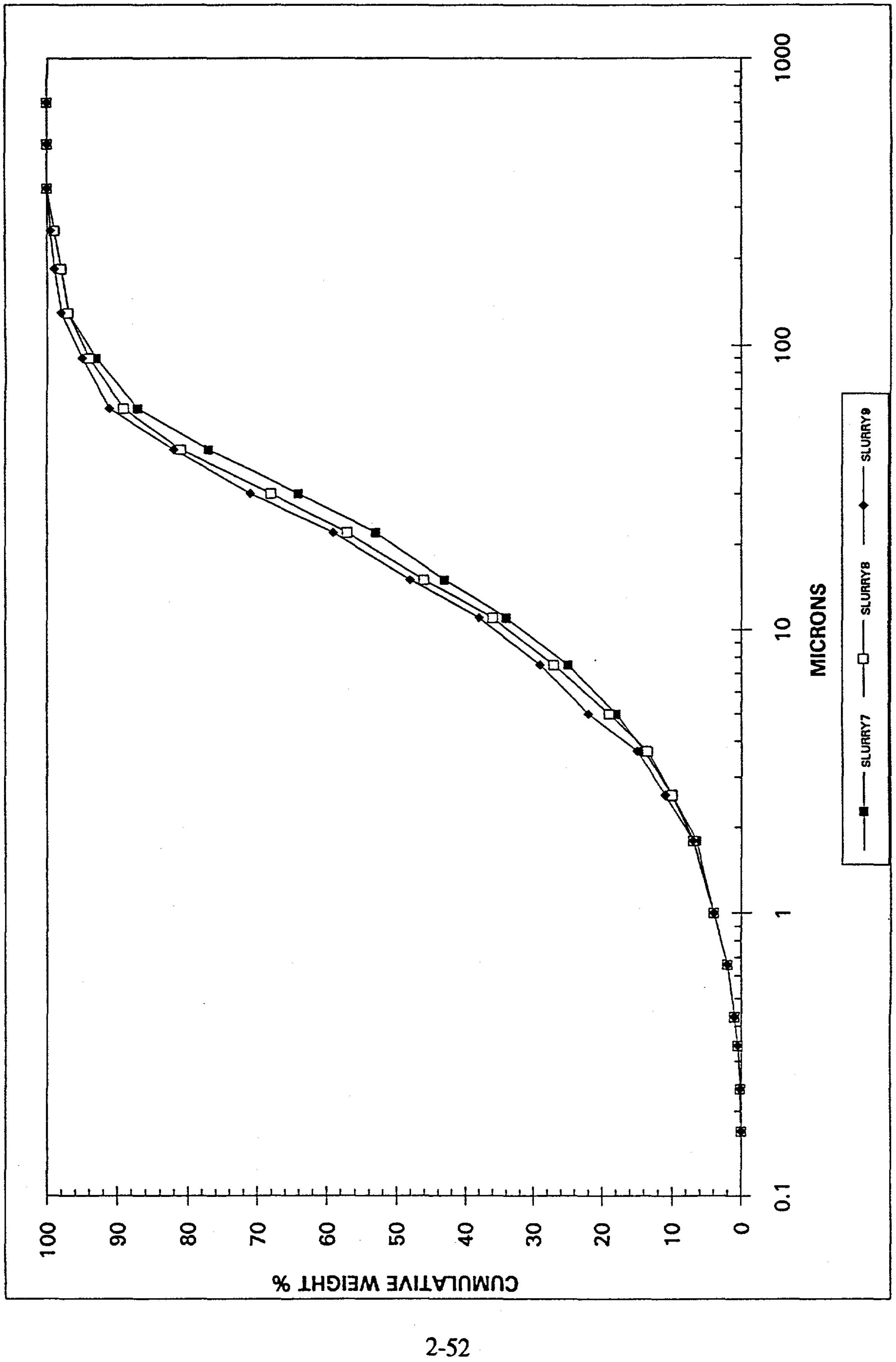
PARTICLE SIZE DISTRIBUTION
Fig. 2-24



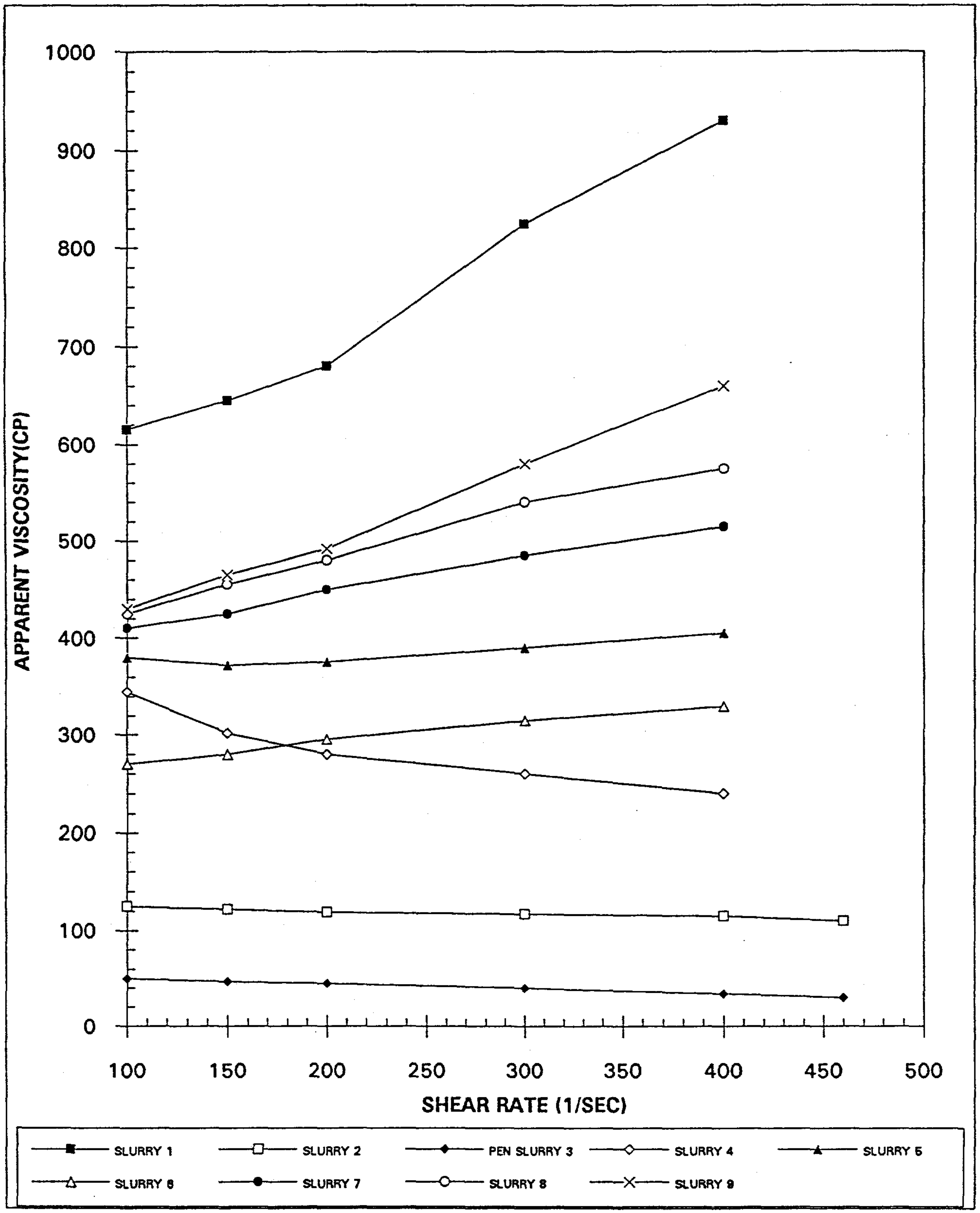
PARTICLE SIZE DISTRIBUTION (CUMULATIVE)
Fig. 2-25



PARTICLE SIZE DISTRIBUTION (CUMULATIVE)
Fig. 2-26



PARTICLE SIZE DISTRIBUTION (CUMULATIVE)
Fig. 2-27



APPARENT VISCOSITY VS. SHEAR RATE
Fig. 2-28

pump is protected by a downstream pressure switch. The slurry is then filtered in a 2 inch Hayward duplex basket strainer to remove any particles that would plug the atomizer. The CWS then flows through a series of valves that provide automatic recirculation to the CWS storage tank and isolation of the atomizer if a burner/boiler trip occurs. The slurry is measured in an Exac flow meter installed just prior to the atomizer. The slurry flow meter measures flow, temperature and density. The CWS atomizer is a twin fluid design using compressed air as the atomization medium.

2.3.3 Atomization Tests

Prior to any combustion tests, EER supplied an atomizer with three different tips so that an optimum atomizer tip could be selected. Designing an atomizer tip that would not plug on such a small scale was a difficult task, but the success of the long term firing would require that the atomizer give excellent atomization results and operate for extended periods of time without cleaning.

The atomization tests were performed at the UA/JWR atomization spray test facility located in Brookwood, AL. The facility was designed to spray 100 pounds per hour. The slurry is stored in a 55 gallon drum equipped with a three blade mixer and pumped from the drum by a Moyno progressive cavity pump. The slurry lines are 3/4" and the air lines are 1". The facility was equipped with two air compressors that had a capacity of 200 Pounds per hour at 125 psig. The spray chamber was 2'x2'x4' Plexiglass with the nozzle in a down-flow position. The air flow was straightened by a honeycomb that was installed in the top and bottom of the chamber. The slurry was pumped from the bottom of the chamber with an air operated diaphragm pump. The spray chamber was evacuated by two air blowers that provided a downward air velocity of 11 ft/sec in the test chamber. A Malvern was used to measure the droplet size of the spray. A 300mm lens was utilized to measure particles in the range of 5.8 to 564 microns. Figure 2-29 is a schematic of the atomization spray test facility.

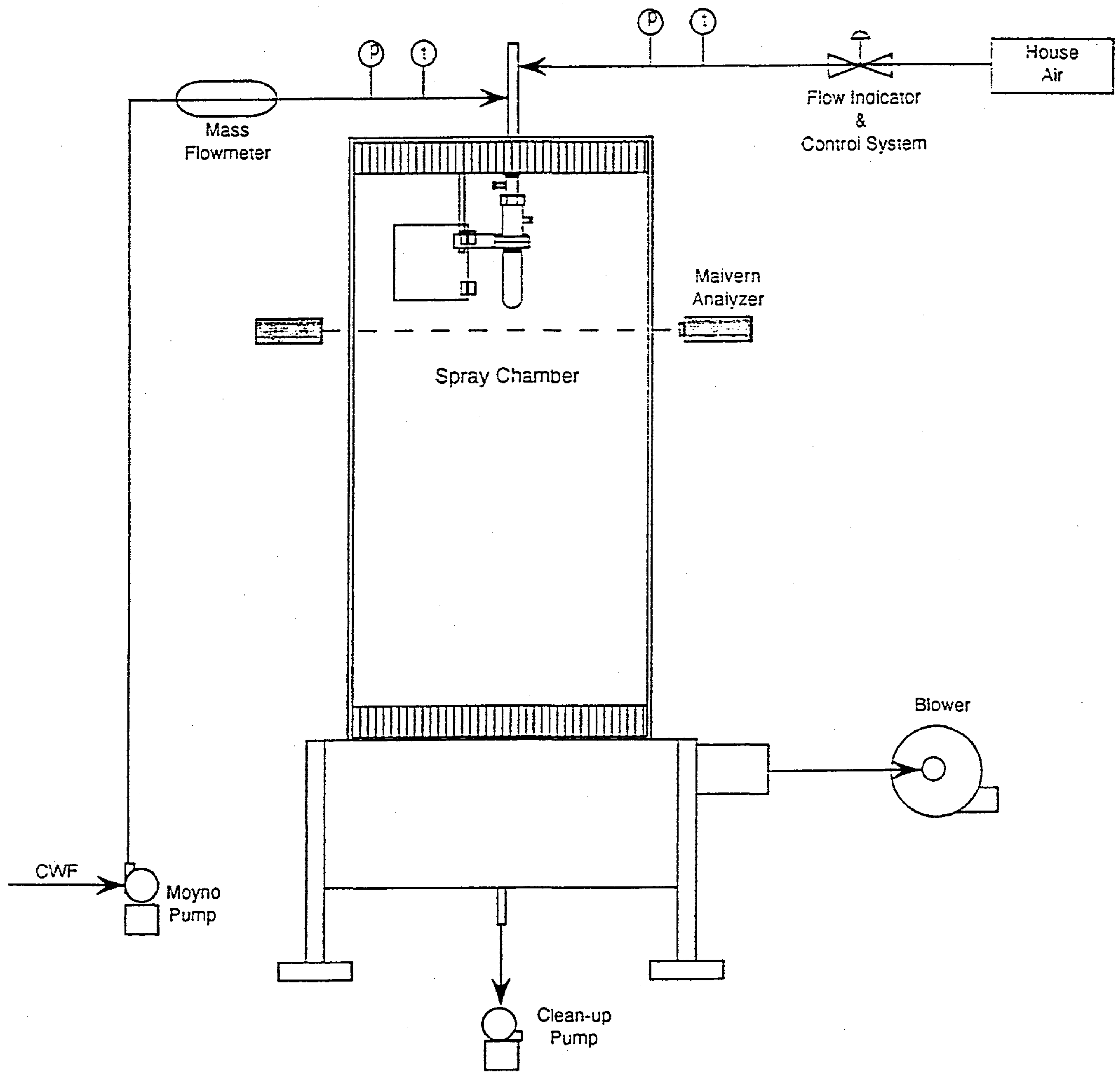


Figure 2-29. Atomization Spray Test Facility.

Table 2-11 reports the solids, ash, and particle size distribution (PSD) of the CWS used during the atomization tests. The JWRI (Jim Walter Resources Inc.) PSD was determined on a Cilas Model 715 granulometer and the UA PSD from a Microtrac. The UA samples were collected from the nozzle during the atomization testing, while the JWRI sample was collected during production of the slurry. This explains the slight difference between the PSD. Figure 2-30 is a plot of the PSD.

Three CWS viscosity runs were made on the University of Alabama(UA) Haake^R viscometer and the up runs are reported in Table 2-12 for the first shear and the UA average of the three was plotted in Figure 2-31. This shows the CWS to be dilatant. Table 2-13 are rheology results from the JWRI Fann viscometer. Normally JWRI reports viscosities from the down curve of the second shear, but the apparent viscosities in Figure 2-31 are for the up curve during the first shear. Table 2-14 reports viscosities at constant shear versus time. Figure 2-32 shows the curves to be similar in shape with the Fann^R viscosities being lower than the Haake^R. The CWS in all three constant shear runs proved to be stable. Because of the rheology difference in the CWS's, the same Brookfield standard samples were run on both instruments and reported in Table 2-15. Results with both viscometers are close to the standards. Two separate cup and bob viscometers can show identical viscosities on a Newtonian standard, yet show very different apparent viscosities on a non-Newtonian fluid like this CWS. The UA Haake^R MV-I and MV-II heads show different results on the same CWS. The varying rheologies from the two viscometers simply highlights the difficulty of determining the true rheological properties of a CWS.

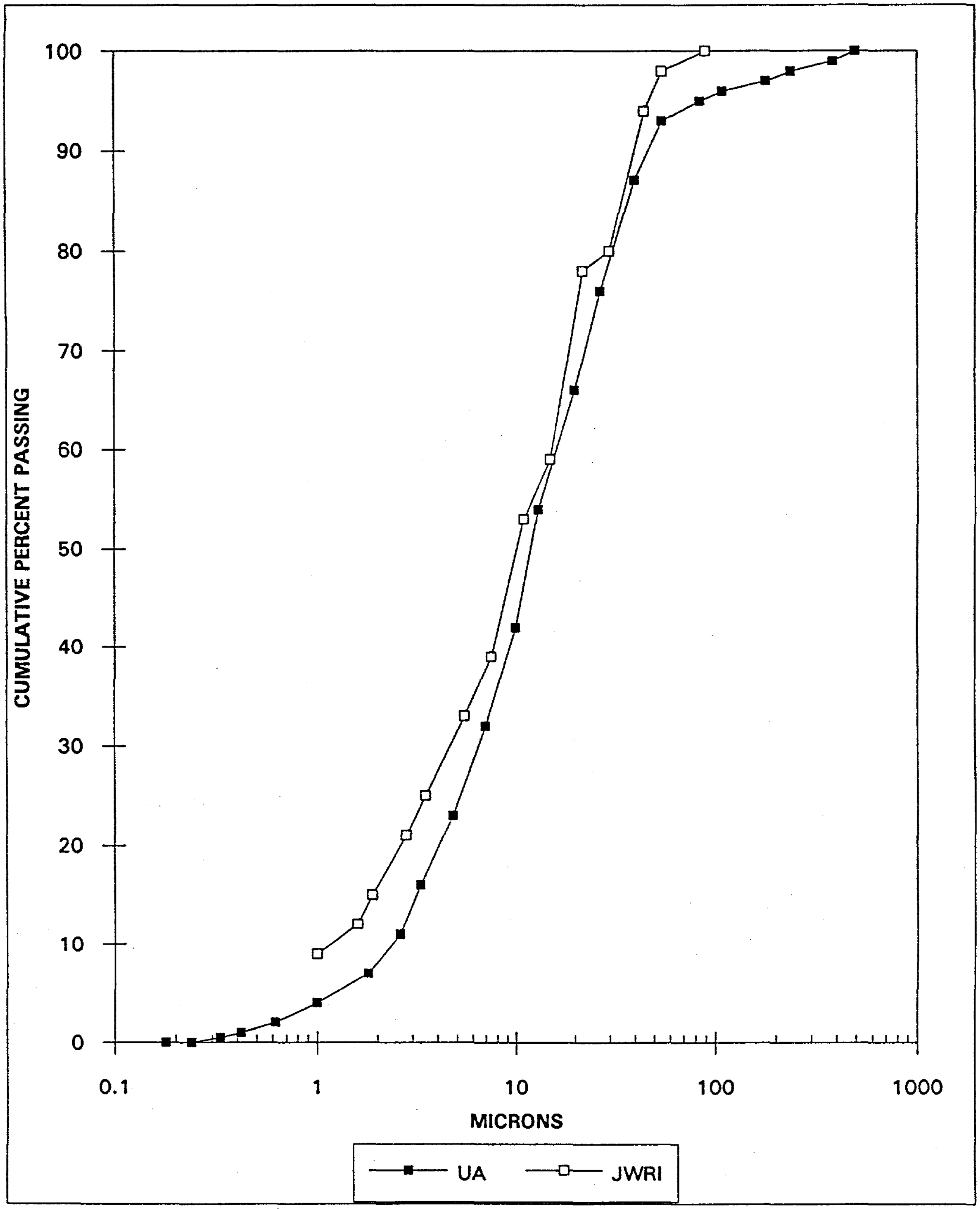
Figure 2-33 is a plot of Sauter Mean Diameter(Microns) verses the air/fuel weight ratio. All three atomizer tips are shown with various CWS flows. The smallest droplets were achieved with Tip #4 when the air/fuel ratio was acceptable. Similarly, Figure 2-34 plots droplets verses the air/water weight ratio while spraying various water flow rates through the three tips. After determining that Tip #4 gave the best performance of the three tips that were tested, Figures 2-35 and 2-36 were plotted with only Tip #4 performance for clarity. While the actual droplet diameter remains relatively constant, the air/fuel weight ratio can be lowered by increasing the

TABLE 2-11

Characteristics of the JWRI CWS Made May 28-29, 1992

	JWRI	UA
Solids	63.89	63.79 UA average of 3
Ash	8.00	7.80 UA average of 2

JWRI PSD Microns	JWRI Cumulative % Passing	UA PSD Microns	UA Cumulative % Passing
1	8.8	0.17	0.00
1.5	11.6	0.24	0.09
2	15.2	0.34	0.27
3	21.6	0.43	0.73
4	25.4	0.66	2.09
6	34.9	1.01	4.18
8	39.6	1.69	7.45
12	53.0	2.63	11.60
16	58.2	3.73	16.30
24	77.5	5.27	23.10
32	79.9	7.46	32.80
48	93.6	10.55	43.10
64	96.8	14.92	53.80
96	100.0	21.10	66.00
128	100.0	29.85	77.30
192	100.0	42.21	87.70
		59.69	92.70
		88.00	94.60
		125.00	96.20
		176.00	97.50
		250.00	98.70
		350.00	99.50
		500.00	99.80
		700.00	100.00

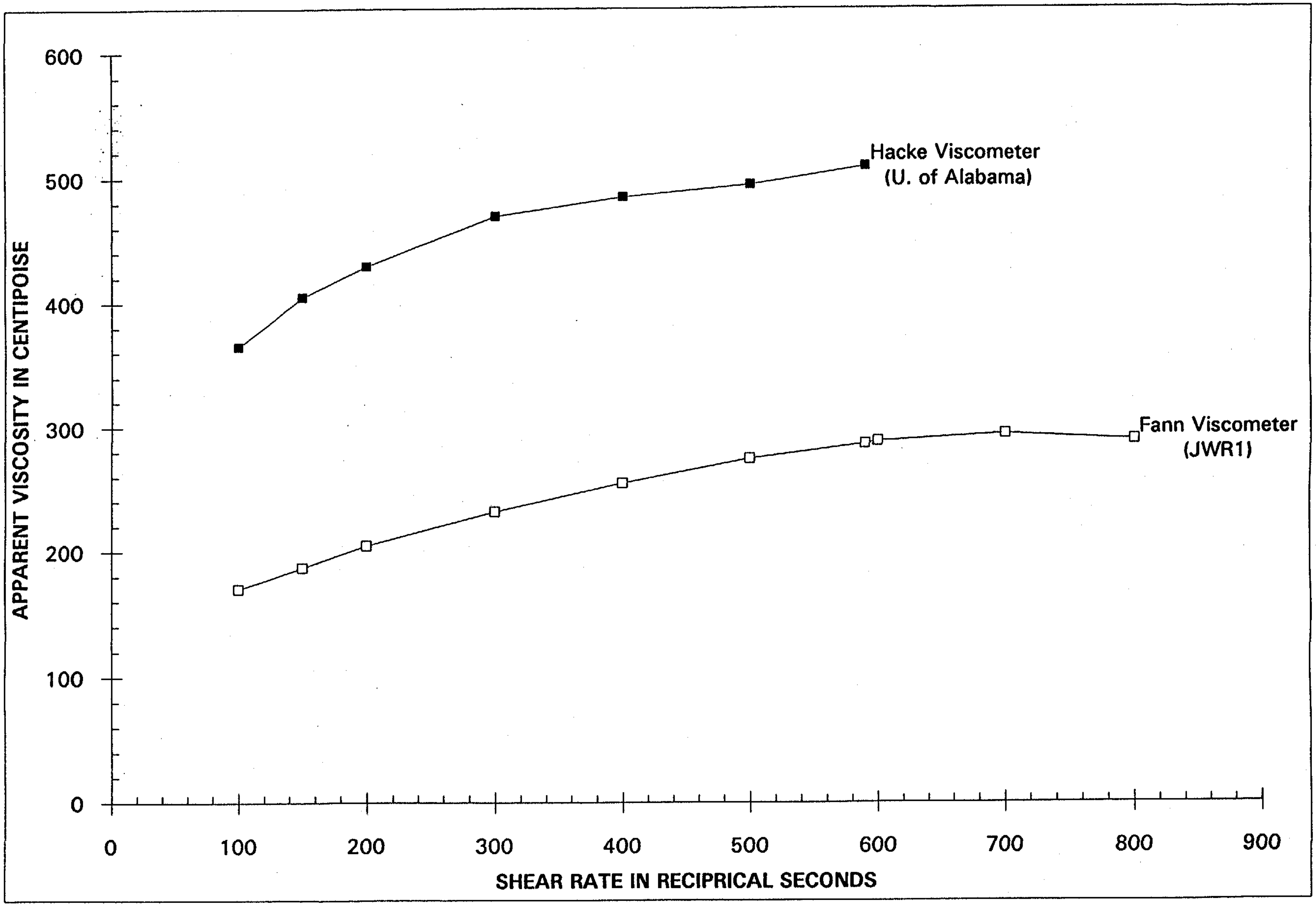


PARTICLE SIZE DISTRIBUTION FOR JWRI CWF
Fig. 2-30

TABLE 2-12

Apparent Viscosity of Three JWRI CWS Samples versus Shear Rate in Reciprocal Seconds with UA RV-12 Viscometer

	Sample 1	Sample 2	Sample 3		
Shear Rate	Viscosity Centipoise	Viscosity Centipoise	Viscosity Centipoise	Average	Standard Deviation
100	353	362	377	364	12.1
150	407	394	413	405	9.7
200	434	424	437	432	6.8
300	473	458	482	471	12.1
400	491	474	499	488	12.8
500	499	485	508	497	11.6
590	535	490	504	510	23.0



APPARENT VISCOSITY VS. SHEAR RATE
Fig. 2-31

TABLE 2-13

Apparent Viscosity of Two JWRI CWS Samples versus Shear Rate in Reciprocal Seconds with JWRI Fann Viscometer

	Sample 1 Viscosity Centipoise	
Shear Rate	Second Up	Shear Down
100	144	120
150	160	133
200	180	160
300	200	187
400	210	200
500	234	224
590	237	244
600	237	245
700	254	248
800	260	256
900	244	245
906	256	256
970		

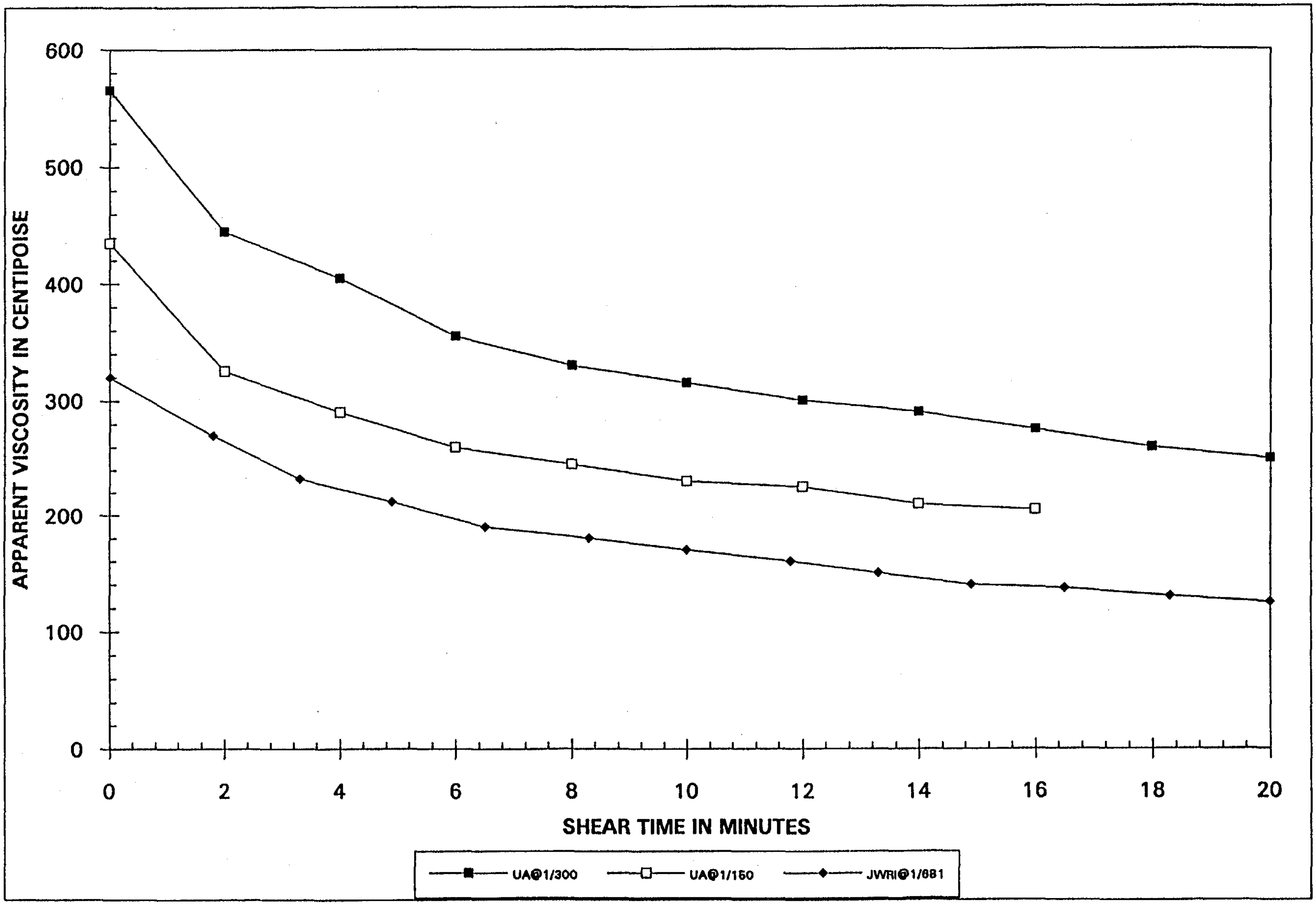
Sample 2 Viscosity Centipoise			
First Up	Shear Down	Second Up	Shear Down
168	128	128	120
192	160	149	138
210	176	164	156
240	200	187	174
265	226	200	195
284	244	220	209
295	258	230	223
295	260	218	232
300	274	240	234
295	280	245	244
	279	245	245
		-------	-------
		243	243

TABLE 2-14

Viscosity of Three JWRI CWS Samples at Constant Shear Rate versus Time

	UA @ 1/300 sec	UA @ 1/150 sec
Time Minutes	Viscosity Centipoise	Viscosity Centipoise
0	560	436
2	445	331
4	408	292
6	362	268
8	347	253
10	324	244
12	311	237
14	294	225
16	283	216
18	270	off
20	260	scale

JWRI @ 1/681 sec	
Time Minutes	Viscosity Centipoise
0.00	323
1.67	270
3.33	238
5.00	217
6.66	200
8.33	188
10.00	176
11.66	168
13.33	161
15.00	154
16.66	149
18.33	144
20.00	140



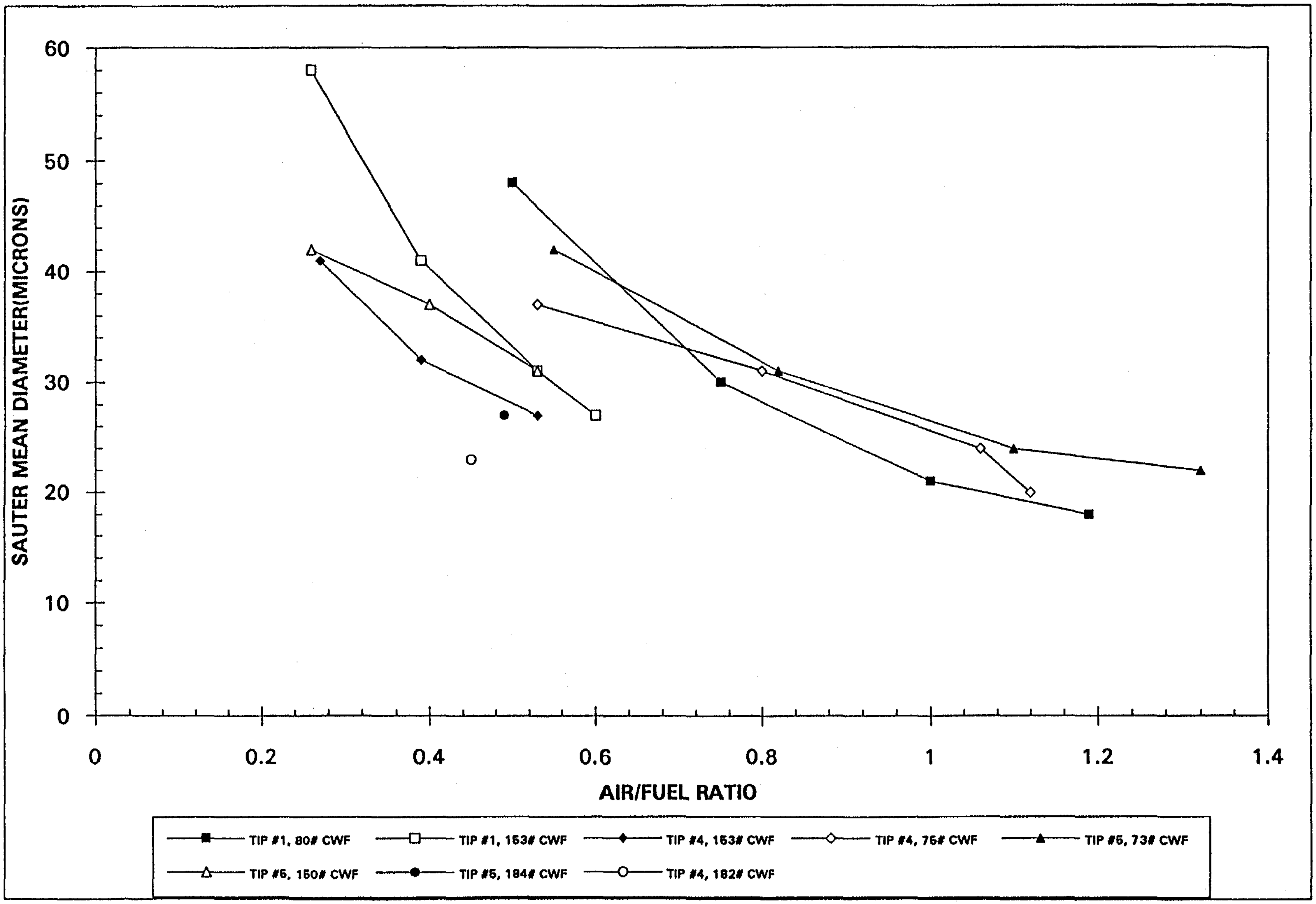
APPARENT VISCOSITY VS. TIME
Fig. 2-32

TABLE 2-15

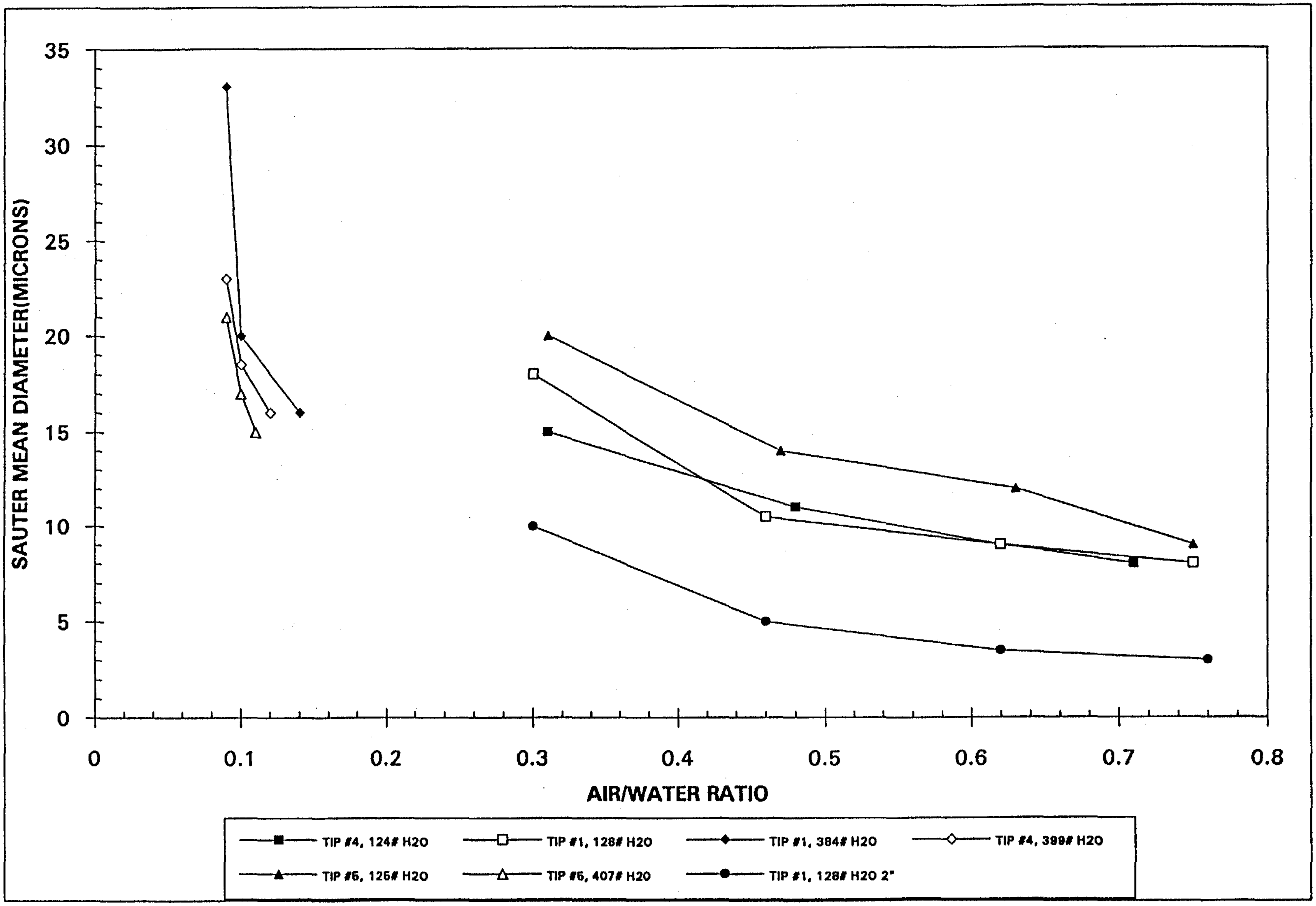
Viscosity of Two Brookfield Viscosity Standards with UA and JWRI

UA Haake RV-12 MV-I Head		
	98 Cp	1000 Cp
Shear Rate	Viscosity Centipoise	Viscosity Centipoise
100	-----	1058
150	102	1058
200	100	1074
300	101	1067
400	102	
500	102	off
600	102	scale
700	103	
800	103	
900	103	
1000	103	
1170	104	

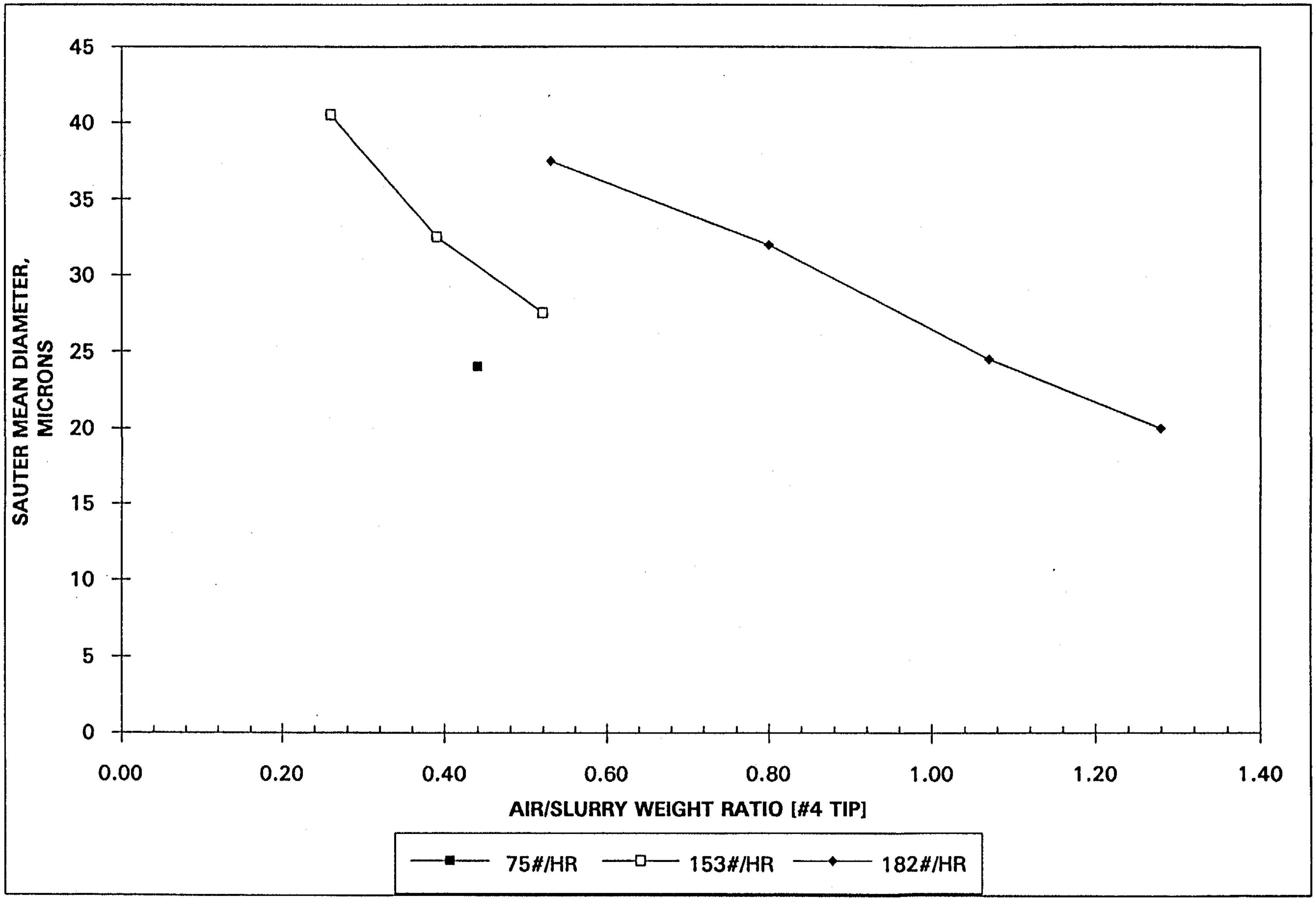
JWRI Fann	
98 Cp	1000 Cp
Viscosity Centipoise	Viscosity Centipoise
85.00	1008
87.00	1019
88.00	1019
89.00	1024
90.00	976
90.00	952
90.00	
91.00	off
91.00	scale
91.00	
91.00	



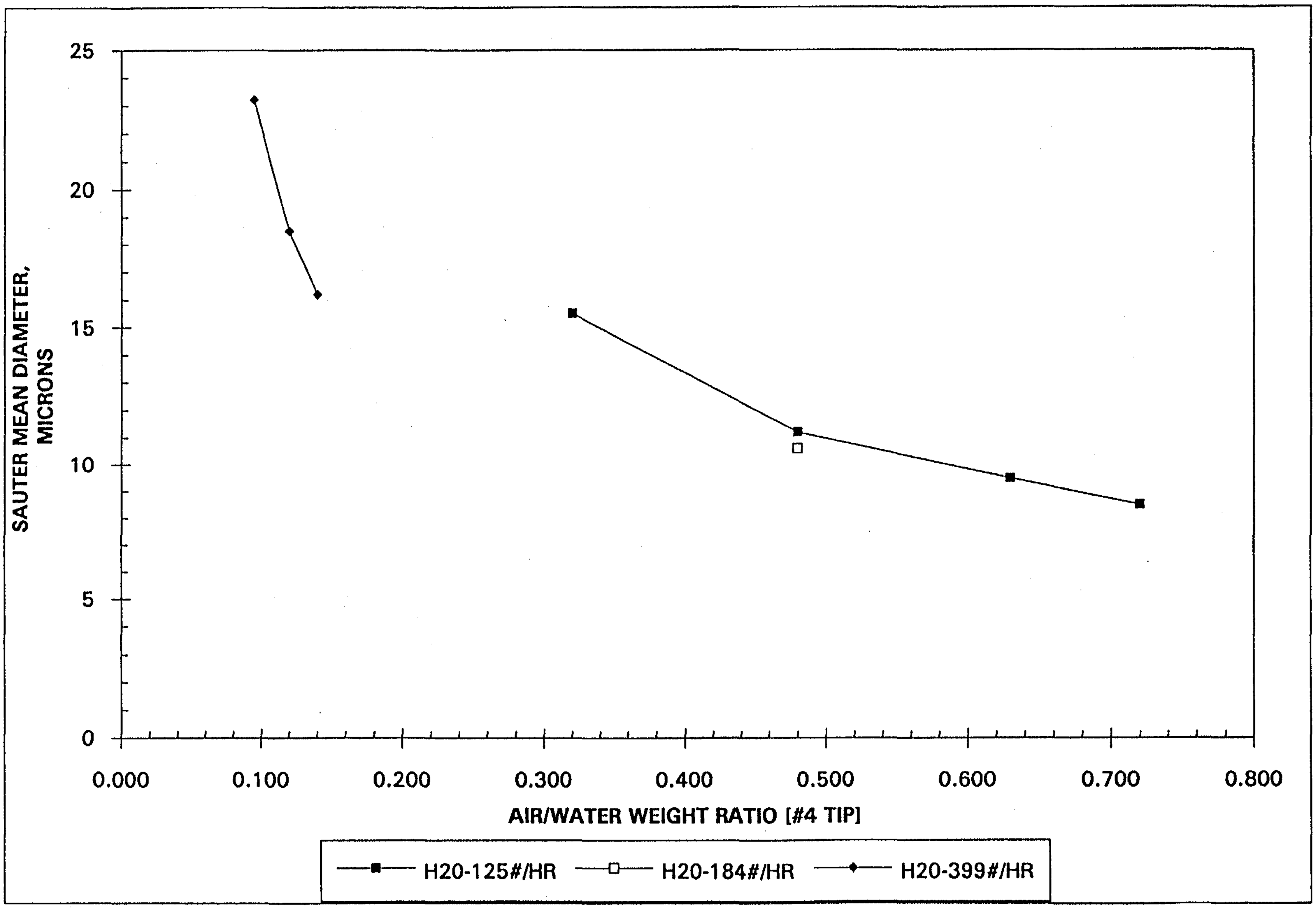
S.M.D. VS. AIR/FUEL RATIO
Fig. 2-33



S.M.D. VS. AIR/WATER RATIO
Fig. 2-34



PARTICLE SIZE VS. AIR/SLURRY RATIO
Fig. 2-35



PARTICLE SIZE VS. AIR/WATER RATIO
Fig. 2-36

actual CWS flowrate. The result on Figure 2-35 is that the curve continues to slide to the left. This indicates that the atomizer tip is approaching it's optimum operating point as the CWS flow was increased. The reason for this increase in performance is that as the CWS pressure drop is increased, additional mechanical shear is occurring before the atomizing air provides the final shear to the CWS.

The atomizer tip designed for this project was ultimately named the VEER^{TM} Jet Atomizer. The atomization and dependability of the VEER Jet exceeded all expectations. The atomizer gave remarkable Sauter Mean Diameters at reasonable air/fuel ratios of .3 to .5 and the tip never plugged while operating under normal conditions.

2.3.4 Combustion Air and CWS Preheat

Combustion air preheat was installed to increase the energy added to the ignition zone. The combustion air preheater is capable of 600°F outlet temperature. The energy for the air preheater is supplied by a slipstream of flue gas that is extracted after the 2nd pass of the boiler. The flue gas at this point is approximately 1000°F. The flue gas extraction is 60% of the total flue gas at most of the boiler loads. This flow had to be adjusted with dampers installed in the ductwork to correct for changes in boiler load and combustion air inlet temperature. The air preheater had an additional benefit of reducing the flue gas velocity in the 3rd and 4th passes which decreased the possibility of fly ash erosion.

The combustion air preheater is constructed of 304 stainless steel corrugated plates at 1/2" spacing. The air preheater has 544 square feet of heat transfer surface area, with a pressure drop of less than 1" of water column on both the air and flue gas sides. The air preheater is oriented such that the flue gas is flowing down to minimize the possibility of ash particles settling out. An ash hopper, including an ash clean out port is installed under the air preheater. The air preheater has a wash header to flush any ash that might have collected on the plates; the wash was performed while the boiler was off line.

The addition of the combustion air preheater increased the boiler efficiency on natural gas by 2% over the range of boiler loads of 50 to 100% This gain in boiler efficiency was enough to balance the loss in boiler efficiency due to the additional moisture in the fuel and the carbon in ash.

CWS preheat was expected to decrease the viscosity of the slurry and subsequently improve the atomization quality. With the CWS heated to a temperature above 212 degree F, the water in the slurry will flash to steam as it leaves the atomizer tip which will decrease the droplet size. Additionally the heat associated with preheating the CWS reduced the amount of heat transfer required to ignite the coal particles, and therefore enhanced the ignition process. The amount of energy which can be added to the ignition zone by this method is small, however, and the primary benefit of CWS heating is the result of improved atomization quality. The CWS preheater is an annulus type with CWS inside the inner pipe and 50 psig condensing steam on the outside. The preheater has two, 20 foot sections. The CWS preheater is designed to heat 400#/hr of CWS from 40 to 250 degree F using 50 psig saturated steam. The CWS preheater was installed in the system but was not utilized because the CWS exhibited excessive increases in viscosity when heated at DOE PETC. The ability to heat CWS is very specific to formulation. Therefore the CWS preheater may be used if the CWS formulation is changed to produce a heatable slurry in the future.

2.3.5 Ash Handling

The ash handling equipment located in the boiler was designed to control ash deposition on the tubes and the rear wall. Sootblowers were installed on the 2nd, 3rd, and 4th passes to control deposition on the tubes. The 56 tubes were divided into 4 zones for sootblowing. The 4 manifolds were constructed from stainless steel with a nozzle aimed down the center line of each of the tubes. The sootblowers cycled every hour. Compressed air at 125 psig was used as the sootblowing media. The rear wall ash deposition was controlled with a scraper mounted on a shaft that was manually cycled to knock off any ash deposits.

The ash handling equipment located outside of the boiler house included a baghouse and ash hopper. The baghouse was equipped with Nomex bags having a continuous temperature rating of 425°F and an air to cloth ratio of 3 to 1. The bags were cleaned with pulses of compressed air. The ash collection hopper installed on the bottom of the baghouse consisted of a flexible hose with a slide valve attached to a 55 gallon drum lid cover. This provided a system that was dust-free.

2.3.6 Fly Ash Recycle

A Fly ash recycle system was installed to increase the CWS carbon conversion. The system consisted of a cyclone, an eductor, and ash injection nozzle. The cyclone, installed in the duct work just prior to the baghouse, was equipped with an adjustable outlet spool and a level switch so the particle capture size and injection rates could be adjusted to the boiler conditions. Insulation was applied to the outside of the cyclone so the ash particles would remain hot and require less time to reach ignition temperature. The ash particles captured in the cyclone were injected into the boiler with a venturi eductor, which uses compressed air as the motive force for ash injection. The ash injection nozzle consisted of a piece of stainless steel pipe inserted through the burner's refractory quarl.

2.3.7 Control System

The boiler controls were designed to operate automatically after the operator manually starts the system and selects an operating point. The control panel, located in front of the boiler, contains the following components:

Preferred-Rimcor PCC-II "Fuel-Air" Controller - Controls the Boiler Air Flow (FD Fan Damper), Natural Gas Flow (Gas Valve), and Slurry Flow (Pump Speed). This unit also controls the slurry tank agitator when in automatic operation, as well as displaying various alarms.

Preferred-Rimcor PCC-II "Draft" Controller - Controls the Boiler Draft (ID Fan Damper), Slurry Temperature (Heat Exchanger Valve), and Steam Flow Output (Steam Totalizer). This unit also controls the Soot Blowing valves sequence and timing, as well as displaying various alarms.

Honeywell RM4140 Burner Management/Flame Safety System - Used to check boiler limits, start and run permissives, and initiate a gas fire in the boiler.

Kessler-Ellis Products KEPtrol R/T Indicator - Displays the Natural Gas Flow and Total Gas Usage as well as transmitting the Gas Flow to the Fuel-Air Controller.

Other miscellaneous components include digital readouts of various boiler temperatures, start-stop buttons for motors and slurry valves, indicator lights for motor run status and slurry valve positions.

Following is a brief description of the sequence of events for firing the boiler from a cold start through full load firing of Coal Water Slurry.

Starting the boiler involves turning on all breakers which feed power to the various motors and controls of the system, and opening the manual valves which supply cooling air or act as isolation of control valves. The FD fan start circuit is interlocked with the ID fan run circuit to prevent inadvertent starting of the FD fan until the ID fan is running.

With both fans running at minimum air flow and the gas control valve at minimum position the permissives for "lighting off" are satisfied, allowing for the start of the gas burner. The sequence starts with a 30-second purge during which time the FD fan damper moves to the 100% open position for maximum air flow through the boiler. At the end of the purge period the FD damper returns to minimum air flow for actual light off. When the damper reaches minimum position the spark ignitor is energized and the gas block valves open. This begins a 10-second "trial for ignition" which will initiate a safety shutdown if flame is not detected within this time period. If flame is detected the programmer generates a "gas flame on" signal and enters into a "run" state until such time as a run permissive is lost or the system is shut down by the operator.

After flame is established, the controller will begin to modulate the fan dampers and gas valve to achieve the firing rate desired for boiler warm-up and pressure raising. The FD fan demand is a function of the summation of the natural gas and slurry flows to maintain a proper air-fuel ratio. The ID fan demand is a function of the desired boiler draft setpoint entered by the operator. The gas valve demand is a function of the desired natural gas flow setpoint entered by the operator.

The slurry system control consists mainly of push button controlled valves on the slurry and flush valves with relay interlocks to prevent inadvertent operation. The slurry flow is controlled by the Fuel-Air controller, which varies the speed of the pump drive motor to maintain flow equal to the operator entered setpoint. With the slurry out of service, the pump is running at a minimum speed with the recirculation valve open to maintain a flow of slurry in the supply lines to prevent settling. To introduce slurry to the boiler the atomizing air valve is opened; the flush valve is opened for a short time to cool and wet the atomizer; and the slurry trip valve is opened and the recirculation valve is closed to direct the slurry flow to the atomizer.

When slurry is flowing to the boiler the natural gas flow is decreased as the slurry flow is increased to prevent over-firing the boiler. When slurry is removed from the burner, the slurry line from the trip valve through the atomizer is flushed with water to prevent hardening of any remaining slurry, and the recirculation valve is opened to allow the slurry in the supply line to recirculate to the tank.

The soot blowing cycle can be started and stopped by the operator at any time via a push button on the boiler draft controller. The supply tank agitator can be started or stopped by the operator at any time via the on-off switch on the panel or placed in the auto position for automatic operation by the Fuel-Air controller.

2.3.8 Balance of Plant

The equipment described in Section 2 is illustrated in Figure 2-37.

AIR COMPRESSOR

A 30 hp rotary screw air compressor was installed to supply 120 scfm of compressed air at 125 psig for CWS atomization, sootblowers, baghouse pulse jets and actuators on the control valves. The air compressor is located in an utility room near an existing 2500 gallon air receiver that was used for this project. A smaller air receiver was located behind the boiler to minimize pressure fluctuations while operating the sootblowers.

STACK

A 30' high stack was installed to exhaust the flue gas. It has an internal diameter of 10" and is manufactured from 1/4" carbon steel. The lower 15' of the stack is insulated to comply with OSHA. The stack is equipped with a 6" access door at the bottom for cleaning. A stack cap was installed so that when the boiler is offline it can be closed to minimize rain and foreign material from entering the stack.

REFRACTORY LINING

Refractory lining was installed in the fire-tube to reduce the amount of heat extracted from the CWS flame. The refractory lining had a major impact on the carbon conversion and flame stability. The refractory lining consisted of a 1/4" layer of ceramic paper with 1" of rammable plastic refractory. The ceramic paper was installed for the purpose of insulation and the refractory for wear resistance. Studs welded to the fire-tube were used to attach the lining which was 3 feet long initially and then reduced to one foot when slagging became a problem. The thickness of the total lining was kept to a minimum to prevent a significant reduction in the volume of the fire-tube(combustion chamber).

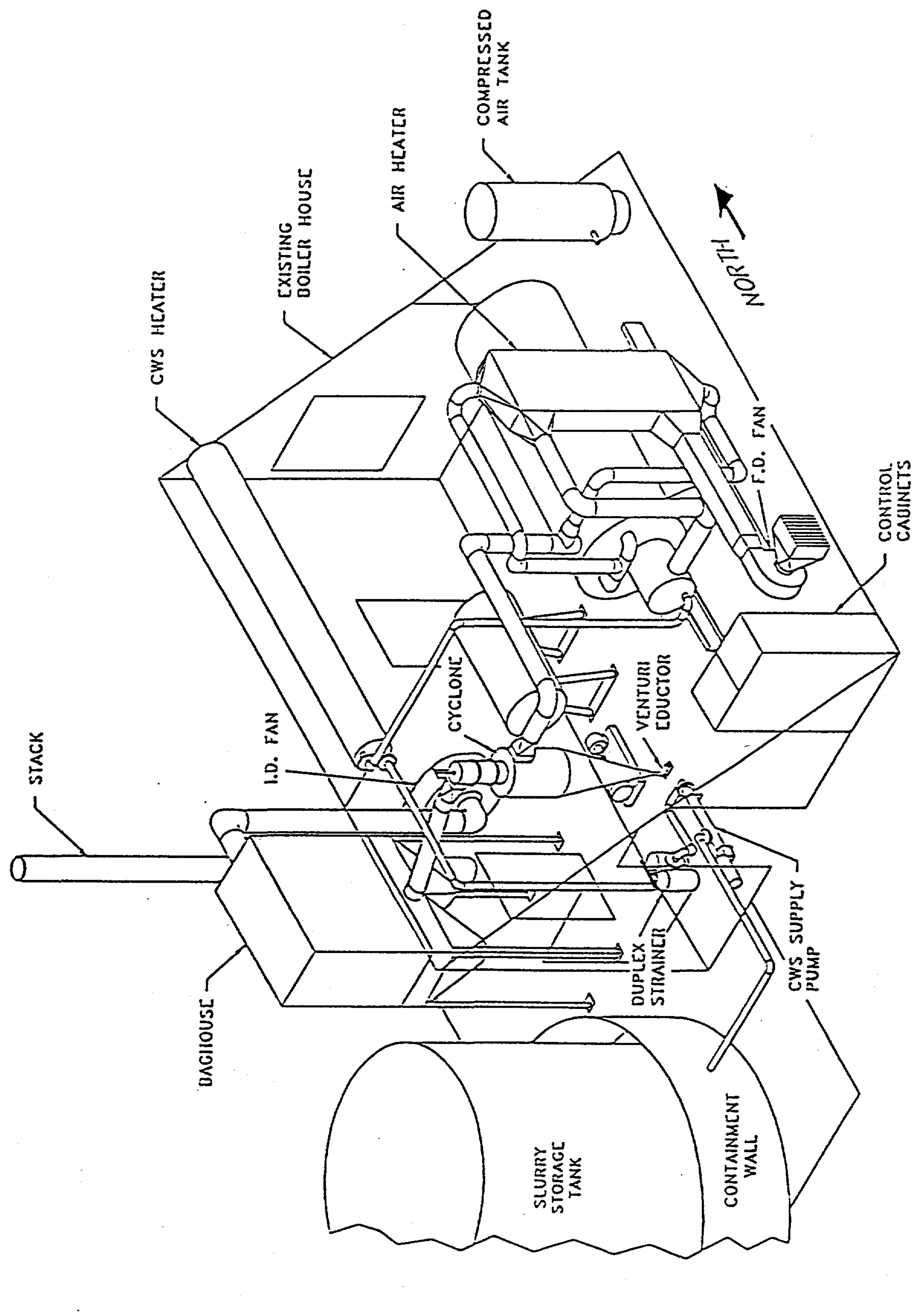


Figure 2-37. Boiler Isometric.

BURNER

The burner was developed by EER for use in small, relatively "cold" combustion chambers. It utilizes a narrow angle refractory quarl to improve CWS ignition stability. Swirl is also imparted to the combustion air to improve CWS ignition through recirculation of hot combustion products back into the ignition zone. The burner was equipped with six gas spuds operating at 5 psig that are electrically ignited. The gas manifold is located inside the windbox. The location of the atomizer tip and the impeller are adjustable. The windbox is internally insulated to maintain a safe outside wall temperature during operation with preheated combustion air. A flame scanner and an observation port is provided. The boiler was brought up to operating temperature by firing natural gas, after which the slurry was brought on slowly as the gas flow was reduced.

FANS

The boiler retrofit to fire CWS required the replacement of the FD fan and the addition of an ID fan. The FD fan was replaced because of it's condition and the need for greater flows and pressure rise. The ID fan was required to overcome the additional pressure losses associated with the air preheater, cyclone and baghouse. The FD fan was rated at 10" wc and the ID fan at 14" wc.

NATURAL GAS SYSTEM

A new natural gas system was installed with the CWS retrofit since the existing system was not compatible with the retrofit requirements. The system consisted of a pressure regulator, roots type flow meter, 2 block valves, bleed valve, control valve, pressure switches and miscellaneous pipe fittings.

INSPECTION PORTS

Sight ports were installed at each end of the fire-tube to provide visual access to the CWS flame. An ash clean-out port was installed at the 3rd pass outlet chamber. The cyclone was also equipped with an inspection port.

2.4 Allowable Emissions

From an emission perspective, these small slurry fired units will have to comply with the EPA 40 CFR Part 60, "Standards of Performance for New Stationary Sources: Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule (Federal Register, September 12, 1990)". In addition to the Federal Rules, each State can reduce the allowable emissions and these regulations would have to be researched on an individual basis.

The highlights of this regulation are as follows:

The affected facilities to which these standards apply is to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input of 100 million Btu/hr or less, but greater than or equal to 10 million Btu/hr.

Standards for Sulfur Dioxide

For coal-fired steam generating units with greater than 10 million Btu/hr heat input capacity but less than 75 million Btu/hr heat input capacity, the standards limit SO_2 emissions to 1.2 lb/MM Btu coal fired.

Standards for Particulate Matter

For coal fired steam generating units with heat input capacities greater than 30 million Btu/hr the standards limit particulate matter to 0.05 lb/MM Btu of coal fired and limit the opacity to 20%.

Standards for Nitrogen Oxides

For coal fired steam generating units with heat input capacities of 100 MM Btu/hr and less, there are no standards promulgated for NO_x.

Water and Solid Waste

Under the final standards, no significant water pollution impacts are projected, and the projected impacts on solid waste generation are small. In addition, the wastes produced by particulate matter control processes are non-hazardous and can be disposed of using traditional treatment and disposal techniques. Therefore, no adverse water pollution or solid waste impacts are anticipated as a result of the standards.

3.0 BOILER OPERATIONS AND PERFORMANCE TESTING EQUIPMENT

The University of Alabama (host site agreement) required that a University Boiler Operator or an EER employee be on site anytime that the boiler was operating. Graduate students assisted with the operations, performance testing, and data recording. Because of this constraint that someone would be on site at all times, it was decided that the development of an expensive automatic data acquisition system was not required. A data sheet was created that the operator would fill in manually. Figure 3-1 is the blank data sheet used to record data every 30 minutes or sooner depending on the type and length of the test.

3.1 Setup and Test Equipment

Test equipment was installed on the boiler to monitor critical boiler parameters. A flue gas monitoring system was installed to analyze the flue gas leaving the boiler prior to entering the cyclone. This system consisted of the following equipment;

- A stainless steel probe for removing a sample of flue gas at the exit of the boiler.
- A chiller to remove the majority of the moisture from the gas.
- An auxiliary vacuum pump that ensured the flow of gas through all the equipment.
- Miscellaneous hoses, fittings, and spare parts.
- Enerac Model 2000E complete with built in vacuum pump, printer, and all sensors.

Utilization of CWF in Fire-tube Boilers Tested at University of Alabama Tuscaloosa, Alabama						
Test No.						
Time						
Comb. Air lb/hr						
Nat. Gas SCFH						
Slurry lb/hr						
F						
Pump PSIG						
Atomizer PSIG						
Atom. Medium PSIG						
Uncorrected ACFM						
SCFM						
Cyclone Setting						
Venturi On/Off						
HX Gas Inlet F						
HX Gas Outlet F						
HX Air Inlet F						
HX Air Outlet F						
Cyclone Gas F						
3rd Pass F						
4th Pass F						
Bag Diff. in H2O						
Steam lb/hr						
PSIG						
F						
O2 %						
CO PPM						
Ambient F						
NO PPM						
SO2 PPM						
NO2 PPM						
CO2 %						
Excess Air %						
NOx PPM						
C in Ash Bag %						
Cyclone %						
Nat. Gas Inlet PSIG						
Burner PSIG						
Comp. Air Supply PSIG						
Venturi Air PSIG						
Baghouse Air PSIG						
Cyclone Exit in H2O						
Boiler Exit in H2O						
Burner Air in H2O						
Baghouse Exit in H2O						
Firetube Exit in H2O						

Figure 3-1

The Enerac provided the following measurements:

- Temperature of stack gas (if chiller was removed) minus the ambient temperature.
  Range: 0-2000°F
  Resolution: 1 °F
  Accuracy: 5 °F

- Ambient temperature.
  Range: 0-150°F
  Resolution: 1 °F
  Accuracy: 3 °F

- Carbon Monoxide Data. The sensor was a sealed electrochemical cell consisting of four platinum electrodes and an electrolyte.
  Range: 0-2000 PPM
  Resolution: 1 PPM
  Accuracy: 2% of reading

- O_2 Data. The oxygen sensor was a two electrode electrochemical cell that has a silver cathode and a lead anode.
  Range: 0-25%
  Resolution: 0.1%
  Accuracy: 0.2%

- NO Data. The nitric oxide sensor was a three electrode electrochemical cell.
  Range: 0-2000 PPM
  Resolution: 1 PPM
  Accuracy: 2% of reading

- SO_2 Data. The sulfur dioxide sensor was an electrochemical cell similar to the NO sensor.
  Range: 0-2000 PPM
  Resolution: 1 PPM
  Accuracy: 2% of reading

- NO_2 Data. The nitrogen dioxide sensor was an electrochemical cell similar to the NO sensor.
  Range: 0-1000 PPM
  Resolution: 1 PPM
  Accuracy: 2% of reading

The Enerac provided the following computed parameters:

- Carbon Dioxide
  Range: 0-40%
  Resolution: 0.1%
  Accuracy: 5% of reading

  Excess Air
  Range: 0-1000%
  Resolution: 1%
  Accuracy: 10% of reading

- Oxides of Nitrogen
  Range: 0-3000 PPM
  Resolution: 1 PPM
  Accuracy: 2% of reading

- CO, NO_x, and SO_2 given in milligrams/cubic meter and lb/million Btu.

In addition to the flue gas monitoring system, a high velocity thermocouple (HVT) was inserted from the back of the fire-tube to obtain temperature and gas analysis. The data from the HVT was critical for adjusting the length of the refractory to eliminate slagging. Samples of the CWS fuel, ash recycle, and baghouse were taken periodically for analysis. These samples were analyzed for particle size distribution and carbon content. The CWS fuel was also tested for Viscosity vs. shear rate. The boiler controls supplied data such as CWS flow, natural gas flow, boiler temperature at various locations, and steam flow and pressure that were required to calculate carbon conversion and ASME efficiency.

4.0 RESULTS

4.1 Preliminary System Test Results

The optimization tests as described in the contract were to consist of at least 50 hours of boiler operation. The tests began on 8-14-92 and were considered complete on 10-13-92 after approximately 120 hours of slurry firing and 80 hours of natural gas only operation. EER met with DOE on 10-9-92 to discuss results of the testing to date. The results were encouraging, but the major problem encountered has been a build up of slag on the refractory wall. However, in order to determine whether a given operating condition would or would not slag took approximately 24 hours of continuous operation. Accordingly it was decided at the review meeting that EER should proceed with the proof of concept tests beginning on 10-14-92. The first 400 hours of the proof of concept tests would be an extension of the optimization tests in order to determine the final operating configuration for the last 600 hours. EER prepared this test plan for DOE approval.

Conclusions from Optimization Tests

The firing rate has a direct effect on carbon conversion and the rate of slagging. The optimal firing rate was not determined during the optimization tests but a derate of 20-25% was expected in order to continuously fire the boiler.

A high rate of combustion air preheat instead of using natural gas for adding energy to the flame zone had proven to be advantageous for operational constraints. The advantage from diverting nearly all of the flue gas from the second pass to the air heater was a reduced flue gas temperature entering the baghouse. The air heater surface area was 3.1 times greater than the combined areas of the 3rd and 4th pass. Without this flue gas temperature reduction the operating point was near the maximum continuous operating temperature of the bag material.

Utilizing the air heater provided an additional benefit of displacing a premium fuel and increasing boiler efficiency.

In order to keep CO levels below 500 ppm it was necessary to operate with O_2 levels between 5 and 7%. The generation of high CO was probably due to high unburned carbon in the ash particles. Some of the ash would settle out and slowly oxidize to create CO.

Several different slurry formulations were evaluated during the optimization tests. The first slurry was produced by grinding all of the filter cake in the stirred ball mill. The slurry flow rate through the mill was moderate to high. In order to reduce viscosity and increase the production rate the next batch of slurry was produced by grinding 25% of the filter cake at a very slow rate and the remaining filter cake was not ground. The result was a broader particle size distribution and lower viscosity, but a much larger mass mean particle size. A couple other slurry formulations were tried and it became apparent that a slurry with a very small mass mean particle size was required to operate with acceptable carbon conversion efficiencies and prevent slagging. All remaining slurry tests utilized the finely ground coal particles.

The combustion enhancement technique that had not been optimized was the cyclone. The cyclone has an adjustable spool that will change the vortex location within the cyclone to affect the size of particles captured. After several successful tests with no fly ash reinjection, the cyclone was adjusted for maximum capture and the fly ash was injected into the fire-tube. Eight hour tests were run, so each morning two hours of natural gas firing were required to warm up the boiler. Those tests indicated that the cyclone could operate at a maximum injection rate without affecting the boiler. With 24 hour per day operation, however, it appeared that the maximum injection rate was accelerating the rate of slag build up.

4.2 Modifications

The refractory lining just downstream of the burner throat quarl was reduced in length from 3 feet to 1 foot. This reduction was necessary since slag was forming on the last twothirds of the refractory lining. After this modification the problem of slagging in the combustion chamber occurred only when atomization quality deteriorated due to nozzle wear.

The piping located between the CWS pump and the CWS duplex basket strainer was replaced with a smaller size pipe. This was necessary due to slurry settling because the velocity was too low. The modification eliminated the problem.

4.3 Proof of Concept Test Results

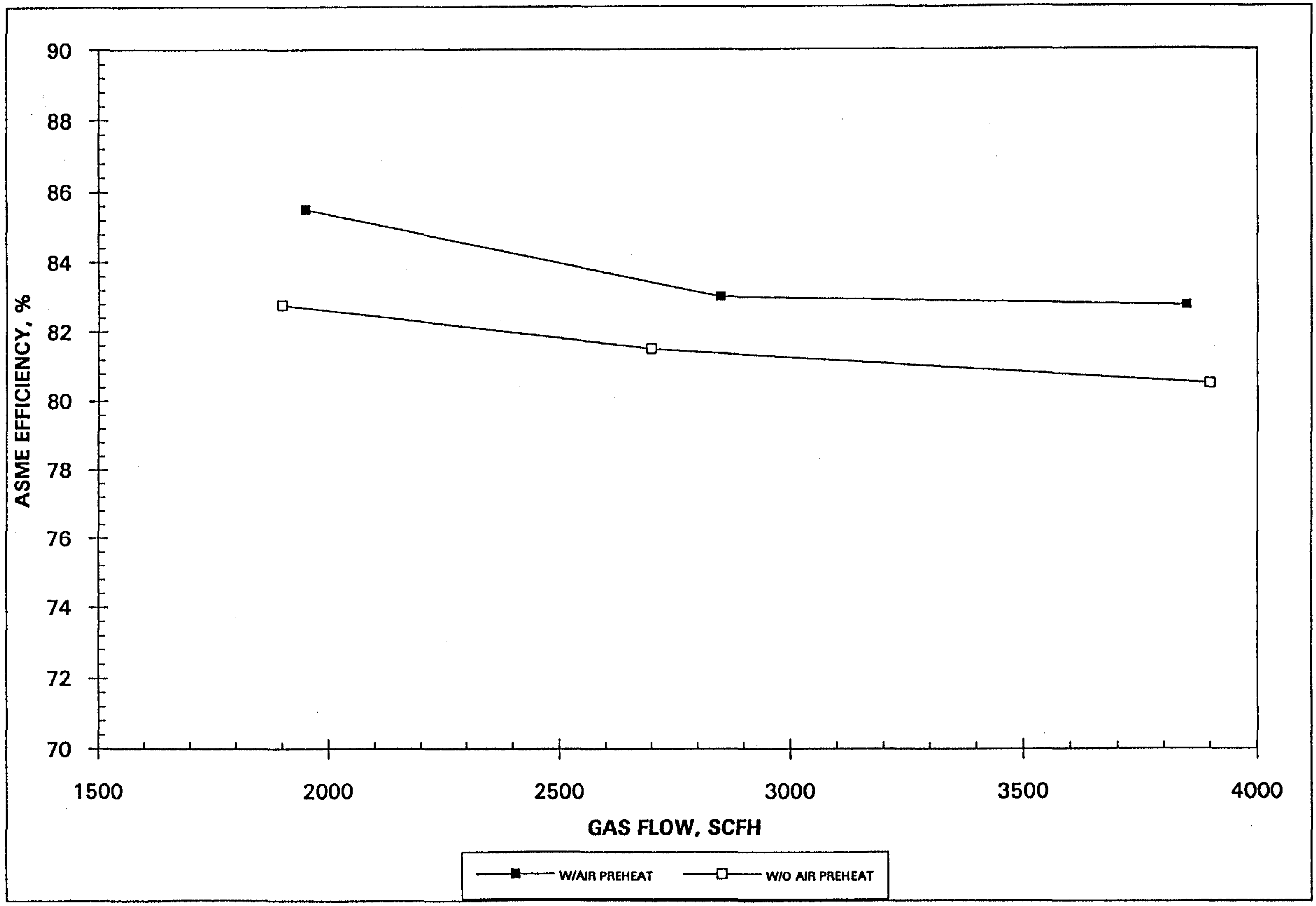
At the conclusion of the long term boiler testing the boiler had operated on CWS for 800 hours plus approximately 400 hours on natural gas only. A boiler derate of 20% was required for acceptable carbon conversion. Air preheating, ash recycle, refractory lining and natural gas co-firing had a positive effect on carbon conversion.

Air Preheat

A series of tests were performed to determine the overall increase in boiler efficiency due to the utilization of a combustion air preheater that provided a 250 percent increase in heat transfer surface area. The average efficiency increase due to combustion air preheat was 2 percent over the load range of 50-100 percent. This series of tests were performed using natural gas. Tests varying the air preheat temperatures were also performed while firing CWS but required natural gas flows were unacceptable. Figure 4-1 presents a summary of the gas flow vs. boiler efficiency data.

Refractory Length

The boiler was retrofitted with a 3 foot refractory liner at the inlet to the fire-tube to maintain a higher combustion zone temperature. Thermal modelling predicted a gas temperature less than the ash softening temperature. During the initial operation of the boiler, slag began to accumulate at the end of the refractory. The slag was produced because the actual



ASME BOILER EFFICIENCY VS. GAS FLOW
Fig. 4-1

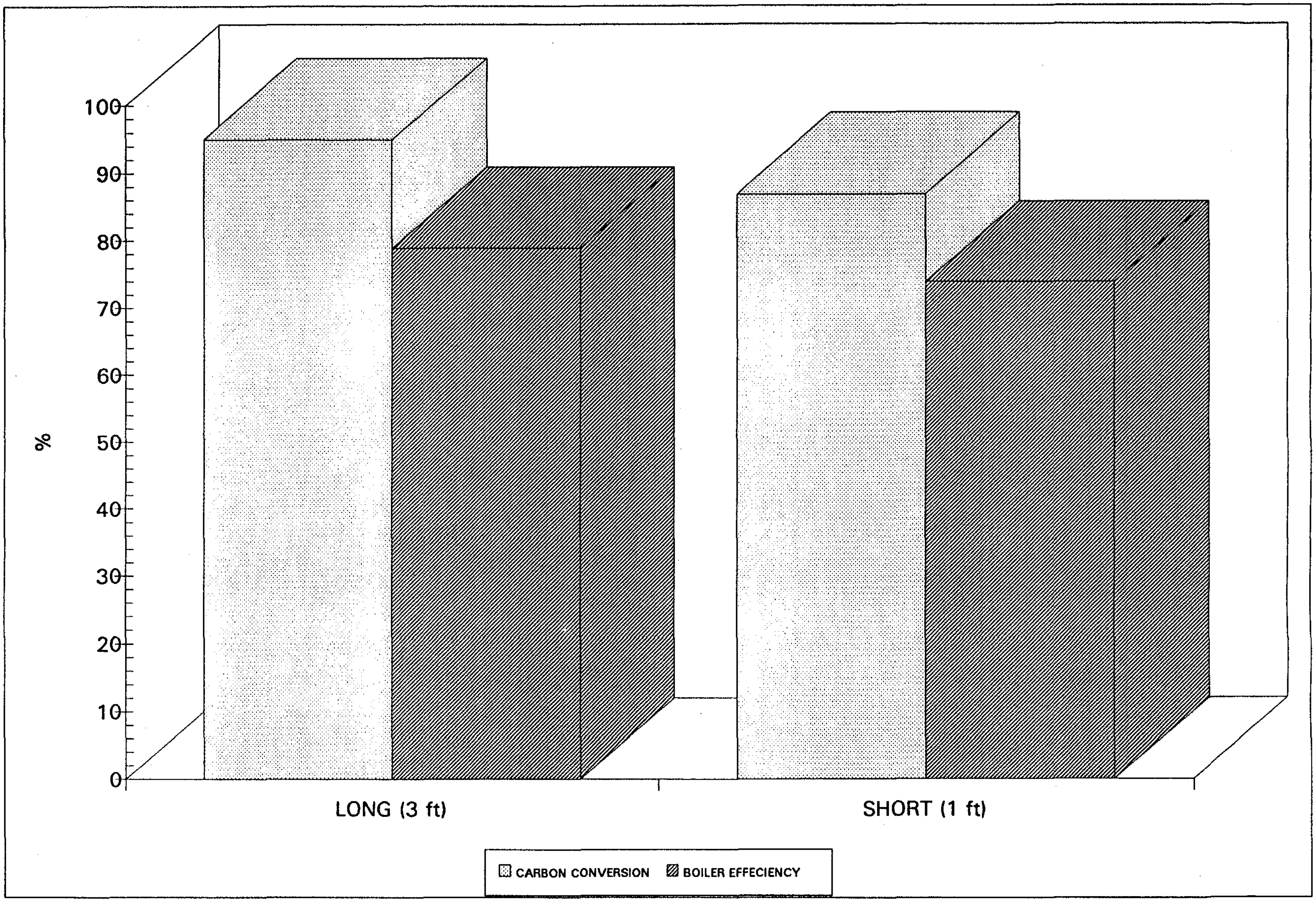
temperature of the coal particles during combustion were higher than the predicted gas temperature. The high swirl of the burner also contributed to the slagging conditions by forcing molten particles onto the wall. It was decided to shorten the refractory liner to 1 foot which eliminated the slagging. However, due to this change, the carbon conversion dropped from 95 percent to 87 percent and the boiler efficiency dropped from 79 percent to 74 percent. Figure 4-2 shows the effect of refractory length on carbon conversion and boiler efficiency.

Ash Recycle

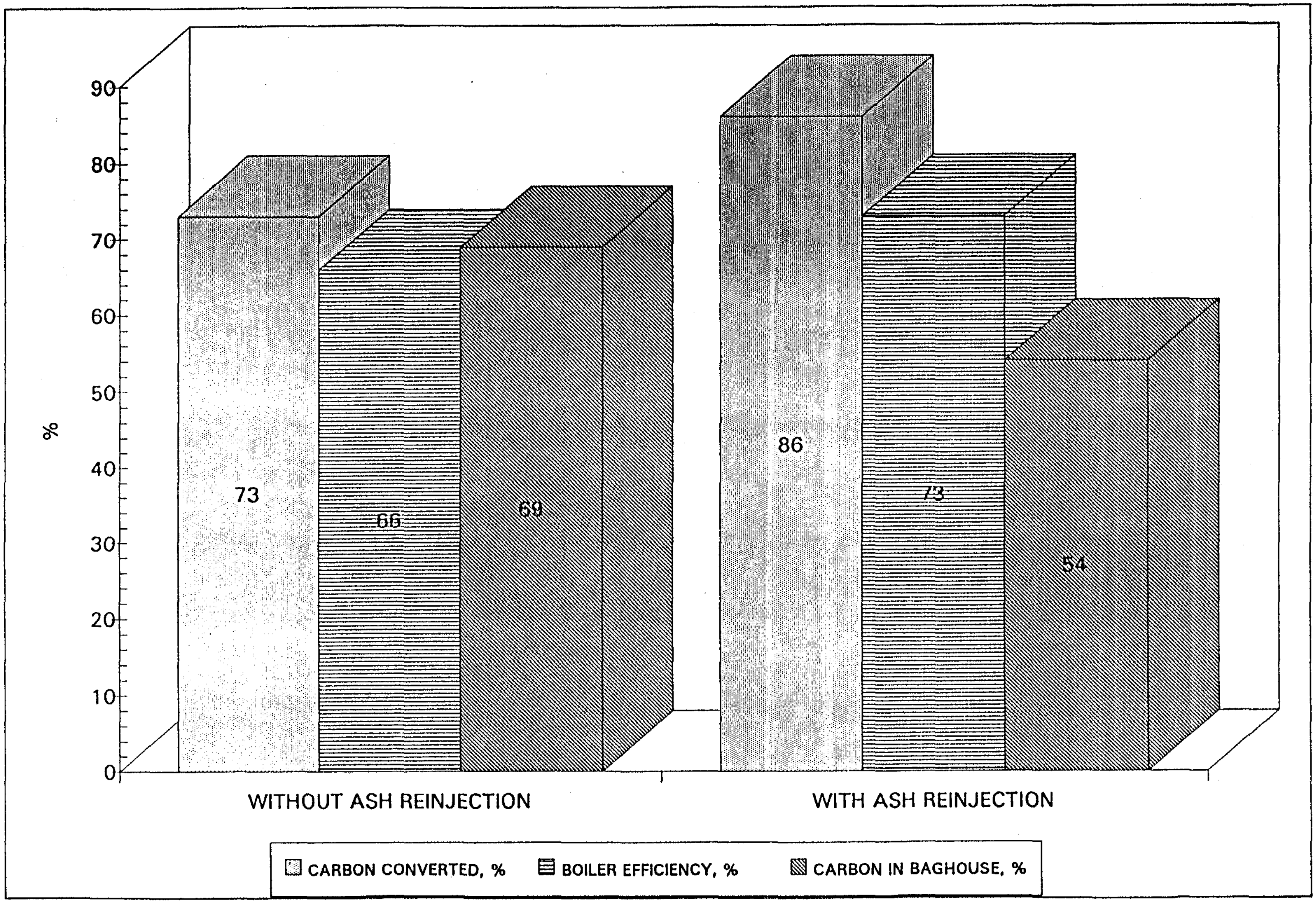
Flyash recycle was investigated as a means of reducing carbon losses. A baseline test was performed with all of the ash going to the baghouse. The ash that was collected in the cyclone was injected into the baghouse by the venturi eductor. The second test was identical to the first test with the exception that the cyclone ash was recycled into the boiler. The carbon in the ash dropped from 69 percent to 54 percent and the carbon conversion increased from 73 percent to 86 percent. The boiler efficiency increased from 66 percent to 73 percent. Figure 4-3 shows the effect of ash recycle vs. carbon in ash, carbon conversion and boiler efficiency. The ash was analyzed for carbon content as a function of particle size. The carbon increased as particle size increased. Figure 4-4 shows carbon content vs. particle size. In addition to the above test, cyclone and baghouse samples were collected over a wide range of slurry and natural gas flows. The natural gas flow rate varied from 700 scfh to 1250 scfh and the slurry flow rate varied from 100 #/hr to 200 #/hr. The carbon content of the cyclone catch was an average 15 percent higher than the ash in the baghouse. Figure 4-5 presents a summary of ash carbon content in both the cyclone and the baghouse as a function of gas flow for several slurry flow rates.

Natural Gas Support

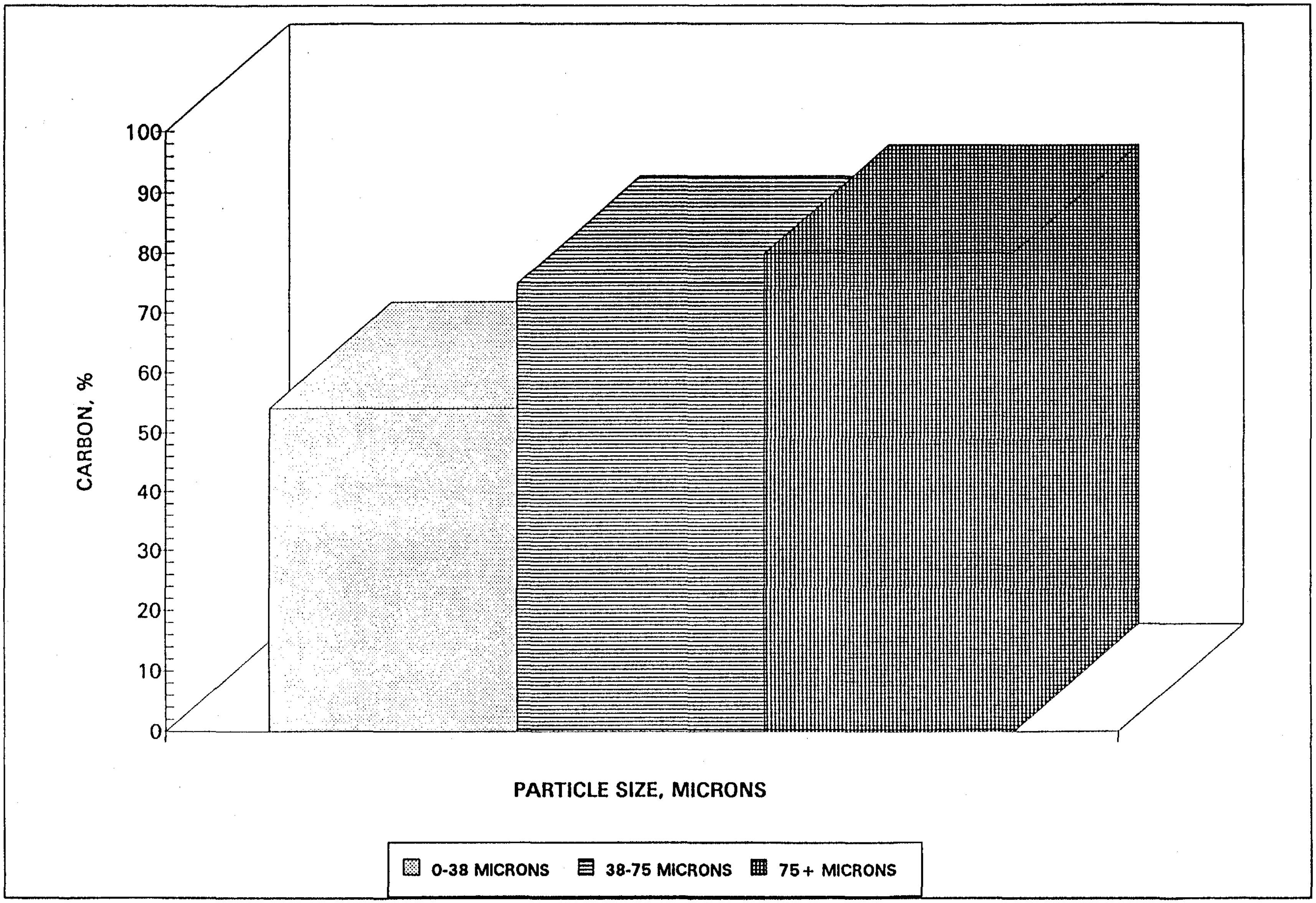
The boiler was warmed by firing natural gas only. CWS firing was initiated when a 400°F air preheat temperature was obtained. The natural gas flow rate was reduced as the CWS flow rate was increased to maintain a constant boiler load. Figures 4-6 and 4-7 illustrate the



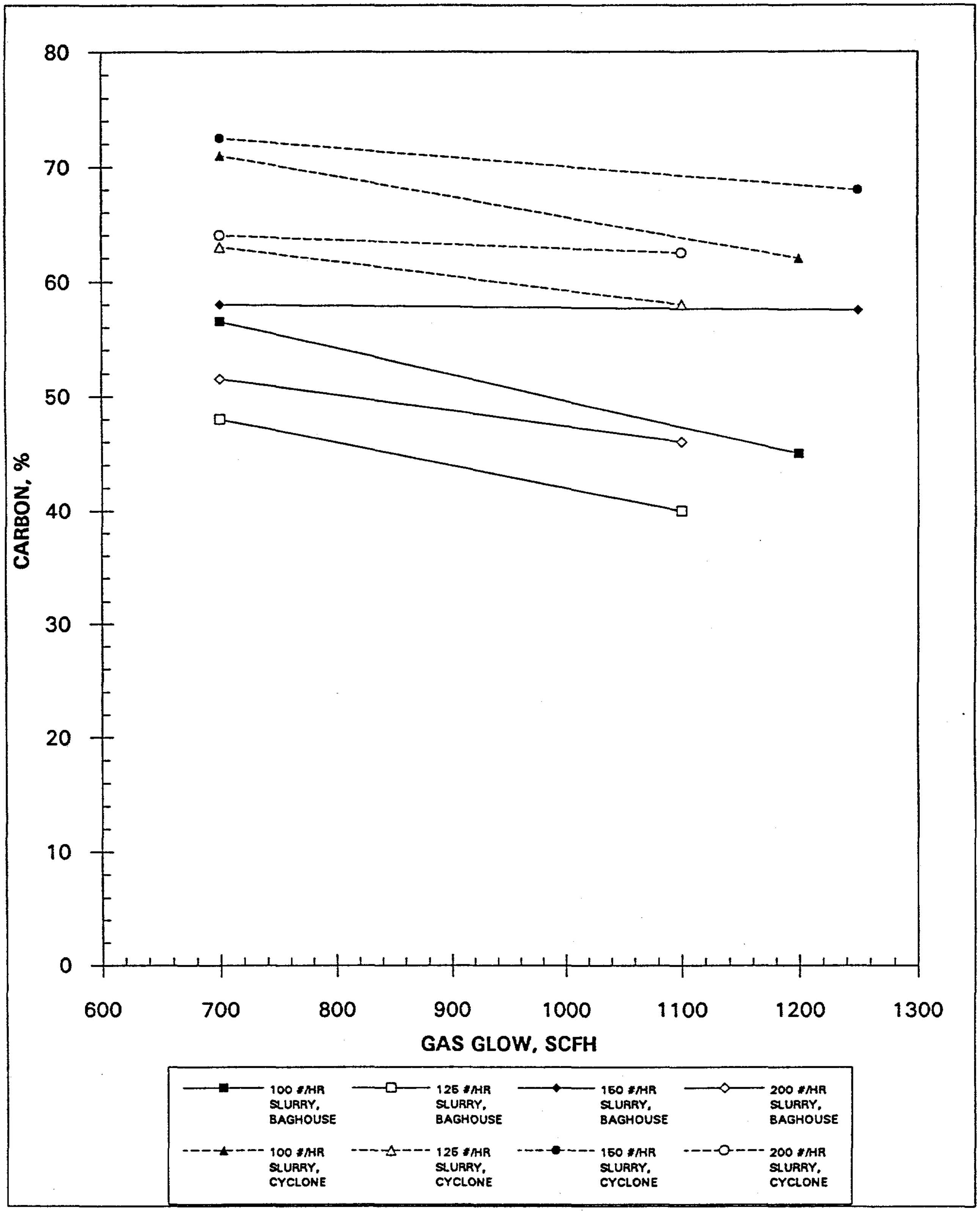
EFFECT OF REFRACTORY LENGTH VS. BOILER EFFECIENCY % AND CARBON %
Fig. 4-2



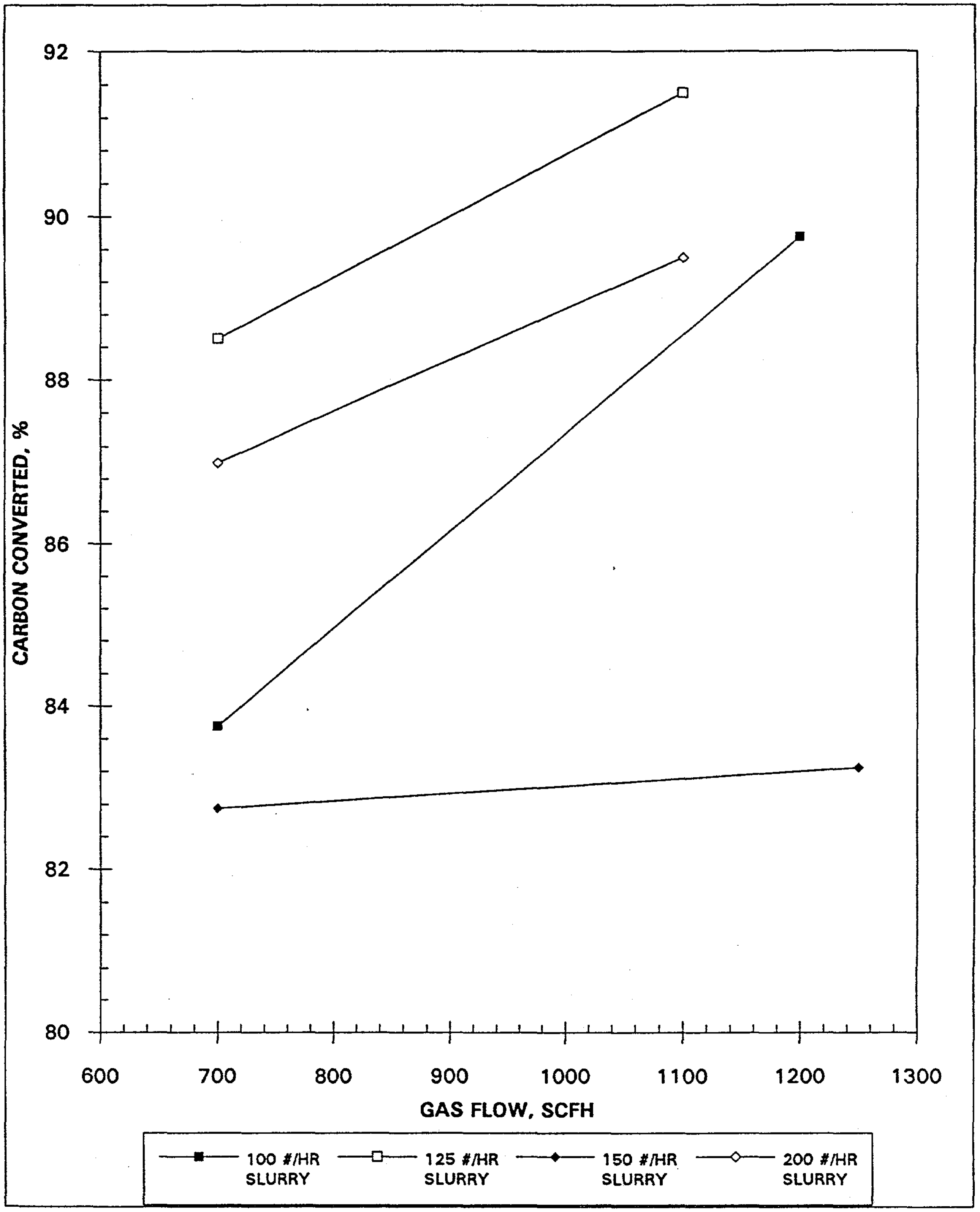
ASH REINJECTION VS. BOILER PERFORMANCE
Fig. 4-3



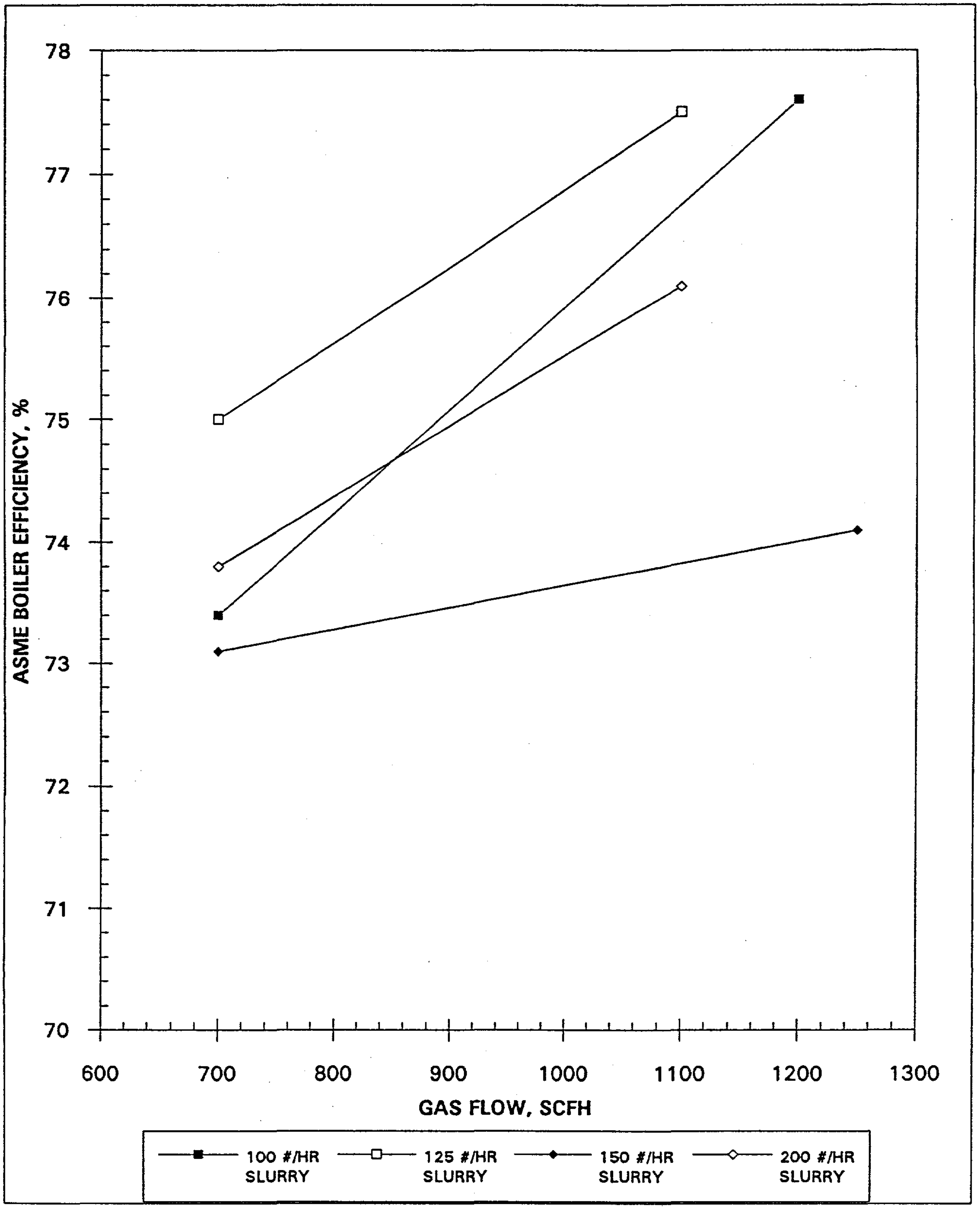
CARBON CONTENT VS. PARTICLE SIZE
Fig. 4-4



CARBON CONTENT VS. GAS FLOW
Fig. 4-5



CARBON CONVERTED VS. GAS FLOW
Fig. 4-6



ASME BOILER EFFECIENCY VS. GAS FLOW
Fig. 4-7

effect of increasing natural gas flow on carbon conversion and ASME boiler efficiency, respectively, for four slurry flows.

To evaluate the effect of supplementary firing of natural gas, ash samples were taken at the cyclone outlet and at the baghouse and analyzed for carbon content. The highest carbon conversion measured was 92 percent. This was obtained while firing 1100 scfh natural gas and 125 #/hr slurry. These flow rates equate to 60 percent boiler load with 52% of the heat from slurry and 48% from gas.

The maximum boiler load achieved was 80 percent, with CWS accounting for 62 percent of the total heat input. Boiler loads did not exceed 80 percent due to baghouse inlet flue gas temperature restrictions. The highest heat input due to CWS occurred at 200 #/hr slurry and 700 scfh gas flow. The boiler load was 70 percent under these conditions with CWS accounting for 72 percent of the heat input. Carbon conversion decreased to 87 percent from 92 percent.

The boiler was operated at 150 #/hr slurry corresponding to a boiler load of 38 percent with no gas support for a period of 5-10 minutes on two different occasions. The test was terminated due to a loss in air preheat temperature and flame instability. The test occurred with the 3 foot refractory configuration still in place. Figures 4-6 and 4-7 illustrate carbon conversions, natural gas flow, and ASME boiler efficiency for four slurry flows, respectively.

Boiler Emissions

Boiler parameters were varied to determine the boiler's operational limits and compare emissions. The variables were load, heat fraction due to slurry, ash recycle, air preheat and excess air. During the testing the NO_x operated in the range of .53 to .66 depending on the firing scenario. The range for CO emissions was normally 750 to 1050 ppm corrected to 3% O_2. These high CO levels are attributed to the flue gas being rapidly cooled and ash deposits with high unburned carbon settling in the end passes. See Figure 4-8 for a summary of some typical emissions. Figure 4-9 shows NO_x verses O_2 for a boiler with 60% load. The heat input was 50% due to slurry and 50% due to natural gas.

UNIVERSITY OF ALABAMA
EMISSION SUMMARY SHEET

DATE	NAT. GAS	SLURRY	FRACT. HEAT		LOAD	% MCR	O2	CO			NOX			C IN ASH	C CONV
	SCFH	#/HR	GAS	CWS	MBTU/HR		%	MEAS.	CORR.	#/MBTU	MEAS.	CORR.	#/MBTU	%	%
								ppm	3% *		ppm	3% *			
2/1/1993a	700	150	0.34	0.66	2.03	54.4	5.6	885	1035	1.87	436	510	0.66	58.5	82.8
2/1/1993b	1250	150	0.48	0.52	2.58	69.1	5.4	886	1023	1.82	411	475	0.61	57.8	83.3
2/2/1993a	700	200	0.28	0.72	2.48	66.3	5.8	639	757	1.38	361	428	0.56	51.6	87.0
2/2/1993b	1100	200	0.38	0.62	2.88	77.0	5.9	803	954	1.72	372	442	0.57	45.9	89.6
2/3/1993a	700	100	0.44	0.56	1.59	42.5	8.2	742	1046	1.87	373	526	0.67	56.8	83.9
2/3/1993b	1200	100	0.57	0.43	2.09	55.9	5.3	735	845	1.49	365	420	0.53	45.2	89.9
2/3/1993c	690	128	0.38	0.62	1.83	48.9	6.5	713	886	1.59	363	451	0.58	48.6	88.4
2/3/1993d	1100	126	0.50	0.50	2.22	59.4	5.2	832	949	1.69	367	418	0.53	40.9	91.5

* ppm, corrected to 3% O2
Natural Gas Btu/scf = 1000
Slurry Btu/# = 8891
C in ash sampled at baghouse outlet

Figure 4-8

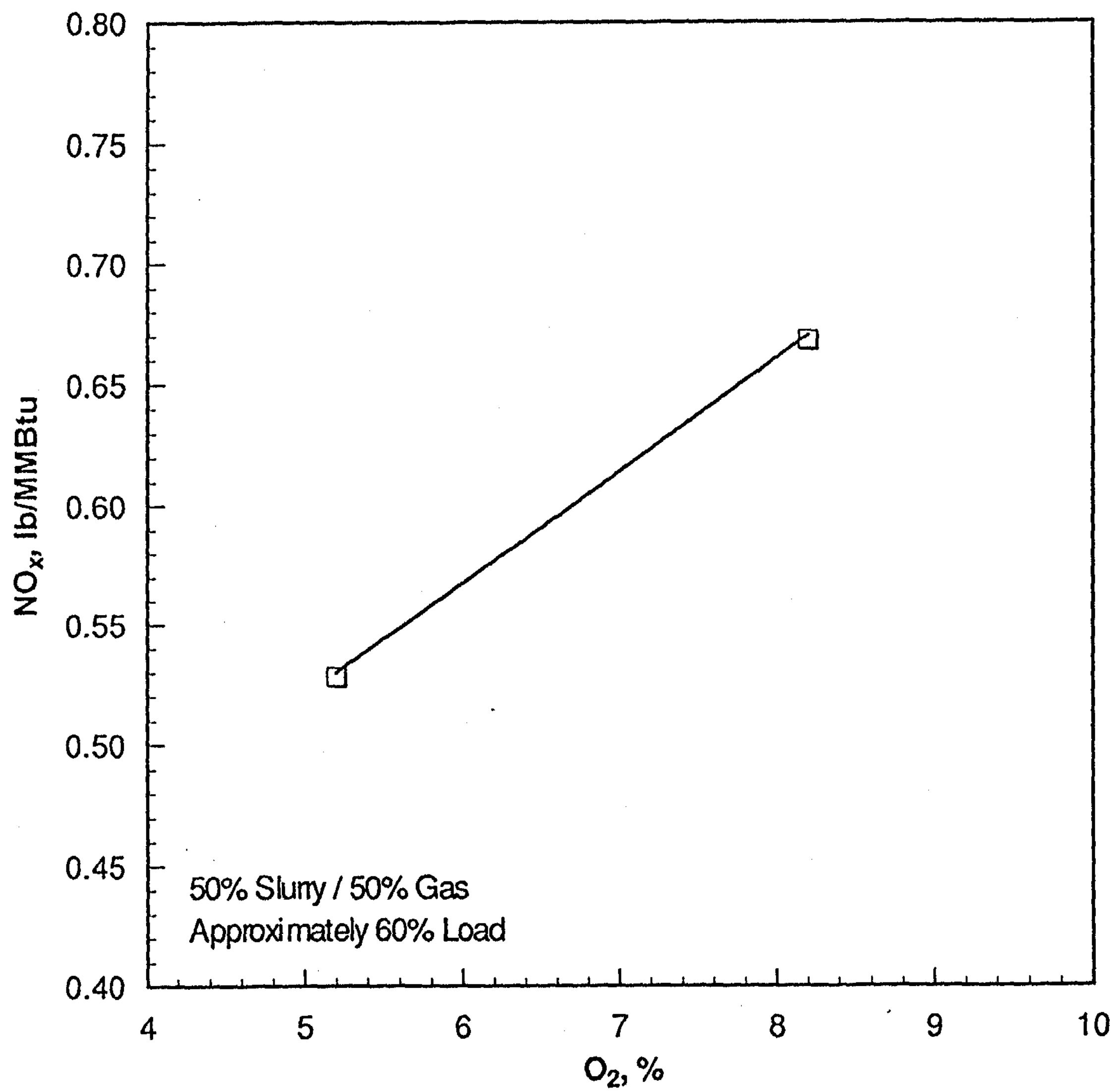


Figure 4-9. NO_x vs. O_2

5.0 ECONOMICS

A brief summary of the U.S. Boiler population will be presented so that the available market is clearly defined. The economics of converting these boilers to fire coal water slurry will then be analyzed using a simple payback analysis.

5.1 Commercial and Industrial Market Analysis

As mentioned previously, this program was focused on boilers in the 1-10 million Btu/hr (1,000 - 10,000 lb/hr steam equivalent) size range. However, the majority of the expertise developed under this program can be utilized equally well on larger fire-tube boilers and water-tube boilers.

All of the information on Market Analysis was taken from "Commercial Sector Firetube Boiler Market Analysis" prepared for DOE PETC by Burns and Roe Services Corporation under Contract No. DE-AC22-89PC88400. The draft report was dated February 1990. Additional information regarding the available market is available from that report as only a summary will be presented in this report.

In 1986, the commercial sector consumed about 6.11 Quads of energy, which is 11 percent of the total energy used in the United States. In the commercial sector, there are approximately 877,000 boilers, that consume between 2 and 2.5 Quads of energy annually. This breaks down as shown in Figure 5-1. For the less than 10 million Btu/hr segment, there are approximately 872,500 boilers which translates to over 99 percent of the total boiler population in the commercial market sector, as shown in Figure 5-2. By far the majority of these boilers do not fire coal. Coal fired equipment has not been cost competitive in this small size.

The industrial boiler market sector consumes almost 3 times the commercial sector's annual energy (19.7 Quads). The boiler portion of this market consumes about 7.0 Quads of

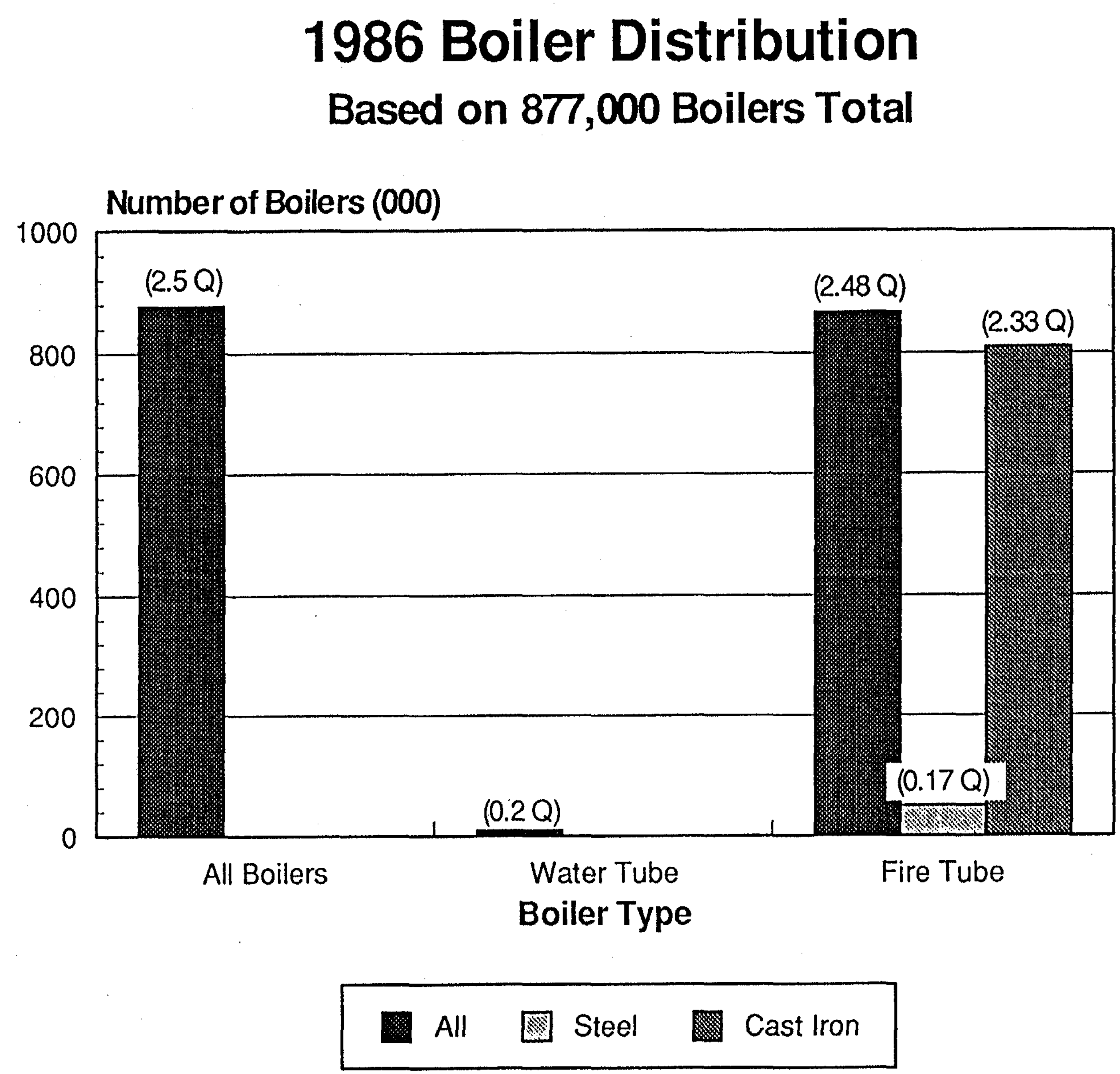


Figure 5-1. Boiler Distribution

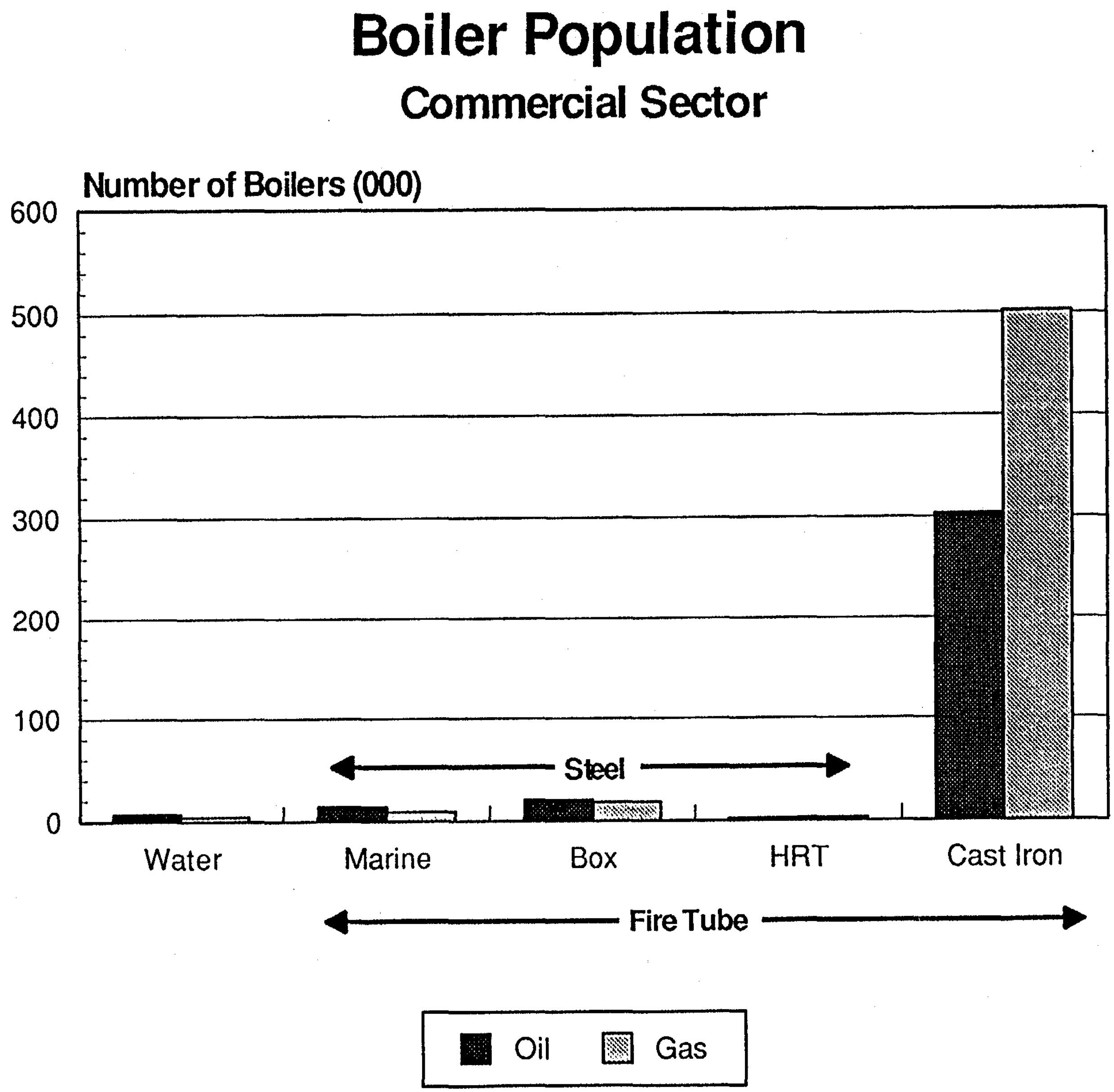


Figure 5-2. Commercial Boiler Population <10 MMBtu/hr

energy, or 52 percent of total manufacturing heat and power energy consumption. In 1985, the U.S. industrial boiler market consisted of 36,820 boilers. Of these, 35,415 boilers are below 250,000 million Btu/hr, 32,325 boilers are below 100,000 million Btu/hr, and 26,115 boilers are in the 10 to 24 million Btu/hr range. For the industrial sector, the choice of fuel is price driven. If coal fired equipment can be installed and provide a reasonable payback it would be considered for use.

5.2 Slurry Conversion Economics

An advanced coal based system will require a larger initial investment than a comparable gas-or-oil fired boiler. To be attractive to a potential customer, differential operating and maintenance costs must be sufficiently low, to offset the higher initial investment and provide net overall cost savings over a reasonable time.

This economic evaluation is for the retrofit of a coal water slurry system to an existing fire-tube boiler. The operating costs of the existing gas-or-oil fired boiler were calculated. The new operating costs and the total plant investment to add slurry firing was then calculated and compared. The analysis was performed by varying the fuel costs, capacity factor, and capacity of the boiler. The analysis is based upon the simple payback period method of evaluating investment decisions. Payback period is the length of time required for an investment to pay for itself; payback occurring when cumulative net cash inflows produce savings or gross profit to the owner. The payback period approach to investment decision making is frequently used by small business since it is a very simple and straight forward method.

As mentioned above one of the variables in this analysis is capacity factor. Capacity factor is defined as the ratio of actual boiler load to maximum design load. For example, a boiler that operates at 80% of it's capacity and operates 80% of the time would have a capacity factor of 64%. Capacity factor is a very important parameter when considering the additional investment for a slurry system. Based on the experience from this project, it is estimated that most oil and gas fired boilers when retrofitted with slurry will require about a 20% derate. So the analysis considered the boiler operating at 80% load and 80, 60, and 40 percent of the available time for corresponding capacity factors of 64, 48, and 32 percent.

Another variable is the rated capacity of the boiler. This program was directed at the 1.5-10 million Btu/hr range (1,000 to 10,000 lb/hr steam equivalent), so boiler capacities utilized were 2,800, 4,000, 10,000, 15,000, and 28,000 lb/hr steam. The two larger sizes were evaluated because some fire-tubes exist at this capacity and because the economics are more attractive for the larger sizes.

The third variable is fuel cost. The University of Alabama was paying $4.72 per MMBtu for gas during the long term testing. The cost of gas used for the analysis was 4, 5, and $6 per MMBtu which should approximate the cost paid by most commercial/industrial users. The fuel cost for oil was 5, 6, and $7 per MMBtu ($6 per MMBtu is equivalent to $.84 per gallon) which should also approximate current oil prices. Slurry costs of 1.5 and $2.0 per MMBtu were analyzed. Supporting evidence for the slurry cost is in a report titled "Integrated Coal Preparation and CWF Processing Plant" prepared by Science Applications International Corporation for DOE PETC where the annualized cost of CWF in 1992 dollars was estimated at $1.84 per MMBtu. The cost estimate included a feedstock coal cost (mine mouth, pre-cleaned) of $1.00/MMBtu, and was based on a 20-year plant life, with a constant inflation rate of 4 percent per annum over the life of the plant, 100 percent equity investment (as opposed to debt financing) and a 15 percent nominal after-tax internal rate of return on investment. In contrast to the $1.84/MMBtu, an eastern utility has evaluated the cost of producing a low cost slurry for co-firing into utility boilers. The feedstock for this slurry would be coal fines from a coal preparation facility or fines reclaimed from existing coal ponds. This utility has calculated that they can produce the slurry for $1.00/MMBtu.

The costs for the major equipment for each case was determined by scaling the actual costs from this project. The method used was the six-tenths-factor, where the cost of a given unit at one capacity is known, the cost of a similar unit with X times the capacity of the first is approximately $(X)^{0.6}$ times the cost of the initial unit.

Table 5-1 and 5-2 are a summary of the payback period for existing natural gas and oil fired boilers when converted to fire slurry. The payback period for 2,800 and 4,000 lb/hr steam boilers is too long to make them attractive candidates for conversion to slurry. The 10,000 lb/hr boiler has a few configurations for which the payback period is in the 3-4 year range when the fuel cost differential and the capacity factor are high. The 15,000 and 28,000 lb/hr boilers have many scenarios that have potential for conversion to slurry firing. There are 30 cases where the payback period is less than 3 years. The detailed cost analysis for each test case with a payback period of less than five (5) years is included in Appendix B.

The majority of this economic analysis is also valid when considering the purchase of a new boiler as opposed to retrofitting an existing one. The majority of the original costs for the boiler are still valid, however some auxiliary equipment must be upgraded or replaced during a retrofit, so a cost reduction is available in the following areas:

- The forced draft fan will normally require replacement due to increased pressure drop through the system.

- The boiler controls must be upgraded to operate the additional equipment. Designing a complete system will be more economical than adding on or replacing.

- The burner on the existing boiler would have to be replaced with a dual fuel burner.

A new boiler installation was analyzed and compared to the cost for retrofitting an existing boiler. At the same time the payback period for producing a new boiler in mass quantities was calculated. Tables 5-3 and 5-4 are summaries of the payback period for the retrofit, the one new boiler, and large quantities of new boilers for gas and oil fired installations. Figures 5-3 through 5-13 illustrate the payback period graphically. A capacity factor of 48% was utilized for all boiler capacities. Considering the oil fired boiler at 2800 lb/hr steam, the lowest payback period is 5.7 years with a fuel cost differential of $5.5 per MMBtu, so the smaller boiler is not considered a good candidate for conversion. For the same parameters, the payback period for the 4000 lb/hr boiler is 3.6 years and 1.6 years for the 10,000 lb/hr boiler.

The conclusion from this economic analysis is that the boilers smaller than 4000 lb/hr steam are not good candidates for conversion to slurry unless they are produced in large quantities in a factory. Boilers in the 4,000 to 10,000 lb/hr range become attractive for a retrofit case with high fuel cost differentials and high capacity factors. Most boilers larger than 10,000 lb/hr steam have low payback periods and are excellent candidates for conversion to coal water slurry.

FIRE-TUBE BOILER ECONOMIC SUMMARY
Natural Gas fired boiler

Boiler Rated Capacity	N.G. cost	Slurry cost	Payback period in years		
in #/hr	$/mmbtu	$/mmbtu	32%cf	48%cf	64%cf
2800	4	1.5	-	-	-
2800	5	1.5	-	-	-
2800	6	1.5	-	-	-
2800	4	2	-	-	-
2800	5	2	-	-	-
2800	6	2	-	-	-
4000	4	1.5	-	-	-
4000	5	1.5	-	-	-
4000	6	1.5	-	15.31	9.99
4000	4	2	-	-	-
4000	5	2	-	-	-
4000	6	2	-	-	13.41
10000	4	1.5	-	14.69	9.64
10000	5	1.5	12.45	7.14	5.01
10000	6	1.5	7.79	4.72	3.38
10000	4	2	-	-	17.93
10000	5	2	17.74	9.61	6.59
10000	6	2	9.58	5.68	4.04
15000	4	1.5	15.67	8.68	6.00
15000	5	1.5	7.95	4.80	3.44
15000	6	1.5	5.32	3.32	2.41
15000	4	2	-	14.56	9.56
15000	5	2	10.55	6.18	4.37
15000	6	2	6.38	3.93	2.84
28000	4	1.5	8.06	4.86	3.48
28000	5	1.5	4.68	2.94	2.14
28000	6	1.5	3.29	2.11	1.55
28000	4	2	12.63	7.23	5.07
28000	5	2	5.92	3.66	2.65
28000	6	2	3.86	2.45	1.80

- means that the payback period exceeds 20 years
cf = capacity factor based on the derated boiler load

Table 5-1

FIRE-TUBE BOILER ECONOMIC SUMMARY
Oil fired boiler

Boiler Rated Capacity	OIL cost	Slurry cost	Payback period in years		
in #/hr	$/mmbtu	$/mmbtu	32%cf	48%cf	64%cf
2800	5	1.5	-	-	-
2800	6	1.5	-	-	-
2800	7	1.5	-	18.23	11.61
2800	5	2	-	-	-
2800	6	2	-	-	-
2800	7	2	-	-	15.03
4000	5	1.5	-	-	-
4000	6	1.5	-	15.17	9.91
4000	7	1.5	17.70	9.59	6.58
4000	5	2	-	-	-
4000	6	2	-	-	13.27
4000	7	2	-	11.76	7.91
10000	5	1.5	12.33	7.09	4.97
10000	6	1.5	7.75	4.69	3.39
10000	7	1.5	5.65	3.51	2.54
10000	5	2	17.51	9.51	6.53
10000	6	2	9.52	5.65	4.01
10000	7	2	6.53	4.01	2.90
15000	5	1.5	7.89	4.77	3.42
15000	6	1.5	5.30	3.30	2.40
15000	7	1.5	3.99	2.53	1.85
15000	5	2	10.44	6.13	4.34
15000	6	2	6.34	3.90	2.82
15000	7	2	4.55	2.86	2.09
28000	5	1.5	4.65	2.92	2.13
28000	6	1.5	3.28	2.10	1.54
28000	7	1.5	2.53	1.63	1.21
28000	5	2	5.87	3.64	2.63
28000	6	2	3.84	2.44	1.79
28000	7	2	2.86	1.84	1.35

- means that the payback period exceeds 20 years
cf = capacity factor based on the derated boiler load

Table 5-2

FIRE-TUBE BOILER ECONOMIC SUMMARY
Natural Gas fired boiler

Boiler Rated Capacity	N.G. cost	Slurry cost	Payback period in years		
in #/hr	$/mmbtu	$/mmbtu	retro	single	mass
2800	4	1.5	-	-	-
2800	5	1.5	-	-	-
2800	6	1.5	-	-	9.50
2800	4	2	-	-	-
2800	5	2	-	-	-
2800	6	2	-	-	14.08
4000	4	1.5	-	-	-
4000	5	1.5	-	-	9.59
4000	6	1.5	15.31	10.86	5.27
4000	4	2	-	-	-
4000	5	2	-	-	16.26
4000	6	2	-	14.80	6.80
10000	4	1.5	14.69	10.32	5.73
10000	5	1.5	7.14	5.28	3.13
10000	6	1.5	4.72	3.55	2.15
10000	4	2	-	19.74	9.83
10000	5	2	9.61	6.98	4.05
10000	6	2	5.68	4.24	2.55
15000	4	1.5	8.68	6.32	3.87
15000	5	1.5	4.80	3.60	2.28
15000	6	1.5	3.32	2.51	1.61
15000	4	2	14.56	10.18	5.96
15000	5	2	6.18	4.58	2.87
15000	6	2	3.93	2.96	1.89
28000	4	1.5	4.86	3.62	2.44
28000	5	1.5	2.94	2.22	1.52
28000	6	1.5	2.11	1.60	1.10
28000	4	2	7.23	5.30	3.50
28000	5	2	3.66	2.76	1.87
28000	6	2	2.45	1.86	1.28

- means that the payback period exceeds 20 years
Economic analysis performed at 48% capacity factor

Table 5-3

FIRE-TUBE BOILER ECONOMIC SUMMARY
Oil fired boiler

Boiler Rated Capacity	OIL cost	Slurry cost	Payback period in years		
in #/hr	$/mmbtu	$/mmbtu	retro	single	mass
2800	5	1.5	-	-	-
2800	6	1.5	-	-	9.41
2800	7	1.5	18.23	12.80	5.72
2800	5	2	-	-	-
2800	6	2	-	-	13.87
2800	7	2	-	16.84	7.11
4000	5	1.5	-	-	9.47
4000	6	1.5	15.17	10.78	5.23
4000	7	1.5	9.59	7.05	3.61
4000	5	2	-	-	15.92
4000	6	2	-	14.64	6.74
4000	7	2	11.76	8.52	4.27
10000	5	1.5	7.09	5.24	3.11
10000	6	1.5	4.69	3.53	2.14
10000	7	1.5	3.51	2.66	1.63
10000	5	2	9.51	6.91	4.01
10000	6	2	5.65	4.22	2.53
10000	7	2	4.01	3.03	1.85
15000	5	1.5	4.77	3.57	2.26
15000	6	1.5	3.30	2.50	1.61
15000	7	1.5	2.53	1.92	1.25
15000	5	2	6.13	4.55	2.85
15000	6	2	3.90	2.94	1.88
15000	7	2	2.86	2.18	1.40
28000	5	1.5	2.92	2.21	1.51
28000	6	1.5	2.10	1.60	1.10
28000	7	1.5	1.63	1.25	0.86
28000	5	2	3.64	2.74	1.86
28000	6	2	2.44	1.85	1.27
28000	7	2	1.84	1.40	0.97

- means that the payback period exceeds 20 years
Ecomonic analysis performed at 48% capacity factor

Table 5-4

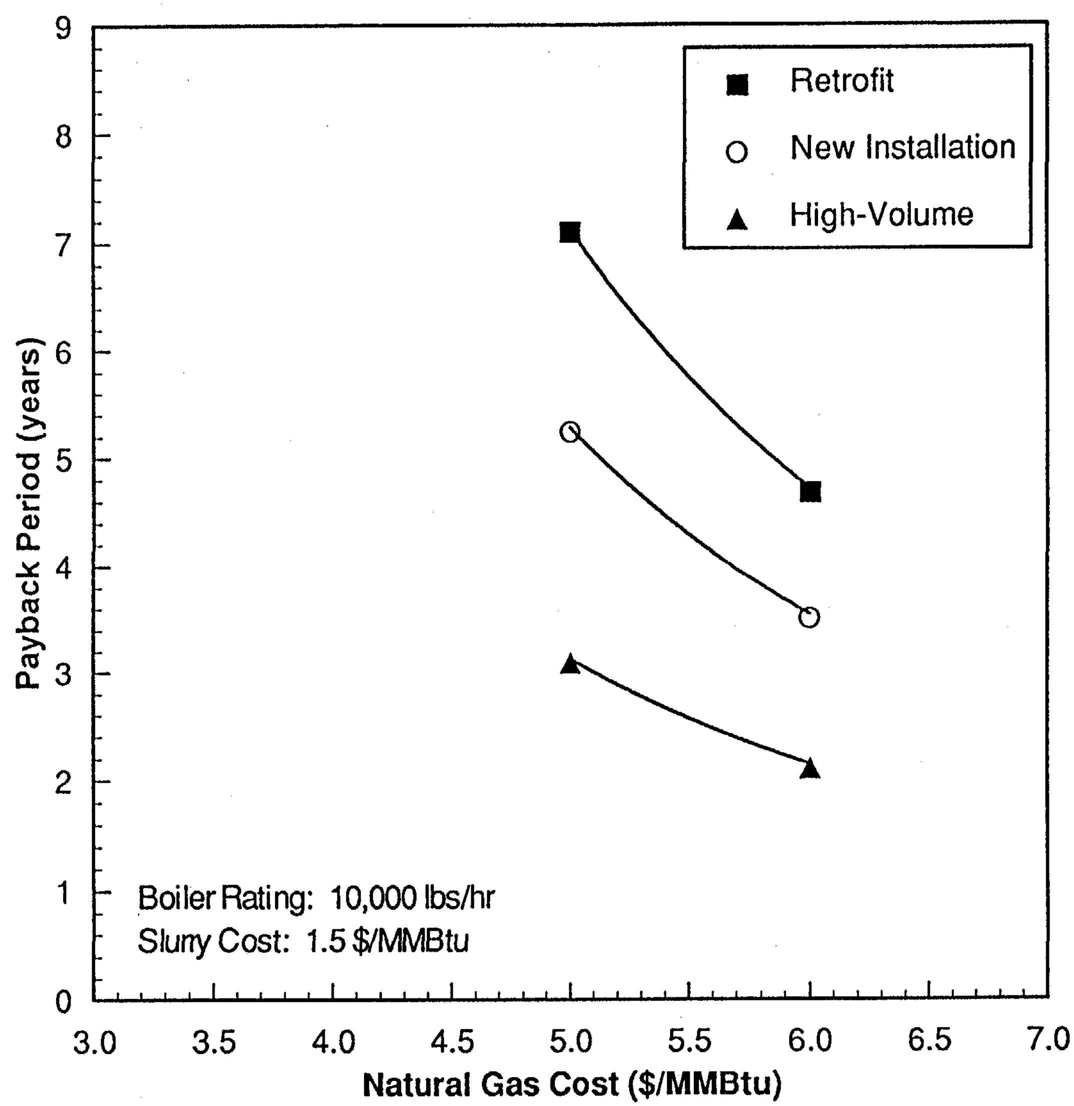


Figure 5-3. Payback Period vs. Natural Gas Cost of Gas Fired Fire-Tube Boilers

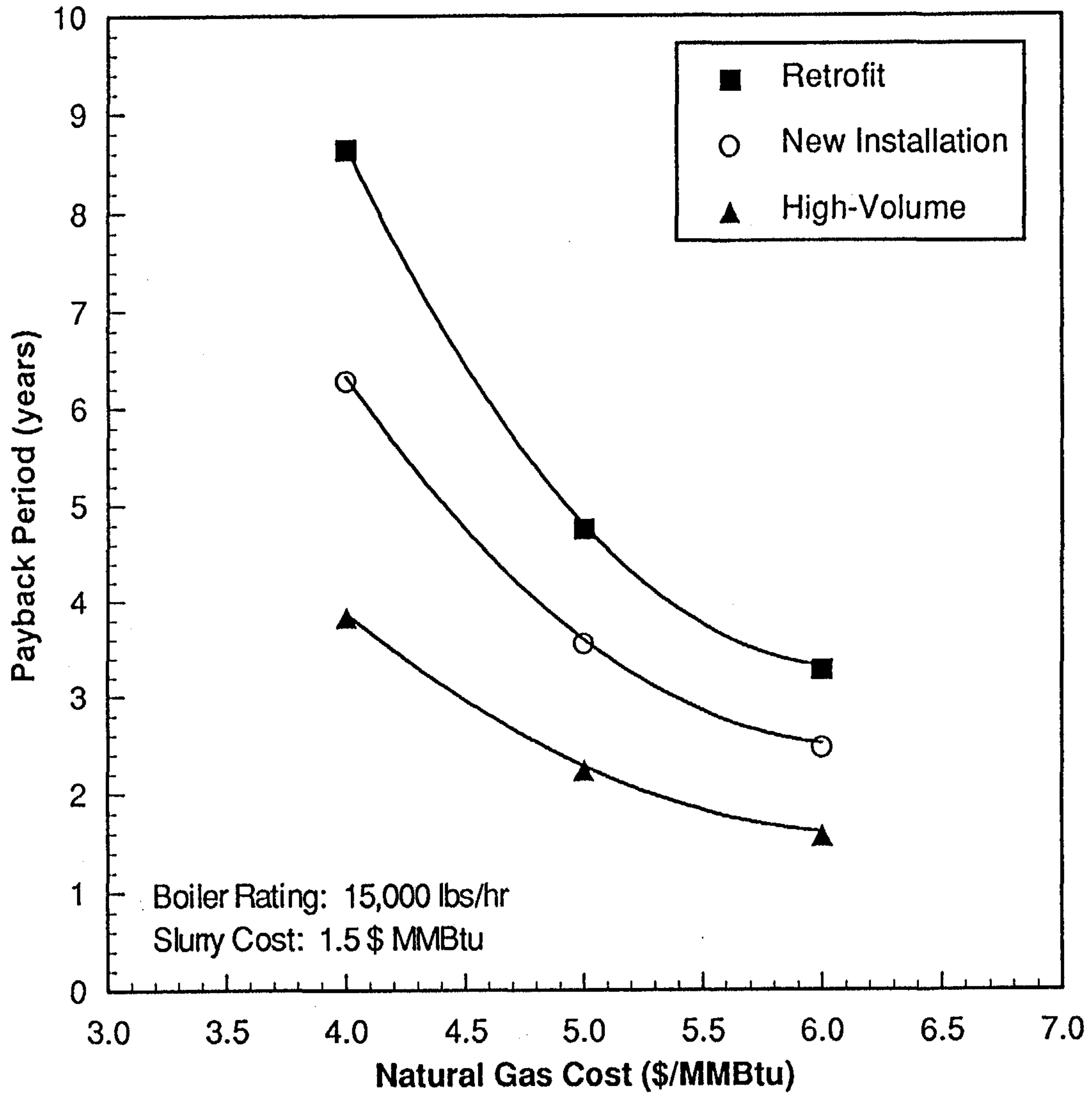


Figure 5-4. Payback Period vs. Natural Gas Cost of Gas Fired Fire-Tube Boilers

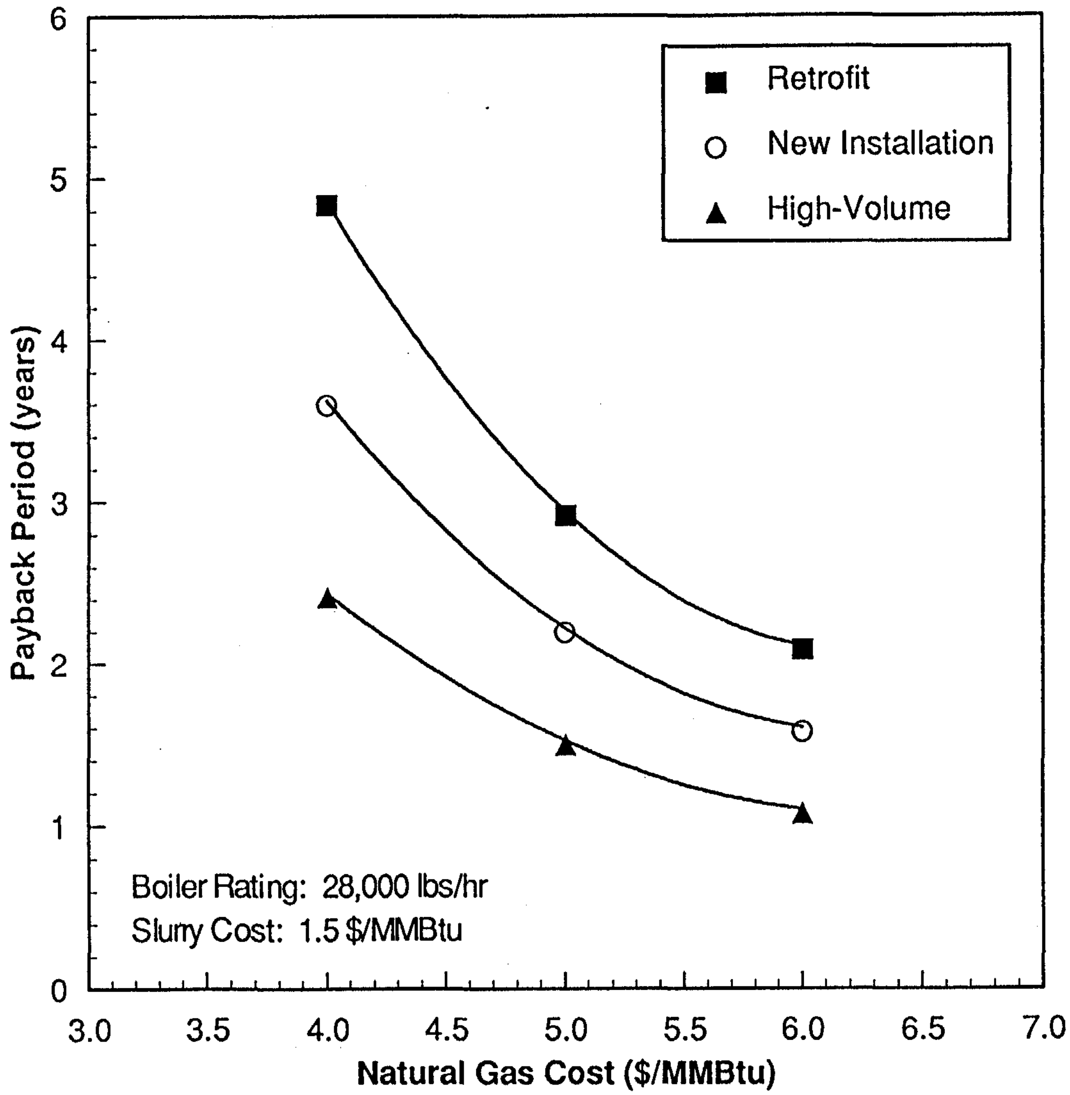


Figure 5-5. Payback Period vs. Natural Gas Cost of Gas Fired Fire-Tube Boilers

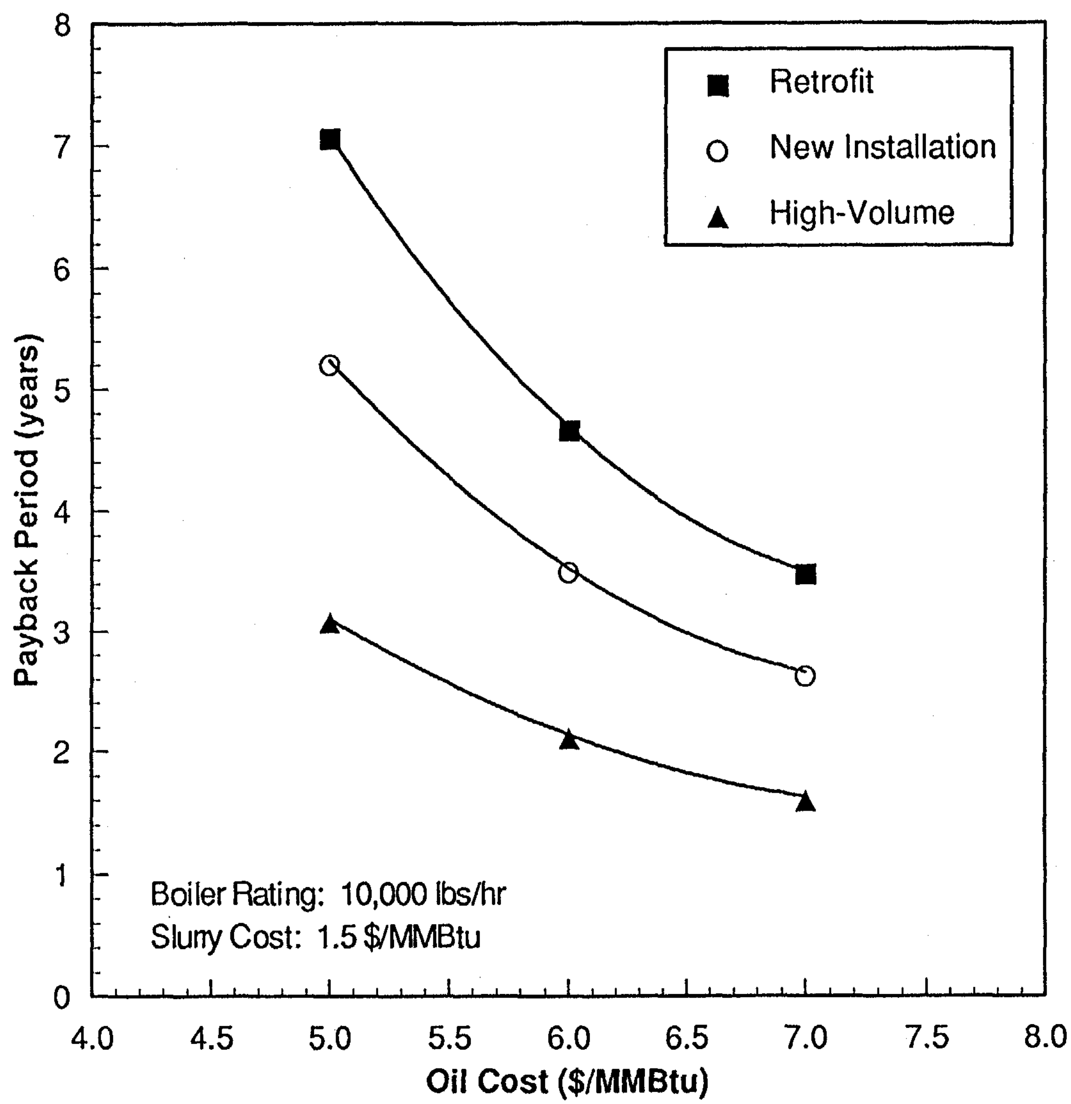


Figure 5-6. Payback Period vs. Oil Cost for Oil Fired Fire-Tube Boilers

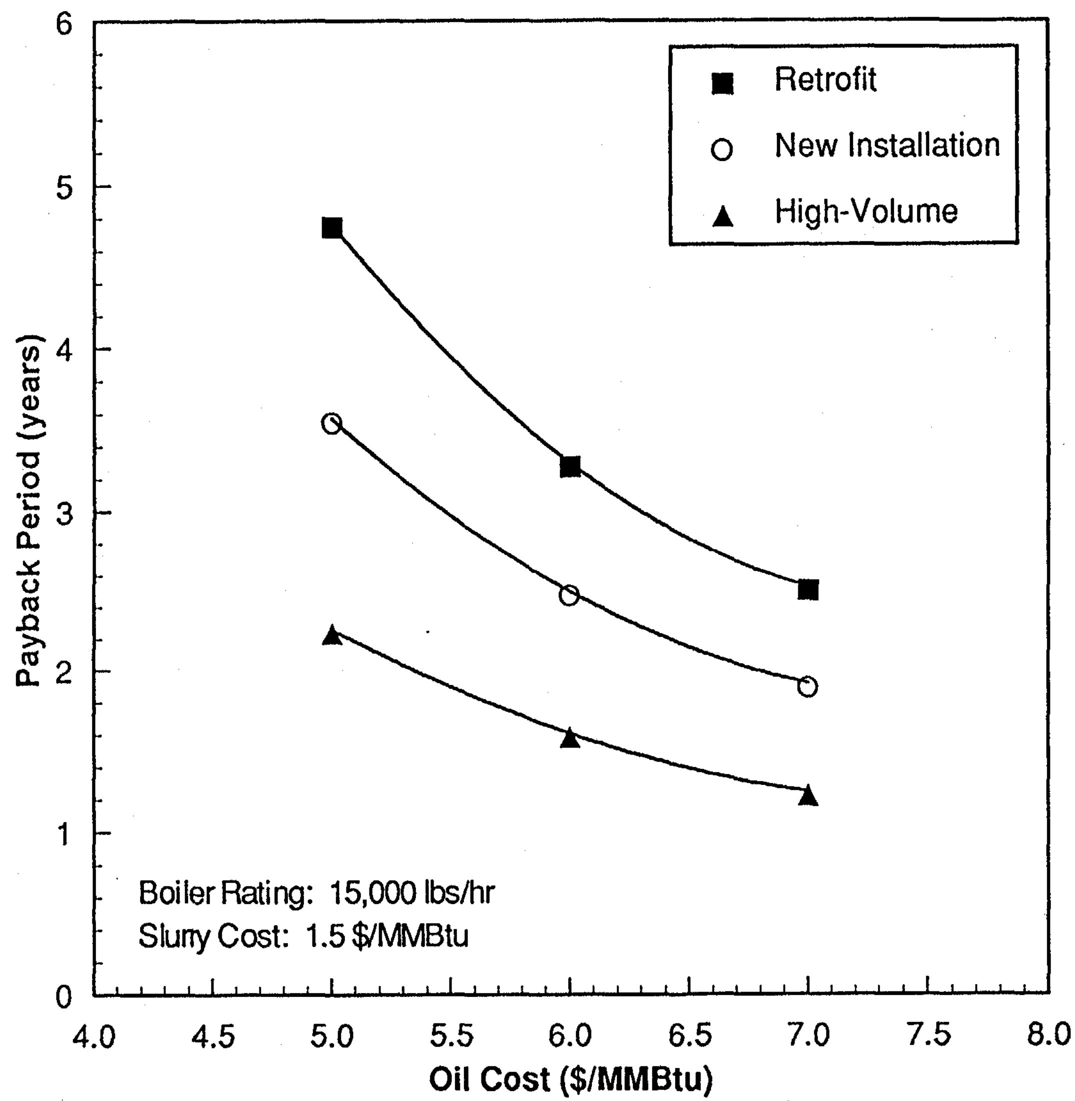


Figure 5-7. Payback Period vs. Oil Cost for Oil Fired Fire-Tube Boilers

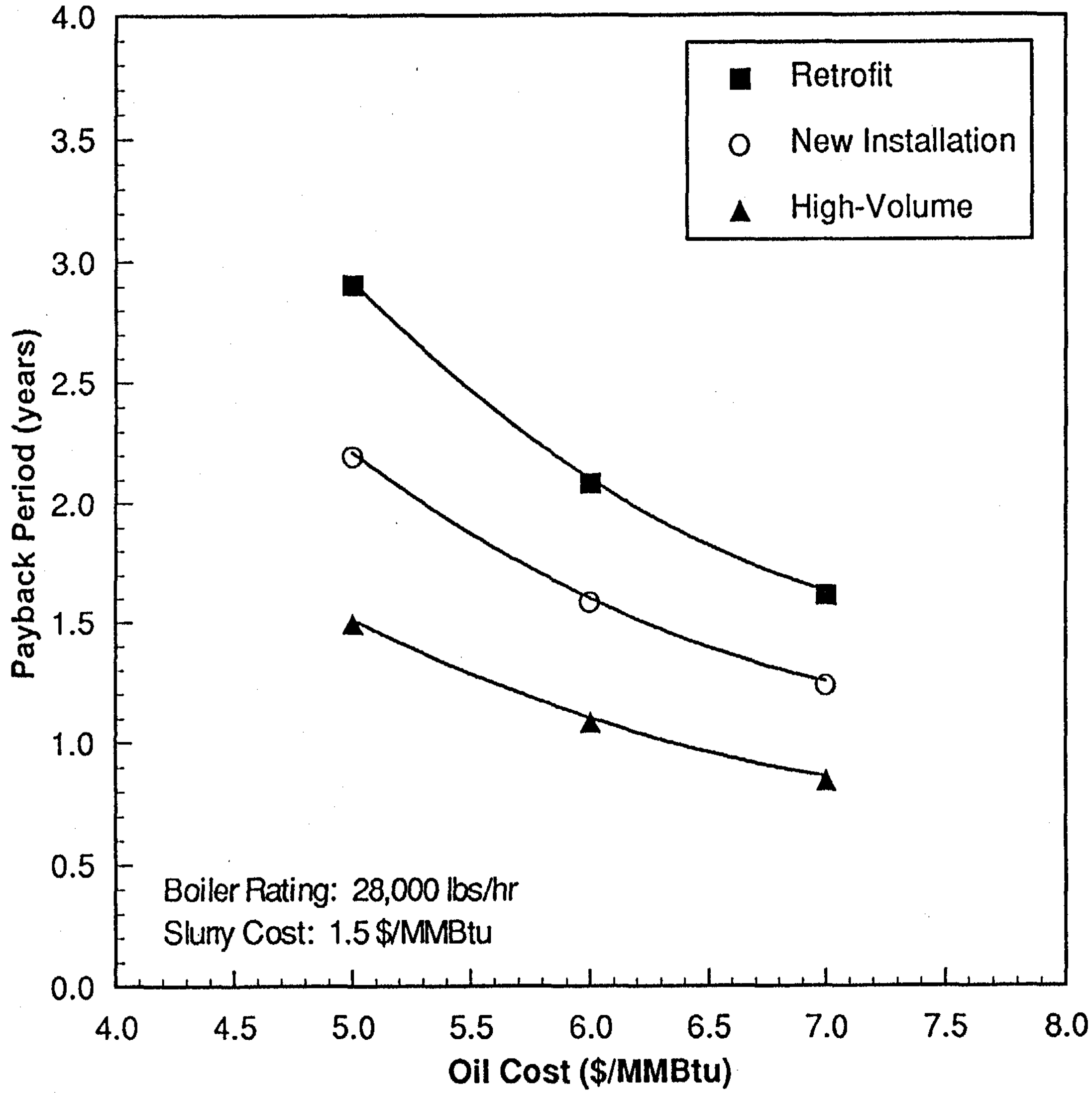


Figure 5-8. Payback Period vs. Oil Cost for Oil Fired Fire-Tube Boilers

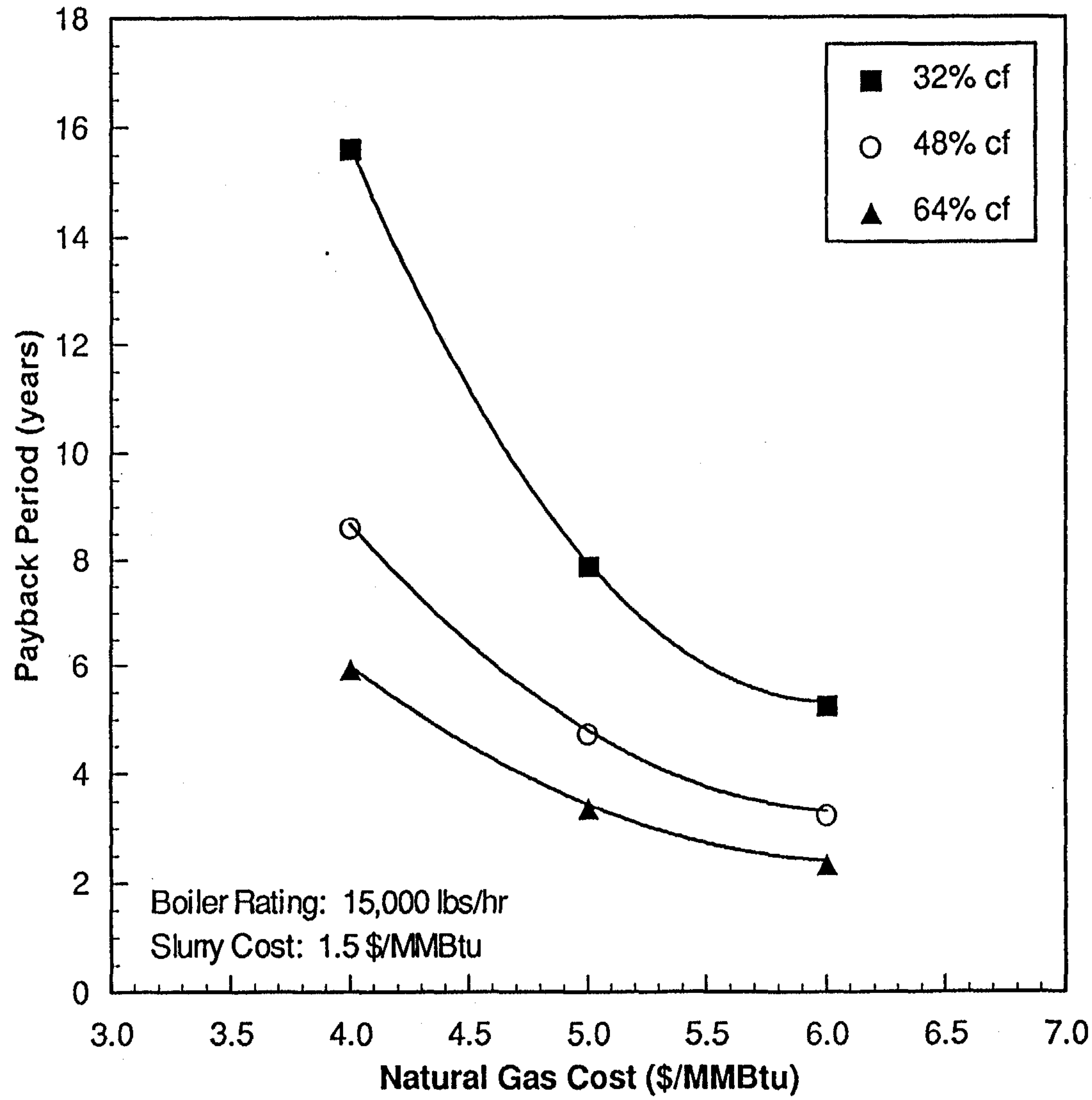


Figure 5-9. Payback Period vs. Natural Gas Cost of Gas Fired Fire-Tube Boilers

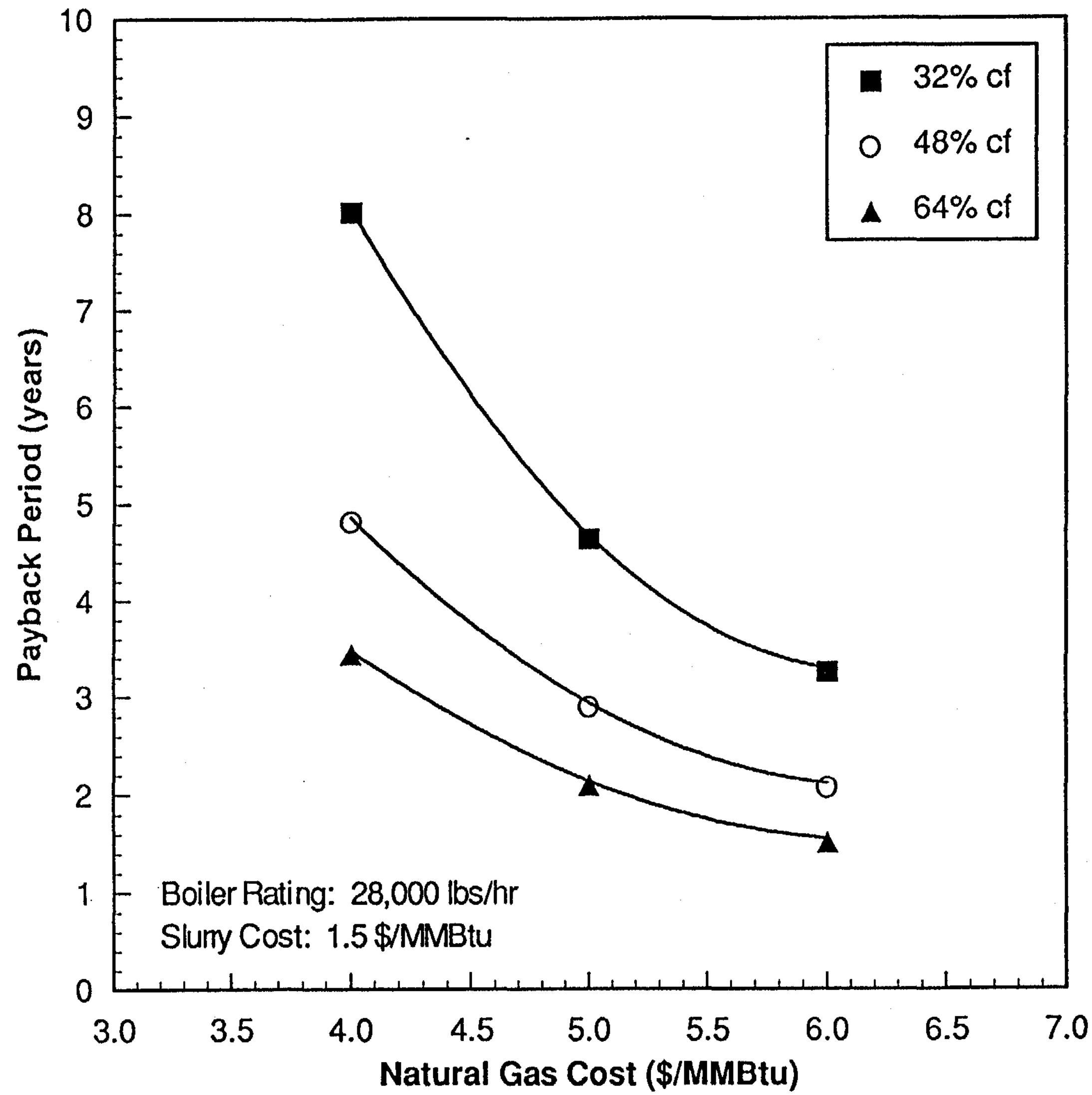


Figure 5-10. Payback Period vs. Natural Gas Cost of Gas Fired Fire-Tube Boilers

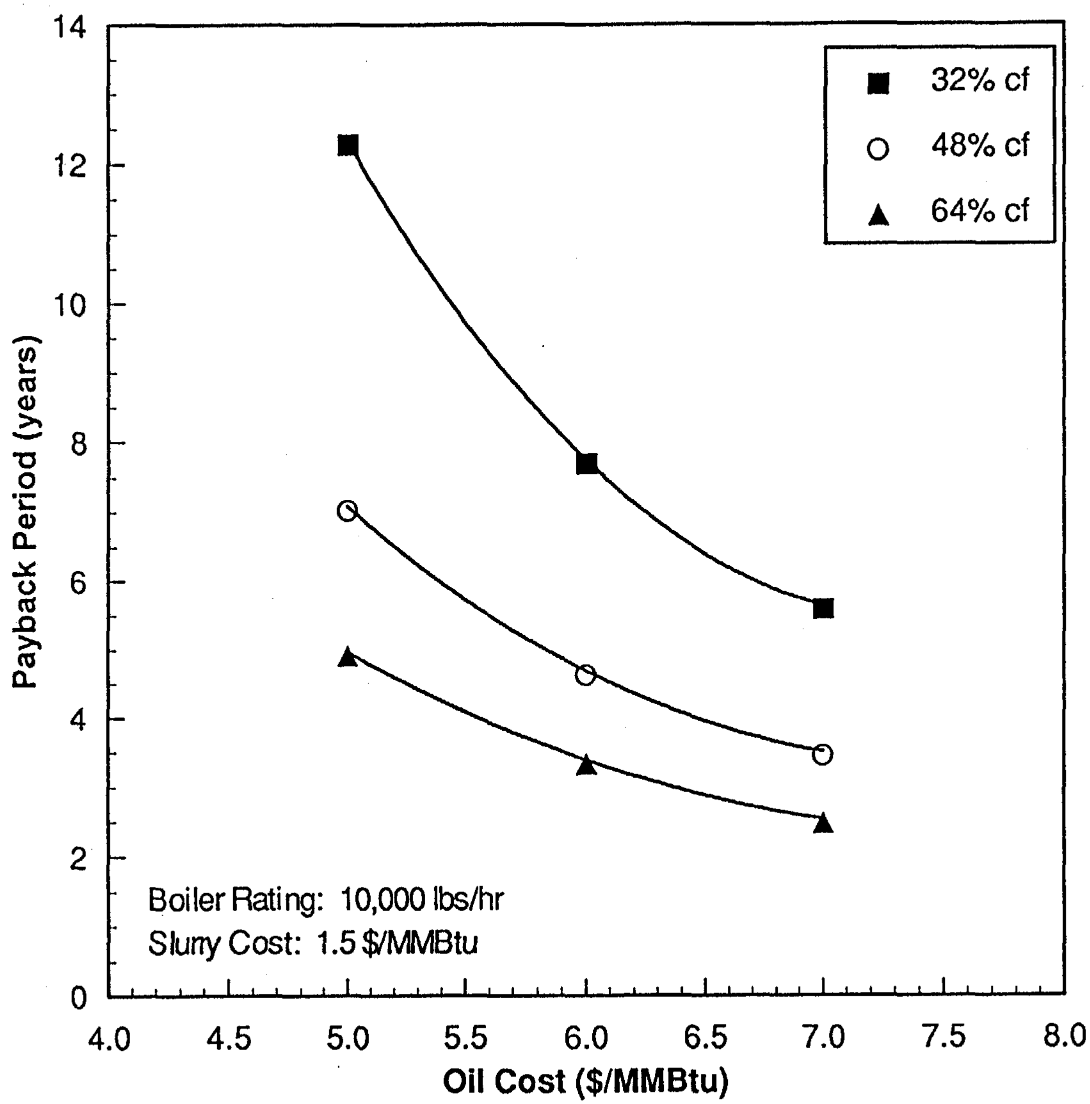


Figure 5-11. Payback Period vs. Oil Cost of Oil Fired Fire-Tube Boilers

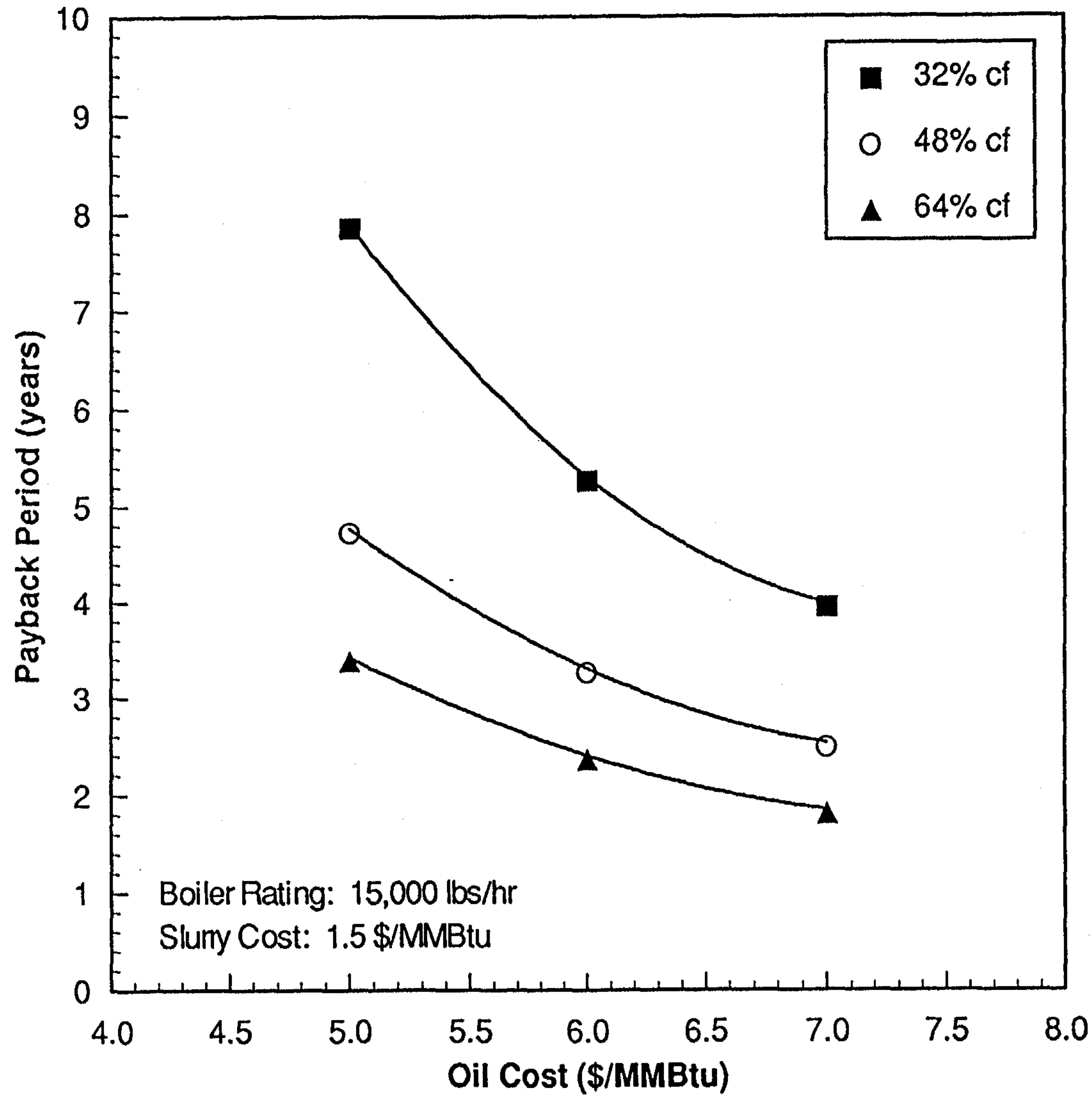


Figure 5-12. Payback Period vs. Oil Cost of Oil Fired Fire-Tube Boilers

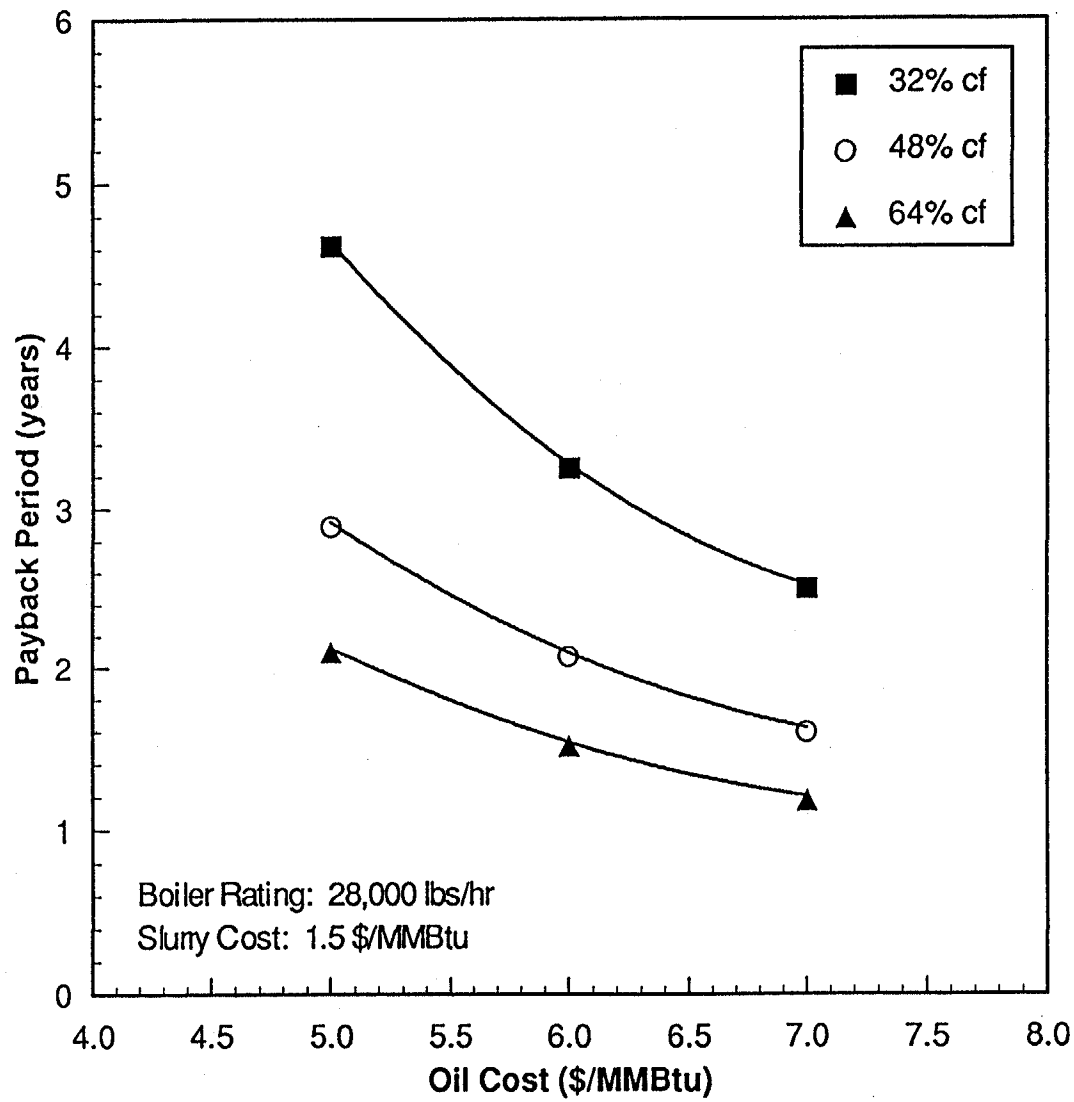


Figure 5-13. Payback Period vs. Oil Cost for Oil Fired Fire-Tube Boilers

6.0 CONCLUSIONS AND RECOMMENDATIONS

A fire-tube boiler system has been successfully designed and operated to fire coal-water slurry for extended periods of time with few slurry related operational problems. The following performance goals were met:

- Fully automatic start-up
- Turndown of 3:1
- Reliability/safety comparable to oil fired boilers
- Automatic dustfree ash removal
- Local emissions compliance

The most significant performance goal that was not satisfied was combustion efficiency. Although the program goal was 99 percent, the maximum obtained during testing was 95 percent.

Retrofitting an existing oil or gas fired boiler to slurry becomes economical when the boiler capacity is more than 10,000 lb/hr steam when using 1994 fuel costs. If the fuel cost differential increases in the future the minimum boiler size will decrease. When considering new boiler systems or new boiler systems produced in large quantities, the economics look attractive for boilers in the 4,000-10,000 lb/hr range.

Improving carbon burnout is the most significant area that will make the economics more attractive and convince boiler owners to convert to firing coal water slurry. This program did not allow for any modifications to the furnace volume; however, the heat transfer modelling clearly showed that adequate first pass temperature and residence time are required to achieve high carbon conversion. The population of fire-tube boilers simply cannot provide adequate residence time for coal combustion and achieve 99% carbon conversion, although many units could be retrofit with small pre-combustion chambers to achieve this goal.

EER believes that this concept could be demonstrated in a very cost effective manner utilizing the facilities and information resulting from this program. The precombustor will improve the ability to offer a commercial product that will compete with oil- and gas-fired boilers. The predicted enhancements are as follows:

- Improve carbon burnout
- Improve combustion efficiency
- Reduce the payback period
- Eliminate 80% of the ash in the boiler
- Reduce the NO_x emissions
- Eliminate support fuel
- Remove ash collecting and recycling equipment

APPENDIX A

Summary: Thermal Performance Impact Analysis of Initial Parametric Study

INTRODUCTION

An initial parametric model study was performed to provide information needed to optimize the design modifications and to select optimum operational conditions for a fire-tube boiler retrofitted with coal-water slurry fuels. Since the critical pass governing the combustion performance achievable in the boiler is in the first pass, the parametric study was focusing on the thermal performance impact on the fire tube only. This appendix summarizes the study results. Keep in mind that this is the initial study and that several design changes occured before the final design was complete. This appendix is included to illustrate all ideas that were evaluated, whether good or bad.

The first pass of the boiler was divided into a two-dimensional computational grid configured to model an axisymmetric cylinder. Figure A-1 shows a sectional view of the fire tube and illustrates how the tube was divided into sixteen layers in an axisymmetric cylindric grid. Based on this grid, the volumes occupied by refractory linings were initially assumed negligible, while Figure A-2 shows that the grid was modified afterwards to account for actual volumes of refractory linings. The thermal conductivity of Kaowool 3000 board was used for the refractory thermal properties in the initial parametric study. The Kaowool 3000 board, with the maximum allowance temperature of 3000°F and the continuous use limit up to 2800°F, is manufactured by the Thermal Ceramics Company. Figure A-3 shows the conductivity of Kaowool 3000 board as a function of refractory service temperature. The cross-sectional view of the fire tube with the installation of the Kaowool 3000 board is shown in Figure A-4.

The model was initially calibrated using field data to verify that it was properly simulating the performance of the fire tube for baseline gas-fired operating conditions at a thermal input of 2.84 million Btu/hr. A series of simulations were then run to investigate the effects of various design modifications and a wide range of operational conditions. The key design parameters and operational conditions studied were the length and thickness of the refractory lining, refractory conductivity, burner swirl, air preheat, fly ash recycle, natural gas co-firing, overall excess air level, combustion volume and thermal load variation. The thermal performance impacts evaluated included mean gas temperatures, refractory surface temperatures, unburned fixed carbon in ash, and cumulative fuel heat releases. In the model, the refractory lining is composed of two segments: the burner refractory lining (typical 15 inches long) followed by the refractory sleeve covering the fire tube.

Table A-1 summarizes key parameters of the initial parametric study cases for the fire tube. Burner swirl effects were simulated by adjusting the volatile mixing times in the model. Higher the burner swirl number is, smaller the volatile mixing time is used to model faster heat release rate. The following section summarizes the model results with a brief discussion focusing on relative and qualitative impacts of each individual parameter under study.

RESULTS AND DISCUSSION

Calibration

The major model parameter adjusted for the calibration case was the fuel heat release rate. The rate was determined using an existing database, where the rate is described as a function of burner thermal load. Figure A-5 shows that the predicted gas temperature at the exit of the fire tube agrees with the mean measured data for the baseline case.

Refractory Length

Figures A-6a, -6b, -6c, and -6d shows the impacts of the length of refractory lining on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release, respectively. As the length of the refractory lining increases, gas temperatures in the fire tube are elevated. As a result, the potential to cause ash slagging in the fire tube becomes higher and refractory surface temperatures increase. For the longer refractory linings the higher gas temperatures favor increased carbon conversion in the combustion zone and therefore improve the overall combustion efficiency. Figure A-6d shows that increasing the refractory coverage in the fire tube enhances the total fuel heat release due to the reduction of unburned carbon in ash.

Burner Swirl

The impacts of burner swirl number on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release are shown in Figures A-7a, -7b, -7c, and -7d, respectively. Increasing the swirl number results in higher gas temperatures in the refractory lining area due to faster fuel heat release rate. Consequently higher refractory-surface temperatures and higher carbon burnout occur there. However, the overall impacts on carbon conversion and total fuel heat release at the fire-tube exit are insignificant.

Refractory Thickness

Figures A-8a, -8b, -8c, and -8d are plotted to show the impacts of refractory thickness on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release, respectively. Increasing the refractory thickness in the fire tube reduces the heat transfer rate to the water surrounding the tube, resulting in higher gas and refractory surface temperatures. There are minimal effects on the carbon burnout and total fuel heat release in the fire tube.

Air Preheat

The impacts of air preheat temperature on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release are presented in Figures A-9a, -9b, -9c, and -9d, respectively. Preheating the combustion air to 600°F in comparison to 350°F increases gas and refractory surface temperatures, consequently resulting in about a 10% reduction in unburned carbon at the fire-tube exit. The total fuel heat release increases slightly for the high air-temperature case due to less carbon loss from the fly ash.

Ash Recycle

Figures A-10a, -10b, -10c, and -10d show the impacts of 60% ash recycle on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release, respectively. Recycling the ash (collected before entering the baghouse) back to the fire tube slightly increases gas and refractory-surface temperatures due to the additional heat input carried by recycled ash. The reduction of carbon content in the fly ash is caused by the slight increase of gas temperatures and by increase of ash content in the boiler. The impact of ash recycle on the heat release profile is negligible.

Excess Air Level

The impacts of overall excess air level on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release are displayed in Figures A-11a, -11b, -11c, and -11d, respectively. Increasing the excess air level in the fire tube slightly reduces the gas and refractory-surface temperatures due to the increase of throughput to the boiler. As a result, a slightly higher carbon content in ash occurs in the refractory zone for the high excess-air case. A slightly lower carbon-in-ash value at the fire-tube exit for the high excess-air case is due to the higher amount of oxygen available there. The delay of fuel heat release for the high excess-air case is caused by the reduction of residence time in the refractory zone.

Load Variation

Figures A-12a, -12b, -12c, and -12d show the impacts of thermal load on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release, respectively. Increasing the boiler load from 50 to 100% reduces the mean gas temperatures in the refractory zone due to delay of fuel chemical heat release. As the load increases, the carbon burnout is also reduced. This is because both gas temperatures and residence times are lowered in the flame zone as the load increases. The higher cumulative percentage of fuel heat release for the lower load cases is caused by the significant reduction of unburned carbon in ash.

Gas Co-firing

The impacts of natural gas co-firing on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release are displayed in Figures A-13a, -13b, -13c, and -13d, respectively. Replacing the coal-water fuels with natural gas up to 30% of total heat input to the boiler does not have significant impacts on the carbon conversion profiles along the fire-tube axial distance, because the model assumes that a stable flame can be achieved throughout the load range on CWS alone. In actual practice, small amounts of natural gas are required for flame stability.

Combustion Volume

All the cases studied above were assumed that the refractory volumes are negligible. In practice a 1.5 inch thick of refractory lining can occupy approximately thirty percent of the bare tube volume in the event that the entire tube is covered with insulation material. This assumption will influence the combustion volume available for the flue gas. Therefore, the impacts of fire-tube combustion volume on the thermal performance were studied.

Figures A-14a, -14b, -14c, and -14d display the impacts of combustion volume on the mean gas temperature distribution, surface temperature, unburned fixed carbon in ash, and cumulative fuel heat release, respectively. Reducing the combustion volume in the fire tube by 30% decreases the residence time of combustion products, resulting in delaying fuel heat release to down stream of the tube, reducing gas and refractory-surface temperatures and consequently increasing carbon loss from the fly ash. So only the minimum amount of refractory should be utilized for flame stability and thus avoid the loss in residence time.

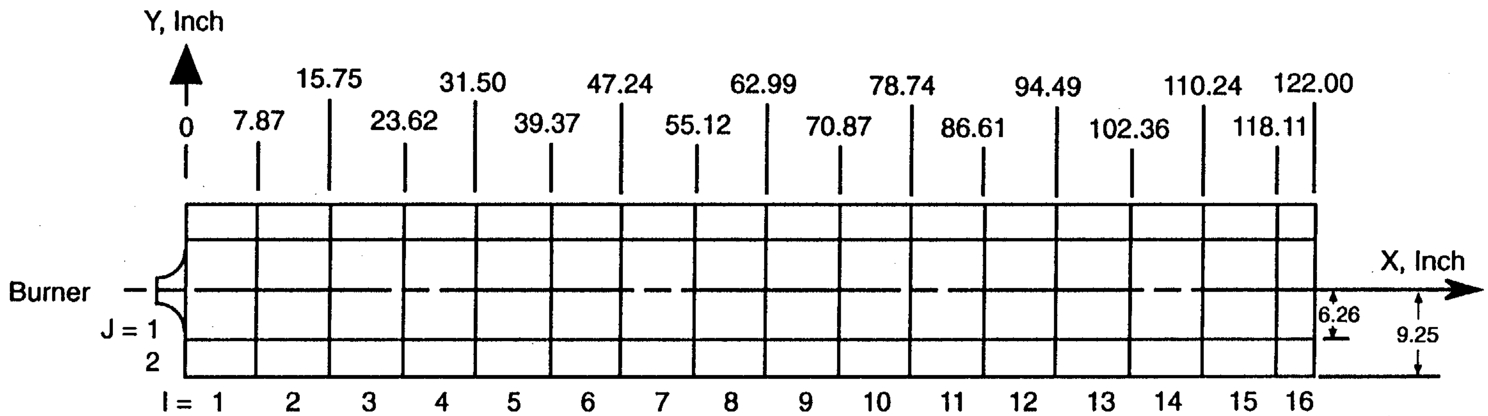


Figure A-1. Sectional view of actual fire-tube geometry and 2D computational grid for initial parametric study.

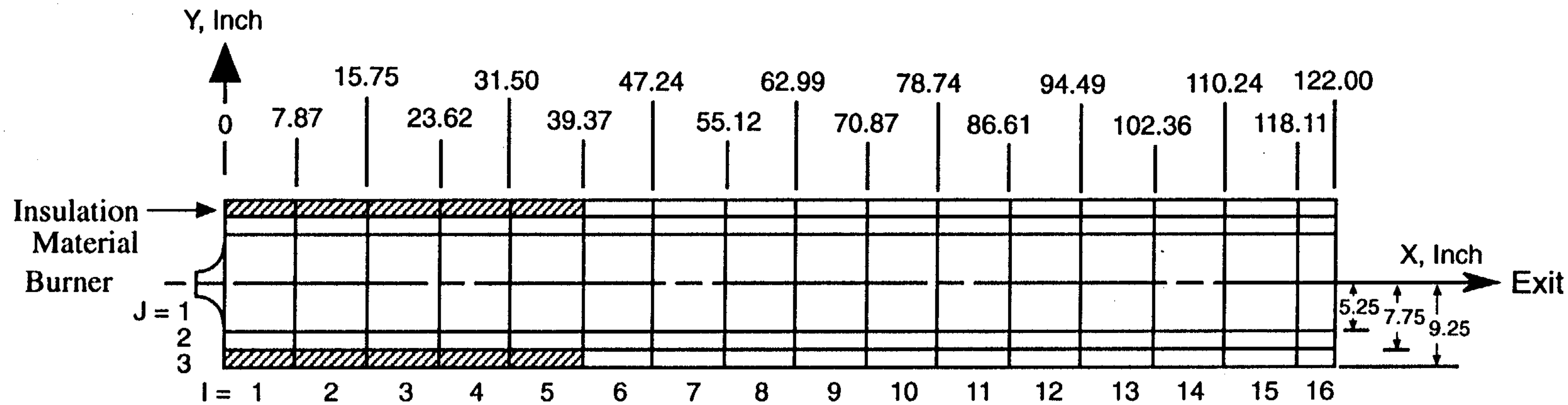


Figure A-2. Sectional view of actual fire-tube geometry with refractory lining and 2D computational grid for initial parametric study.

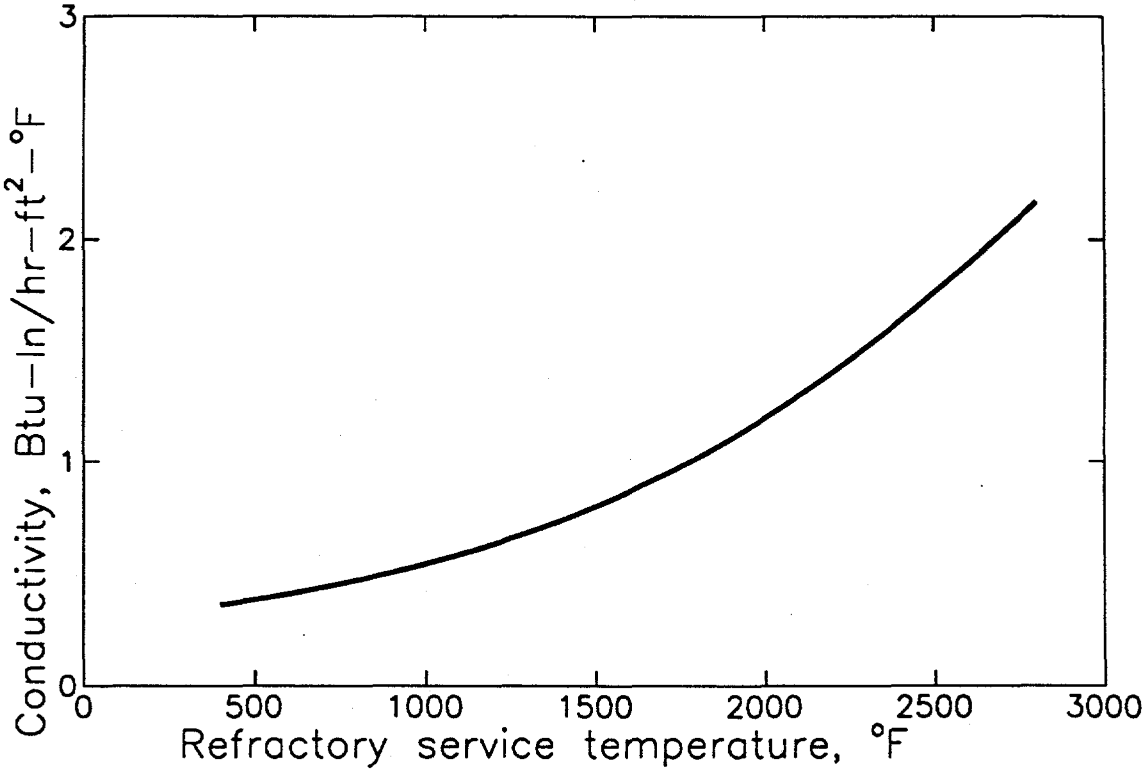


Figure A-3. Thermal conductivity of Kaowool 3000 Board as a function of service temperature.

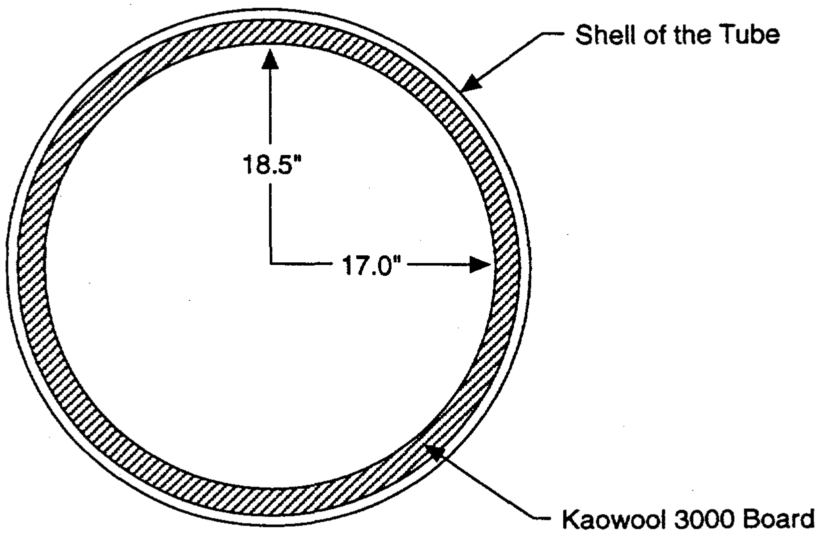


Figure A-4. Cross-sectional view of the fire tube lined with Kaowool 3000 Board.

TABLE A-1. SUMMARY OF KEY PARAMETERS OF INITIAL PARAMETRIC STUDY CASES FOR THE FIRE TUBE.

Case No.	Load (%)*1	Fuel	Air Number	High or Low Swirl Burner	Refractory Length*2 (of total length)	Refractory Thickness (Inches)	Preheated Air Temp. (°F)	2D Grid	60% Ash Recycled
A-1	84%	**Natural Gas**	1.17	High	n/a	n/a	77	Figure A-1	n/a
A-2a	100%	CWS	1.20	High	**1/3**	1.5	600	Figure A-1	No
A-2b	100%	CWS	1.20	High	**2/3**	1.5	600	Figure A-1	No
A-2c	100%	CWS	1.20	High	**Total length**	1.5	600	Figure A-1	No
A-2c-1	100%	CWS	1.20	High	Total length	1.5	600	**Figure A-2**	No
A-2d	100%	CWS	1.20	**Low**	2/3	1.5	600	Figure A-1	No
A-2e	100%	CWS	1.20	High	2/3	**0.5**	600	Figure A-1	No
A-2f	100%	CWS	1.20	High	2/3	1.5	**350**	Figure A-1	No
A-2g	100%	CWS	1.20	High	2/3	1.5	600	Figure A-1	**Yes**
A-2h	100%	CWS	**1.30**	High	2/3	1.5	600	Figure A-1	No
A-2i	100%	**85%CWS+15%Gas**	1.20	High	2/3	1.5	600	Figure A-1	No
A-2j	100%	**85%CWS+30%Gas**	1.20	High	2/3	1.5	600	Figure A-1	No
A-3	**75%**	CWS	1.20	High	2/3	1.5	600	Figure A-1	No
A-4	**50%**	CWS	1.20	High	2/3	1.5	600	Figure A-1	No

*1 Thermal heat input of fuel at 100% load equals 3.43 MBtu/hr, based on dry lower heating values.
*2 Conductivities of Kaowool 3000 board were used in the initial study.

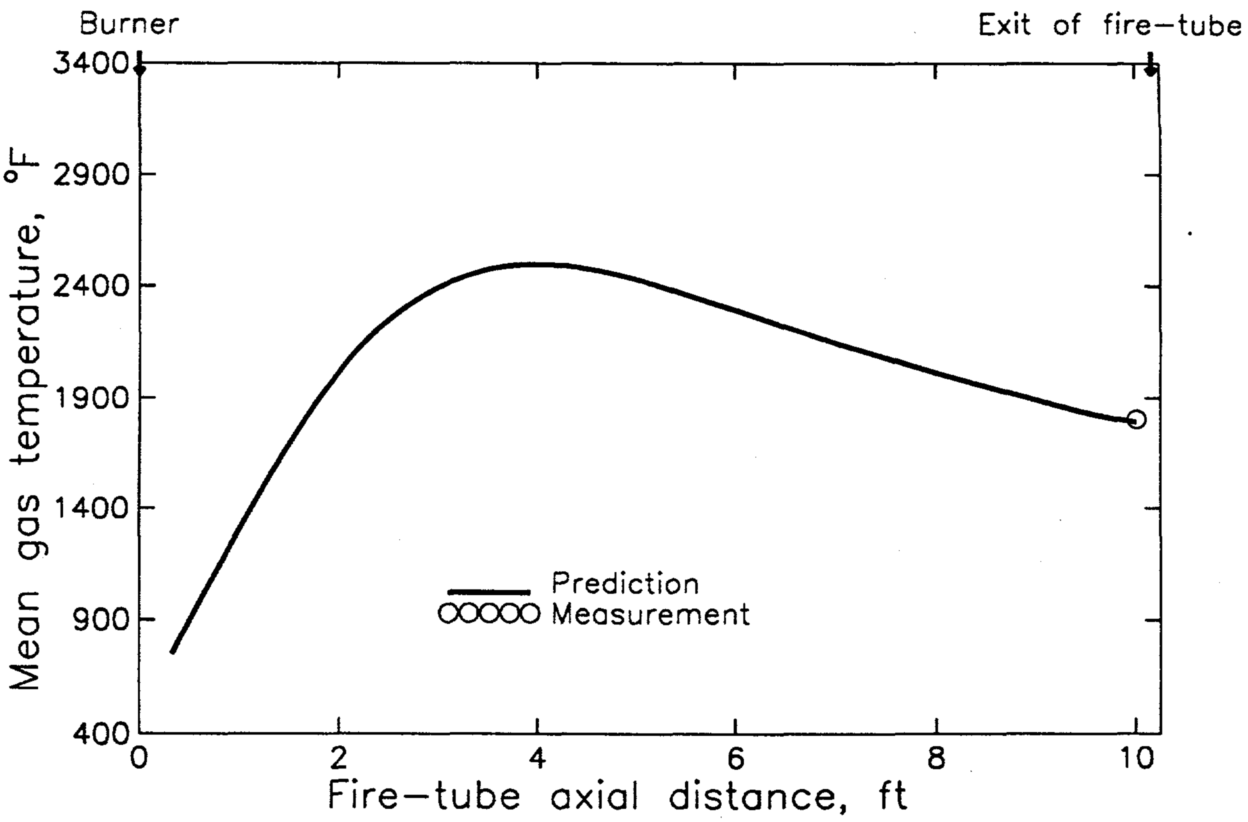


Figure A–5. Mean gas temperature distribution for the gas–firing calibration case.

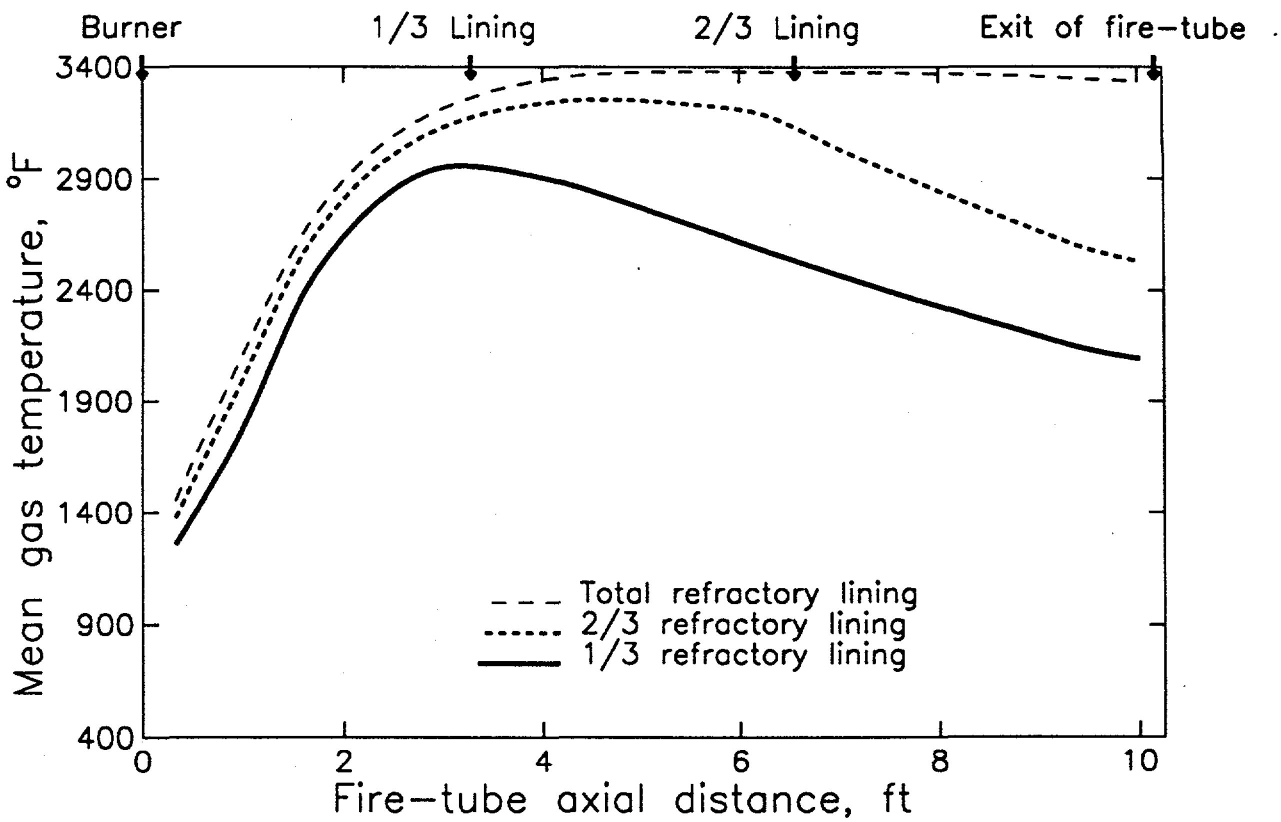


Figure A-6a. Impacts of length of refractory lining on mean gas temperatures.

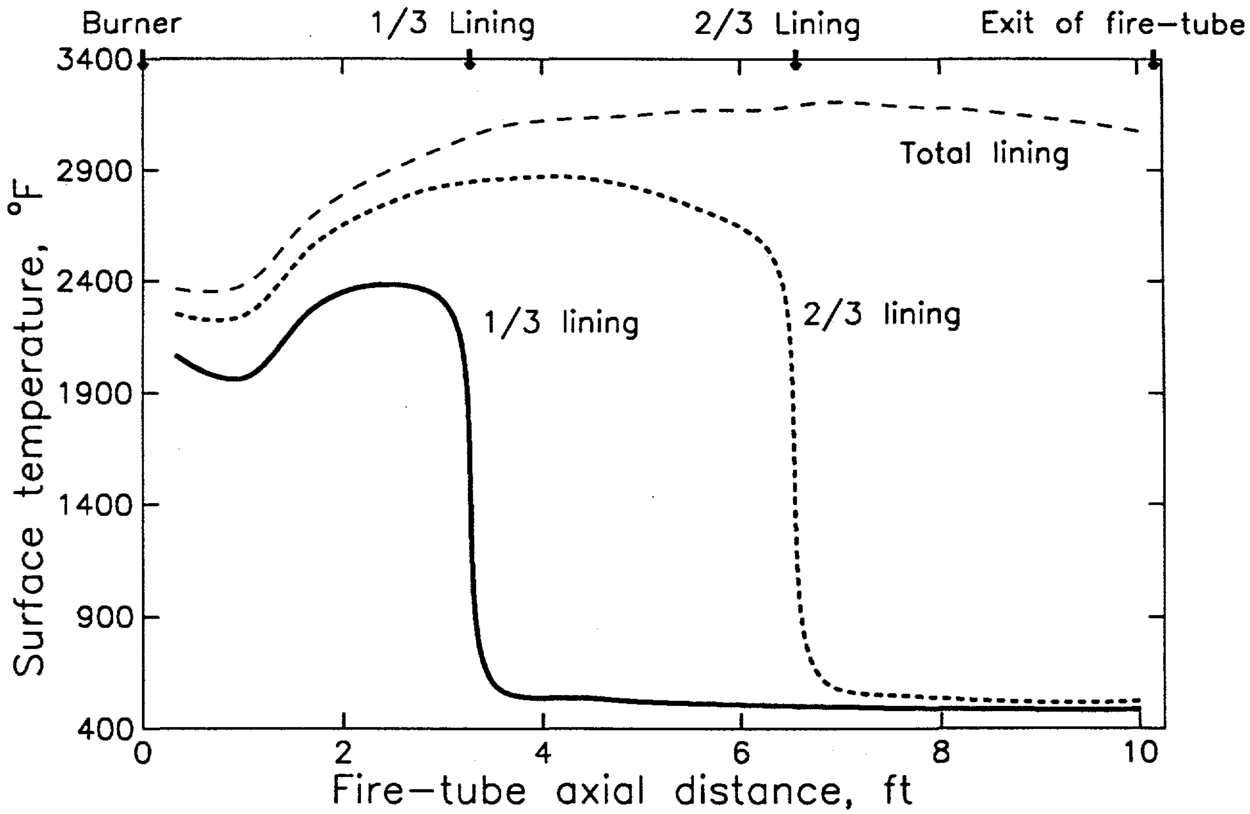


Figure A-6b. Impacts of length of refractory lining on surface temperatures.

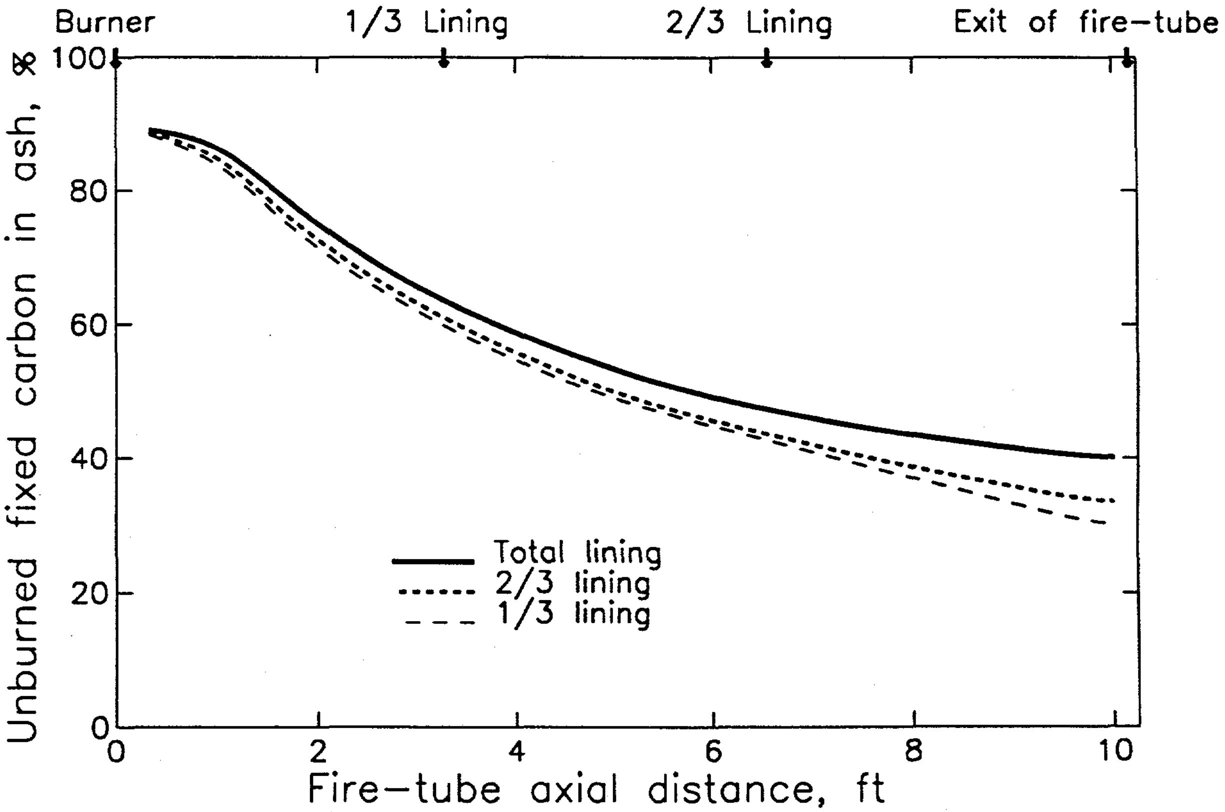


Figure A–6c. Impacts of length of refractory lining on unburned fixed carbon in ash.

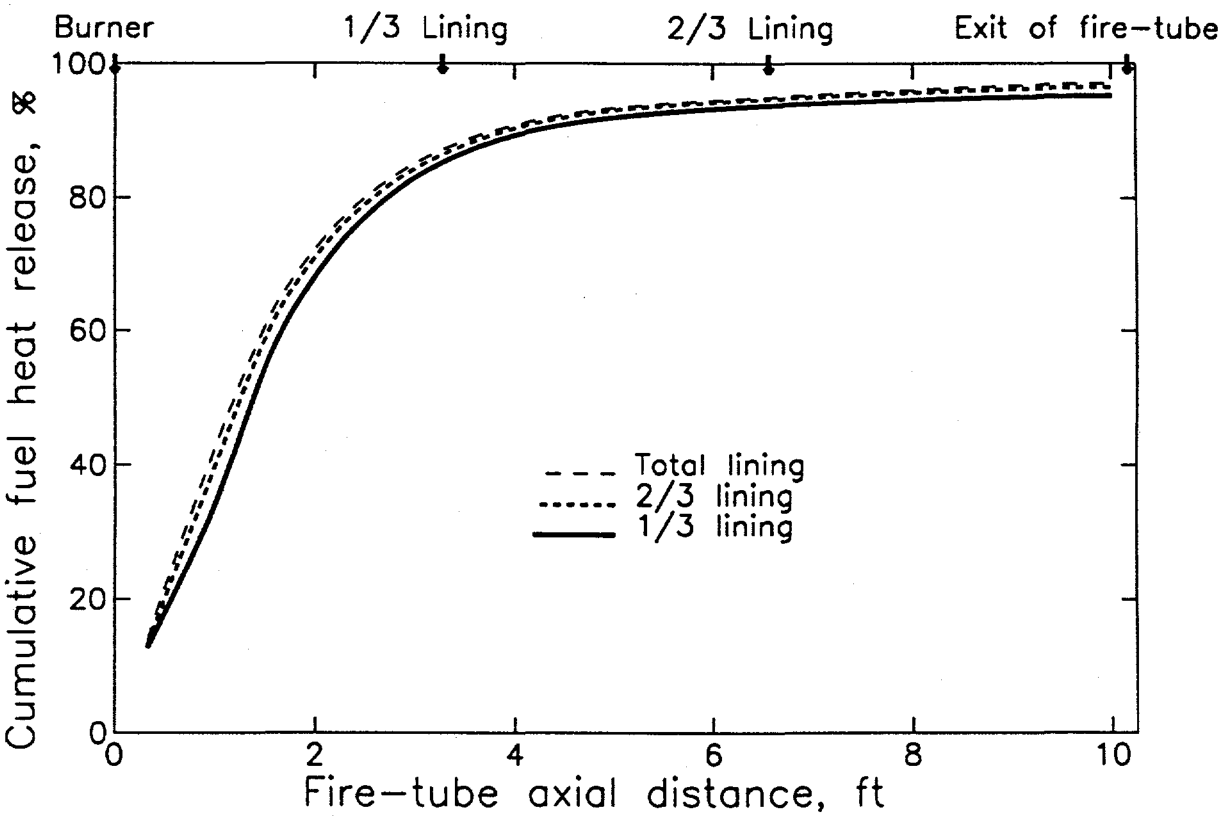


Figure A-6d. Impact of length of refractory lining on cumulative fuel heat release (% of total heat input) along fire-tube axial distance.

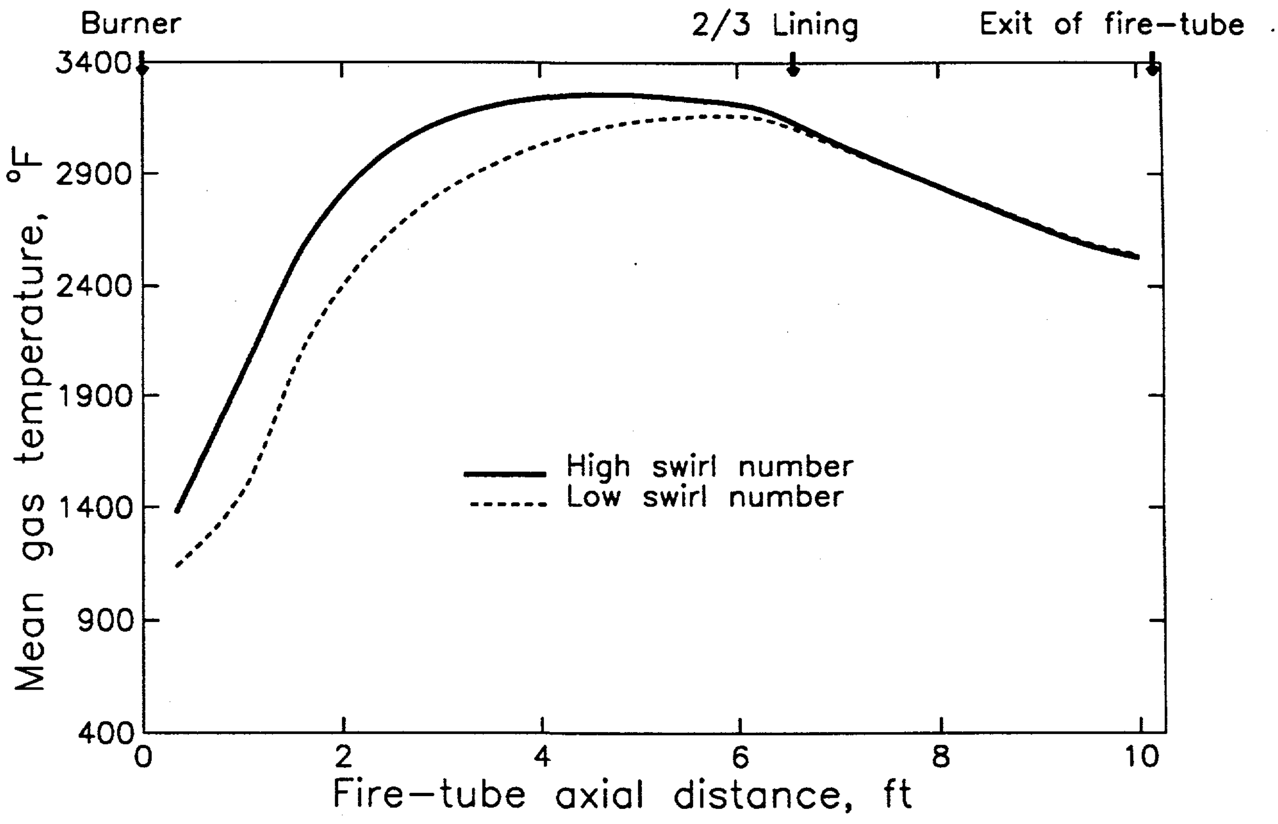


Figure A-7a. Impacts of burner swirl number on mean gas temperatures.

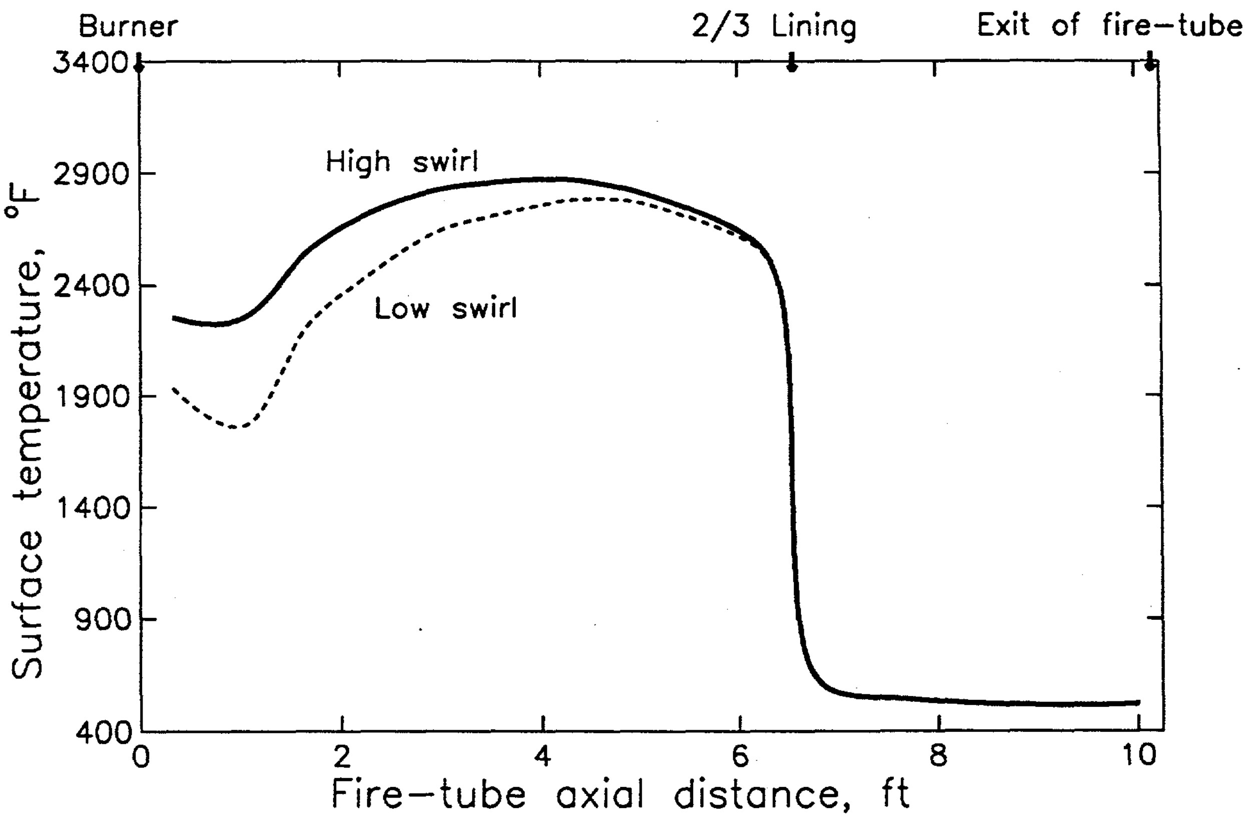


Figure A–7b. Impacts of burner swirl number on surface temperatures.

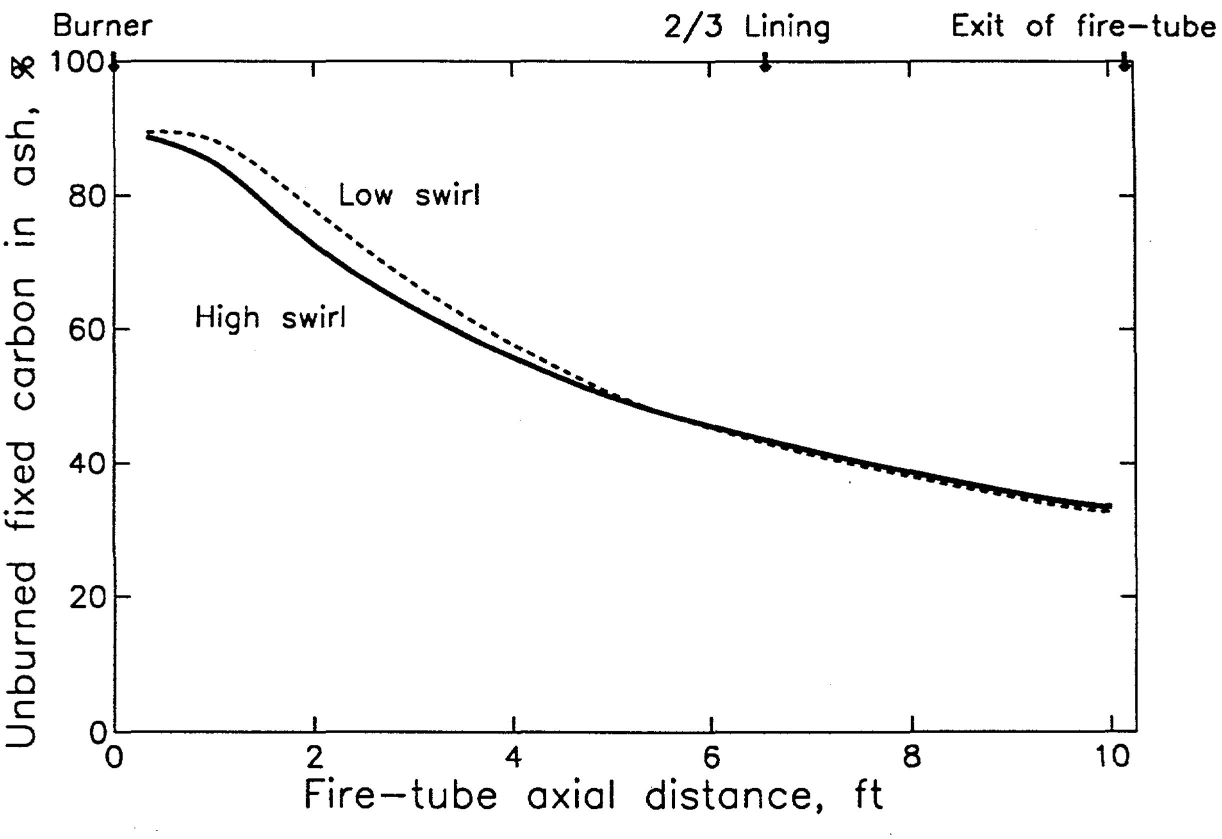


Figure A-7c. Impacts of burner swirl number on unburned fixed carbon in ash.

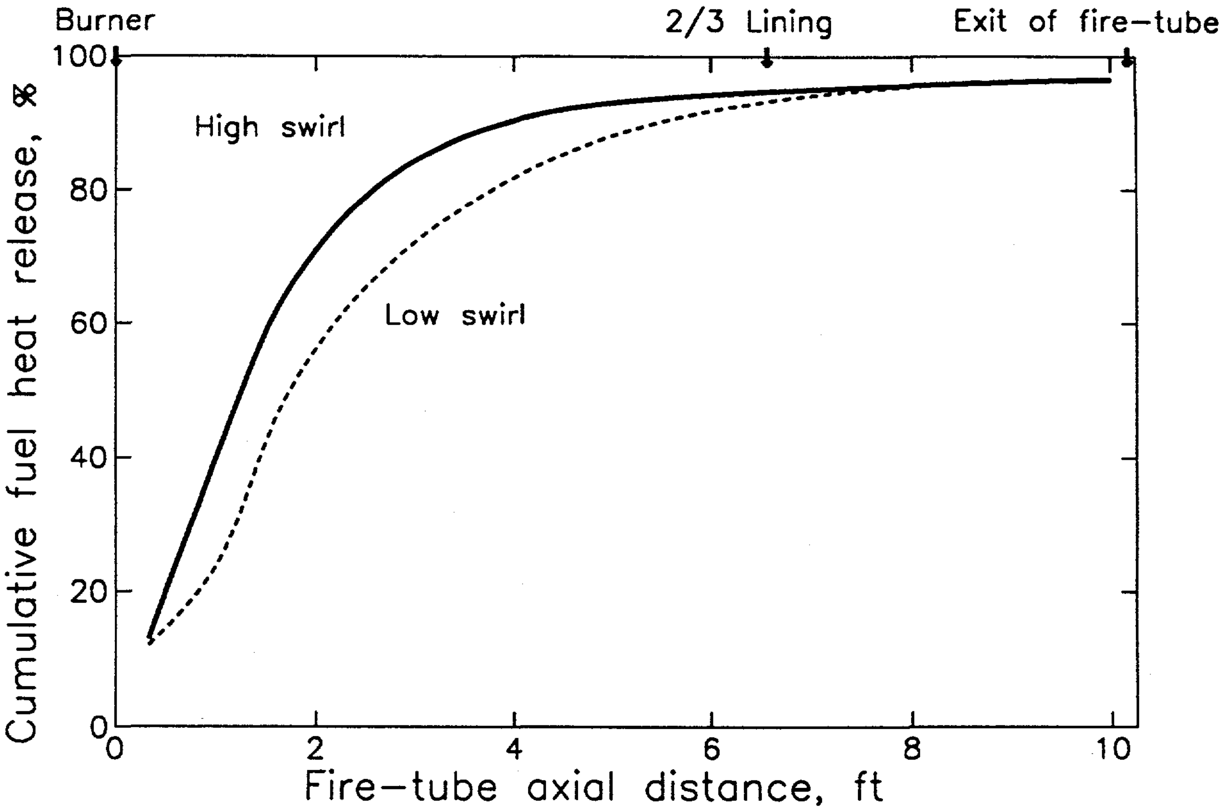


Figure A-7d. Impact of burner swirl number on cumulative fuel heat release (% of total heat input) along fire-tube axial distance.

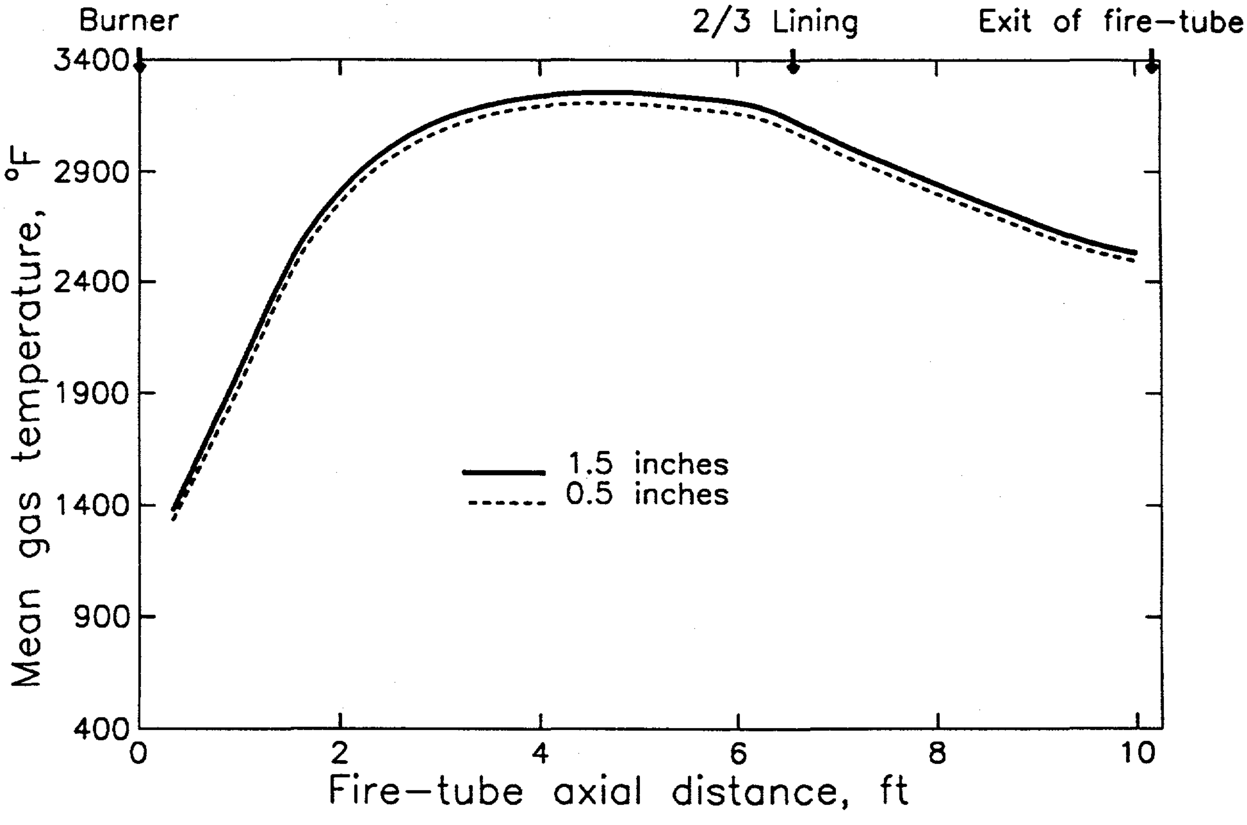


Figure A-8a. Impacts of refractory thickness on mean gas temperatures.

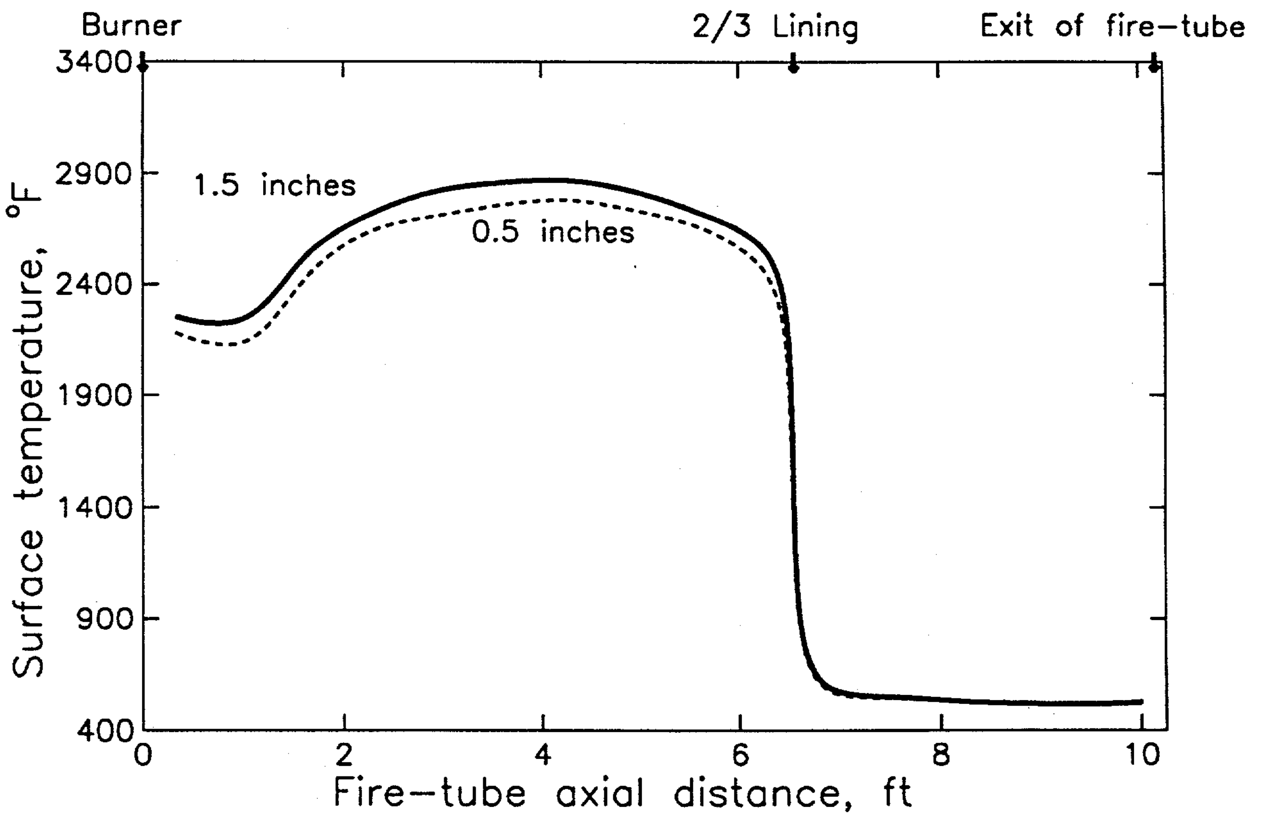


Figure A-8b. Impacts of refractory thickness on surface temperatures.

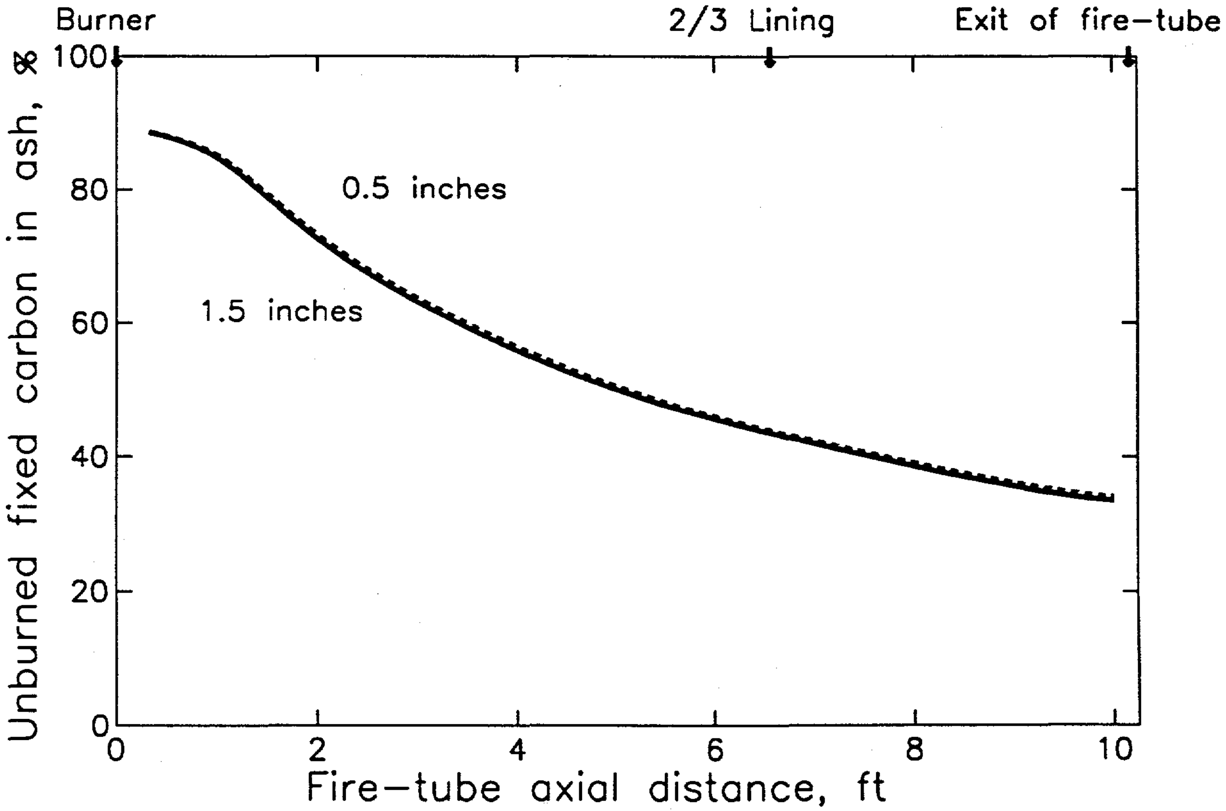


Figure A-8c. Impacts of refractory thickness on unburned fixed carbon in ash.

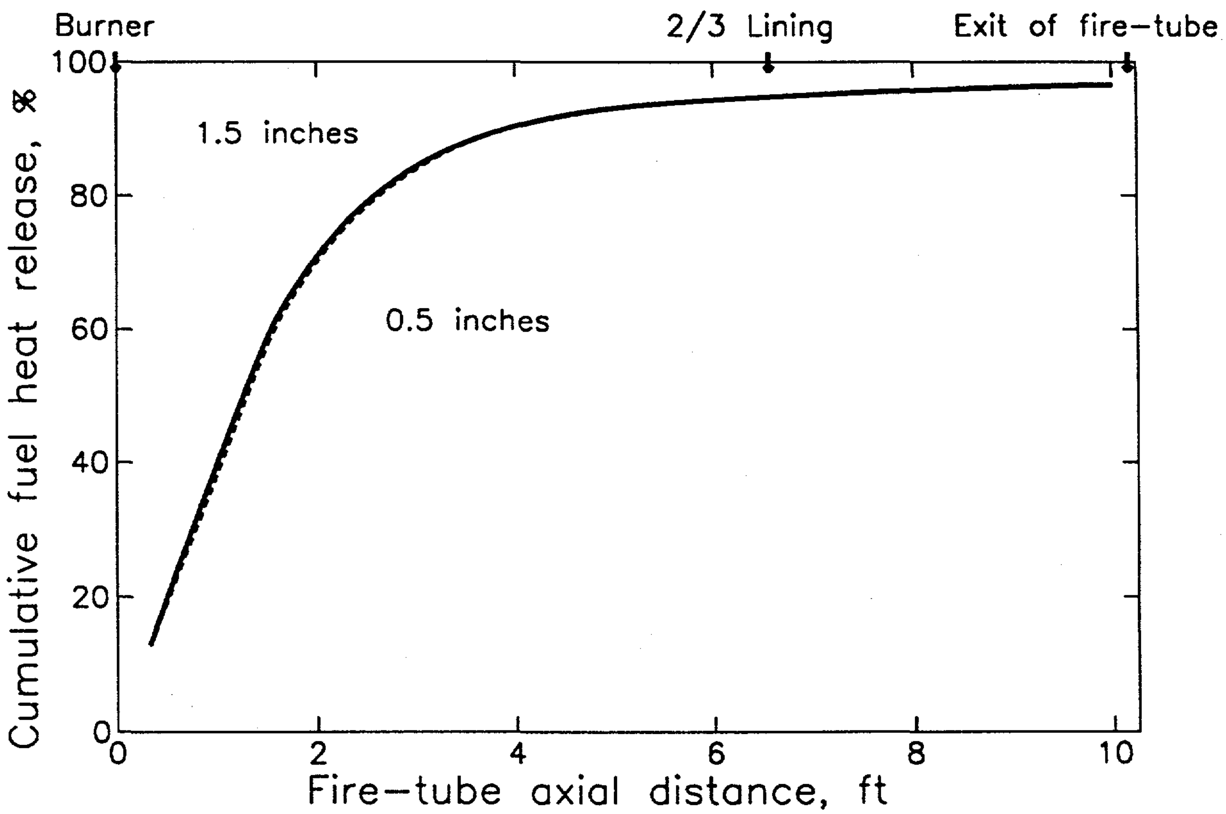


Figure A−8d. Impact of refractory thickness on cumulative fuel heat release (% of total heat input) along fire−tube axial distance.

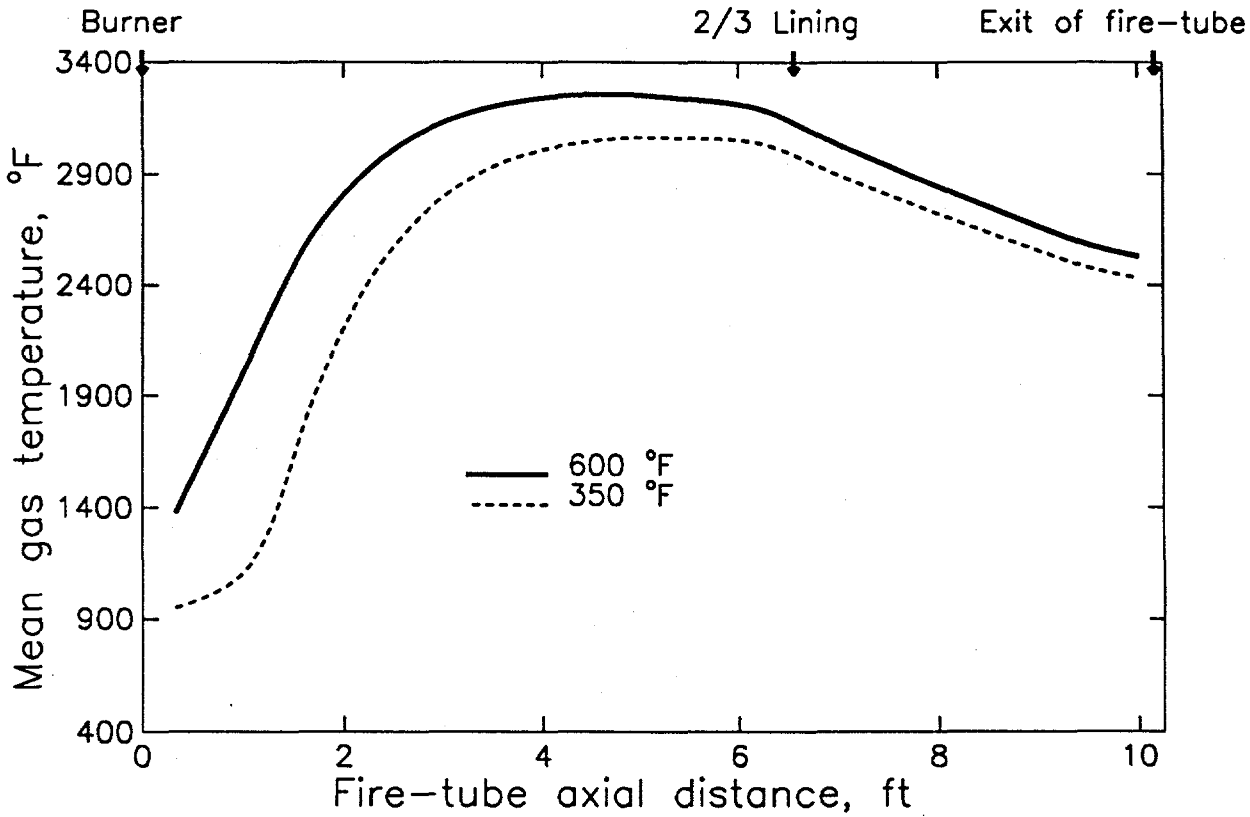


Figure A–9a. Impacts of air preheat temperature on mean gas temperatures.

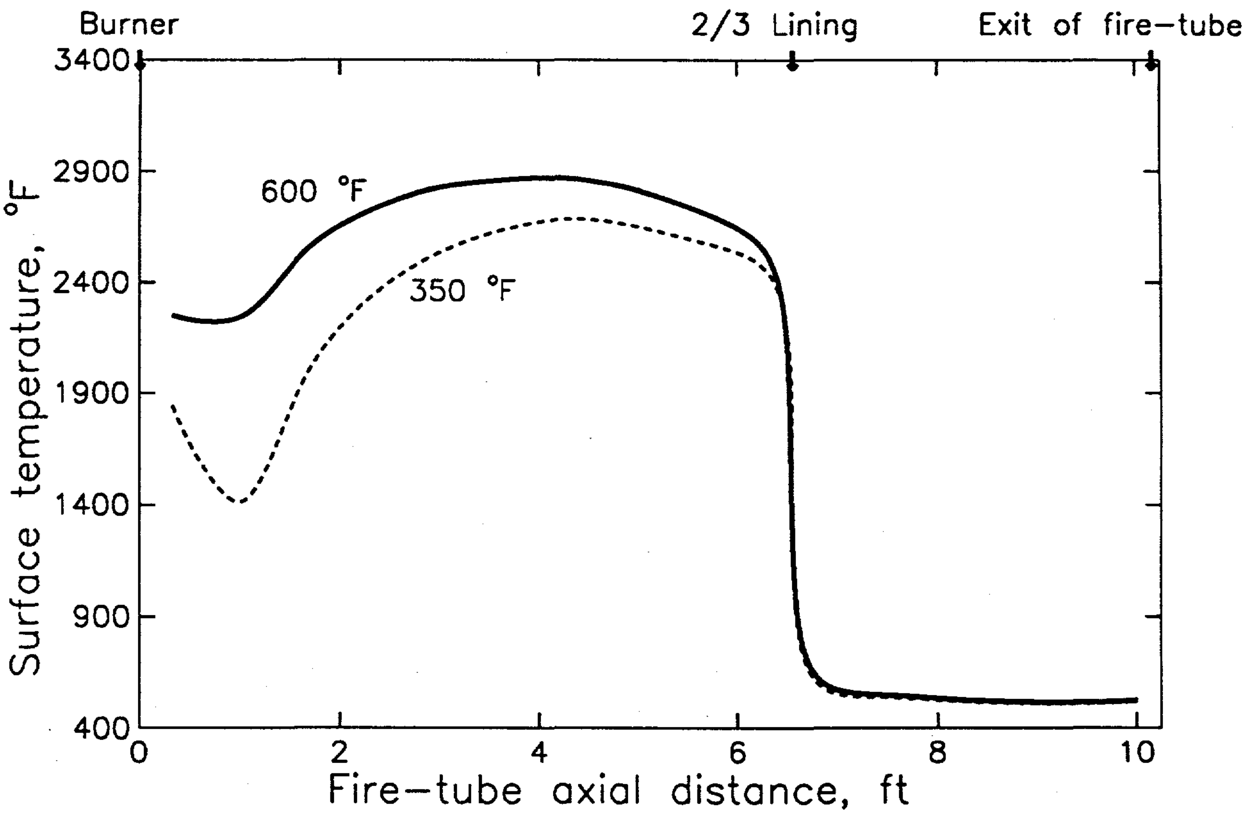


Figure A-9b. Impacts of air preheat temperature on surface temperatures.

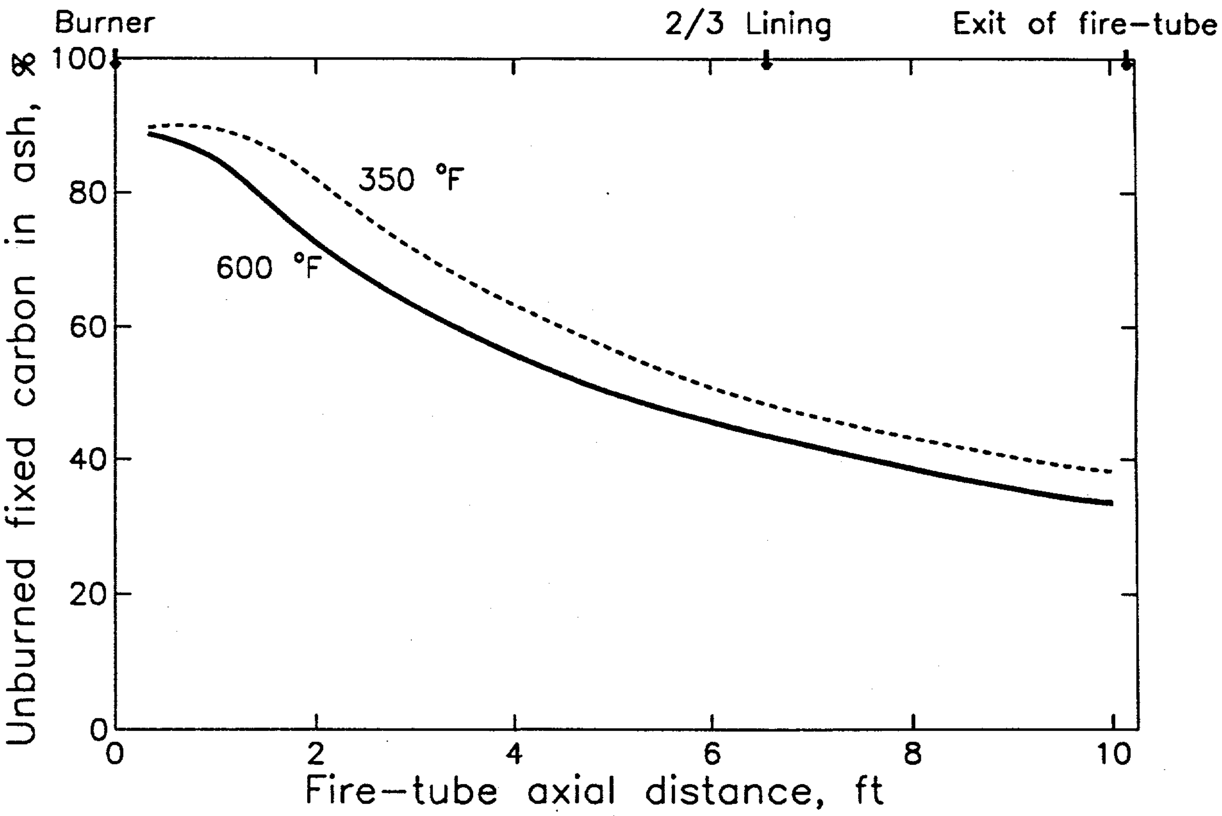


Figure A-9c. Impacts of air preheat temperature on unburned fixed carbon in ash.

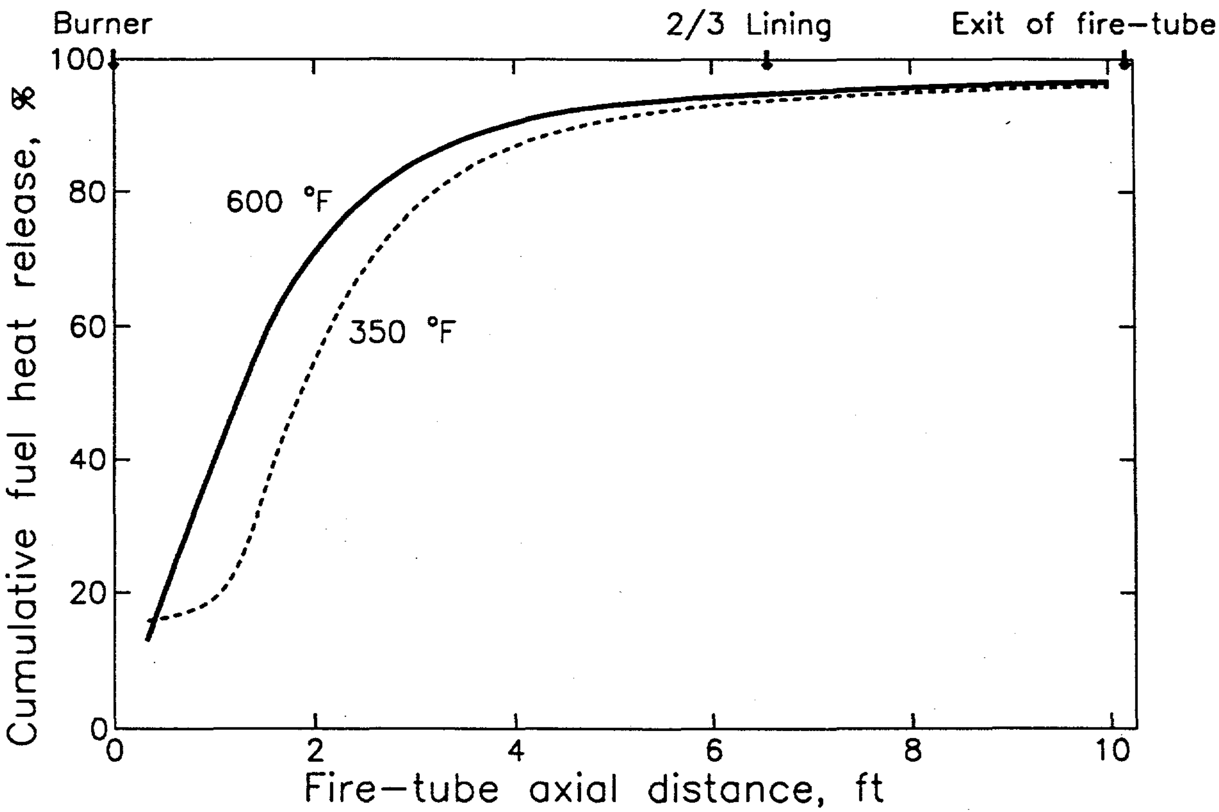


Figure A−9d. Impact of air preheat temperature on cumulative fuel heat release (% of total heat input) along fire−tube axial distance.

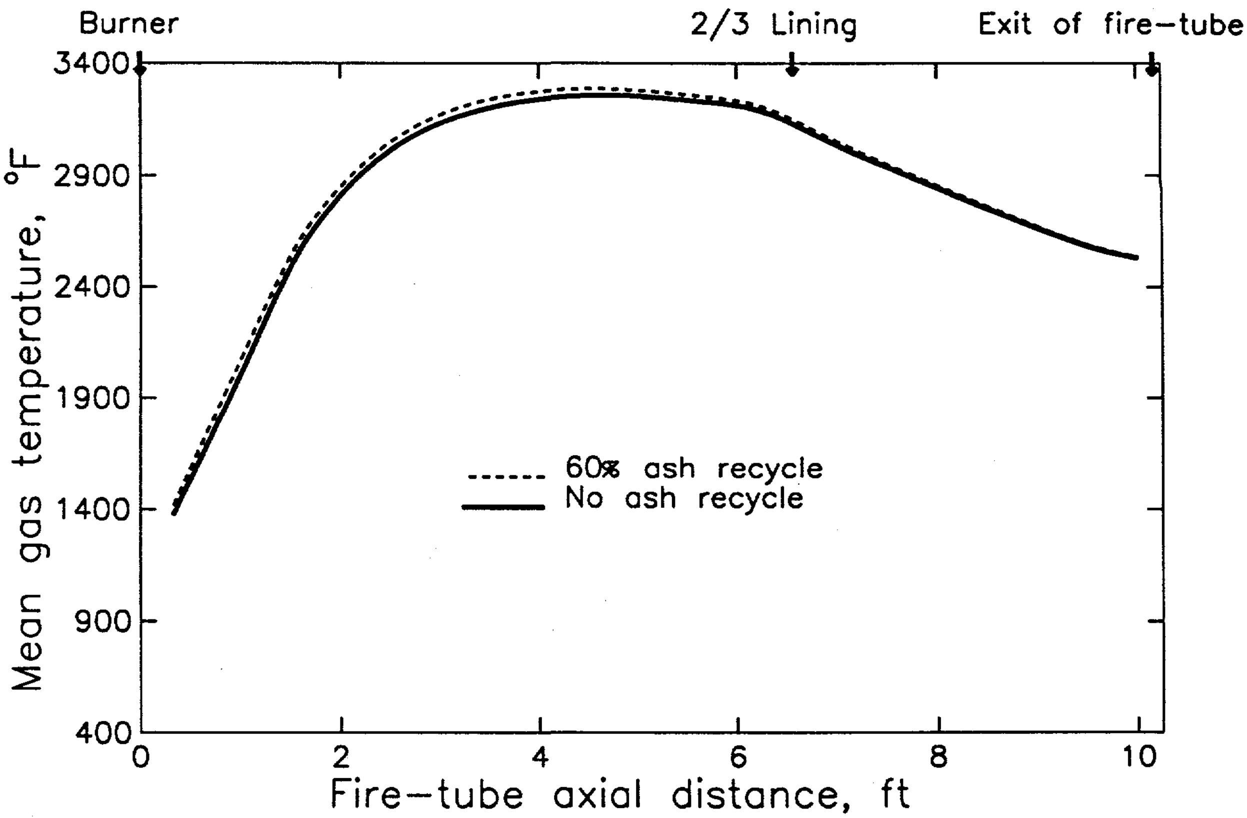


Figure A−10a. Impacts of 60% ash recycle on mean gas temperatures.

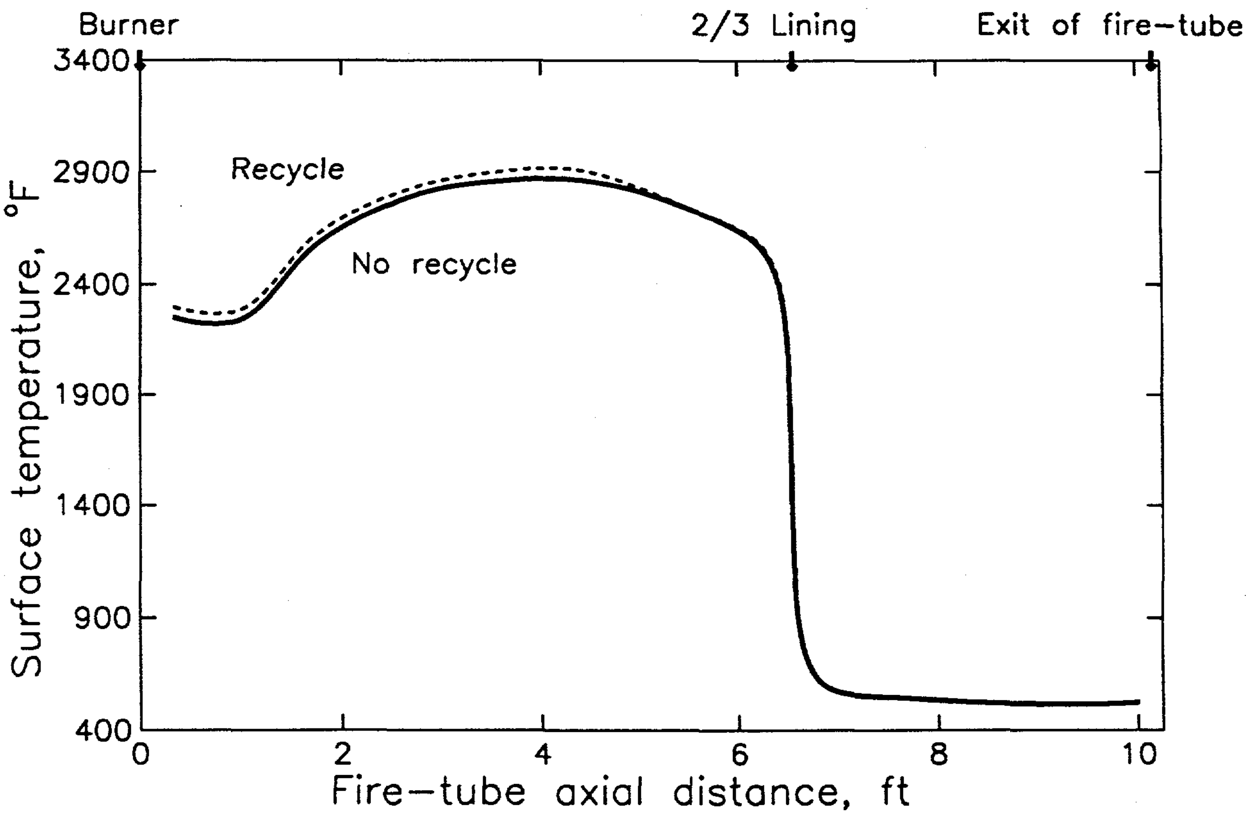


Figure A−10b. Impacts of 60% ash recycle on surface temperatures.

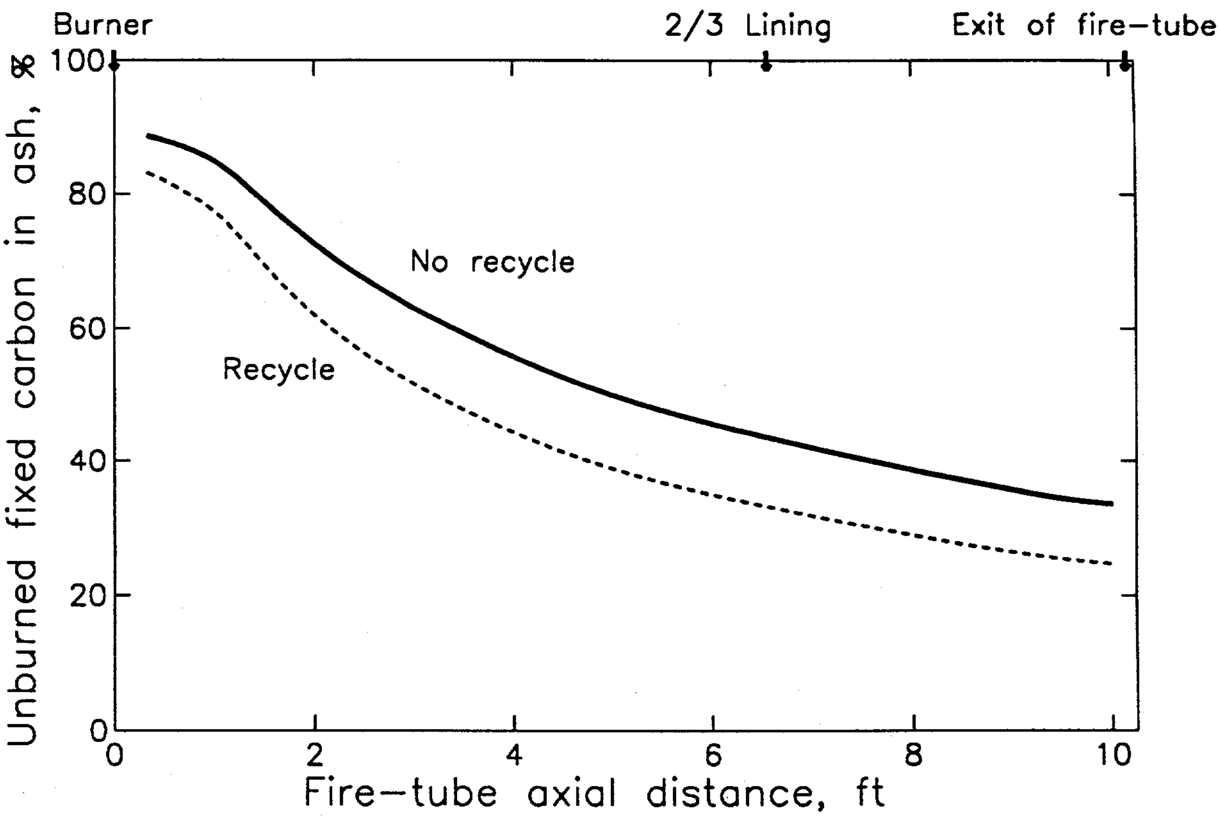


Figure A-10c. Impacts of 60% ash recycle on unburned fixed carbon in ash.

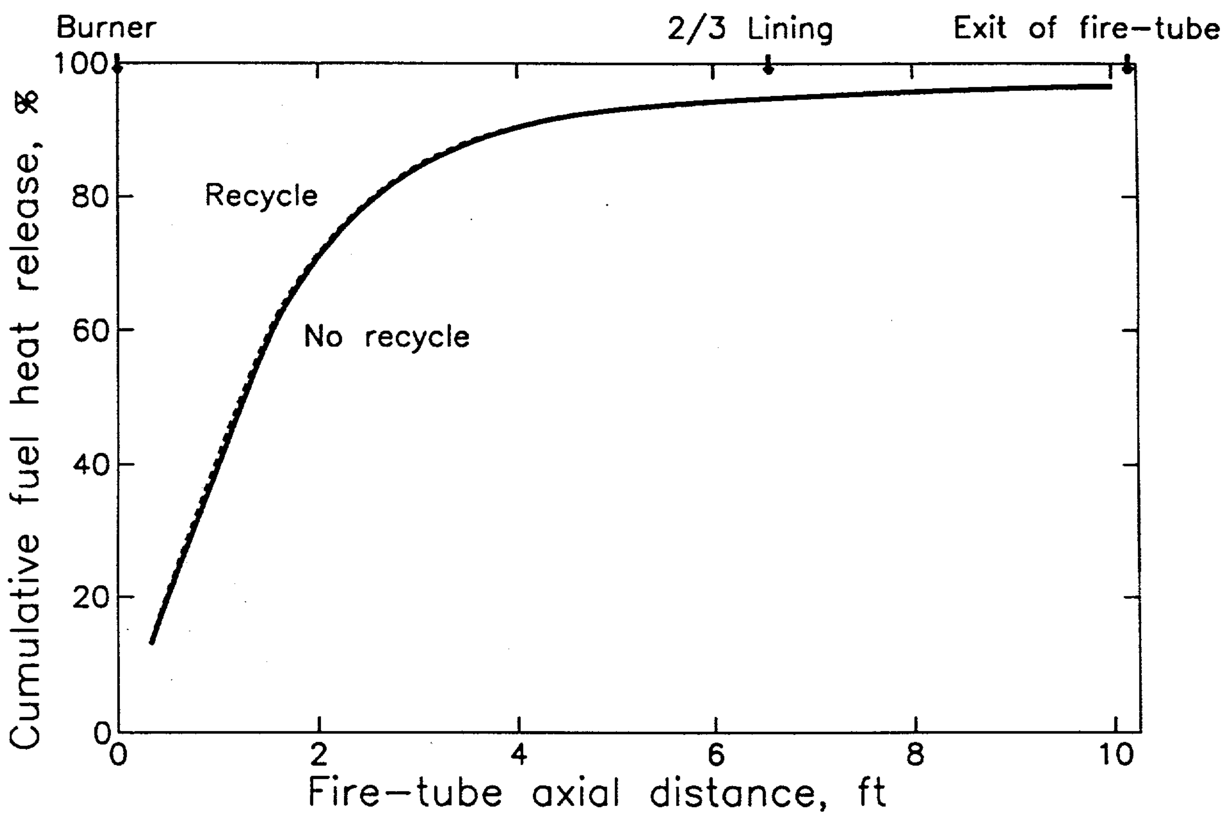


Figure A-10d. Impact of 60% ash recycle on cumulative fuel heat release (% of total heat input) along fire-tube axial distance.

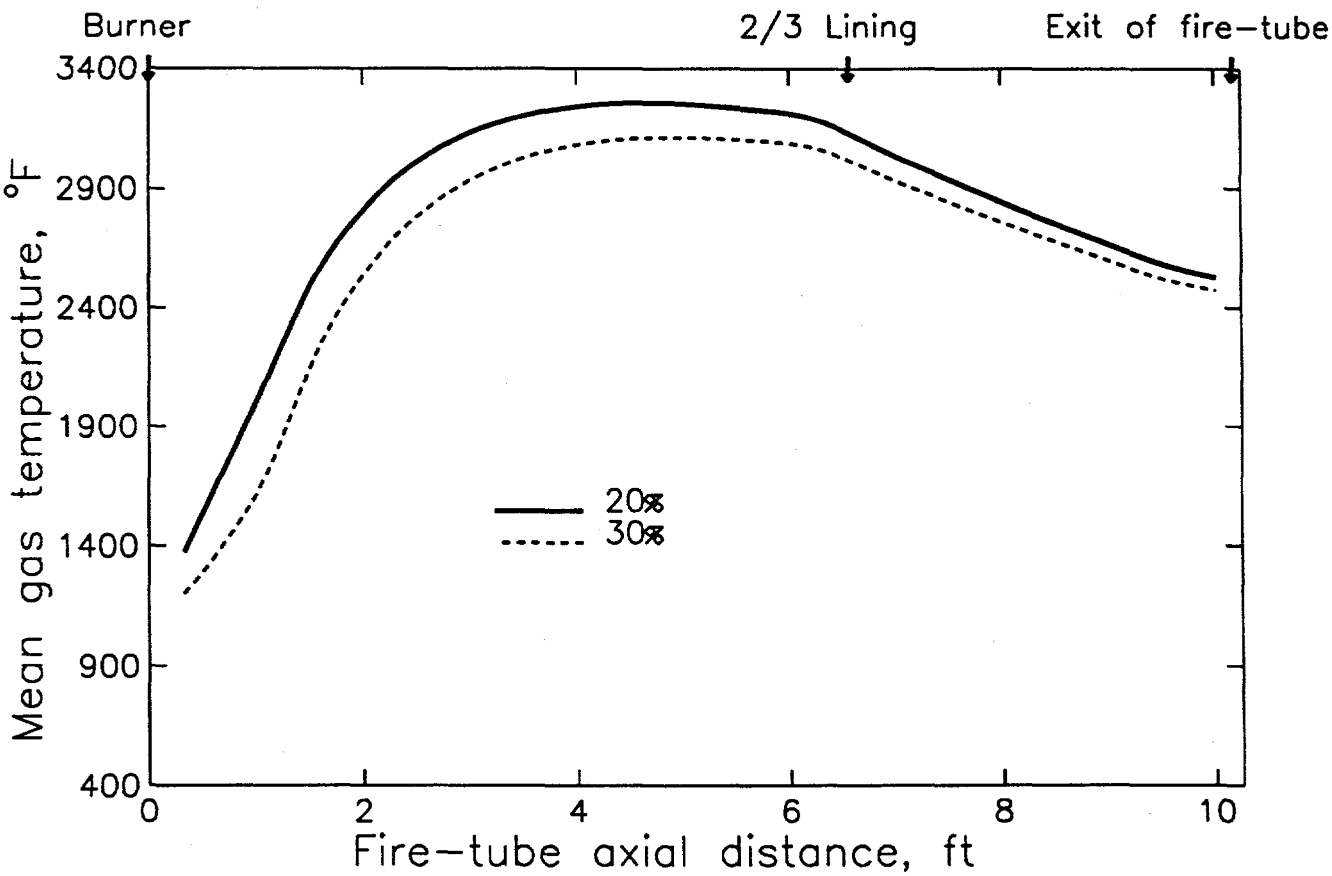


Figure A-11a. Impacts of excess air level on mean gas temperatures.

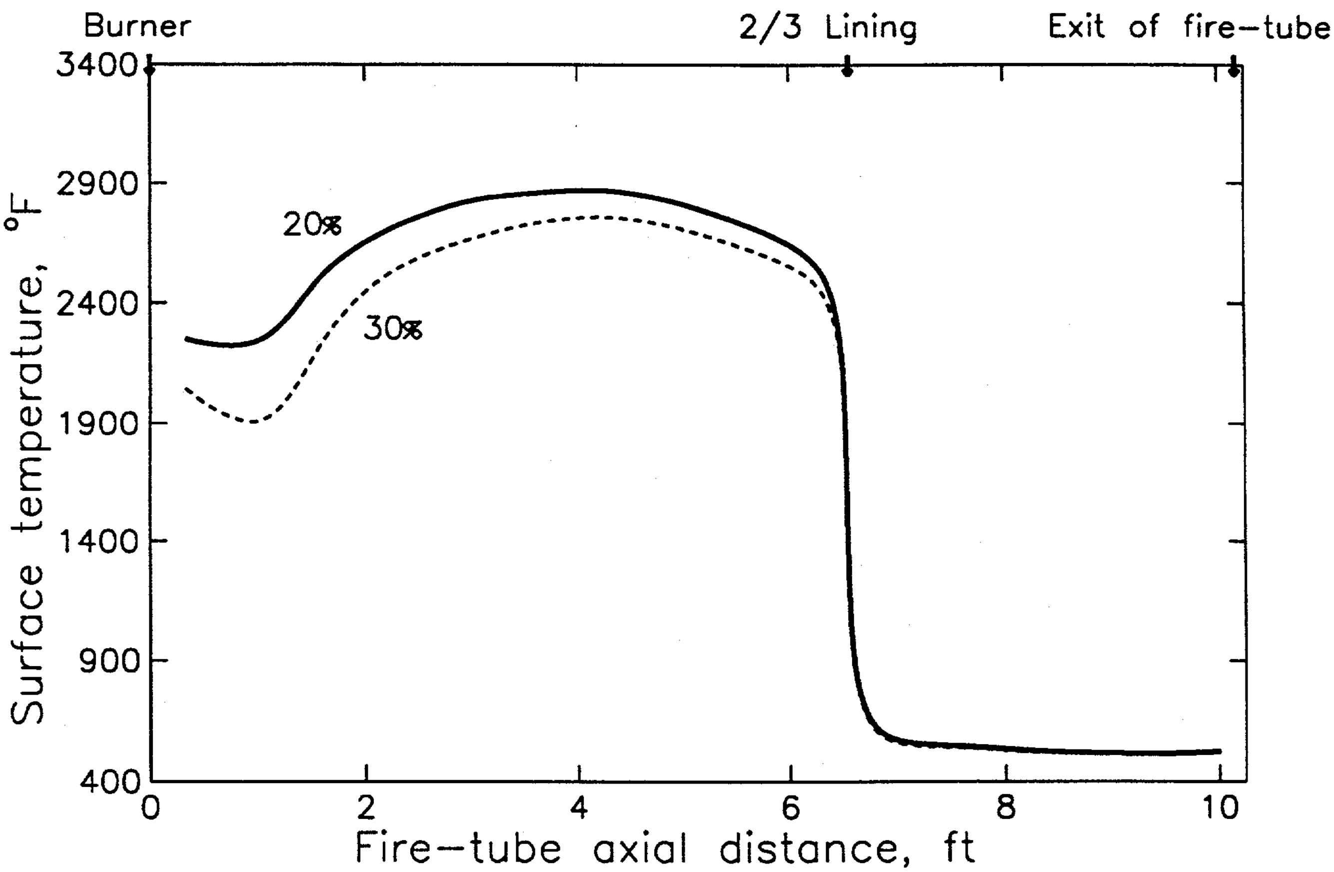


Figure A-11b. Impacts of excess air level on surface temperatures.

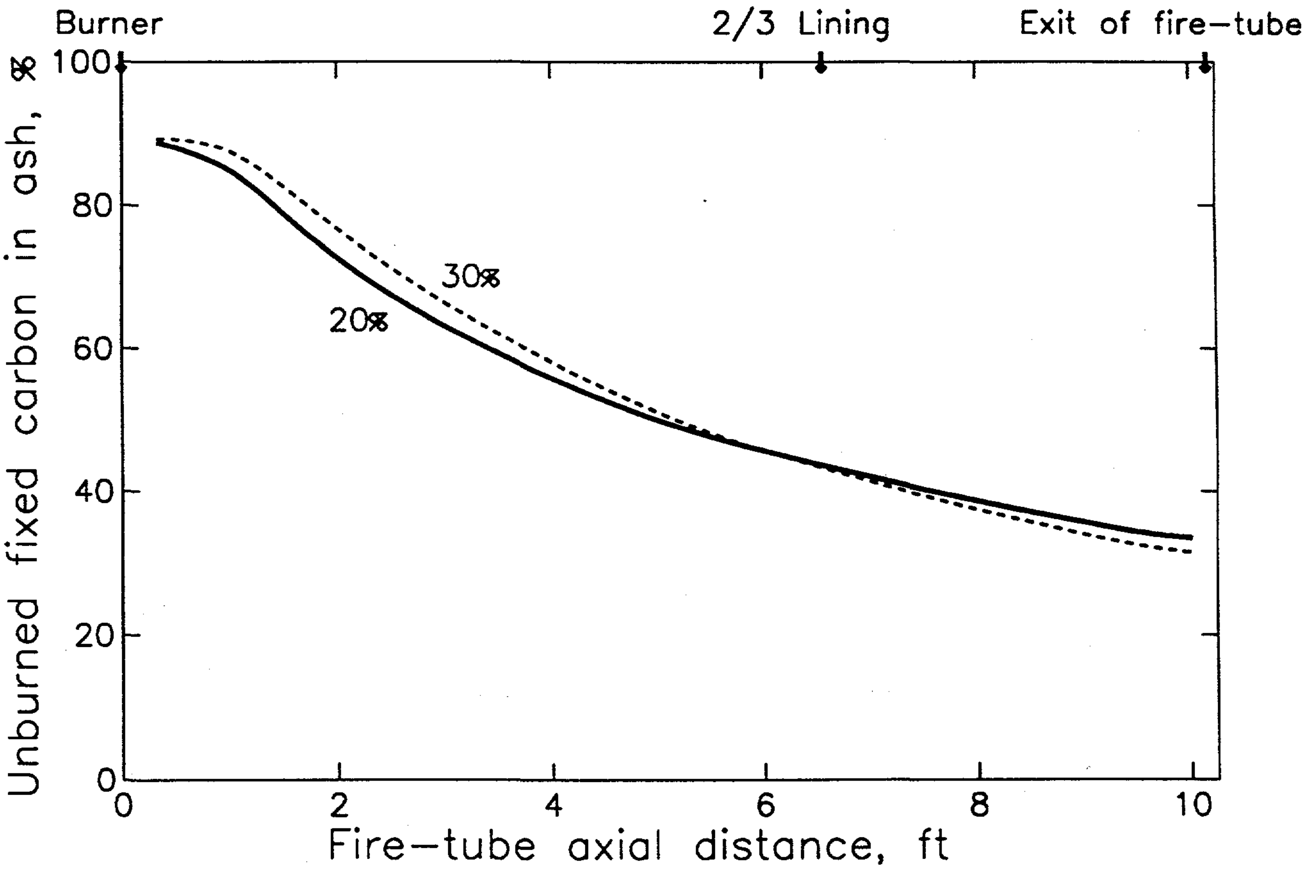


Figure A—11c. Impacts of excess air level on unburned fixed carbon in ash.

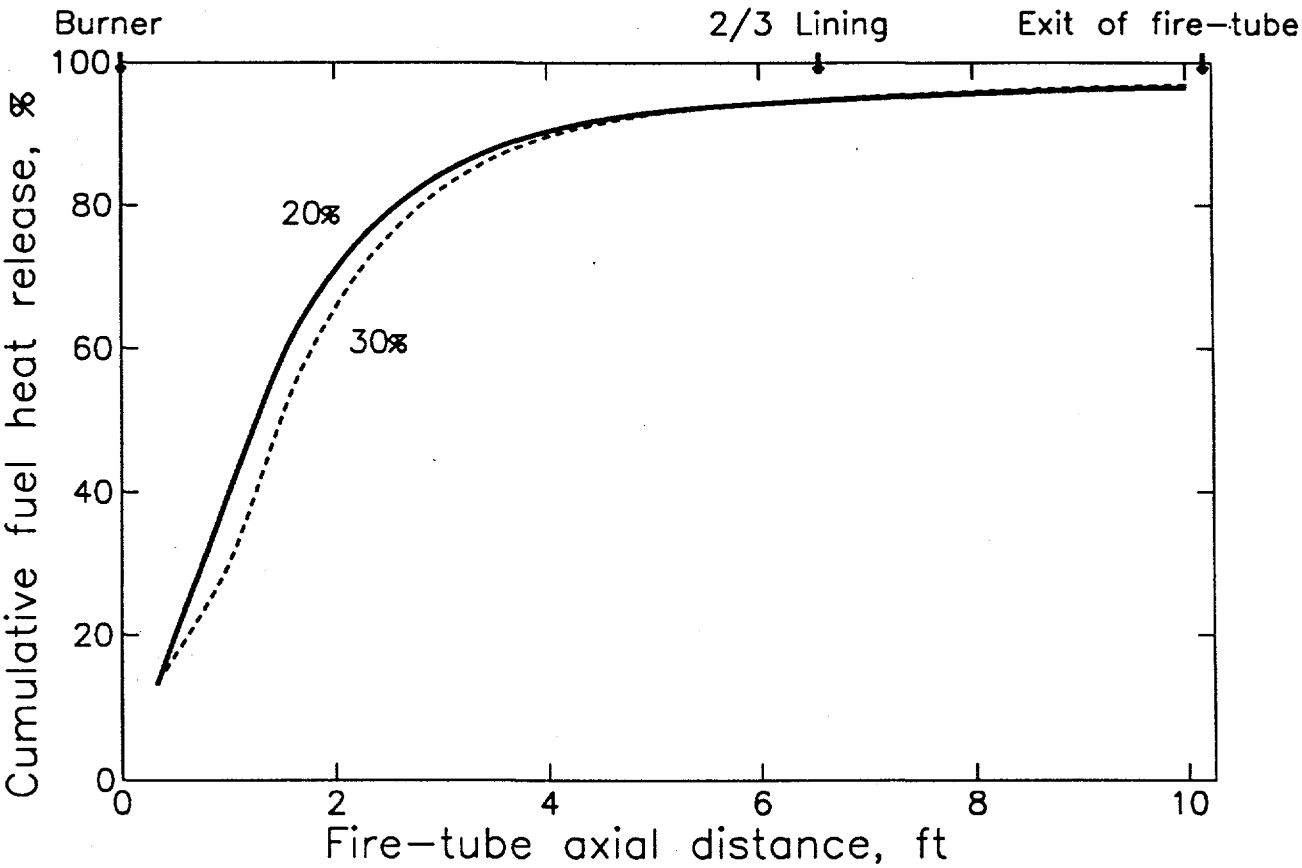


Figure A-11d. Impact of excess air level on cumulative fuel heat release (% of total heat input) along fire-tube axial distance.

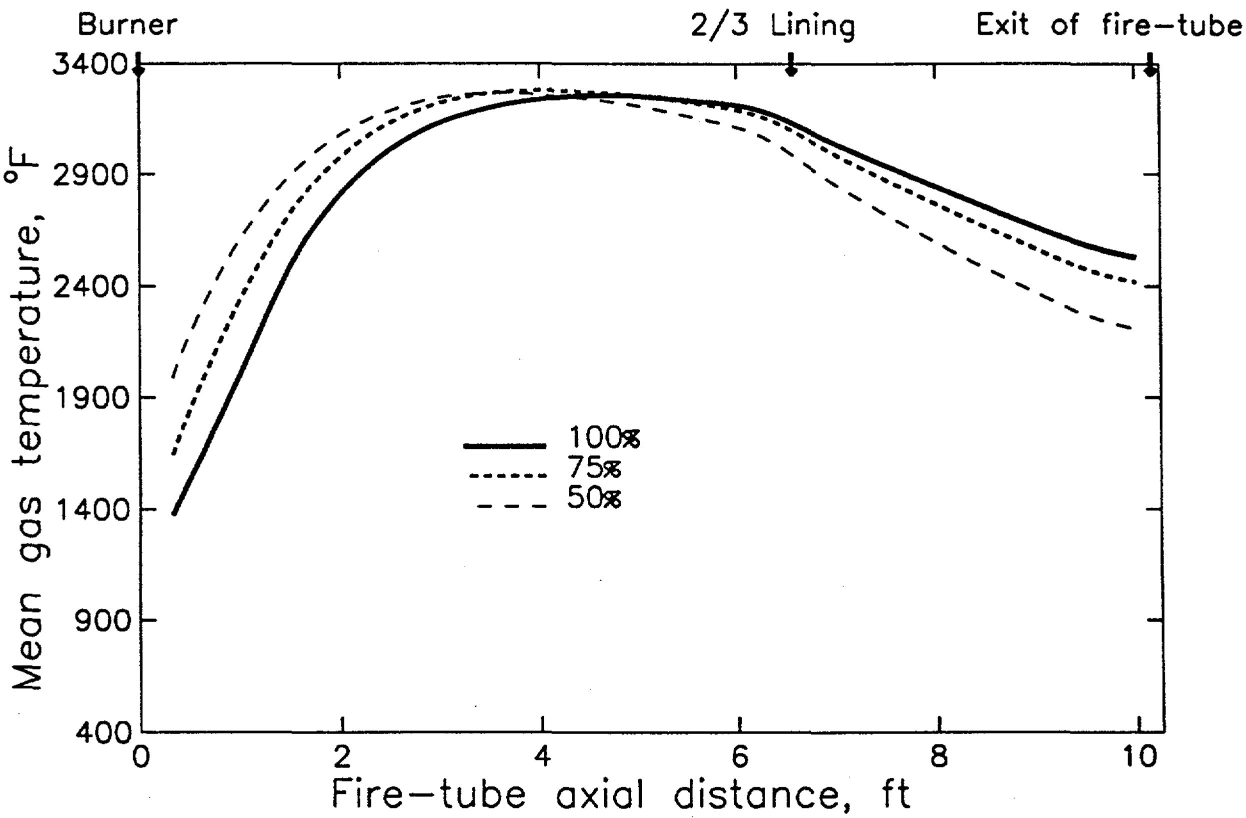


Figure A-12a. Impacts of thermal load on mean gas temperatures.

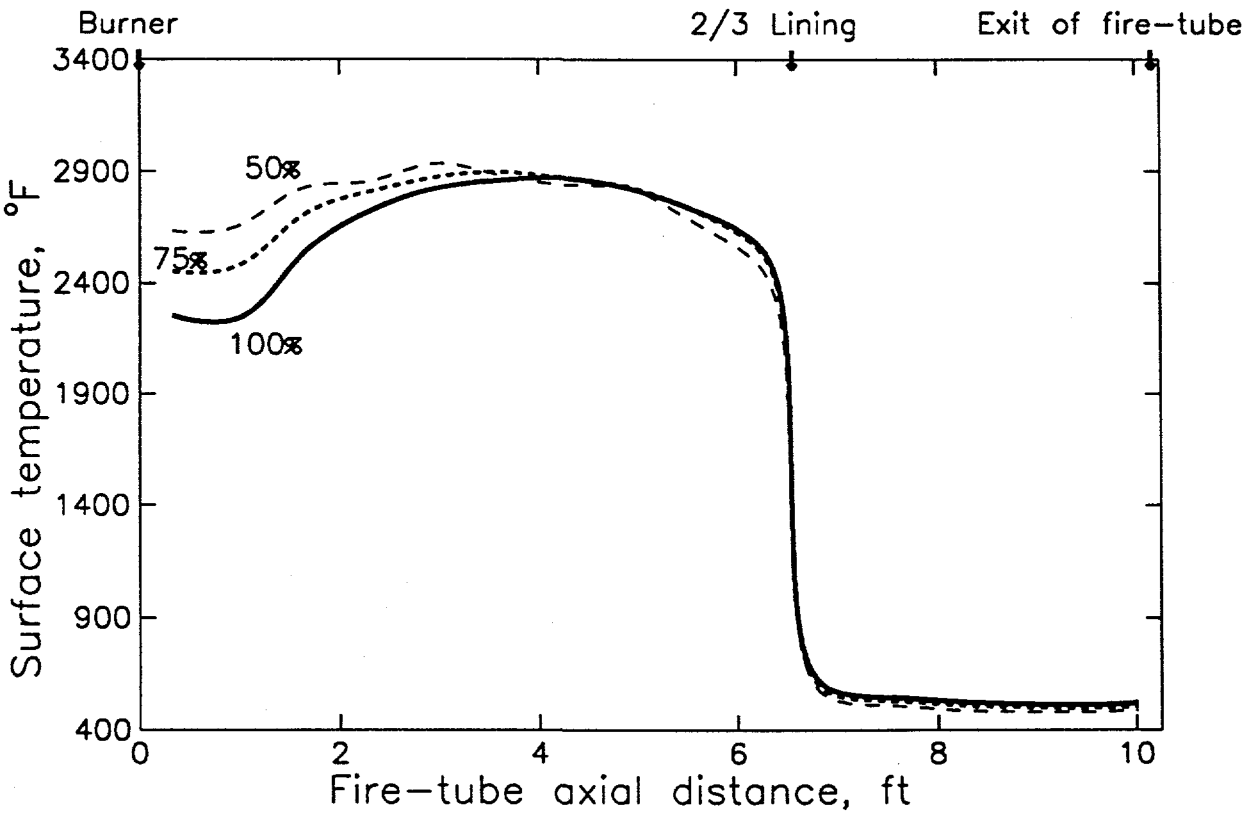


Figure A-12b. Impacts of thermal load on surface temperatures.

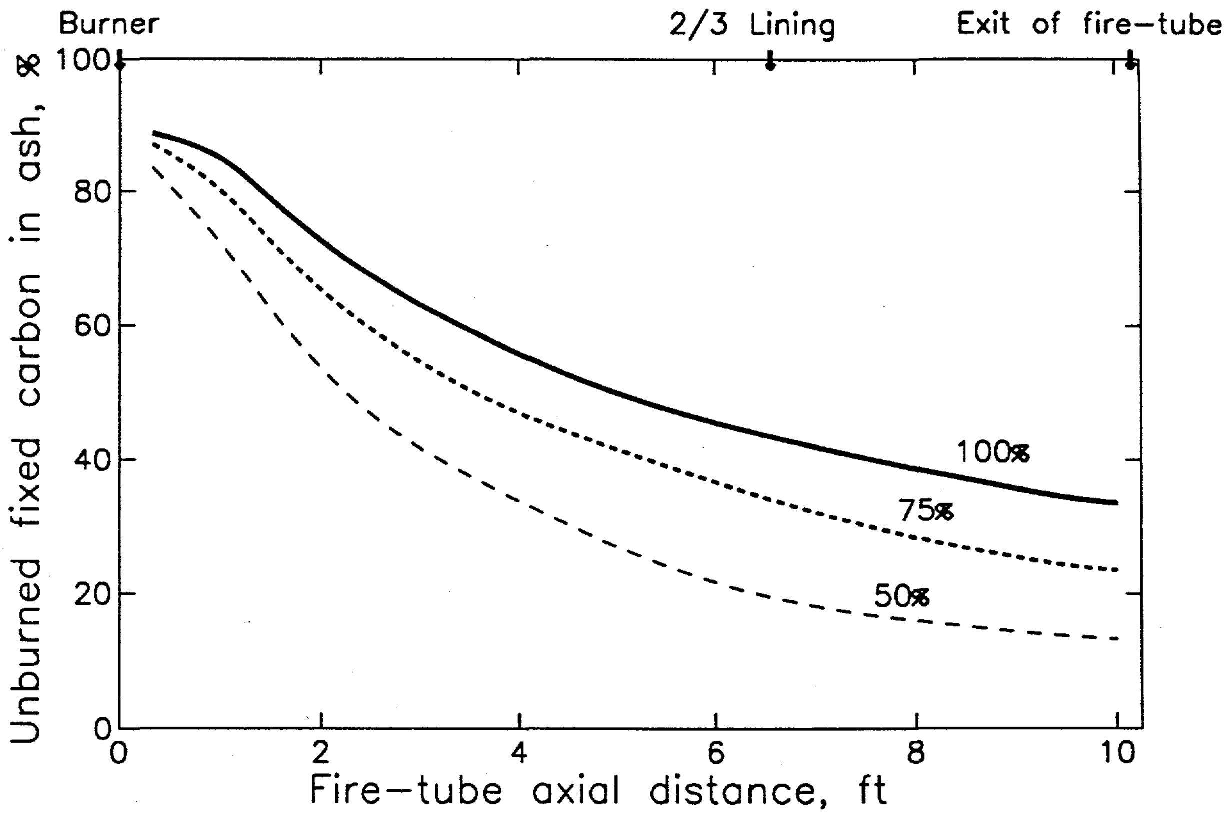


Figure A—12c. Impacts of thermal load on unburned fixed carbon in ash.

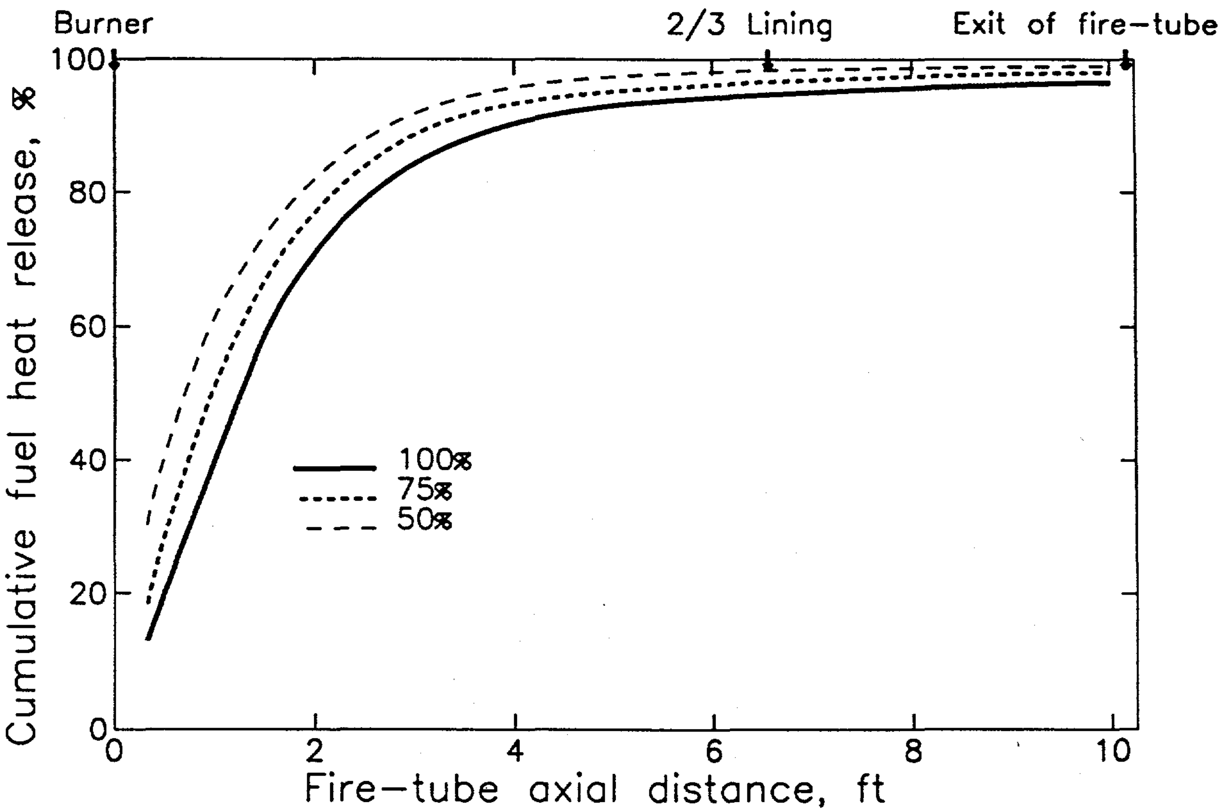


Figure A-12d. Impact of thermal load on cumulative fuel heat release (% of total heat input) along fire-tube axial distance.

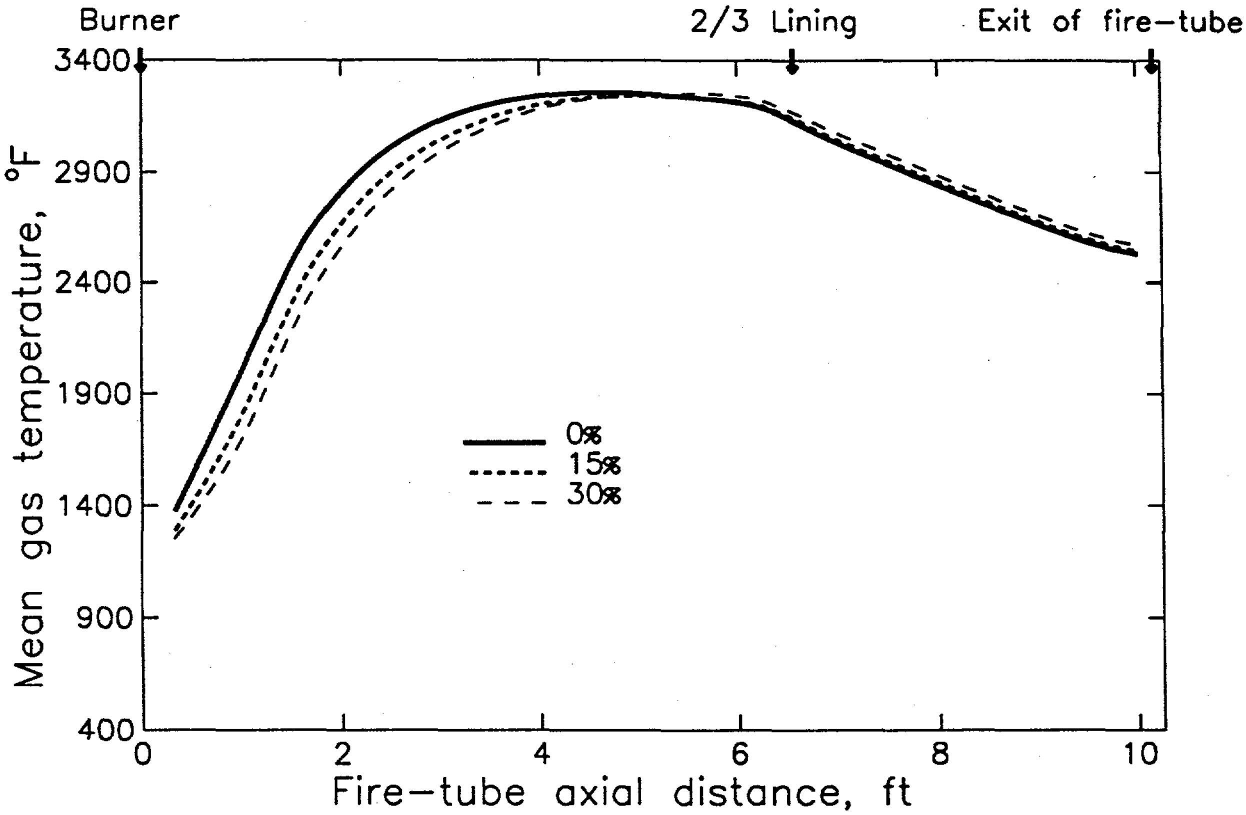


Figure A-13a. Impacts of percent of natural gas co-firing on mean gas temperatures.

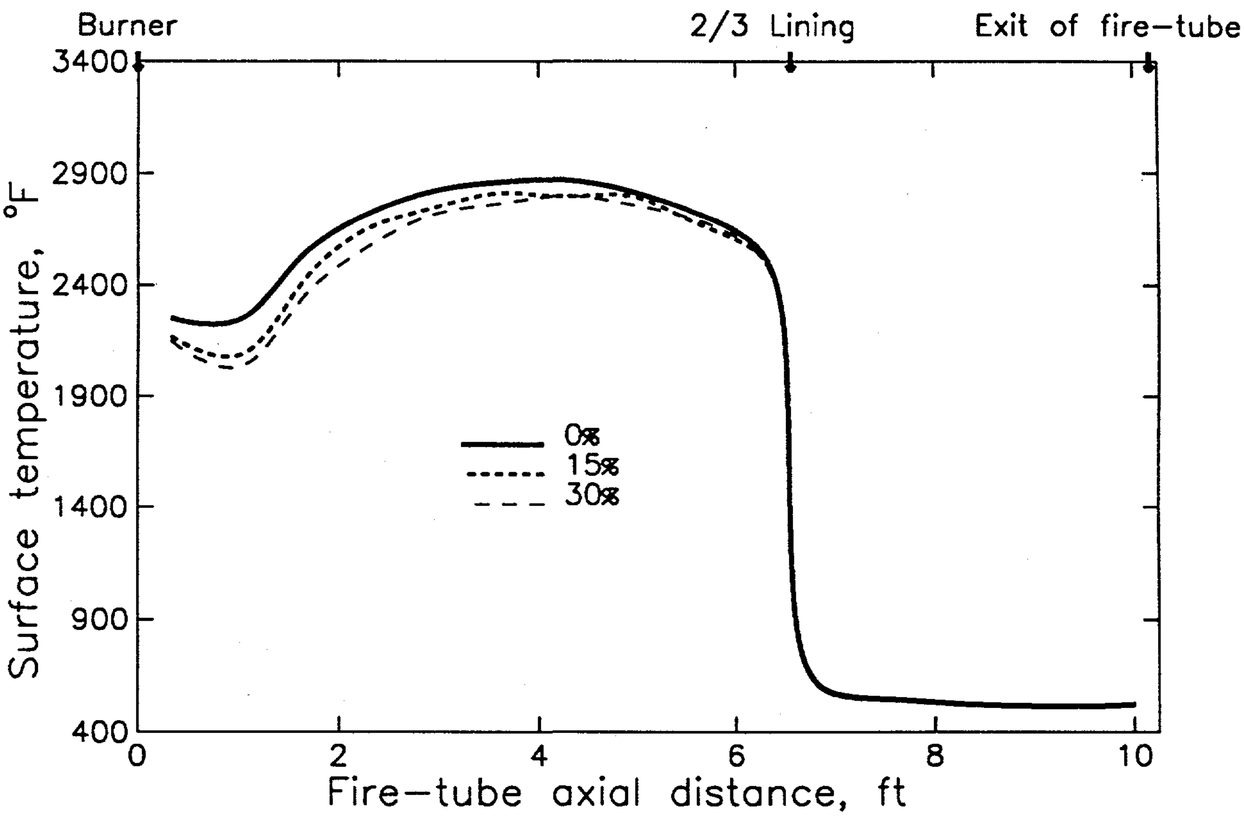


Figure A-13b. Impacts of percent of natural gas co-firing on surface temperatures.

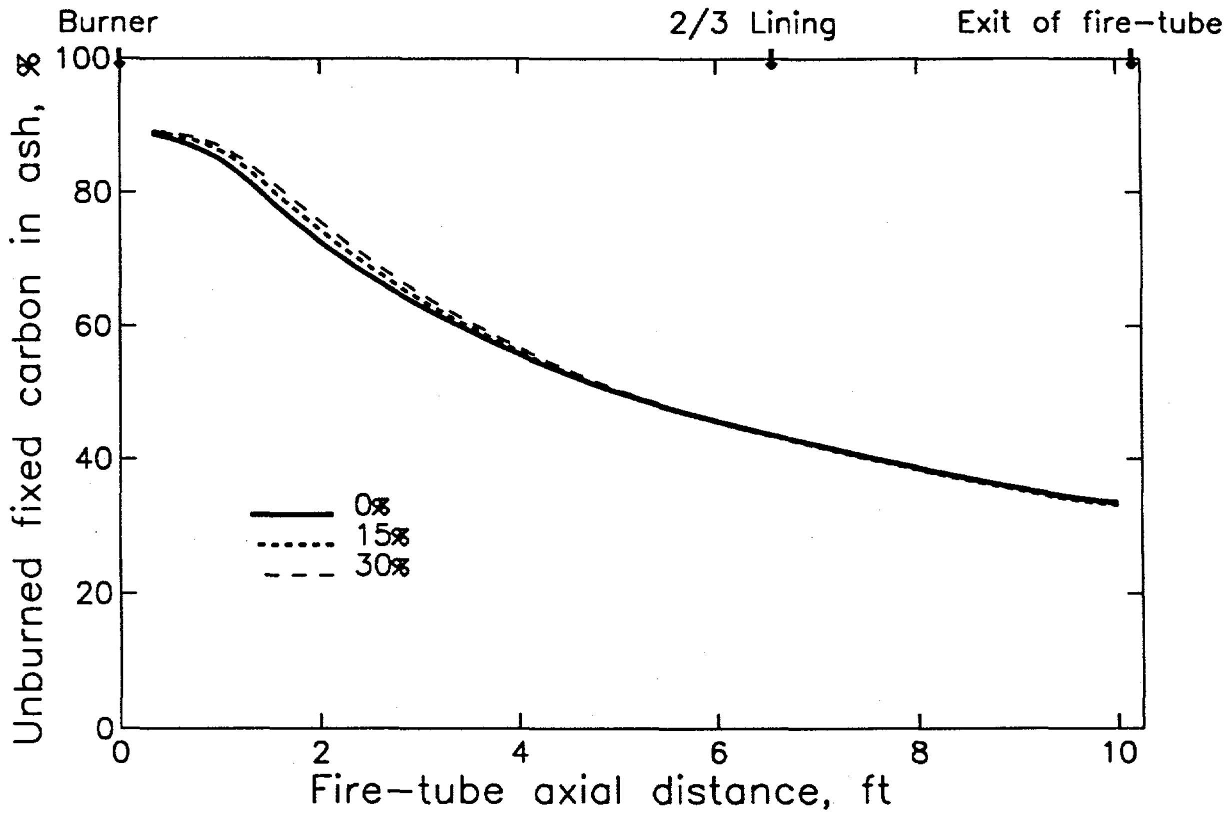


Figure A-13c. Impacts of percent of natural gas co-firing on unburned fixed carbon in ash.

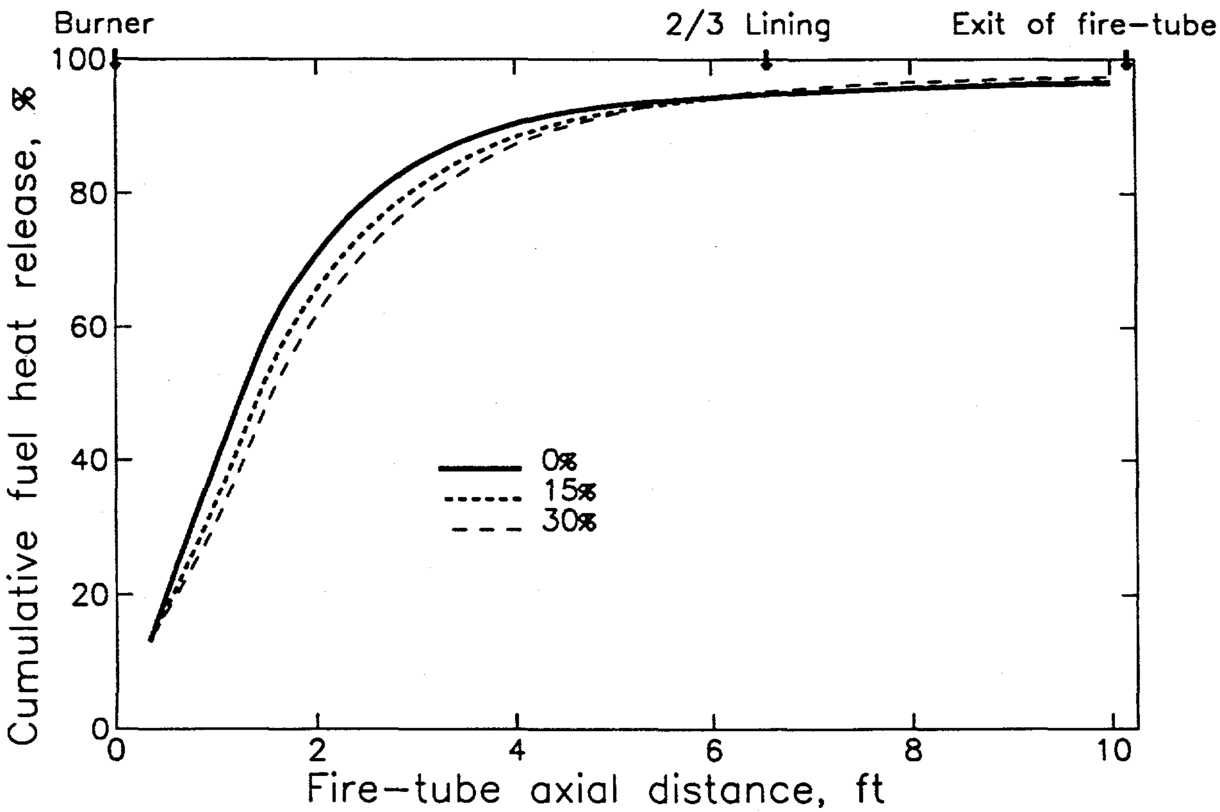


Figure A-13d. Impact of percent of natural gas co-firing on cumulative fuel heat release (% of total heat input).

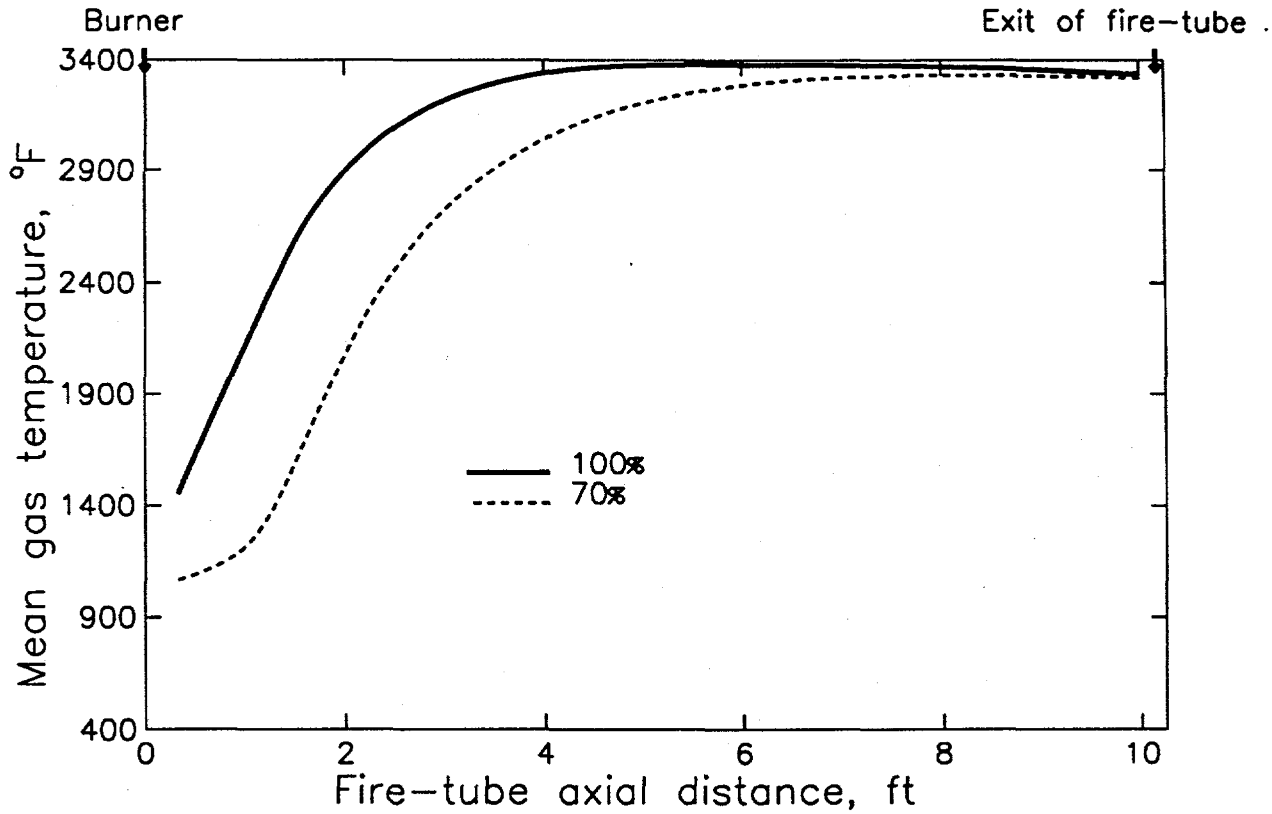


Figure A-14a. Impacts of combustion volume on mean gas temperatures.

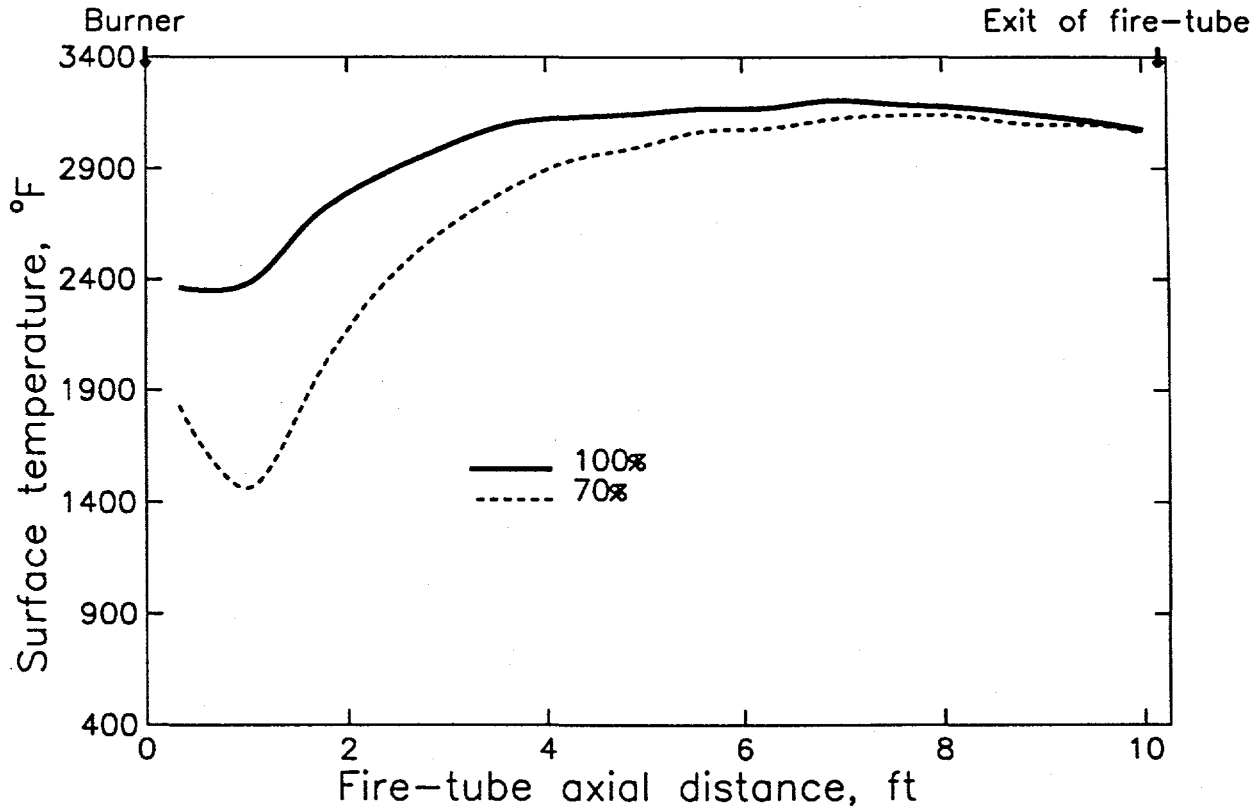


Figure A–14b. Impacts of combustion volume on surface temperatures.

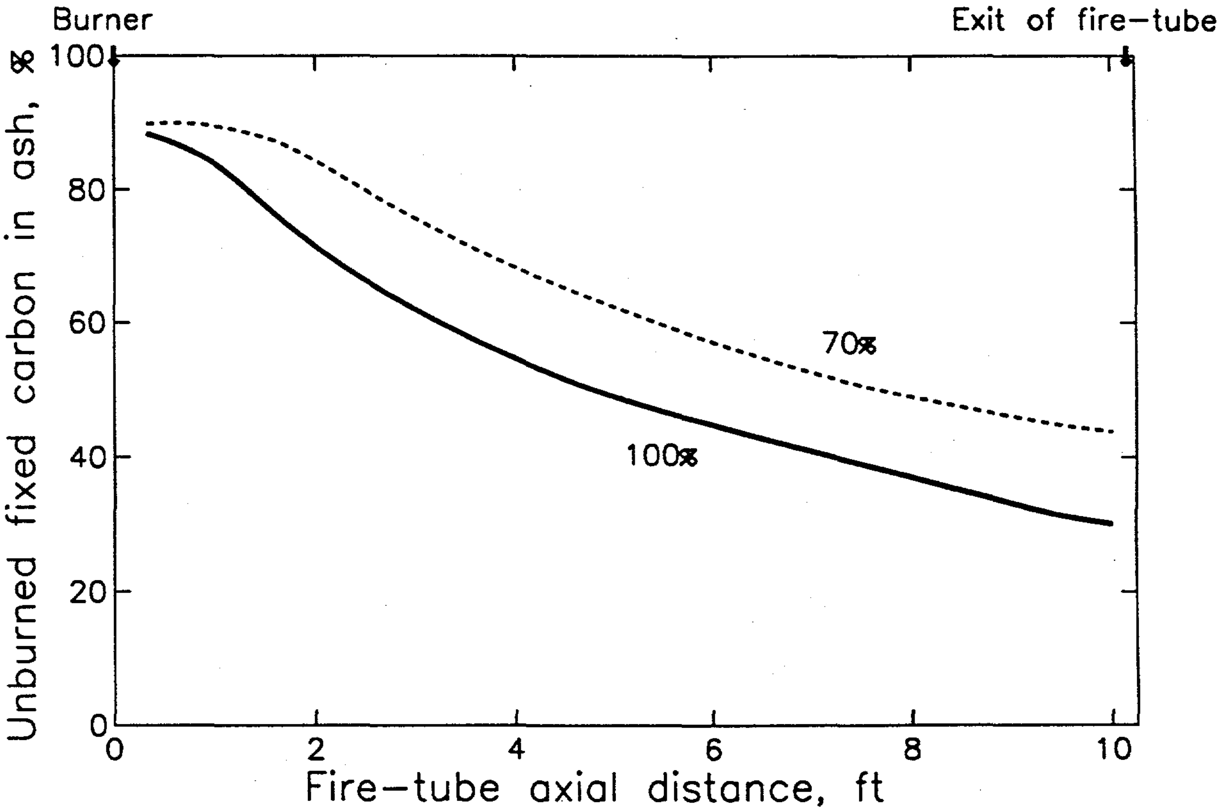


Figure A–14c. Impacts of combustion volume on unburned fixed carbon in ash.

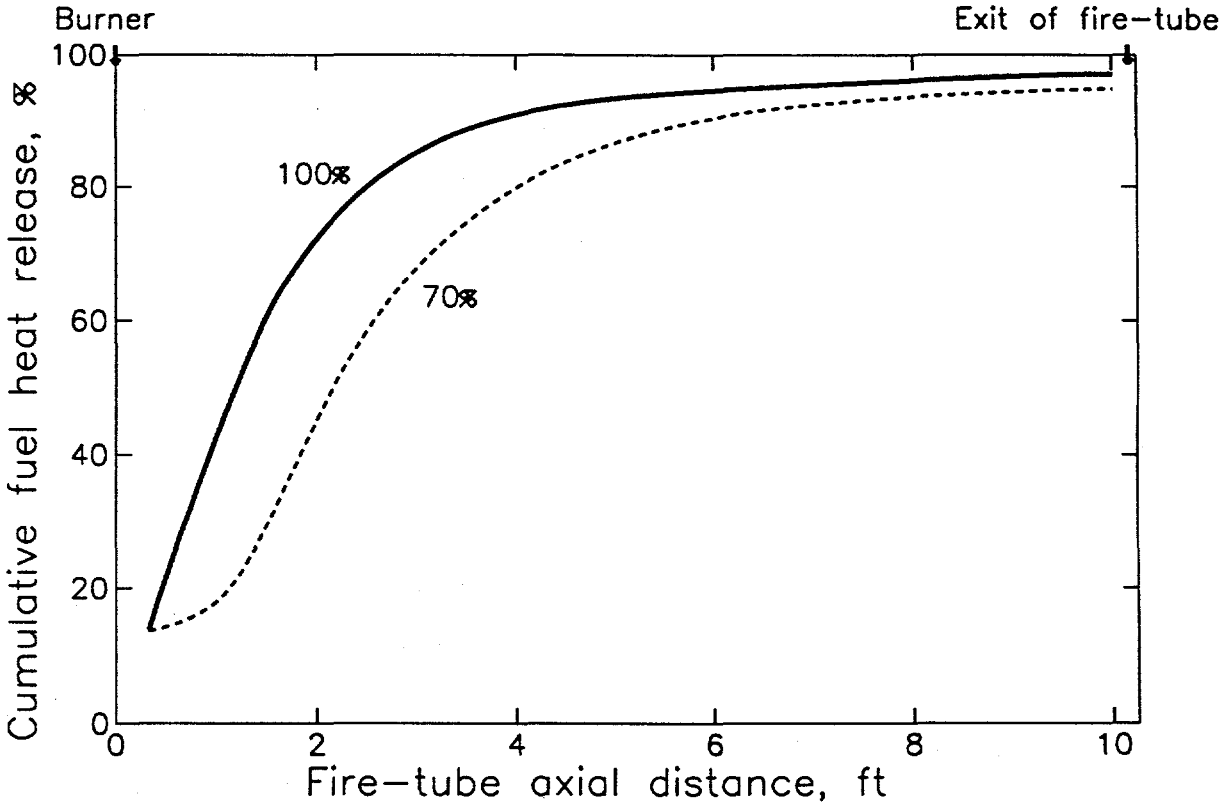


Figure A–14d. Impact of combustion volume on cumulative fuel heat release (% of total heat input).

TABLE A-1. SUMMARY OF KEY PARAMETERS OF INITIAL PARAMETRIC STUDY CASES FOR THE FIRE TUBE.

Case No.	Load (%)*1	Fuel	Air Number	High or Low Swirl Burner	Refractory Length*2 (of total length)	Refractory Thickness (Inches)	Preheated Air Temp. (°F)	2D Grid	60% Ash Recycled
A-1	84%	**Natural Gas**	1.17	High	n/a	n/a	77	Figure A-1	n/a
A-2a	100%	CWS	1.20	High	**1/3**	1.5	600	Figure A-1	No
A-2b	100%	CWS	1.20	High	**2/3**	1.5	600	Figure A-1	No
A-2c	100%	CWS	1.20	High	**Total length**	1.5	600	Figure A-1	No
A-2c-1	100%	CWS	1.20	High	Total length	1.5	600	**Figure A-2**	No
A-2d	100%	CWS	1.20	**Low**	2/3	1.5	600	Figure A-1	No
A-2e	100%	CWS	1.20	High	2/3	**0.5**	600	Figure A-1	No
A-2f	100%	CWS	1.20	High	2/3	1.5	**350**	Figure A-1	No
A-2g	100%	CWS	1.20	High	2/3	1.5	600	Figure A-1	**Yes**
A-2h	100%	CWS	**1.30**	High	2/3	1.5	600	Figure A-1	No
A-2i	100%	**85%CWS+15%Gas**	1.20	High	2/3	1.5	600	Figure A-1	No
A-2j	100%	**85%CWS+30%Gas**	1.20	High	2/3	1.5	600	Figure A-1	No
A-3	**75%**	CWS	1.20	High	2/3	1.5	600	Figure A-1	No
A-4	**50%**	CWS	1.20	High	2/3	1.5	600	Figure A-1	No

*1 Thermal heat input of fuel at 100% load equals 3.43 MBtu/hr, based on dry lower heating values.
*2 Conductivities of Kaowool 3000 board were used in the initial study.

APPENDIX B

The economics of converting oil- or gas-fired boilers to burn coal water slurry was analyzed using a simple payback analysis. The analysis was performed by varying the fuel costs, capacity factor, and capacity of the boiler. The detailed approach to this analysis was defined in Section 5 along with a summary of the various test cases. Appendix B contains a detailed cost analysis for selected test cases with reasonable payback periods. The order of the analyses is as follows:

Natural Gas Fired Boiler
Payback Period Calculation Programs

Load #/hr	Capacity Factor	Production Type/ Quantity	Nat. Gas $/MMBtu	Slurry Cost $/MMBtu	Payback Period Years	Page Number
15,000	64%	Retrofit	6	1.5	2.41	B-3
15,000	64%	Retrofit	6	2	2.84	B-6
28,000	48%	Retrofit	6	2	2.45	B-9
28,000	64%	Retrofit	6	1.5	1.55	B-12
10,000	48%	Retrofit	6	1.5	4.72	B-15
10,000	48%	New / Single	6	1.5	3.55	B-17
10,000	48%	New / Mass	6	1.5	2.15	B-19
15,000	48%	Retrofit	5	1.5	4.8	B-21
15,000	48%	New / Single	5	1.5	3.6	B-23
15,000	48%	New / Mass	5	1.5	2.28	B-25
28,000	48%	Retrofit	5	1.5	2.94	B-27
28,000	48%	New / Single	5	1.5	2.22	B-29
28,000	48%	New / Mass	5	1.5	1.52	B-31

University of Alabama
Fire-tube Boiler

64 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
7008 Hours of uses per year
80 % of year in service

NATURAL GAS ONLY
0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$6.00	/MM Btu	120,467,520	SCF	$0.006	/SCF	$722,805
Utilities:							
Electricity			74,653	kWhr	$0.05	/kWhr	$3,733
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$738,784
District Heat Sales:	**steam**		96,374	MM Btu	$7.67	/MM Btu	$738,784
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	3,438	ACFM	10	"WC	14
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					14

CWS RETROFITTED BOILER

80	% Boiler effciency
12.89	MM Btu/hr Average Rate of Coal Fired
13.75	MM Btu/hr Average for District Heating
0.75	Fractional heat input due to CWS
0.25	Fractional heat input due to Natural Gas
9510	CWS HHV in Btu/lb

Major Equipment	$334,527
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$79,180
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$32,651
Subtotal	$693,879
Project Contingency @ 5%	$34,694
Total Plant Investment (TPI)	$728,572

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	4750	tons	$29	/ton	$135,526
N. GAS	$6.00	/MM Btu	30,116,880	SCF	$0.006	/SCF	$180,701
Utilities:							
Electricity			754,521	kWhr	$0.05	/kWhr	$37,726
Ash Disposal:			570	tons	$20	/ton	$11,401
Labor:							
Operating			1,168	mnhrs	$15	/mnhr	$17,520
Maintenance			140	mnhrs	$15	/mnhr	$2,102
Supervision @ 20% of O & M labor							$3,924
Supplies:							
Operating @ 30% of operating labor							$5,256
Maintenance @ 40% of 3% of TPI							$8,743
Admin. and Gen. Ovhd. (60% of total labor):							$14,128
Insurance and Taxes (2.7% of TPI):							$19,671
Total Gross Operating Cost							$436,699
District Heat Sales:	**steam**		96,374	MM Btu	$7.67	/MM Btu	$738,784
Total Net Operating Cost							($302,085)
Payback period in years							2.41

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	2.74	$1,200	2.31	$22,488
BOILER MODIFICATIONS	$25,800	2.74	$6,000	2.31	$84,516
DUCTWORK	$43,200	2.74	$5,000	2.31	$129,834
CONTROL CABINET	$12,000	2.74	$5,000	2.31	$44,423
SLURRY SYSTEM	$34,000	2.74	$7,500	2.31	$110,435
SUPPLIES	6400	2.74			$17,520
Total	$128,600	2.74	$24,700	2.31	$409,217

Construction Indirect Costs

Field Supervision	$6,175
Construction OVHD & Fee	$15,836
Freight	$10,561
Taxes	$22,089
Total	$463,879

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	3,721 ACFM	10 "WC	15.457
ID FAN	7,852 ACFM	15 "WC	48.919
PUMP	1355.6782 LB/HR	150 PSIG	1.32
A/C	271.13565 SCFM	125 PSIG	78.43
MIXER			0.20
TOTAL HORSE POWER REQUIRED			144.32

University of Alabama
Fire-tube Boiler
64 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
7008 Hours of uses per year
80 % of year in service

NATURAL GAS ONLY
0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	0	tons	$38	/ton	$0
N. GAS	$6.00	/MM Btu	120,467,520	SCF	$0.006	/SCF	$722,805
Utilities:							
Electricity			74,653	kWhr	$0.05	/kWhr	$3,733
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$738,784
District Heat Sales:	steam		96,374	MM Btu	$7.67	/MM Btu	$738,784
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLCW		DELTA P		HORSEPOWER
FD FAN	3,438	ACFM	10	"WC	14
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					14

CWS RETROFITTED BOILER

80 % Boiler effciency
12.89 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$334,527
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$79,180
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$32,651
Subtotal	$693,879
Project Contingency @ 5%	$34,694
Total Plant Investment (TPI)	$728,572

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	4750	tons	$38	/ton	$180,701
N. GAS	$6.00	/MM Btu	30,116,880	SCF	$0.006	/SCF	$180,701
Utilities:							
Electricity			754,521	kWhr	$0.05	/kWhr	$37,726
Ash Disposal:			570	tons	$20	/ton	$11,401
Labor:							
Operating			1,168	mnhrs	$15	/mnhr	$17,520
Maintenance			140	mnhrs	$15	/mnhr	$2,102
Supervision @ 20% of O & M labor							$3,924
Supplies:							
Operating @ 30% of operating labor							$5,256
Maintenance @ 40% of 3% of TPI							$8,743
Admin. and Gen. Ovhd. (60% of total labor):							$14,128
Insurance and Taxes (2.7% of TPI):							$19,671
Total Gross Operating Cost							$481,875
District Heat Sales:	steam		96,374	MM Btu	$7.67	/MM Btu	$738,784
Total Net Operating Cost							($256,910)
Payback period in years							2.84

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	2.74	$1,200	2.31	$22,488
BOILER MODIFICATIONS	$25,800	2.74	$6,000	2.31	$84,516
DUCTWORK	$43,200	2.74	$5,000	2.31	$129,834
CONTROL CABINET	$12,000	2.74	$5,000	2.31	$44,423
SLURRY SYSTEM	$34,000	2.74	$7,500	2.31	$110,435
SUPPLIES	6400	2.74			$17,520
Total	$128,600	2.74	$24,700	2.31	$409,217

Construction Indirect Costs	
Field Supervision	$6,175
Construction OVHD & Fee	$15,836
Freight	$10,561
Taxes	$22,089
Total	$463,879

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	3,721	ACFM	10	"WC	15.457
ID FAN	7,852	ACFM	15	"WC	48.919
PUMP	1355.6782	LB/HR	150	PSIG	1.32
A/C	271.13565	SCFM	125	PSIG	78.43
MIXER					0.20
TOTAL HORSE POWER REQUIRED					144.32

University of Alabama
Fire-tube Boiler

48 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY
0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

		Annual Use	Cost/Unit	Cost/ Yr
Raw Material:				
CWS	$2.00 /MM Btu	0 tons	$38 /ton	$0
N. GAS	$6.00 /MM Btu	168,654,528 SCF	$0.006 /SCF	$1,011,927
Utilities:				
Electricity		104,514 kWhr	$0.05 /kWhr	$5,226
Ash Disposal:		0 tons	$20 /ton	$0
Labor:				
Operating		219 mnhrs	$15 /mnhr	$3,285
Maintenance		66 mnhrs	$15 /mnhr	$986
Supervision @ 20% of O & M labor				$854
Supplies:				
Operating @ 30% of operating labor				$986
Maintenance @ 40% of 3% of TPI				$0
Admin. and Gen. Ovhd. (60% of total labor):				$3,075
Insurance and Taxes (2.7% of TPI):				$0
Total Gross Operating Cost				$1,026,338
District Heat Sales:	steam	134,924 MM Btu	$7.61 /MM Btu	$1,026,338
Total Net Operating Cost				$0

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	6,418 ACFM	10 "WC	27
ID FAN	0 ACFM	15 "WC	0
PUMP	0 LB/HR	150 PSIG	0
A/C	0 SCFM	125 PSIG	0
MIXER			0
TOTAL HORSE POWER REQUIRED			27

CWS RETROFITTED BOILER

80 % Boiler effciency
24.07 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$486,487
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$105,354
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$46,993
Subtotal	$894,313
Project Contingency @ 5%	$44,716
Total Plant Investment (TPI)	$939,028

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	6650	tons	$38	/ton	$252,982
N. GAS	$6.00	/MM Btu	42,163,632	SCF	$0.006	/SCF	$252,982
Utilities:							
Electricity			1,055,650	kWhr	$0.05	/kWhr	$52,782
Ash Disposal:			798	tons	$20	/ton	$15,961
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$11,268
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$25,354
Total Gross Operating Cost							$643,527
District Heat Sales:	**steam**		134,924	MM Btu	$7.61	/MM Btu	$1,026,338
Total Net Operating Cost							($382,810)
Payback period in years							2.45

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	3.98	$1,200	3.16	$32,458
BOILER MODIFICATIONS	$25,800	3.98	$6,000	3.16	$121,685
DUCTWORK	$43,200	3.98	$5,000	3.16	$187,794
CONTROL CABINET	$12,000	3.98	$5,000	3.16	$63,584
SLURRY SYSTEM	$34,000	3.98	$7,500	3.16	$159,074
SUPPLIES	6400	3.98			$25,479
Total	$128,600	3.98	$24,700	3.16	$590,074

Construction Indirect Costs

Field Supervision	$6,175
Construction OVHD & Fee	$21,071
Freight	$15,359
Taxes	$31,634
Total	$664,313

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	6,947 ACFM	10 "WC	28.853
ID FAN	14,657 ACFM	15 "WC	91.315
PUMP	2530.5994 LB/HR	150 PSIG	2.46
A/C	506.11987 SCFM	125 PSIG	146.40
MIXER			0.20
TOTAL HORSE POWER REQUIRED			269.23

University of Alabama
Fire-tube Boiler

64 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
7008 Hours of uses per year
80 % of year in service

NATURAL GAS ONLY
0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$6.00	/MM Btu	224,872,704	SCF	$0.006	/SCF	$1,349,236
Utilities:							
Electricity			139,352	kWhr	$0.05	/kWhr	$6,968
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$1,368,450
District Heat Sales:	**steam**		179,898	MM Btu	$7.61	/MM Btu	$1,368,450
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	6,418	ACFM	10	"WC	27
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					27

CWS RETROFITTED BOILER

80 % Boiler effciency
24.07 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$486,487
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$105,354
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$46,993
Subtotal	$894,313
Project Contingency @ 5%	$44,716
Total Plant Investment (TPI)	$939,028

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	8867 tons	$29 /ton	$252,982
N. GAS	$6.00	/MM Btu	56,218,176 SCF	$0.006 /SCF	$337,309
Utilities:					
Electricity			1,407,533 kWhr	$0.05 /kWhr	$70,377
Ash Disposal:			1,064 tons	$20 /ton	$21,281
Labor:					
Operating			1,168 mnhrs	$15 /mnhr	$17,520
Maintenance			140 mnhrs	$15 /mnhr	$2,102
Supervision @ 20% of O & M labor					$3,924
Supplies:					
Operating @ 30% of operating labor					$5,256
Maintenance @ 40% of 3% of TPI					$11,268
Admin. and Gen. Ovhd. (60% of total labor):					$14,128
Insurance and Taxes (2.7% of TPI):					$25,354
Total Gross Operating Cost					$761,502
District Heat Sales:	**steam**		179,898 MM Btu	$7.61 /MM Btu	$1,368,450
Total Net Operating Cost					($606,948)
Payback period in years					1.55

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	3.98	$1,200	3.16	$32,458
BOILER MODIFICATIONS	$25,800	3.98	$6,000	3.16	$121,685
DUCTWORK	$43,200	3.98	$5,000	3.16	$187,794
CONTROL CABINET	$12,000	3.98	$5,000	3.16	$63,584
SLURRY SYSTEM	$34,000	3.98	$7,500	3.16	$159,074
SUPPLIES	6400	3.98			$25,479
Total	$128,600	3.98	$24,700	3.16	$590,074

Construction Indirect Costs	
Field Supervision	$6,175
Construction OVHD & Fee	$21,071
Freight	$15,359
Taxes	$31,634
Total	$664,313

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	6,947	ACFM	10	"WC	28.853
ID FAN	14,657	ACFM	15	"WC	91.315
PUMP	2530.5994	LB/HR	150	PSIG	2.46
A/C	506.11987	SCFM	125	PSIG	146.40
MIXER					0.20
TOTAL HORSE POWER REQUIRED					269.23

University of Alabama
Fire-tube Boiler

48 % Boiler Capacity Factor
10000 #/ hr Boiler Capacity
8000 #/ hr Derated Boiler Capacity
9.17 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY
0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$6.00	/MM Btu	60,233,760	SCF	$0.006	/SCF	$361,403
Utilities:							
Electricity			37,326	kWhr	$0.05	/kWhr	$1,866
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$372,454
District Heat Sales:	**steam**		48,187	MM Btu	$7.73	/MM Btu	$372,454
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	2,292	ACFM	10	"WC	10
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					10

CWS RETROFITTED BOILER

80 % Boiler effciency
8.60 MM Btu/hr Average Rate of Coal Fired
9.17 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$262,287
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$66,067
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$25,799
Subtotal	$597,890
Project Contingency @ 5%	$29,894
Total Plant Investment (TPI)	$627,784

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	2375 tons	$29 /ton	$67,763
N. GAS	$6.00	/MM Btu	15,058,440 SCF	$0.006 /SCF	$90,351
Utilities:					
Electricity			377,522 kWhr	$0.05 /kWhr	$18,876
Ash Disposal:			285 tons	$20 /ton	$5,700
Labor:					
Operating			876 mnhrs	$15 /mnhr	$13,140
Maintenance			105 mnhrs	$15 /mnhr	$1,577
Supervision @ 20% of O & M labor					$2,943
Supplies:					
Operating @ 30% of operating labor					$3,942
Maintenance @ 40% of 3% of TPI					$7,533
Admin. and Gen. Ovhd. (60% of total labor):					$10,596
Insurance and Taxes (2.7% of TPI):					$16,950
Total Gross Operating Cost					$239,372
District Heat Sales:	**steam**		48,187 MM Btu	$7.73 /MM Btu	$372,454
Total Net Operating Cost					($133,082)
Payback period in years					4.72

University of Alabama
Fire-tube Boiler

NEW UNIT QTY 1

48 % Boiler Capacity Factor
10000 #/ hr Boiler Capacity
8000 #/ hr Derated Boiler Capacity
9.17 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
83 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$6.00	/MM Btu	58,056,636	SCF	$0.006	/SCF	$348,340
Utilities:							
Electricity			35,977	kWhr	$0.05	/kWhr	$1,799
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$359,324
District Heat Sales:	steam		48,187	MM Btu	$7.46	/MM Btu	$359,324
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	2,209	ACFM	10	"WC	9
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					9

CWS RETROFITTED BOILER

83 % Boiler effciency

8.28 MM Btu/hr Average Rate of Coal Fired

9.17 MM Btu/hr Average for District Heating

0.75 Fractional heat input due to CWS

0.25 Fractional heat input due to Natural Gas

9510 CWS HHV in Btu/lb

Major Equipment	$196,715
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$36,469
Engineering/thermal modelling	$150,000
Purchasing	$30,000
Freight/Taxes	$21,151
Subtotal	$448,072
Project Contingency @ 5%	$22,404
Total Plant Investment (TPI)	$470,476

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	2289	tons	$29	/ton	$65,314
N. GAS	$6.00	/MM Btu	14,514,159	SCF	$0.006	/SCF	$87,085
Utilities:							
Electricity			363,905	kWhr	$0.05	/kWhr	$18,195
Ash Disposal:			275	tons	$20	/ton	$5,494
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$5,646
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$12,703
Total Gross Operating Cost							$226,635
District Heat Sales:	**steam**		48,187	MM Btu	$7.46	/MM Btu	$359,324
Total Net Operating Cost							($132,689)
Payback period in years							3.55

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
10000 #/ hr Boiler Capacity
8000 #/ hr Derated Boiler Capacity
9.17 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
83 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$6.00	/MM Btu	58,056,636	SCF	$0.006	/SCF	$348,340
Utilities:							
Electricity			35,977	kWhr	$0.05	/kWhr	$1,799
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$359,324
District Heat Sales:	**steam**		48,187	MM Btu	$7.46	/MM Btu	$359,324
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	2,209	ACFM	10	"WC	9
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					9

CWS RETROFITTED BOILER

83 % Boiler effciency
8.28 MM Btu/hr Average Rate of Coal Fired
9.17 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$157,372
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$36,469
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$17,777
Subtotal	$285,355
Project Contingency @ 5%	$14,268
Total Plant Investment (TPI)	$299,622

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	2289	tons	$29	/ton	$65,314
N. GAS	$6.00	/MM Btu	14,514,159	SCF	$0.006	/SCF	$87,085
Utilities:							
Electricity			363,905	kWhr	$0.05	/kWhr	$18,195
Ash Disposal:			275	tons	$20	/ton	$5,494
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$3,595
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$8,090
Total Gross Operating Cost							$219,972
District Heat Sales:	**steam**		48,187	MM Btu	$7.46	/MM Btu	$359,324
Total Net Operating Cost							($139,352)
Payback period in years							**2.15**

University of Alabama
Fire-tube Boiler

48 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY
0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$5.00	/MM Btu	90,350,640	SCF	$0.005	/SCF	$451,753
Utilities:							
Electricity			55,990	kWhr	$0.05	/kWhr	$2,799
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$463,738
District Heat Sales:	steam		72,281	MM Btu	$6.42	/MM Btu	$463,738
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	3,438	ACFM	10	"WC	14
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					14

CWS RETROFITTED BOILER

80	% Boiler effciency
12.89	MM Btu/hr Average Rate of Coal Fired
13.75	MM Btu/hr Average for District Heating
0.75	Fractional heat input due to CWS
0.25	Fractional heat input due to Natural Gas
9510	CWS HHV in Btu/lb

Major Equipment	$334,527
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$79,180
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$32,651
Subtotal	$693,879
Project Contingency @ 5%	$34,694
Total Plant Investment (TPI)	$728,572

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	3563	tons	$29	/ton	$101,644
N. GAS	$5.00	/MM Btu	22,587,660	SCF	$0.005	/SCF	$112,938
Utilities:							
Electricity			565,891	kWhr	$0.05	/kWhr	$28,295
Ash Disposal:			428	tons	$20	/ton	$8,551
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$8,743
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$19,671
Total Gross Operating Cost							$312,040
District Heat Sales:	steam		72,281	MM Btu	$6.42	/MM Btu	$463,738
Total Net Operating Cost							($151,697)
Payback period in years							4.80

University of Alabama
Fire-tube Boiler

NEW UNIT QTY 1

48 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
83 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$5.00	/MM Btu	87,084,954	SCF	$0.005	/SCF	$435,425
Utilities:							
Electricity			53,966	kWhr	$0.05	/kWhr	$2,698
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$447,308
District Heat Sales:	steam		72,281	MM Btu	$6.19	/MM Btu	$447,308
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	3,314	ACFM	10	"WC	14
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					14

CWS RETROFITTED BOILER

83 % Boiler effciency
12.43 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$250,895
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$43,708
Engineering/thermal modelling	$150,000
Purchasing	$30,000
Freight/Taxes	$26,790
Subtotal	$518,913
Project Contingency @ 5%	$25,946
Total Plant Investment (TPI)	$544,859

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	3434	tons	$29	/ton	$97,971
N. GAS	$5.00	/MM Btu	21,771,239	SCF	$0.005	/SCF	$108,856
Utilities:							
Electricity			545,465	kWhr	$0.05	/kWhr	$27,273
Ash Disposal:			412	tons	$20	/ton	$8,241
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$6,538
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$14,711
Total Gross Operating Cost							$295,789
District Heat Sales:	**steam**		72,281	MM Btu	$6.19	/MM Btu	$447,308
Total Net Operating Cost							($151,519)
Payback period in years							3.60

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
83 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$5.00	/MM Btu	87,084,954	SCF	$0.005	/SCF	$435,425
Utilities:							
Electricity			53,966	kWhr	$0.05	/kWhr	$2,698
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$447,308
District Heat Sales:	**steam**		72,281	MM Btu	$6.19	/MM Btu	$447,308
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	3,314	ACFM	10	"WC	14
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					14

CWS RETROFITTED BOILER

83 % Boiler effciency
12.43 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$200,716
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$43,708
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$22,486
Subtotal	$344,430
Project Contingency @ 5%	$17,222
Total Plant Investment (TPI)	$361,652

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	3434	tons	$29	/ton	$97,971
N. GAS	$5.00	/MM Btu	21,771,239	SCF	$0.005	/SCF	$108,856
Utilities:							
Electricity			545,465	kWhr	$0.05	/kWhr	$27,273
Ash Disposal:			412	tons	$20	/ton	$8,241
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$4,340
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$9,765
Total Gross Operating Cost							$288,644
District Heat Sales:	**steam**		72,281	MM Btu	$6.19	/MM Btu	$447,308
Total Net Operating Cost							($158,664)
Payback period in years							2.28

University of Alabama
Fire-tube Boiler

48 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
80 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$5.00	/MM Btu	168,654,528	SCF	$0.005	/SCF	$843,273
Utilities:							
Electricity			104,514	kWhr	$0.05	/kWhr	$5,226
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$857,683
District Heat Sales:	**steam**		134,924	MM Btu	$6.36	/MM Btu	$857,683
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	6,418	ACFM	10	"WC	27
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					27

CWS RETROFITTED BOILER

80 % Boiler effciency
24.07 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$486,487
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$105,354
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$46,993
Subtotal	$894,313
Project Contingency @ 5%	$44,716
Total Plant Investment (TPI)	$939,028

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	6650	tons	$29	/ton	$189,736
N. GAS	$5.00	/MM Btu	42,163,632	SCF	$0.005	/SCF	$210,818
Utilities:							
Electricity			1,055,650	kWhr	$0.05	/kWhr	$52,782
Ash Disposal:			798	tons	$20	/ton	$15,961
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$11,268
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$25,354
Total Gross Operating Cost							$538,118
District Heat Sales:	**steam**		134,924	MM Btu	$6.36	/MM Btu	$857,683
Total Net Operating Cost							($319,565)
Payback period in years							2.94

University of Alabama
Fire-tube Boiler

NEW UNIT QTY 1

48 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
83 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$5.00	/MM Btu	162,558,581	SCF	$0.005	/SCF	$812,793
Utilities:							
Electricity			100,736	kWhr	$0.05	/kWhr	$5,037
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$827,015
District Heat Sales:	**steam**		134,924	MM Btu	$6.13	/MM Btu	$827,015
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	6,186	ACFM	10	"WC	26
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					26

CWS RETROFITTED BOILER

83 % Boiler effciency
23.20 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to Natural Gas
9510 CWS HHV in Btu/lb

Major Equipment	$364,865
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$58,155
Engineering/thermal modelling	$150,000
Purchasing	$30,000
Freight/Taxes	$38,610
Subtotal	$667,109
Project Contingency @ 5%	$33,355
Total Plant Investment (TPI)	$700,465

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	6410	tons	$29	/ton	$182,878
N. GAS	$5.00	/MM Btu	40,639,645	SCF	$0.005	/SCF	$203,198
Utilities:							
Electricity			1,017,522	kWhr	$0.05	/kWhr	$50,876
Ash Disposal:			769	tons	$20	/ton	$15,384
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$8,406
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$18,913
Total Gross Operating Cost							$511,853
District Heat Sales:	**steam**		134,924	MM Btu	$6.13	/MM Btu	$827,015
Total Net Operating Cost							($315,161)
Payback period in years							2.22

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

NATURAL GAS ONLY

0.00 Fractional heat input due to CWS
83 % efficiency
80 % Boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
N. GAS	$5.00	/MM Btu	162,558,581	SCF	$0.005	/SCF	$812,793
Utilities:							
Electricity			100,736	kWhr	$0.05	/kWhr	$5,037
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$827,015
District Heat Sales:	**steam**		134,924	MM Btu	$6.13	/MM Btu	$827,015
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	6,186	ACFM	10	"WC	26
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					26

CWS RETROFITTED BOILER

83 % Boiler effciency

23.20 MM Btu/hr Average Rate of Coal Fired

25.67 MM Btu/hr Average for District Heating

0.75 Fractional heat input due to CWS

0.25 Fractional heat input due to Natural Gas

9510 CWS HHV in Btu/lb

Major Equipment	$291,892
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$58,155
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$32,351
Subtotal	$467,877
Project Contingency @ 5%	$23,394
Total Plant Investment (TPI)	$491,271

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	6410	tons	$29	/ton	$182,878
N. GAS	$5.00	/MM Btu	40,639,645	SCF	$0.005	/SCF	$203,198
Utilities:							
Electricity			1,017,522	kWhr	$0.05	/kWhr	$50,876
Ash Disposal:			769	tons	$20	/ton	$15,384
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$5,895
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$13,264
Total Gross Operating Cost							$503,695
District Heat Sales:	**steam**		134,924	MM Btu	$6.13	/MM Btu	$827,015
Total Net Operating Cost							($323,320)
Payback period in years							1.52

Oil Fired Boiler
Payback Period Calculation Programs

Load #/hr	Capacity Factor	Production Type/ Quantity	Nat. Gas $/MMBtu	Slurry Cost $/MMBtu	Payback Period Years	Page Number
15,000	48%	Retrofit	7	2	2.86	B-34
10,000	64%	Retrofit	7	1.5	2.54	B-37
15,000	64%	Retrofit	7	1.5	1.85	B-40
28,000	64%	Retrofit	7	1.5	1.21	B-43
28,000	64%	Retrofit	7	2	1.35	B-46
4,000	48%	New / Mass	7	1.5	3.61	B-49
10,000	48%	Retrofit	7	1.5	3.51	B-51
10,000	48%	New / Single	7	1.5	2.66	B-53
10,000	48%	New / Mass	7	1.5	1.63	B-55
15,000	48%	Retrofit	6	1.5	3.3	B-57
15,000	48%	New / Single	6	1.5	2.5	B-59
15,000	48%	New / Mass	6	1.5	1.61	B-61
28,000	48%	Retrofit	5	1.5	2.92	B-63
28,000	48%	New / SIngle	5	1.5	2.21	B-65
28,000	48%	New / Mass	5	1.5	1.51	B-67

University of Alabama

Fire-tube Boiler

48 % Boiler Capacity Factor

15000 #/ hr Boiler Capacity

12000 #/ hr Derated Boiler Capacity

13.75 MM Btu/hr Average for District Heating

5256 Hours of uses per year

60 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	0	tons	$38	/ton	$0
OIL #2	$7.00	/MM Btu	4,642,890	GAL	$0.136	/GAL	$632,454
Utilities:							
Electricity			323,669	kWhr	$0.05	/kWhr	$16,183
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$657,823
District Heat Sales:	**steam**		72,281	MM Btu	$9.10	/MM Btu	$657,823
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	19,875	ACFM	10	"WC	83
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					83

CWS RETROFITTED BOILER

80 % Boiler effciency
12.89 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due toNo 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$334,527
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$79,180
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$32,651
Subtotal	$693,879
Project Contingency @ 5%	$34,694
Total Plant Investment (TPI)	$728,572

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	3563	tons	$38	/ton	$135,526
#2 OIL	$7.00	/MM Btu	1,160,723	GAL	$0.136	/GAL	$158,114
Utilities:							
Electricity			812,674	kWhr	$0.05	/kWhr	$40,634
Ash Disposal:			428	tons	$20	/ton	$8,551
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$8,743
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$19,671
Total Gross Operating Cost							$403,436
District Heat Sales:	steam		72,281	MM Btu	$9.10	/MM Btu	$657,823
Total Net Operating Cost							($254,386)
Payback period in years							2.86

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	2.74	$1,200	2.31	$22,488
BOILER MODIFICATIONS	$25,800	2.74	$6,000	2.31	$84,516
DUCTWORK	$43,200	2.74	$5,000	2.31	$129,834
CONTROL CABINET	$12,000	2.74	$5,000	2.31	$44,423
SLURRY SYSTEM	$34,000	2.74	$7,500	2.31	$110,435
SUPPLIES	$6,400	2.74			$17,520
Total	$128,600	2.74	$24,700	2.31	$409,217

Construction Indirect Costs

Field Supervision	$6,175
Construction OVHD & Fee	$15,836
Freight	$10,561
Taxes	$22,089
Total	$463,879

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	7,831 ACFM	10 "WC	32.524
ID FAN	15,215 ACFM	15 "WC	94.791
PUMP	1355.6782 LB/HR	150 PSIG	1.32
A/C	271.13565 SCFM	125 PSIG	78.43
MIXER			0.20
TOTAL HORSE POWER REQUIRED			207.26

University of Alabama

Fire-tube Boiler

64 % Boiler Capacity Factor

10000 #/ hr Boiler Capacity

8000 #/ hr Derated Boiler Capacity

9.17 MM Btu/hr Average for District Heating

7008 Hours of uses per year

80 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$7.00	/MM Btu	4,127,013	GAL	$0.136	/GAL	$562,182
Utilities:							
Electricity			287,705	kWhr	$0.05	/kWhr	$14,385
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$588,814
District Heat Sales:	**steam**		64,249	MM Btu	$9.16	/MM Btu	$588,814
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	13,250	ACFM	10	"WC	55
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					55

CWS RETROFITTED BOILER

80	% Boiler effciency
8.60	MM Btu/hr Average Rate of Coal Fired
9.17	MM Btu/hr Average for District Heating
0.75	Fractional heat input due to CWS
0.25	Fractional heat input due toNo 2 OIL
9510	CWS HHV in Btu/lb

Major Equipment	$262,287
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$66,067
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$25,799
Subtotal	$597,890
Project Contingency @ 5%	$29,894
Total Plant Investment (TPI)	$627,784

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	3167	tons	$29	/ton	$90,351
#2 OIL	$7.00	/MM Btu	1,031,753	GAL	$0.136	/GAL	$140,545
Utilities:							
Electricity			722,726	kWhr	$0.05	/kWhr	$36,136
Ash Disposal:			380	tons	$20	/ton	$7,600
Labor:							
Operating			1,168	mnhrs	$15	/mnhr	$17,520
Maintenance			140	mnhrs	$15	/mnhr	$2,102
Supervision @ 20% of O & M labor							$3,924
Supplies:							
Operating @ 30% of operating labor							$5,256
Maintenance @ 40% of 3% of TPI							$7,533
Admin. and Gen. Ovhd. (60% of total labor):							$14,128
Insurance and Taxes (2.7% of TPI):							$16,950
Total Gross Operating Cost							$342,047
District Heat Sales:	steam		64,249	MM Btu	$9.16	/MM Btu	$588,814
Total Net Operating Cost							($246,766)
Payback period in years							2.54

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	2.15	$1,200	1.89	$17,722
BOILER MODIFICATIONS	$25,800	2.15	$6,000	1.89	$66,715
DUCTWORK	$43,200	2.15	$5,000	1.89	$102,172
CONTROL CABINET	$12,000	2.15	$5,000	1.89	$35,206
SLURRY SYSTEM	$34,000	2.15	$7,500	1.89	$87,150
SUPPLIES	$6,400	2.15			$13,737
Total	$128,600	2.15	$24,700	1.89	$322,702

Construction Indirect Costs	
Field Supervision	$6,175
Construction OVHD & Fee	$13,213
Freight	$8,281
Taxes	$17,519
Total	$367,890

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	5,220 ACFM	10 "WC	21.683
ID FAN	10,143 ACFM	15 "WC	63.194
PUMP	903.78549 LB/HR	150 PSIG	0.88
A/C	180.7571 SCFM	125 PSIG	52.29
MIXER			0.20
TOTAL HORSE POWER REQUIRED			138.24

University of Alabama

Fire-tube Boiler

64 % Boiler Capacity Factor

15000 #/ hr Boiler Capacity

12000 #/ hr Derated Boiler Capacity

13.75 MM Btu/hr Average for District Heating

7008 Hours of uses per year

80 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$7.00	/MM Btu	6,190,520	GAL	$0.136	/GAL	$843,273
Utilities:							
Electricity			431,558	kWhr	$0.05	/kWhr	$21,578
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$877,097
District Heat Sales:	**steam**		96,374	MM Btu	$9.10	/MM Btu	$877,097
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	19,875	ACFM	10	"WC	83
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					83

CWS RETROFITTED BOILER

80 % Boiler effciency
12.89 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due toNo 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$334,527
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$79,180
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$32,651
Subtotal	$693,879
Project Contingency @ 5%	$34,694
Total Plant Investment (TPI)	$728,572

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	4750	tons	$29	/ton	$135,526
#2 OIL	$7.00	/MM Btu	1,547,630	GAL	$0.136	/GAL	$210,818
Utilities:							
Electricity			1,083,566	kWhr	$0.05	/kWhr	$54,178
Ash Disposal:			570	tons	$20	/ton	$11,401
Labor:							
Operating			1,168	mnhrs	$15	/mnhr	$17,520
Maintenance			140	mnhrs	$15	/mnhr	$2,102
Supervision @ 20% of O & M labor							$3,924
Supplies:							
Operating @ 30% of operating labor							$5,256
Maintenance @ 40% of 3% of TPI							$8,743
Admin. and Gen. Ovhd. (60% of total labor):							$14,128
Insurance and Taxes (2.7% of TPI):							$19,671
Total Gross Operating Cost							$483,268
District Heat Sales:	steam		96,374	MM Btu	$9.10	/MM Btu	$877,097
Total Net Operating Cost							($393,829)
Payback period in years							1.85

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	2.74	$1,200	2.31	$22,488
BOILER MODIFICATIONS	$25,800	2.74	$6,000	2.31	$84,516
DUCTWORK	$43,200	2.74	$5,000	2.31	$129,834
CONTROL CABINET	$12,000	2.74	$5,000	2.31	$44,423
SLURRY SYSTEM	$34,000	2.74	$7,500	2.31	$110,435
SUPPLIES	$6,400	2.74			$17,520
Total	$128,600	2.74	$24,700	2.31	$409,217

Construction Indirect Costs

Field Supervision	$6,175
Construction OVHD & Fee	$15,836
Freight	$10,561
Taxes	$22,089
Total	$463,879

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	7,831 ACFM	10 "WC	32.524
ID FAN	15,215 ACFM	15 "WC	94.791
PUMP	1355.6782 LB/HR	150 PSIG	1.32
A/C	271.13565 SCFM	125 PSIG	78.43
MIXER			0.20
TOTAL HORSE POWER REQUIRED			207.26

University of Alabama

Fire-tube Boiler

64 % Boiler Capacity Factor

28000 #/ hr Boiler Capacity

22400 #/ hr Derated Boiler Capacity

25.67 MM Btu/hr Average for District Heating

7008 Hours of uses per year

80 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$7.00	/MM Btu	11,555,637	GAL	$0.136	/GAL	$1,574,109
Utilities:							
Electricity			805,575	kWhr	$0.05	/kWhr	$40,279
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$1,626,634
District Heat Sales:	**steam**		179,898	MM Btu	$9.04	/MM Btu	$1,626,634
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	37,099	ACFM	10	"WC	154
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					154

CWS RETROFITTED BOILER

80	% Boiler effciency
24.07	MM Btu/hr Average Rate of Coal Fired
25.67	MM Btu/hr Average for District Heating
0.75	Fractional heat input due to CWS
0.25	Fractional heat input due toNo 2 OIL
9510	CWS HHV in Btu/lb

Major Equipment	$486,487
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$105,354
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$46,993
Subtotal	$894,313
Project Contingency @ 5%	$44,716
Total Plant Investment (TPI)	$939,028

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	8867 tons	$29 /ton	$252,982
#2 OIL	$7.00	/MM Btu	2,888,909 GAL	$0.136 /GAL	$393,527
Utilities:					
Electricity			2,021,750 kWhr	$0.05 /kWhr	$101,087
Ash Disposal:			1,064 tons	$20 /ton	$21,281
Labor:					
Operating			1,168 mnhrs	$15 /mnhr	$17,520
Maintenance			140 mnhrs	$15 /mnhr	$2,102
Supervision @ 20% of O & M labor					$3,924
Supplies:					
Operating @ 30% of operating labor					$5,256
Maintenance @ 40% of 3% of TPI					$11,268
Admin. and Gen. Ovhd. (60% of total labor):					$14,128
Insurance and Taxes (2.7% of TPI):					$25,354
Total Gross Operating Cost					$848,431
District Heat Sales:	steam		179,898 MM Btu	$9.04 /MM Btu	$1,626,634
Total Net Operating Cost					($778,203)
Payback period in years					1.21

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	3.98	$1,200	3.16	$32,458
BOILER MODIFICATIONS	$25,800	3.98	$6,000	3.16	$121,685
DUCTWORK	$43,200	3.98	$5,000	3.16	$187,794
CONTROL CABINET	$12,000	3.98	$5,000	3.16	$63,584
SLURRY SYSTEM	$34,000	3.98	$7,500	3.16	$159,074
SUPPLIES	$6,400	3.98			$25,479
Total	$128,600	3.98	$24,700	3.16	$590,074

Construction Indirect Costs

Field Supervision	$6,175
Construction OVHD & Fee	$21,071
Freight	$15,359
Taxes	$31,634
Total	$664,313

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	14,617 ACFM	10 "WC	60.712
ID FAN	28,401 ACFM	15 "WC	176.94
PUMP	2530.5994 LB/HR	150 PSIG	2.46
A/C	506.11987 SCFM	125 PSIG	146.40
MIXER			0.20
TOTAL HORSE POWER REQUIRED			386.72

University of Alabama

Fire-tube Boiler

64 % Boiler Capacity Factor

28000 #/ hr Boiler Capacity

22400 #/ hr Derated Boiler Capacity

25.67 MM Btu/hr Average for District Heating

7008 Hours of uses per year

80 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	0	tons	$38	/ton	$0
OIL #2	$7.00	/MM Btu	11,555,637	GAL	$0.136	/GAL	$1,574,109
Utilities:							
Electricity			805,575	kWhr	$0.05	/kWhr	$40,279
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			292	mnhrs	$15	/mnhr	$4,380
Maintenance			88	mnhrs	$15	/mnhr	$1,314
Supervision @ 20% of O & M labor							$1,139
Supplies:							
Operating @ 30% of operating labor							$1,314
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$4,100
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$1,626,634
District Heat Sales:	**steam**		179,898	MM Btu	$9.04	/MM Btu	$1,626,634
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	37,099	ACFM	10	"WC	154
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					154

CWS RETROFITTED BOILER

80 % Boiler effciency
24.07 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due toNo 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$486,487
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$105,354
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$46,993
Subtotal	$894,313
Project Contingency @ 5%	$44,716
Total Plant Investment (TPI)	$939,028

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$2.00	/MM Btu	8867	tons	$38	/ton	$337,309
#2 OIL	$7.00	/MM Btu	2,888,909	GAL	$0.136	/GAL	$393,527
Utilities:							
Electricity			2,021,750	kWhr	$0.05	/kWhr	$101,087
Ash Disposal:			1,064	tons	$20	/ton	$21,281
Labor:							
Operating			1,168	mnhrs	$15	/mnhr	$17,520
Maintenance			140	mnhrs	$15	/mnhr	$2,102
Supervision @ 20% of O & M labor							$3,924
Supplies:							
Operating @ 30% of operating labor							$5,256
Maintenance @ 40% of 3% of TPI							$11,268
Admin. and Gen. Ovhd. (60% of total labor):							$14,128
Insurance and Taxes (2.7% of TPI):							$25,354
Total Gross Operating Cost							$932,758
District Heat Sales:	**steam**		179,898	MM Btu	$9.04	/MM Btu	$1,626,634
Total Net Operating Cost							($693,876)
Payback period in years							1.35

Direct Field Costs

	Major	SCALE F	Labor	SCALE F	Total Direct
ASH RECYCLE	$7,200	3.98	$1,200	3.16	$32,458
BOILER MODIFICATIONS	$25,800	3.98	$6,000	3.16	$121,685
DUCTWORK	$43,200	3.98	$5,000	3.16	$187,794
CONTROL CABINET	$12,000	3.98	$5,000	3.16	$63,584
SLURRY SYSTEM	$34,000	3.98	$7,500	3.16	$159,074
SUPPLIES	$6,400	3.98			$25,479
Total	$128,600	3.98	$24,700	3.16	$590,074

Construction Indirect Costs	
Field Supervision	$6,175
Construction OVHD & Fee	$21,071
Freight	$15,359
Taxes	$31,634
Total	$664,313

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	14,617 ACFM	10 "WC	60.712
ID FAN	28,401 ACFM	15 "WC	176.94
PUMP	2530.5994 LB/HR	150 PSIG	2.46
A/C	506.11987 SCFM	125 PSIG	146.40
MIXER			0.20
TOTAL HORSE POWER REQUIRED			386.72

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
4000 #/ hr Boiler Capacity
3200 #/ hr Derated Boiler Capacity
3.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

		Annual Use	Cost/Unit	Cost/ Yr
Raw Material:				
CWS	$1.50 /MM Btu	0 tons	$29 /ton	$0
	$7.00 /MM Btu	1,193,353 GAL	$0.136 /GAL	$162,559
Utilities:				
Electricity		83,192 kWhr	$0.05 /kWhr	$4,160
Ash Disposal:		0 tons	$20 /ton	$0
Labor:				
Operating		219 mnhrs	$15 /mnhr	$3,285
Maintenance		66 mnhrs	$15 /mnhr	$986
Supervision @ 20% of O & M labor				$854
Supplies:				
Operating @ 30% of operating labor				$986
Maintenance @ 40% of 3% of TPI				$0
Admin. and Gen. Ovhd. (60% of total labor):				$3,075
Insurance and Taxes (2.7% of TPI):				$0
Total Gross Operating Cost				$175,903
District Heat Sales:	steam	19,275 MM Btu	$9.13 /MM Btu	$175,903
Total Net Operating Cost				$0

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	5,108 ACFM	10 "WC	21
ID FAN	0 ACFM	15 "WC	0
PUMP	0 LB/HR	150 PSIG	0
A/C	0 SCFM	125 PSIG	0
MIXER			0
TOTAL HORSE POWER REQUIRED			21

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
3.31 MM Btu/hr Average Rate of Coal Fired
3.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$90,816
Instruments	$0
Supplies	$7,927
Building (incl. labor)	$0
Construction Labor	$24,631
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$10,506
Subtotal	$193,880
Project Contingency @ 5%	$9,694
Total Plant Investment (TPI)	$203,574

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	916 tons	$29 /ton	$26,125
#2 OIL	$7.00	/MM Btu	298,338 GAL	$0.136 /GAL	$40,640
Utilities:					
Electricity			209,463 kWhr	$0.05 /kWhr	$10,473
Ash Disposal:			110 tons	$20 /ton	$2,198
Labor:					
Operating			876 mnhrs	$15 /mnhr	$13,140
Maintenance			105 mnhrs	$15 /mnhr	$1,577
Supervision @ 20% of O & M labor					$2,943
Supplies:					
Operating @ 30% of operating labor					$3,942
Maintenance @ 40% of 3% of TPI					$2,443
Admin. and Gen. Ovhd. (60% of total labor):					$10,596
Insurance and Taxes (2.7% of TPI):					$5,497
Total Gross Operating Cost					$119,574
District Heat Sales:	steam		19,275 MM Btu	$9.13 /MM Btu	$175,903
Total Net Operating Cost					($56,329)
Payback period in years					3.61

University of Alabama

Fire-tube Boiler

48 % Boiler Capacity Factor

10000 #/ hr Boiler Capacity

8000 #/ hr Derated Boiler Capacity

9.17 MM Btu/hr Average for District Heating

5256 Hours of uses per year

60 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	0 tons	$29 /ton	$0
OIL #2	$7.00	/MM Btu	3,095,260 GAL	$0.136 /GAL	$421,636
Utilities:					
Electricity			215,779 kWhr	$0.05 /kWhr	$10,789
Ash Disposal:			0 tons	$20 /ton	$0
Labor:					
Operating			219 mnhrs	$15 /mnhr	$3,285
Maintenance			66 mnhrs	$15 /mnhr	$986
Supervision @ 20% of O & M labor					$854
Supplies:					
Operating @ 30% of operating labor					$986
Maintenance @ 40% of 3% of TPI					$0
Admin. and Gen. Ovhd. (60% of total labor):					$3,075
Insurance and Taxes (2.7% of TPI):					$0
Total Gross Operating Cost					$441,610
District Heat Sales:	**steam**		48,187 MM Btu	$9.16 /MM Btu	$441,610
Total Net Operating Cost					$0

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	13,250 ACFM	10 "WC	55
ID FAN	0 ACFM	15 "WC	0
PUMP	0 LB/HR	150 PSIG	0
A/C	0 SCFM	125 PSIG	0
MIXER			0
TOTAL HORSE POWER REQUIRED			55

CWS RETROFITTED BOILER

80	% Boiler effciency
8.60	MM Btu/hr Average Rate of Coal Fired
9.17	MM Btu/hr Average for District Heating
0.75	Fractional heat input due to CWS
0.25	Fractional heat input due toNo 2 OIL
9510	CWS HHV in Btu/lb

Major Equipment	$262,287
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$66,067
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$25,799
Subtotal	$597,890
Project Contingency @ 5%	$29,894
Total Plant Investment (TPI)	$627,784

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	2375	tons	$29	/ton	$67,763
#2 OIL	$7.00	/MM Btu	773,815	GAL	$0.136	/GAL	$105,409
Utilities:							
Electricity			542,044	kWhr	$0.05	/kWhr	$27,102
Ash Disposal:			285	tons	$20	/ton	$5,700
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$7,533
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$16,950
Total Gross Operating Cost							$262,656
District Heat Sales:	**steam**		48,187	MM Btu	$9.16	/MM Btu	$441,610
Total Net Operating Cost							($178,954)
Payback period in years							3.51

University of Alabama
Fire-tube Boiler

NEW UNIT QTY 1

48 % Boiler Capacity Factor
10000 #/ hr Boiler Capacity
8000 #/ hr Derated Boiler Capacity
9.17 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$7.00	/MM Btu	2,983,383	GAL	$0.136	/GAL	$406,396
Utilities:							
Electricity			207,980	kWhr	$0.05	/kWhr	$10,399
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$425,980
District Heat Sales:	steam		48,187	MM Btu	$8.84	/MM Btu	$425,980
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	12,771	ACFM	10	"WC	53
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					53

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
8.28 MM Btu/hr Average Rate of Coal Fired
9.17 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$196,715
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$36,469
Engineering/thermal modelling	$150,000
Purchasing	$30,000
Freight/Taxes	$21,151
Subtotal	$448,072
Project Contingency @ 5%	$22,404
Total Plant Investment (TPI)	$470,476

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	2289	tons	$29	/ton	$65,314
#2 OIL	$7.00	/MM Btu	745,846	GAL	$0.136	/GAL	$101,599
Utilities:							
Electricity			522,481	kWhr	$0.05	/kWhr	$26,124
Ash Disposal:			275	tons	$20	/ton	$5,494
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$5,646
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$12,703
Total Gross Operating Cost							$249,078
District Heat Sales:	**steam**		48,187	MM Btu	$8.84	/MM Btu	$425,980
Total Net Operating Cost							($176,902)
Payback period in years							2.66

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
10000 #/ hr Boiler Capacity
8000 #/ hr Derated Boiler Capacity
9.17 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
	$7.00	/MM Btu	2,983,383	GAL	$0.136	/GAL	$406,396
Utilities:							
Electricity			207,980	kWhr	$0.05	/kWhr	$10,399
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$425,980
District Heat Sales:	**steam**		48,187	MM Btu	$8.84	/MM Btu	$425,980
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	12,771	ACFM	10	"WC	53
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					53

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
8.28 MM Btu/hr Average Rate of Coal Fired
9.17 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$157,372
Instruments	$0
Supplies	$13,737
Building (incl. labor)	$0
Construction Labor	$36,469
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$17,777
Subtotal	$285,355
Project Contingency @ 5%	$14,268
Total Plant Investment (TPI)	$299,622

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	2289 tons	$29 /ton	$65,314
#2 OIL	$7.00	/MM Btu	745,846 GAL	$0.136 /GAL	$101,599
Utilities:					
Electricity			522,481 kWhr	$0.05 /kWhr	$26,124
Ash Disposal:			275 tons	$20 /ton	$5,494
Labor:					
Operating			876 mnhrs	$15 /mnhr	$13,140
Maintenance			105 mnhrs	$15 /mnhr	$1,577
Supervision @ 20% of O & M labor					$2,943
Supplies:					
Operating @ 30% of operating labor					$3,942
Maintenance @ 40% of 3% of TPI					$3,595
Admin. and Gen. Ovhd. (60% of total labor):					$10,596
Insurance and Taxes (2.7% of TPI):					$8,090
Total Gross Operating Cost					$242,415
District Heat Sales:	steam		48,187 MM Btu	$8.84 /MM Btu	$425,980
Total Net Operating Cost					($183,566)
Payback period in years					1.63

University of Alabama

Fire-tube Boiler

48 % Boiler Capacity Factor

15000 #/ hr Boiler Capacity

12000 #/ hr Derated Boiler Capacity

13.75 MM Btu/hr Average for District Heating

5256 Hours of uses per year

60 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	0 tons	$29 /ton	$0
OIL #2	$6.00	/MM Btu	4,642,890 GAL	$0.117 /GAL	$542,104
Utilities:					
Electricity			323,669 kWhr	$0.05 /kWhr	$16,183
Ash Disposal:			0 tons	$20 /ton	$0
Labor:					
Operating			219 mnhrs	$15 /mnhr	$3,285
Maintenance			66 mnhrs	$15 /mnhr	$986
Supervision @ 20% of O & M labor					$854
Supplies:					
Operating @ 30% of operating labor					$986
Maintenance @ 40% of 3% of TPI					$0
Admin. and Gen. Ovhd. (60% of total labor):					$3,075
Insurance and Taxes (2.7% of TPI):					$0
Total Gross Operating Cost					$567,472
District Heat Sales:	steam		72,281 MM Btu	$7.85 /MM Btu	$567,472
Total Net Operating Cost					$0

HORSE POWER CHECK

	FLOW	DELTA P	HORSEPOWER
FD FAN	19,875 ACFM	10 "WC	83
ID FAN	0 ACFM	15 "WC	0
PUMP	0 LB/HR	150 PSIG	0
A/C	0 SCFM	125 PSIG	0
MIXER			0
TOTAL HORSE POWER REQUIRED			83

CWS RETROFITTED BOILER

80 % Boiler effciency

12.89 MM Btu/hr Average Rate of Coal Fired

13.75 MM Btu/hr Average for District Heating

0.75 Fractional heat input due to CWS

0.25 Fractional heat input due toNo 2 OIL

9510 CWS HHV in Btu/lb

Major Equipment	$334,527
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$79,180
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$32,651
Subtotal	$693,879
Project Contingency @ 5%	$34,694
Total Plant Investment (TPI)	$728,572

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50	/MM Btu	3563 tons	$29 /ton	$101,644
#2 OIL	$6.00	/MM Btu	1,160,723 GAL	$0.117 /GAL	$135,526
Utilities:					
Electricity			812,674 kWhr	$0.05 /kWhr	$40,634
Ash Disposal:			428 tons	$20 /ton	$8,551
Labor:					
Operating			876 mnhrs	$15 /mnhr	$13,140
Maintenance			105 mnhrs	$15 /mnhr	$1,577
Supervision @ 20% of O & M labor					$2,943
Supplies:					
Operating @ 30% of operating labor					$3,942
Maintenance @ 40% of 3% of TPI					$8,743
Admin. and Gen. Ovhd. (60% of total labor):					$10,596
Insurance and Taxes (2.7% of TPI):					$19,671
Total Gross Operating Cost					$346,967
District Heat Sales:	**steam**		72,281 MM Btu	$7.85 /MM Btu	$567,472
Total Net Operating Cost					($220,505)
Payback period in years					3.30

University of Alabama
Fire-tube Boiler

NEW UNIT QTY 1

48 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$6.00	/MM Btu	4,475,075	GAL	$0.117	/GAL	$522,510
Utilities:							
Electricity			311,970	kWhr	$0.05	/kWhr	$15,598
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$547,293
District Heat Sales:	**steam**		72,281	MM Btu	$7.57	/MM Btu	$547,293
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	19,156	ACFM	10	"WC	80
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					80

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
12.43 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$250,895
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$43,708
Engineering/thermal modelling	$150,000
Purchasing	$30,000
Freight/Taxes	$26,790
Subtotal	$518,913
Project Contingency @ 5%	$25,946
Total Plant Investment (TPI)	$544,859

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	3434	tons	$29	/ton	$97,971
#2 OIL	$6.00	/MM Btu	1,118,769	GAL	$0.117	/GAL	$130,627
Utilities:							
Electricity			783,329	kWhr	$0.05	/kWhr	$39,166
Ash Disposal:			412	tons	$20	/ton	$8,241
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$6,538
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$14,711
Total Gross Operating Cost							$329,454
District Heat Sales:	**steam**		72,281	MM Btu	$7.57	/MM Btu	$547,293
Total Net Operating Cost							($217,839)
Payback period in years							2.50

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
15000 #/ hr Boiler Capacity
12000 #/ hr Derated Boiler Capacity
13.75 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
	$6.00	/MM Btu	4,475,075	GAL	$0.117	/GAL	$522,510
Utilities:							
Electricity			311,970	kWhr	$0.05	/kWhr	$15,598
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$547,293
District Heat Sales:	**steam**		72,281	MM Btu	$7.57	/MM Btu	$547,293
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	19,156	ACFM	10	"WC	80
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					80

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
12.43 MM Btu/hr Average Rate of Coal Fired
13.75 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$200,716
Instruments	$0
Supplies	$17,520
Building (incl. labor)	$0
Construction Labor	$43,708
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$22,486
Subtotal	$344,430
Project Contingency @ 5%	$17,222
Total Plant Investment (TPI)	$361,652

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	3434	tons	$29	/ton	$97,971
#2 OIL	$6.00	/MM Btu	1,118,769	GAL	$0.117	/GAL	$130,627
Utilities:							
Electricity			783,329	kWhr	$0.05	/kWhr	$39,166
Ash Disposal:			412	tons	$20	/ton	$8,241
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$4,340
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$9,765
Total Gross Operating Cost							$322,309
District Heat Sales:	**steam**		72,281	MM Btu	$7.57	/MM Btu	$547,293
Total Net Operating Cost							($224,984)
Payback period in years							1.61

University of Alabama

Fire-tube Boiler

48 % Boiler Capacity Factor

28000 #/ hr Boiler Capacity

22400 #/ hr Derated Boiler Capacity

25.67 MM Btu/hr Average for District Heating

5256 Hours of uses per year

60 % of year in service

No. 2 Oil only

0.00 Fractional heat input due to CWS

80 % efficiency

80 % boiler load

0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$5.00	/MM Btu	8,666,728	GAL	$0.097	/GAL	$843,273
Utilities:							
Electricity			604,181	kWhr	$0.05	/kWhr	$30,209
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$882,667
District Heat Sales:	steam		134,924	MM Btu	$6.54	/MM Btu	$882,667
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	37,099	ACFM	10	"WC	154
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					154

CWS RETROFITTED BOILER

80 % Boiler effciency
24.07 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due toNo 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$486,487
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$105,354
Engineering/thermal modelling	$200,000
Purchasing	$30,000
Freight/Taxes	$46,993
Subtotal	$894,313
Project Contingency @ 5%	$44,716
Total Plant Investment (TPI)	$939,028

Operating Costs

			Annual Use	Cost/Unit	Cost/ Yr
Raw Material:					
CWS	$1.50 /MM Btu		6650 tons	$29 /ton	$189,736
#2 OIL	$5.00 /MM Btu		2,166,682 GAL	$0.097 /GAL	$210,818
Utilities:					
Electricity			1,516,312 kWhr	$0.05 /kWhr	$75,816
Ash Disposal:			798 tons	$20 /ton	$15,961
Labor:					
Operating			876 mnhrs	$15 /mnhr	$13,140
Maintenance			105 mnhrs	$15 /mnhr	$1,577
Supervision @ 20% of O & M labor					$2,943
Supplies:					
Operating @ 30% of operating labor					$3,942
Maintenance @ 40% of 3% of TPI					$11,268
Admin. and Gen. Ovhd. (60% of total labor):					$10,596
Insurance and Taxes (2.7% of TPI):					$25,354
Total Gross Operating Cost					$561,151
District Heat Sales:		**steam**	134,924 MM Btu	$6.54 /MM Btu	$882,667
Total Net Operating Cost					($321,515)
Payback period in years					2.92

University of Alabama
Fire-tube Boiler

NEW UNIT QTY 1

48 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
OIL #2	$5.00	/MM Btu	8,353,473	GAL	$0.097	/GAL	$812,793
Utilities:							
Electricity			582,343	kWhr	$0.05	/kWhr	$29,117
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$851,095
District Heat Sales:	steam		134,924	MM Btu	$6.31	/MM Btu	$851,095
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	35,758	ACFM	10	"WC	149
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					149

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
23.20 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$364,865
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$58,155
Engineering/thermal modelling	$150,000
Purchasing	$30,000
Freight/Taxes	$38,610
Subtotal	$667,109
Project Contingency @ 5%	$33,355
Total Plant Investment (TPI)	$700,465

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	6410	tons	$29	/ton	$182,878
#2 OIL	$5.00	/MM Btu	2,088,368	GAL	$0.097	/GAL	$203,198
Utilities:							
Electricity			1,461,534	kWhr	$0.05	/kWhr	$73,077
Ash Disposal:			769	tons	$20	/ton	$15,384
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$8,406
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$18,913
Total Gross Operating Cost							$534,054
District Heat Sales:	**steam**		134,924	MM Btu	$6.31	/MM Btu	$851,095
Total Net Operating Cost							($317,041)
Payback period in years							**2.21**

University of Alabama
Fire-tube Boiler

NEW UNIT MASS QUANTITY

48 % Boiler Capacity Factor
28000 #/ hr Boiler Capacity
22400 #/ hr Derated Boiler Capacity
25.67 MM Btu/hr Average for District Heating
5256 Hours of uses per year
60 % of year in service

No. 2 Oil only
0.00 Fractional heat input due to CWS
83 % efficiency
80 % boiler load
0 Total Plant Investment

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	0	tons	$29	/ton	$0
	$5.00	/MM Btu	8,353,473	GAL	$0.097	/GAL	$812,793
Utilities:							
Electricity			582,343	kWhr	$0.05	/kWhr	$29,117
Ash Disposal:			0	tons	$20	/ton	$0
Labor:							
Operating			219	mnhrs	$15	/mnhr	$3,285
Maintenance			66	mnhrs	$15	/mnhr	$986
Supervision @ 20% of O & M labor							$854
Supplies:							
Operating @ 30% of operating labor							$986
Maintenance @ 40% of 3% of TPI							$0
Admin. and Gen. Ovhd. (60% of total labor):							$3,075
Insurance and Taxes (2.7% of TPI):							$0
Total Gross Operating Cost							$851,095
District Heat Sales:	**steam**		134,924	MM Btu	$6.31	/MM Btu	$851,095
Total Net Operating Cost							$0

HORSE POWER CHECK

	FLOW		DELTA P		HORSEPOWER
FD FAN	35,758	ACFM	10	"WC	149
ID FAN	0	ACFM	15	"WC	0
PUMP	0	LB/HR	150	PSIG	0
A/C	0	SCFM	125	PSIG	0
MIXER					0
TOTAL HORSE POWER REQUIRED					149

CWS SYSTEM ON NEW BOILER

83 % Boiler effciency
23.20 MM Btu/hr Average Rate of Coal Fired
25.67 MM Btu/hr Average for District Heating
0.75 Fractional heat input due to CWS
0.25 Fractional heat input due to No 2 OIL
9510 CWS HHV in Btu/lb

Major Equipment	$291,892
Instruments	$0
Supplies	$25,479
Building (incl. labor)	$0
Construction Labor	$58,155
Engineering/thermal modelling	$50,000
Purchasing	$10,000
Freight/Taxes	$32,351
Subtotal	$467,877
Project Contingency @ 5%	$23,394
Total Plant Investment (TPI)	$491,271

Operating Costs

			Annual Use		Cost/Unit		Cost/ Yr
Raw Material:							
CWS	$1.50	/MM Btu	6410	tons	$29	/ton	$182,878
#2 OIL	$5.00	/MM Btu	2,088,368	GAL	$0.097	/GAL	$203,198
Utilities:							
Electricity			1,461,534	kWhr	$0.05	/kWhr	$73,077
Ash Disposal:			769	tons	$20	/ton	$15,384
Labor:							
Operating			876	mnhrs	$15	/mnhr	$13,140
Maintenance			105	mnhrs	$15	/mnhr	$1,577
Supervision @ 20% of O & M labor							$2,943
Supplies:							
Operating @ 30% of operating labor							$3,942
Maintenance @ 40% of 3% of TPI							$5,895
Admin. and Gen. Ovhd. (60% of total labor):							$10,596
Insurance and Taxes (2.7% of TPI):							$13,264
Total Gross Operating Cost							$525,895
District Heat Sales:	**steam**		134,924	MM Btu	$6.31	/MM Btu	$851,095
Total Net Operating Cost							($325,200)
Payback period in years							1.51