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COMBUSTION AND FUEL CHARACTERIZATION OF COAL-WATER FUELS

Volume 6

Commercial Application and Economics of Coal-Water Fuels

By
H. R. Beal
G. W. Gralton
T. W. Gronauer
G. N. Liljedahl
B. F. Love

June 1987

Work Performed Under Contract No. AC22-82PC50271

For
U.S. Department of Energy
Pittsburgh Energy Technology Center
Pittsburgh, Pennsylvania

By
Combustion Engineering, Inc.
Windsor, Connecticut

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VOLUME 6

COMMERCIAL APPLICATION AND ECONOMICS OF COAL-WATER FUELS

PREPARED BY

COMBUSTION ENGINEERING, INC.

WINDSOR, CONNECTICUT 06095

PROJECT MANAGER

M. J. HARGROVE

PRINCIPAL INVESTIGATORS

H. R. BEAL
G. W. GRALTON
T. W. GRONAUER
G. N. LILJEDAHL
B. F. LOVE

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U. S. DEPARTMENT OF ENERGY
PITTSBURGH ENERGY TECHNOLOGY CENTER

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1. INTRODUCTION

Coal-Water Fuels (CWF) offer a potential means of shifting energy dependence from imported oil to domestic coals while reducing the cost of operating commercial oil-fired boilers. There remain, however, unanswered questions concerning the impact which these coal-based, ash producing fuels will have on boilers originally designed for ash-free fuels. The economic viability of CWF firing also requires further investigation. In order to address these issues, Combustion Engineering, under the sponsorship of the Department of Energy, has embarked on a five-year project. Under this project C-E has teamed with Gulf Research and Development, a major subcontractor, to investigate the various aspects of CWF behavior. Activities conducted under the DOE contract include studies on the combustion and fireside behavior of numerous CWFs. The work has been broken down into the following areas:

Task 1 - Selection of Candidate Fuels
Task 2 - Bench Scale Tests
Task 3 - CWF Preparation and Supply
Task 4 - Combustion Characterization
Task 5 - Ash Deposition and Performance Testing
Task 6 - Commercial Applications

This report covers Task 6, the study of commercial applications of CWFs as related to the technical and economic aspects of the conversion of existing boilers and heaters to CWF firing. This work involves the analysis of seven units of various sizes and configurations firing several selected CWFs. Three utility boilers, two industrial boilers, and two process heater designs are included. Each of the units was considered with four primary selected CWFs. A fifth fuel was considered for one of the utility units. A sixth fuel, a microfine grind CWF, was evaluated on two utility units and one industrial unit. The particular fuels were chosen with the objective of examining the effects of coal source, ash level, ash properties, and beneficiation on the CWF performance and economics of the seven units. Based on the results of comprehensive pilot-scale testing conducted as part of Tasks 1 through 5, a set of CWF performance guidelines was developed. These guidelines were employed to estimate the performance of each fuel-unit combination. The principal result of these predictions was the load derating requirement expected for each combination. Once a load derating was established for each combination, a retrofit specification was written. Retrofit cost estimates were then developed. The retrofit costs, along with assumed CWF costs, operating costs and unit derating, were used to perform a series of economic analyses. Conclusions were drawn regarding the following aspects of CWF technology:

- Expected load deratings as affected by CWF characteristics and boiler design.
- Typical retrofit scope and costs as influenced by CWF and unit type.
- Economic incentives for CWF conversion as a function of cost and quality of CWF, oil price, and unit type.

Additional information on other project tasks regarding technical approaches, test equipment, test procedures, test data and analyses relating to specific aspects of the work are provided in the following volumes.

Volume 1 -	Task 1: to 6	Final Summary Report
Volume 2 -	Task 1:	Selection and Procurement of Candidate & Task 3 Coal-Water Fuels with Commercial Potential
Volume 3 -	Task 2:	Bench-Scale Characterization of Chemical, Physical and Combustion Properties of Coal-Water Fuels

Volume 4 - Task 4: Commercial-Scale Atomizer and Burner Evaluation

Volume 5 - Task 5: Pilot-Scale Ash Deposition and Performance Testing of Coal-Water Fuels

2. SUMMARY

This study of retrofit applications shows that from a technical standpoint all seven units considered appear capable of conversion to coal-water fuel (CWF) operation. The potential problems associated with CWF firing can apparently be handled with proper application of current technology, combined with the knowledge gained from results of the other tasks of this project. This study has shown, however, that considerations beyond the strictly technical ones can make CWF conversion a marginal proposition. It was found that factors such as load derating requirements, long economic payback periods, and reduced unit availability can make CWF conversion of specific units with some fuels an infeasible means of reducing dependence on oil as a primary fuel. For most cases considered, the assumed differential fuel costs between oil and CWF played a critical role in the overall desirability of a CWF conversion project. Differential fuel costs (DFC's) ranging from \$1.00 to \$2.00 per 10^6 Btu were analyzed. The following summary brings out some of the principal findings of the study for assumed DFC's of \$1.00/10^6 BTU and \$2.00/10^6 BTU and a "favorable" choice of CWF (in this case Splash Dam 5.7% ash):

Unit	Type	Estimated Max CWF Load (%)	Payback Period (yrs)	
			DFC=1	DFC=2
A	Utility-Close-coupled Screen	74	6.5	2.7
B	Utility-Box	50	6.6	2.7
C	Utility-Close-Coupled Arch	73	2.3	1.0
D	Industrial-Shop-Assembled	30	14.5	6.3
E	Industrial-Modular, Field Assembled	54	5.4	2.4
F	Process Heater-Vertical Cylindrical	100	10.0	4.3
G	Process Heater-Horizontal Cabin	100	7.6	3.4

The summary shows that the close-coupled arch unit (Unit C) is the best candidate for CWF conversion for the Splash Dam 5.7% ash CWF. Ranked below Unit C in suitability are the other utility units and the modular industrial unit. This group of units could be suitable candidates if DFC's rise in the future. It does not appear likely that the process units or shop-assembled industrial units will be good candidates regardless of differential fuel costs. In addition, process heaters generally have high availability requirements, which could be difficult to meet when firing CWF's.

The scope of conversion work varied considerably from unit to unit and from fuel to fuel. For most cases the retrofit work would be extensive, involving fuel handling and storage, boiler island modifications, particulate removal equipment, SO_2 scrubbers (for some fuels), ash collection systems, and other miscellaneous changes. The choice of CWF has some impact on conversion costs, as does the degree to which the unit resembles a "future coal" design.

3. SELECTION AND DESCRIPTION OF THE STUDY UNITS

Seven major fuel burning installations designed for oil or gas, representing three generic classes of oil/gas fired equipment, were selected for CWF performance and economic evaluations. The seven selections are categorized as follows:

- o 3 Utility steam generators
- o 2 Industrial steam generators
- o 2 Process heaters

In this section boiler population characteristics are illustrated, and the selection criteria used are discussed for each equipment category. The selection criteria were defined such that the selected study units are representative of as large a market share as is possible.

3.1 DESCRIPTION OF THE UNITS

The seven units selected for the Task 6 Commercial Application analysis include three utility, two industrial, and two process heater designs. The major characteristics of these units are listed below:

UNIT DESIGNATION	CONFIGURATION	NAMEPLATE CAPACITY (MWe)	MAIN STEAM CAPACITY (10^3 lb/hr)	FIRING RATE (10^6 Btu/hr)
A	Close-coupled Screen	600	4,200	5460
B	Box	400	2,833	4231
C	Close-coupled Arch	850	6,300	7844
D	VU-60 Modular	—	400	527/544
E	Type-A Shop-assembled	—	100	113.5
F	Vert. Cylinder Process Heater	—	494*	71
G	Horiz. Cabin Process Heater	—	466*	142

* NOTE-The process heaters generate heated process fluids rather than steam.

These units were selected to represent a wide range of boiler types and sizes. This variety of capacities and configurations will permit conclusions to be drawn on the suitability of CWF conversion for several generic types of boilers. The selection criteria used to choose the study units include:

* Originally designed for oil and/or gas firing (without any "Future Coal" provision).

* Currently fires oil (or some other low ash fuel).

* At least 20 years of plant life remains.

* Configurations and sizes represent a significant portion of possible CWF conversion candidates.

A summary of the principal characteristics of each unit follows.

UNIT A

USE: Utility Steam Generator
CONFIGURATION: Close-coupled Screen (See Figure 3-1)
PLANT ELECTRICAL CAPACITY: 600 MW
MANUFACTURER: Combustion Engineering
ORIGINAL FUEL: No. 6 Oil
FIRING SYSTEM: Tilting Tangential Burners (5 Elevations)
STEAM TEMP CONTROL: Burner Tilt, Gas Recirculation,
MAIN STEAM FLOW: 4,200,000 lb/hr
MAIN STEAM TEMP.: 1005°F
MAIN STEAM PRESS.: 2,600 psig
REHEAT STEAM FLOW: 3,881,000 lb/hr
REHEAT STEAM TEMP.: 1005°F
REHEAT STEAM PRESS.: 607 psig
AIR PREHEATERS: Two Regenerative Plus Steam Coils
FLUEGAS CLEANUP: Electrostatic Precipitators

UNIT B

USE: Utility Steam Generator
CONFIGURATION: Box (See Figure 3-2)
PLANT ELECTRICAL CAPACITY: 400 MW
MANUFACTURER: Combustion Engineering
ORIGINAL FUEL: No. 6 Oil
FIRING SYSTEM: Tilting Tangential Burners (4 Elevations)
STEAM TEMP CONTROL: Burner Tilt, Superheat and Reheat Spray
MAIN STEAM FLOW: 2,833,000 lb/hr
MAIN STEAM TEMP.: 955°F
MAIN STEAM PRESS.: 1980 psig
REHEAT STEAM FLOW: 2,734,000 lb/hr
REHEAT STEAM TEMP.: 955°F
REHEAT STEAM PRESS.: 447 psig
AIR PREHEATERS: Steam Coil
FLUEGAS CLEANUP: Electrostatic Precipitators

UNIT C

USE: Utility Steam Generator
CONFIGURATION: Close-coupled Arch (See Figure 3-3)
PLANT ELECTRICAL CAPACITY: 850 MW
MANUFACTURER: Foster Wheeler
ORIGINAL FUEL: No. 6 Oil
FIRING SYSTEM: Wall-fired Burners (32)
STEAM TEMP CONTROL: Gas Recirculation, Gas Pass Baffling, Superheat and Reheat Spray
MAIN STEAM FLOW: 6,300,000 lb/hr
MAIN STEAM TEMP.: 1005°F
MAIN STEAM PRESS.: 2480 psig
REHEAT STEAM FLOW: 5,722,000 lb/hr
REHEAT STEAM TEMP.: 1005°F
REHEAT STEAM PRESS.: 693 Psig
AIR PREHEATER: Two Regenerative Plus Two Hot Water Coils Plus Two Glycol Heaters
FLUEGAS CLEANUP: Electrostatic Precipitators

UNIT D

USE: Industrial Saturated Steam Generator
CONFIGURATION: Type-A Shop-assembled (See Figure 3-4)
MANUFACTURER: Combustion Engineering
ORIGINAL FUEL: No. 6 Oil
FIRING SYSTEM: Wall-Fired Burners (2)
STEAM TEMP CONTROL: None Required
MAIN STEAM FLOW: 100,000 lb/hr
MAIN STEAM TEMP.: 388°F (Saturated)
MAIN STEAM PRESS.: 200 psig
AIR PREHEATERS: None
FLUEGAS CLEANUP: None

UNIT E

USE: Industrial Steam Generator
CONFIGURATION: VU-60 Modular (See Figure 3-5)
MANUFACTURER: Combustion Engineering
ORIGINAL FUELS: (1) 90% Pyrolysis Oil Plus 10% Fuel Gas
(2) 90% Distillate Oil Plus 10% Fuel Gas
PRESENT FUEL: Natural Gas
FIRING SYSTEM: Tangential Burners (2 Elevations)
STEAM TEMP CONTROL: Superheat Spray
MAIN STEAM FLOW: 400,000 lb/hr
MAIN STEAM TEMP.: 910°F
MAIN STEAM PRESS.: 1550 psig
AIR PREHEATERS: Regenerative
FLUEGAS CLEANUP: Tubular Dust Collector

UNIT F

USE: Crude Oil Heater
CONFIGURATION: Vertical Cylindrical (See Figure 3-6)
DESIGNER: Lummus
ORIGINAL FUEL: By-products Oil
FIRING SYSTEM: Hearth-fired Vertical Burners (8)
PROCESS TEMP CONTROL: Firing Rate
PROCESS FLUID FLOW: 494,000 lb/hr
FIRING RATE: 71×10^6 Btu/hr
AIR PREHEATER: Regenerative
FLUEGAS CLEANUP: None

UNIT G

USE: Crude Oil Heater
CONFIGURATION: Horizontal Cabin (See Figure 3-7)
DESIGNER: Lummus
ORIGINAL FUEL: By-products Oil
FIRING SYSTEM: Hearth-fired Vertical Burners (20)
PROCESS TEMP CONTROL: Firing Rate
PROCESS FLUID FLOW: 466,000 lb/hr
FIRING RATE: 142×10^6 Btu/hr
AIR PREHEATER: Regenerative
FLUEGAS CLEANUP: None

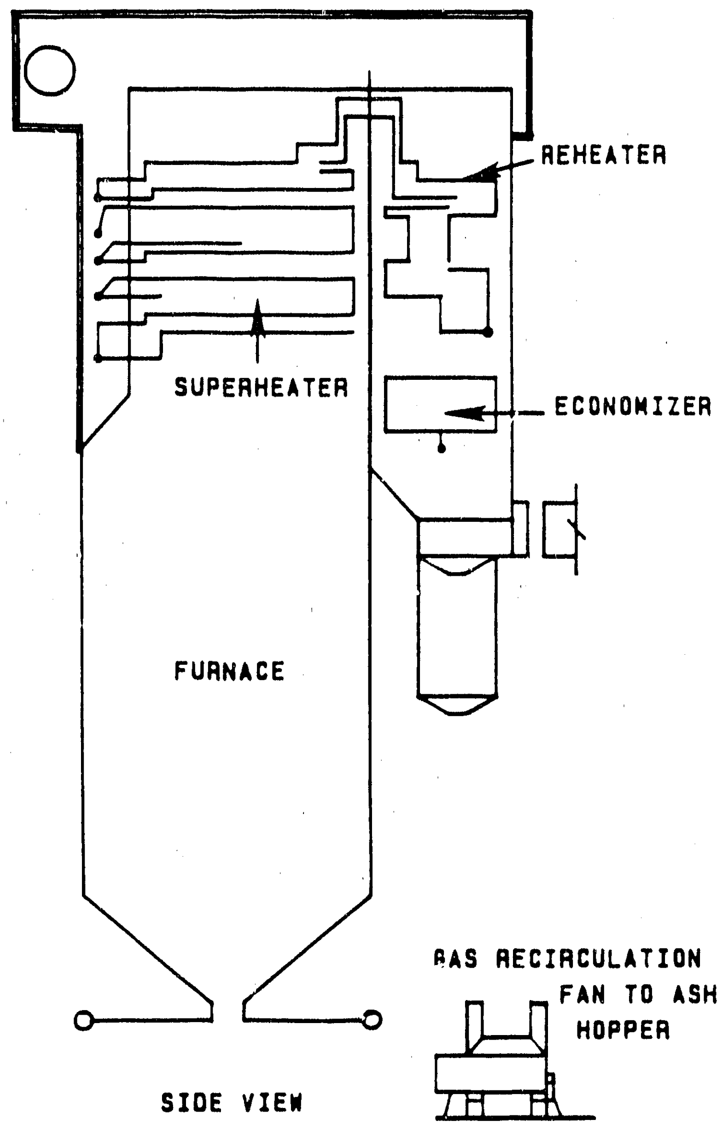


FIGURE 3-1
UNIT A
UTILITY STEAM GENERATOR
CLOSE-COUPLED SCREEN

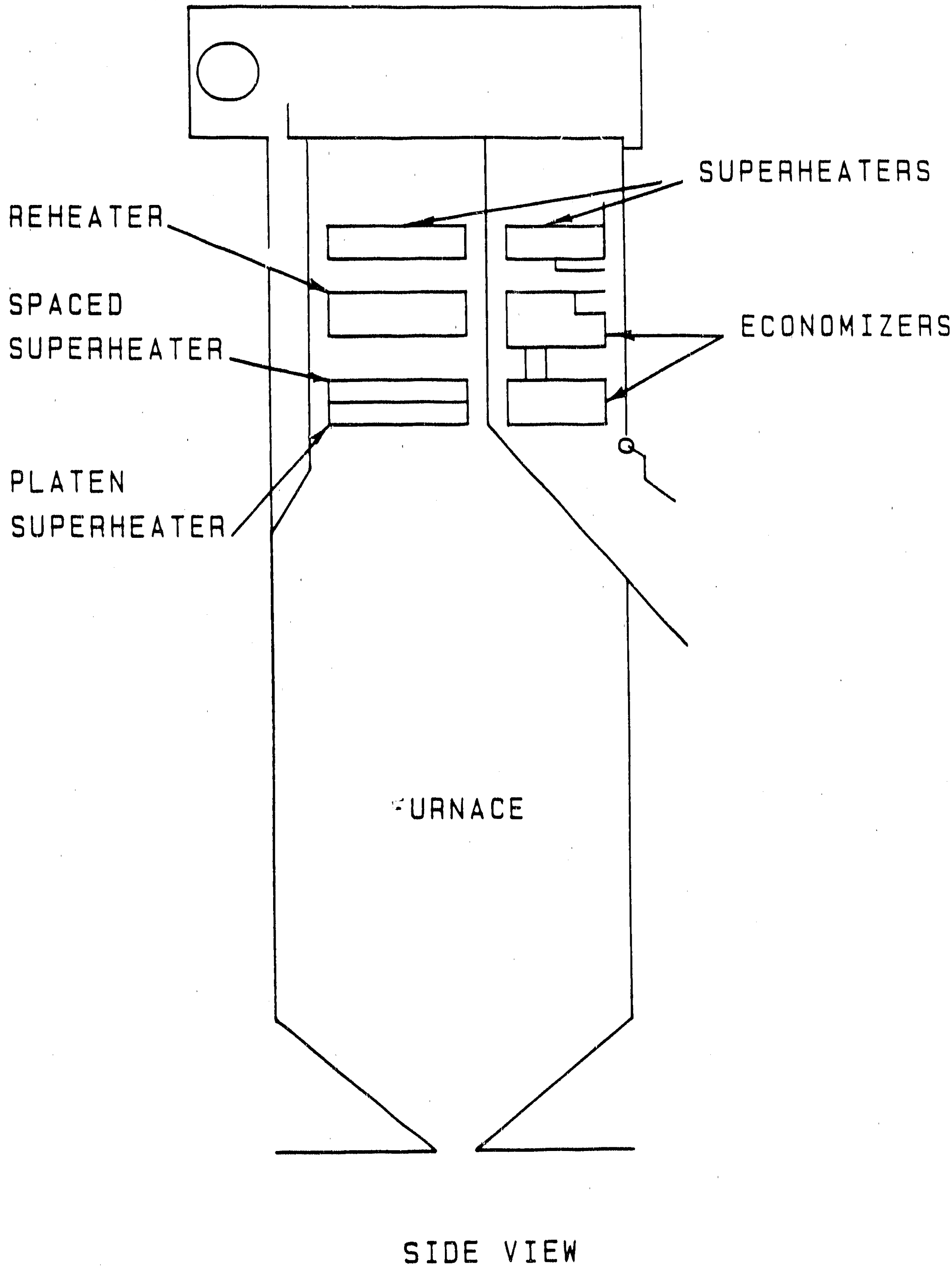


FIGURE 3-2
UNIT B
UTILITY STEAM GENERATOR BOX

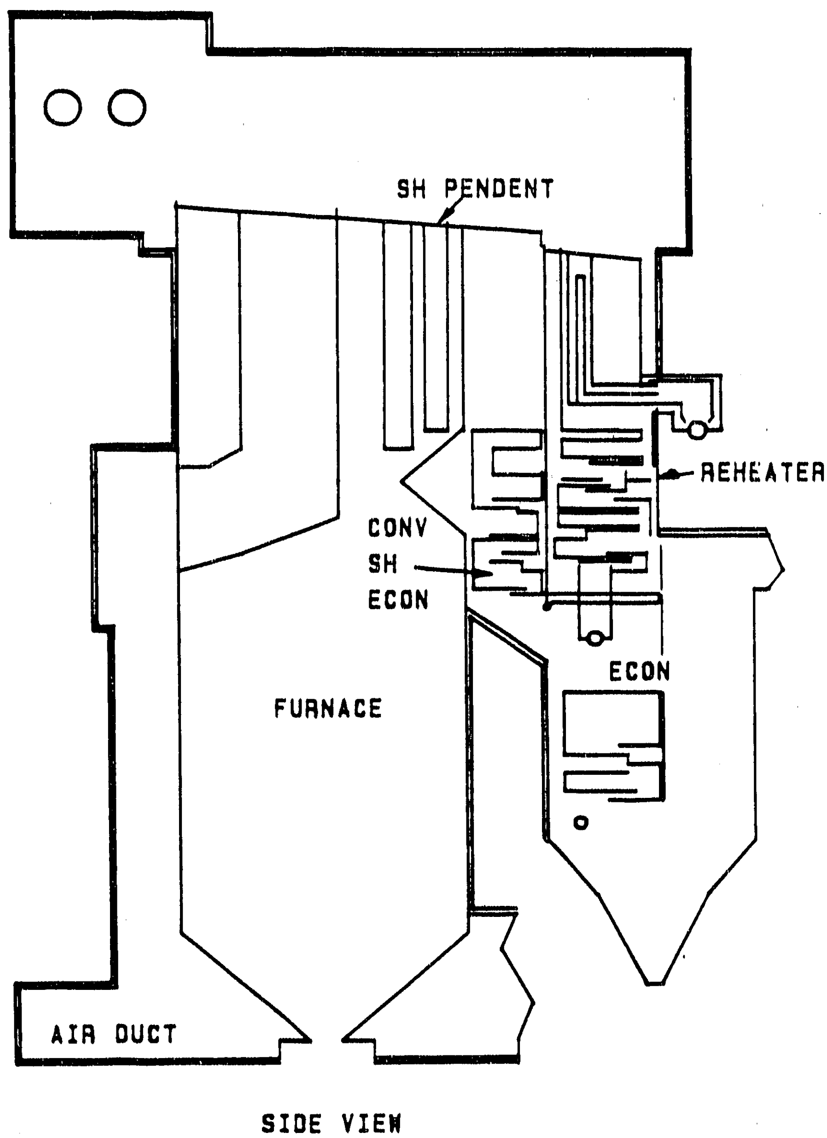


FIGURE 3-3
UNIT C
UTILITY STEAM GENERATOR
CLOSE-COUPLED ARCH

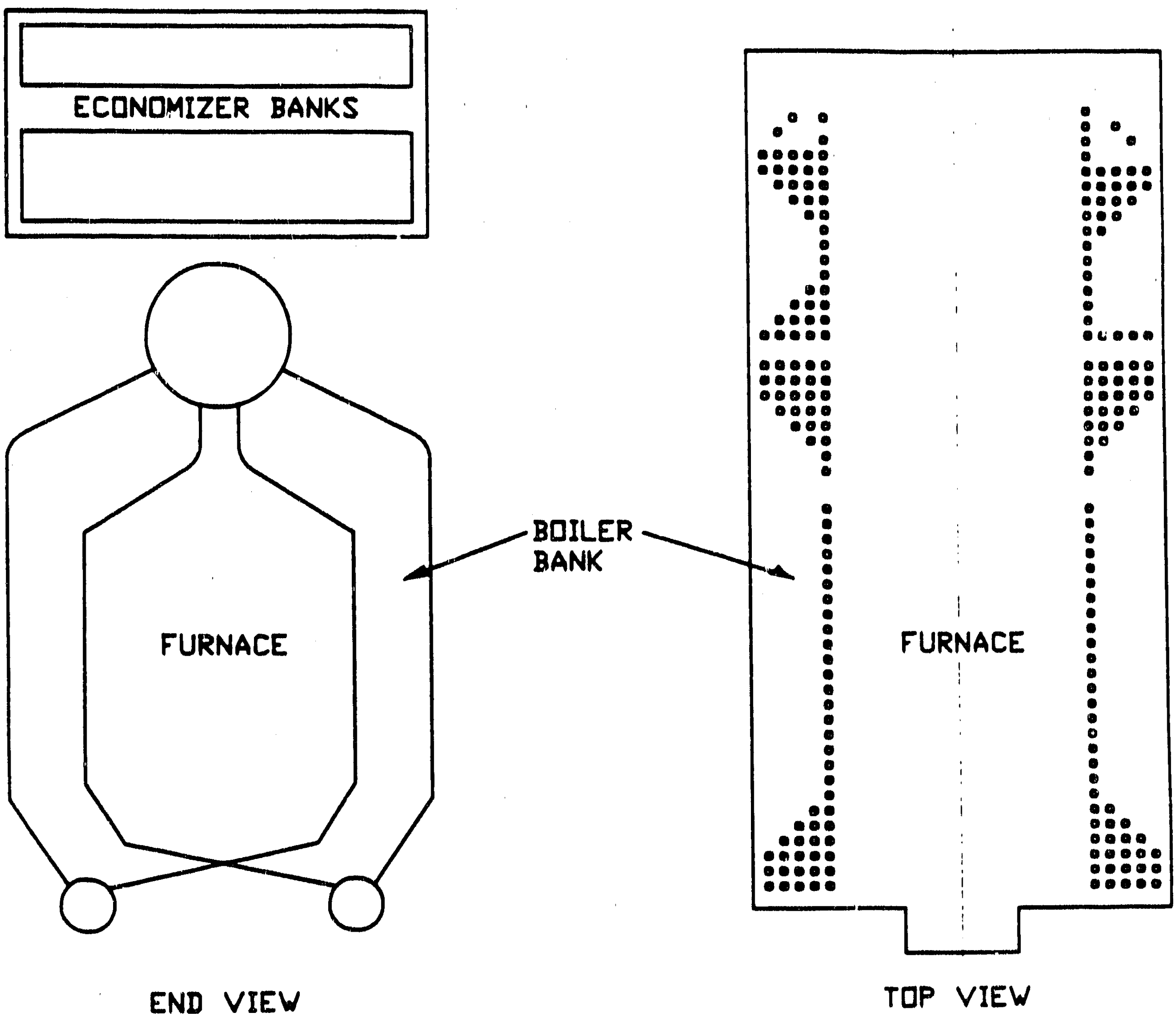


FIGURE 3-4
UNIT D
INDUSTRIAL SHOP-ASSEMBLED STEAM GENERATOR

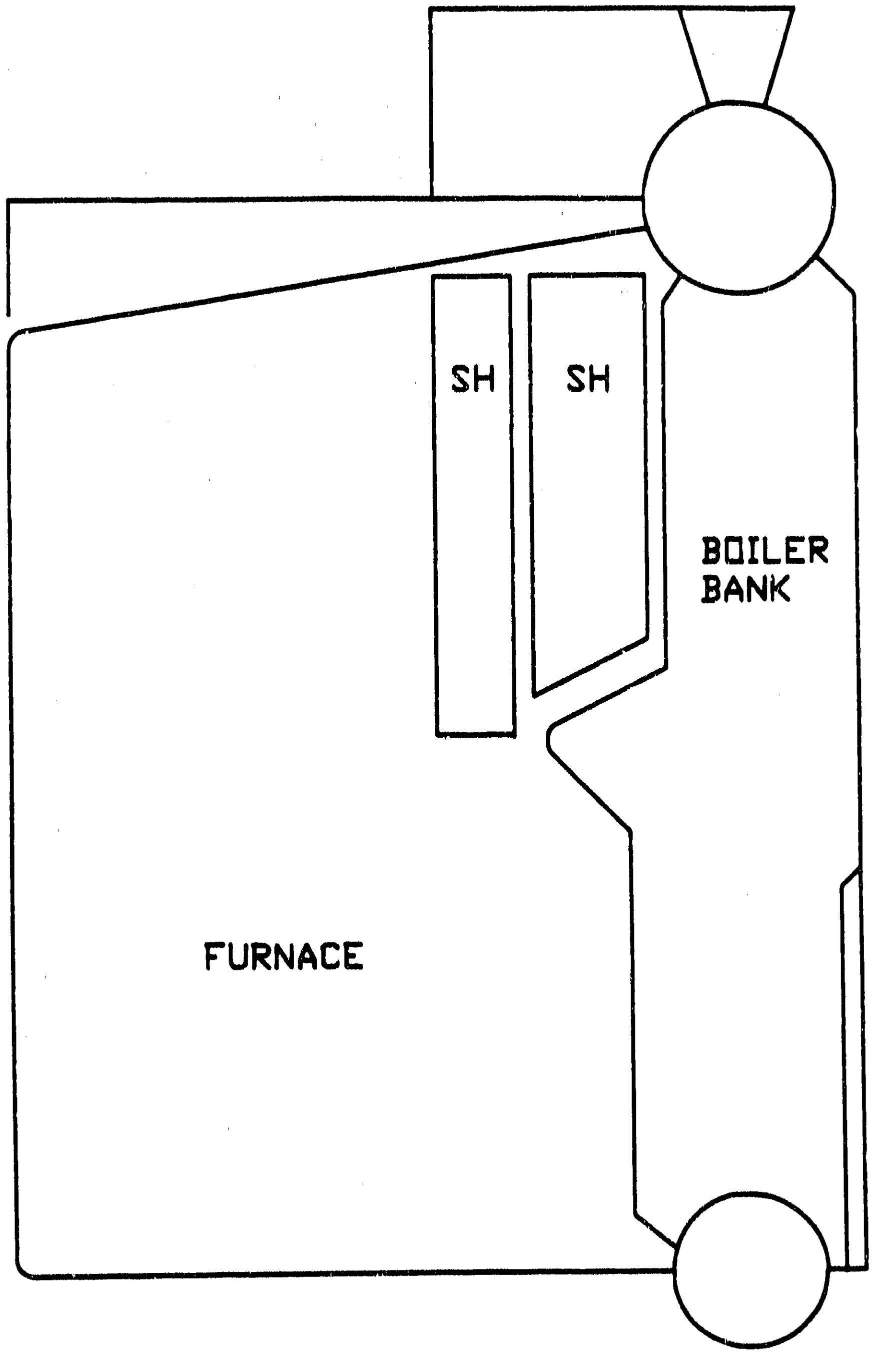


FIGURE 3-5
UNIT E
INDUSTRIAL STEAM GENERATOR MODULAR

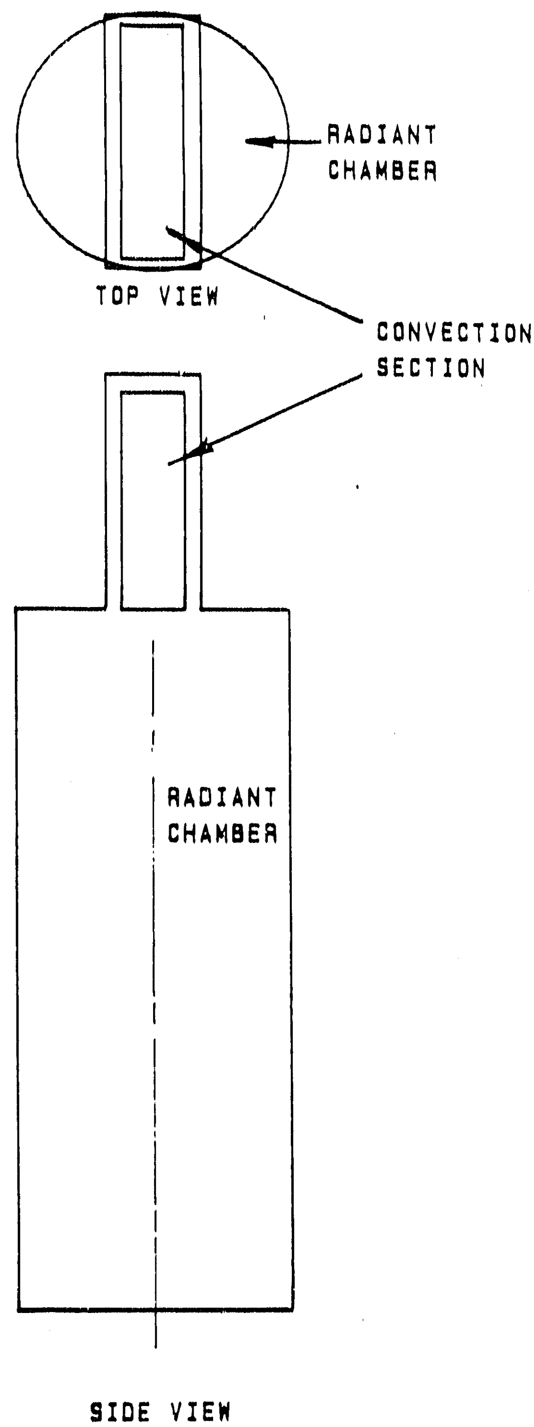


FIGURE 3-6
UNIT F
VERTICAL CYLINDRICAL CRUDE OIL HEATER

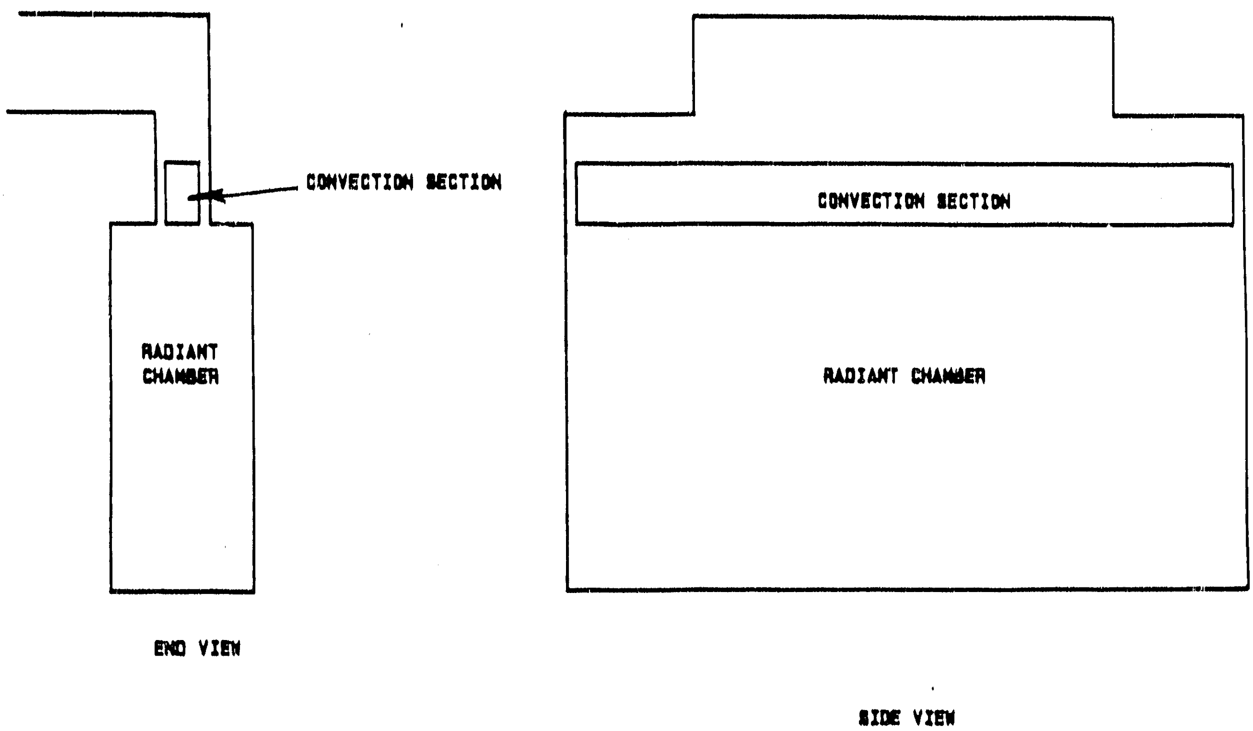


FIGURE 3-7
UNIT G
HORIZONTAL CABIN CRUDE OIL HEATER

3.2 DESCRIPTION OF THE UTILITY BOILER POPULATION

A review was made of the domestic utility oil and gas fired boiler population. The results were then used as a study unit selection aid such that the study units would be well-representative of this market. The survey was limited according to the following criteria:

- o Units are of the domestic utility class
- o Units are designed for oil and/or gas
- o Units were sold since 1960

These basic criteria define a population which consists of about 220 units and 82,000 MW capacity sold by the three major utility boiler manufacturers. The surveyed boiler units were grouped according to unit size, year of order, steam pressure, and unit configuration. The survey results are shown in Figures 3-8 through 3-17.

Figures 3-8, 3-9 and 3-10 indicate that for three major boiler manufacturers, 22% of the total utility oil and gas-fired capacity is in units of 150 to 350 MWe size, 35% is in units of 350 to 550 MWe size, and 20% is in units of 650 to 850 MWe size. Figures 3-11, 3-12 and 3-13 indicate that the largest share of the market (represented by three major boiler manufacturers) belongs to units ordered between 1965 and 1970. Figures 3-14, 3-15, and 3-16, showing the total capacity versus the superheater outlet pressure for units sold by three major boiler manufacturers, indicate that the great majority of units fall in the range of 2400 to 2800 psia.

Figure 3-17 indicates that the majority of units sold by Combustion Engineering were box and close-coupled screen type units. A fairly large number of close-coupled arch units have also been sold by C-E since 1960. (Capacity versus configuration summaries were not developed for boilers sold by Foster Wheeler or Babcock and Wilcox.) The C-E boiler types are illustrated in Figure 3-18.

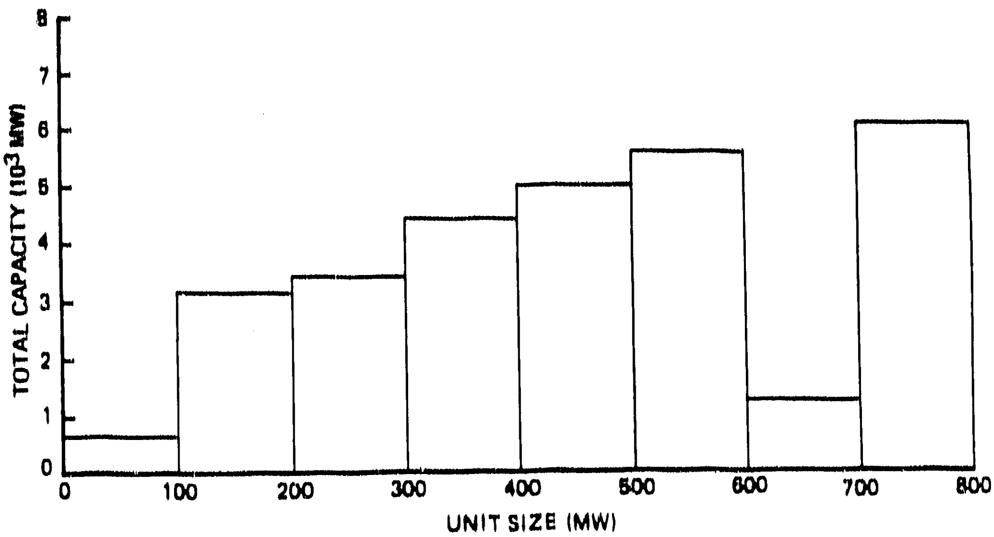


Figure 3-8 TOTAL CAPACITY vs UNIT SIZE – BABCOCK AND WILCOX DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

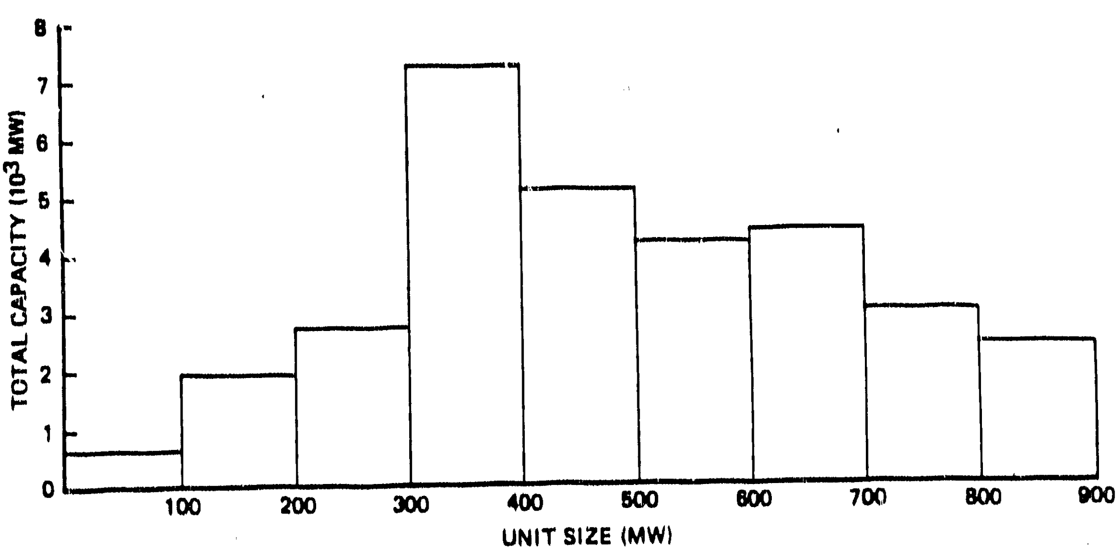


Figure 3-9 TOTAL CAPACITY vs UNIT SIZE – COMBUSTION ENGINEERING DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

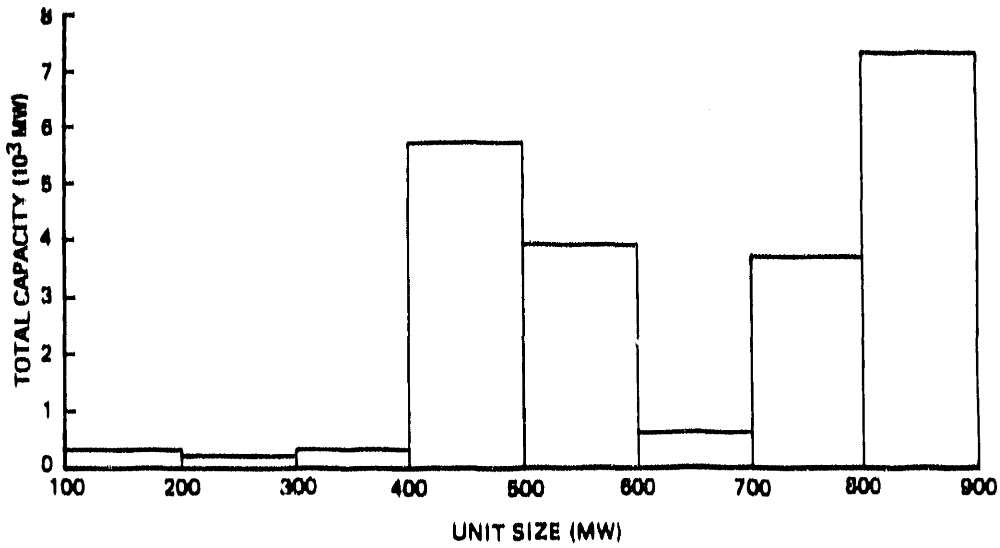


Figure 3-10 TOTAL CAPACITY vs UNIT SIZE – FOSTER WHEELER DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

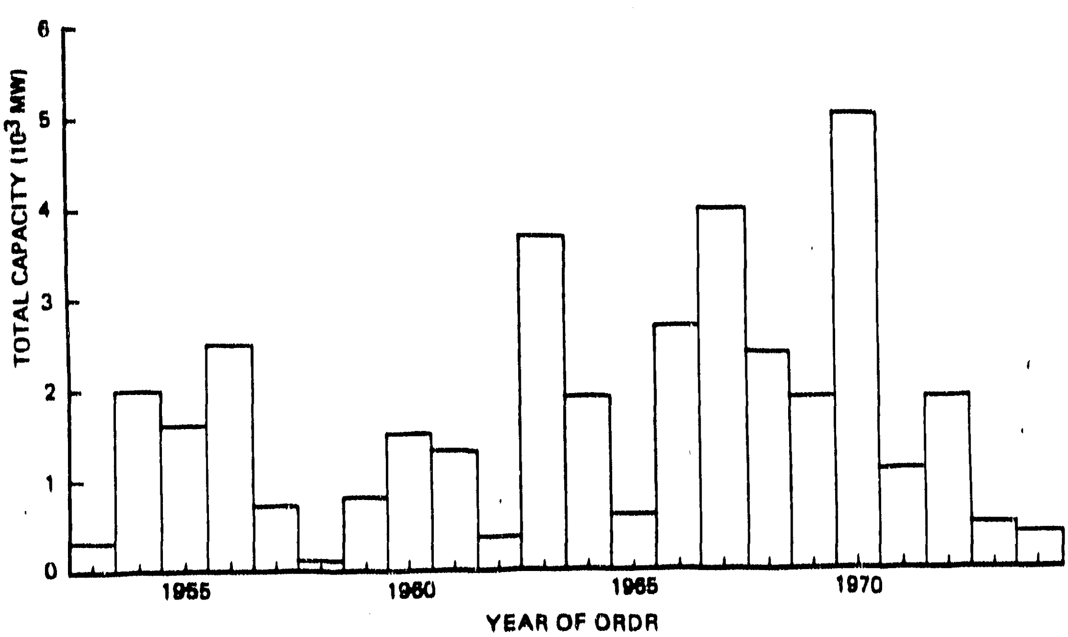


Figure 3-11 TOTAL CAPACITY vs YEAR OF ORDER – BABCOCK AND WILCOX DOMESTIC UNITS (Oil and Gas Units)

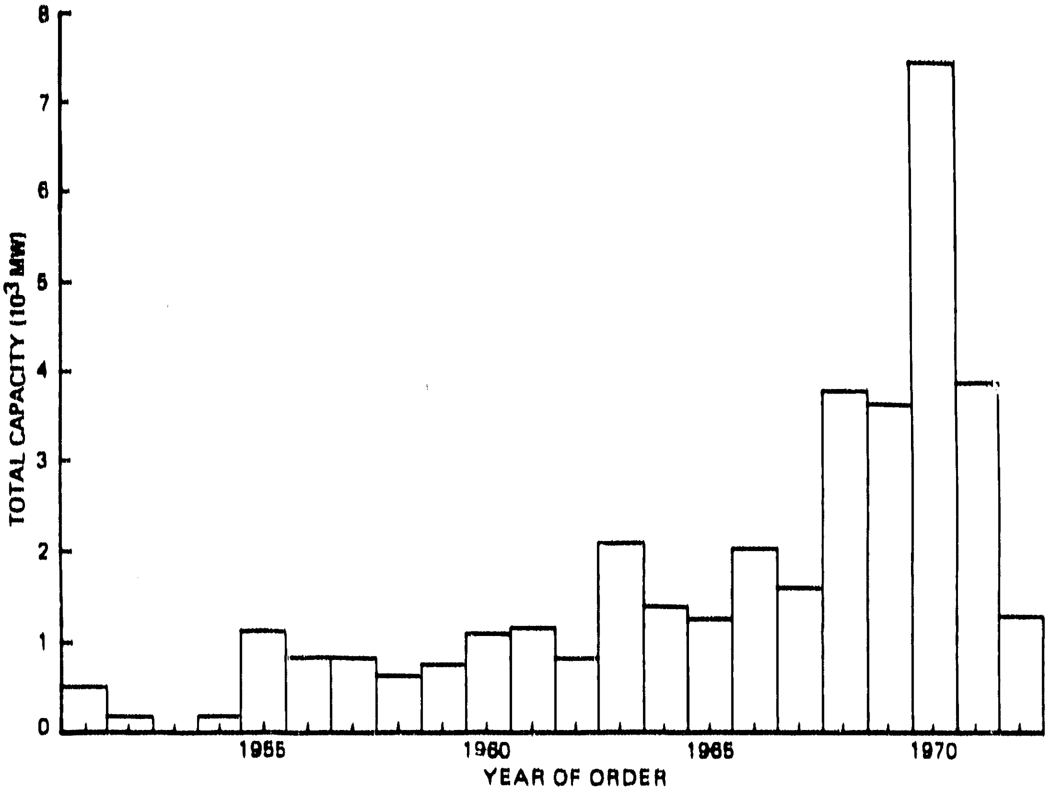


Figure 3-12 TOTAL CAPACITY vs YEAR OF ORDER – COMBUSTION ENGINEERING DOMESTIC UNITS (Oil and Gas Units)

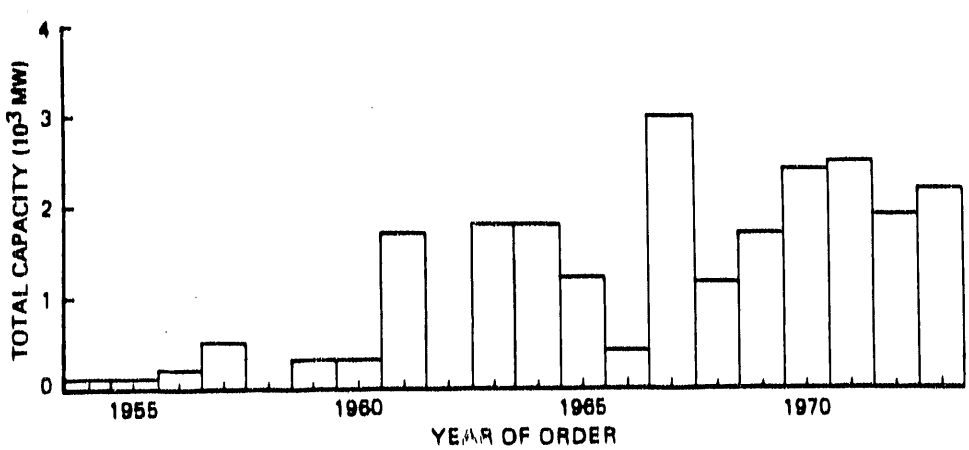


Figure 3-13 TOTAL CAPACITY vs YEAR OF ORDER – FOSTER WHEELER DOMESTIC UNITS (Oil and Gas Units)

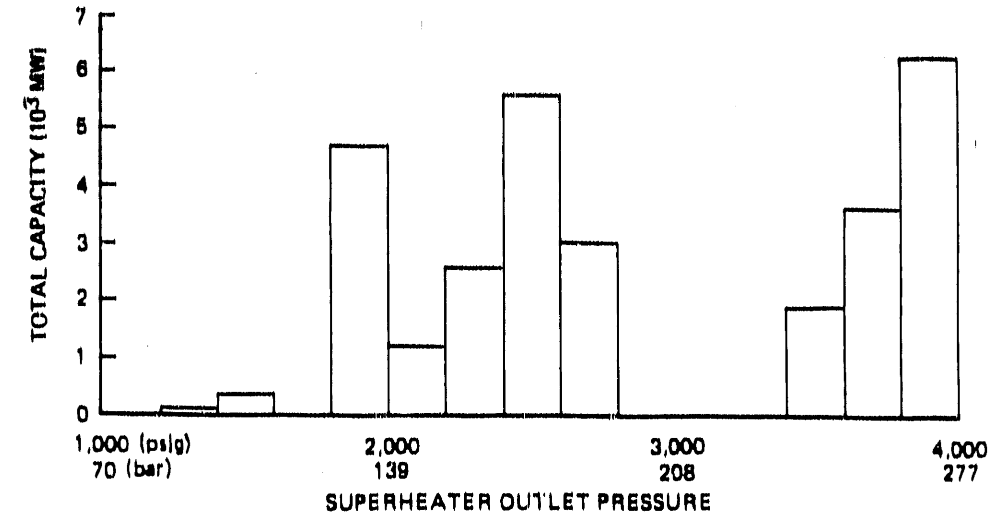


Figure 3-14 TOTAL CAPACITY vs SUPERHEATER OUTLET PRESSURE – BABCOCK AND WILCOX DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

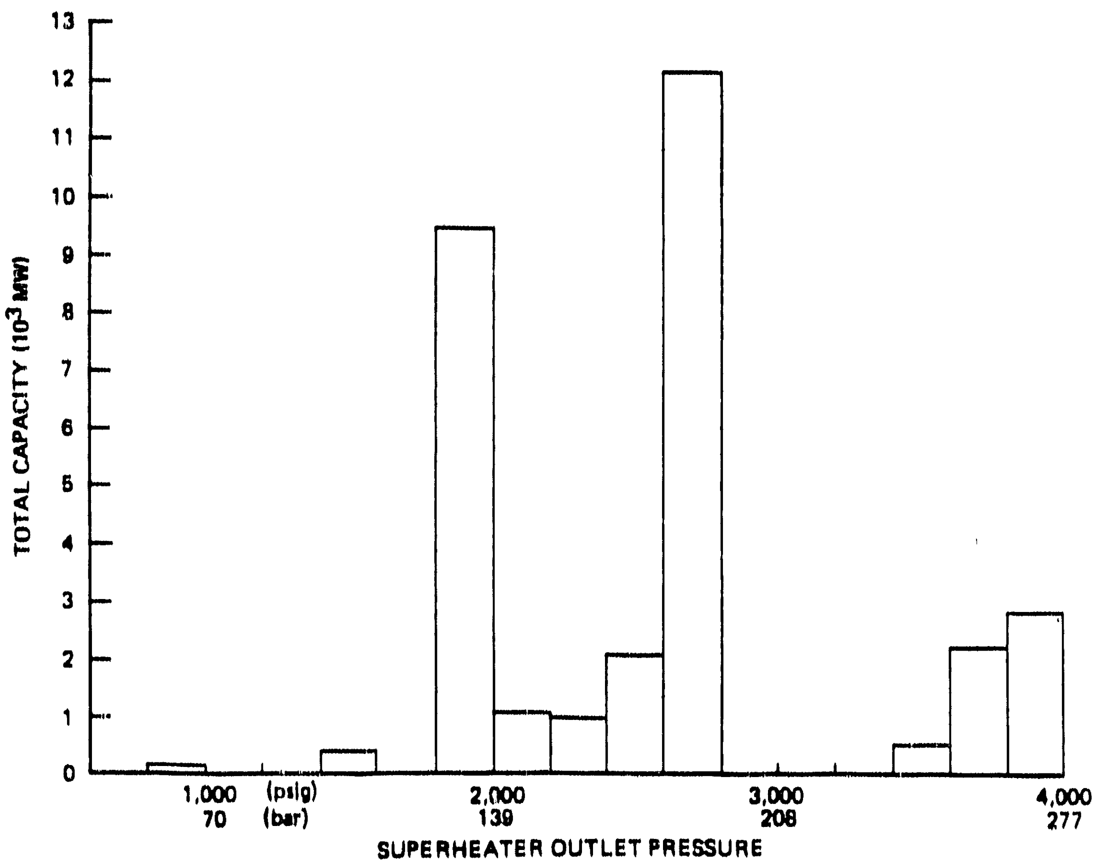


Figure 3-15 TOTAL CAPACITY vs SUPERHEATER OUTLET PRESSURE – COMBUSTION ENGINEERING DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

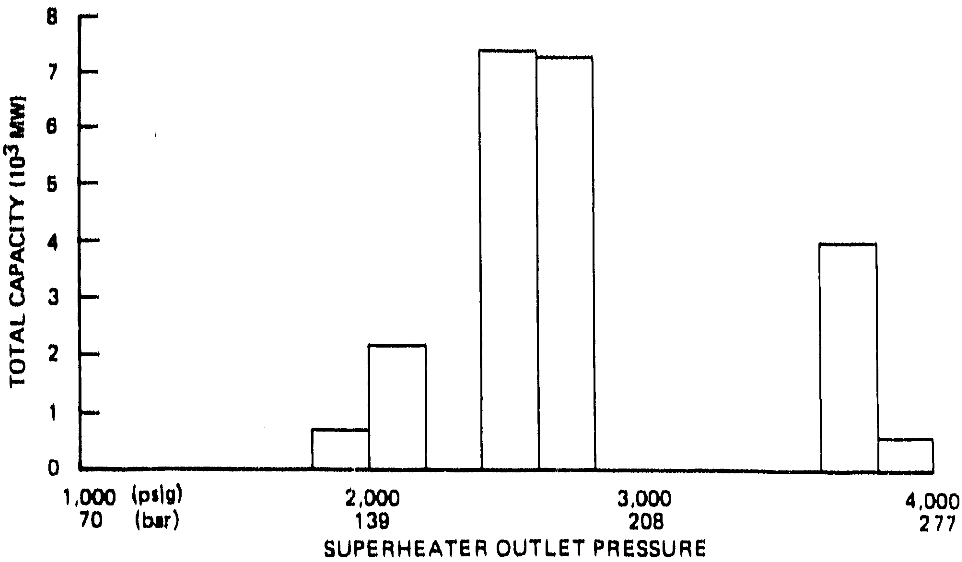


Figure 3-16 TOTAL CAPACITY vs SUPERHEATER OUTLET PRESSURE – FOSTER WHEELER DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

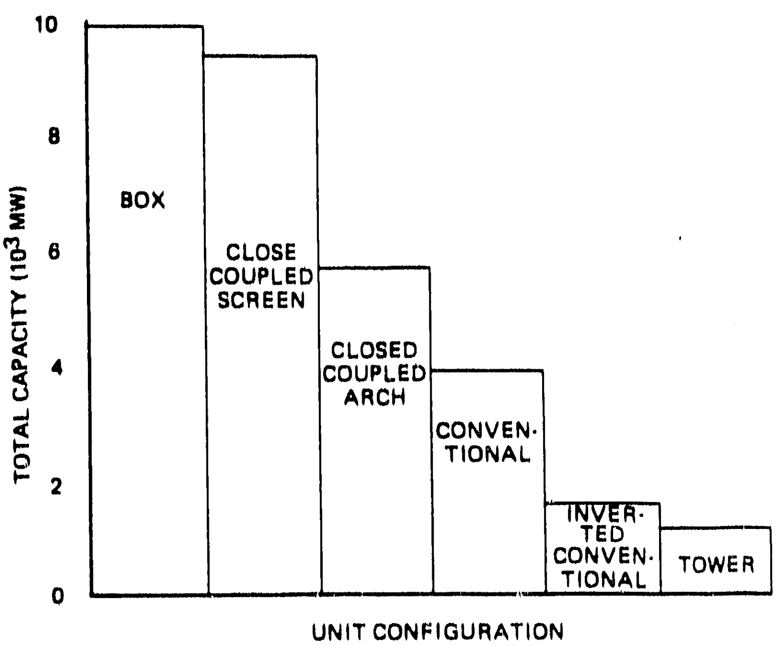


Figure 3-17 TOTAL CAPACITY vs BOILER CONFIGURATION – COMBUSTION ENGINEERING DOMESTIC UNITS (Oil and Gas Units Ordered Since 1960)

STANDARD
UTILITY STEAM GENERATOR
UNIT DESIGNATIONS

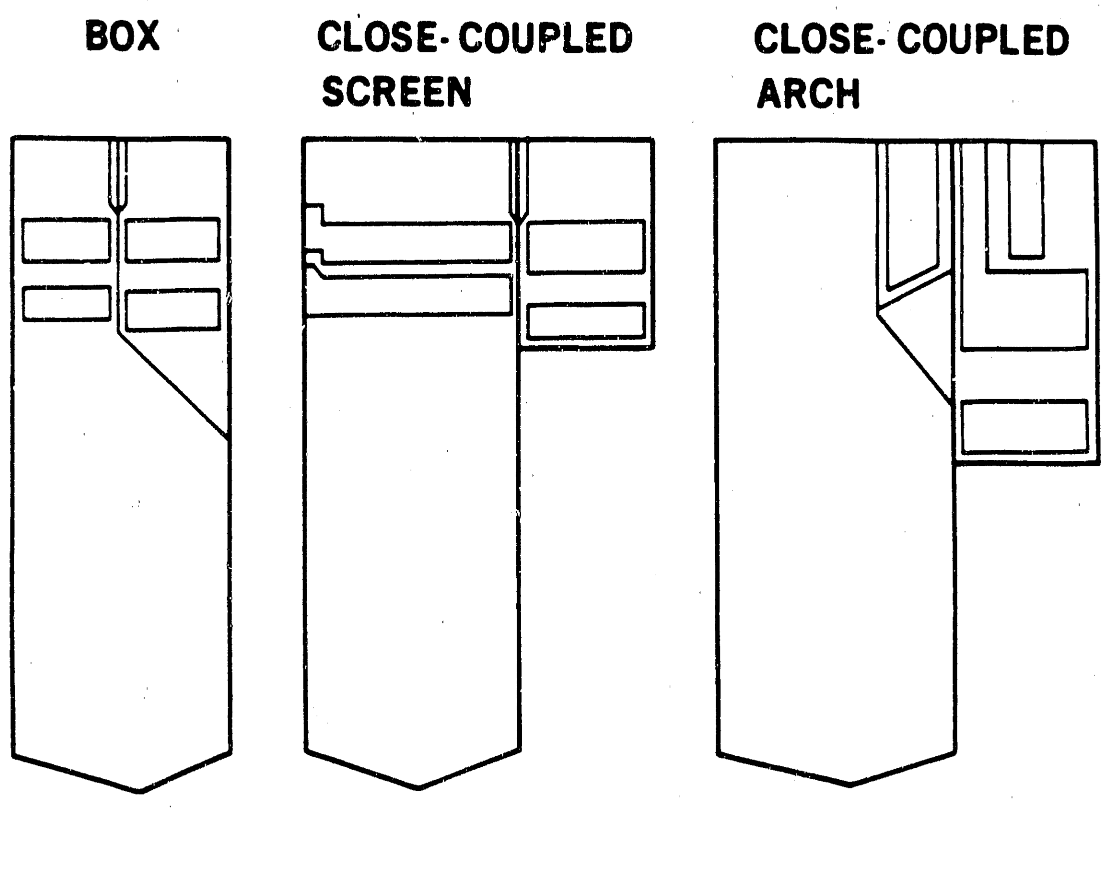


Figure 3-18

Based on the selection criteria and the results of the boiler population market survey, three representative boilers were selected. These boilers are located in three different power plants owned by different utility companies. The utility boiler data, shown in Table 3-1, are discussed below:

- Foster Wheeler sold 14 units, similar to the selected close-coupled arch (CCA) unit, with nominal capacities ranging between 730 and 850 MWe, for a total of 11,000 MWe. This represents about 12% of the total market.

- Combustion Engineering sold 20 units, similar to the selected close- coupled screen (CCS) unit, with nominal capacities ranging from 400 to 600 MWe, for a total of 9,400 MWe. This represents about 10% of the total market. These units are also similar to CCS units sold by Babcock and Wilcox, representing an additional 11% of the total market.

- Babcock and Wilcox sold approximately 30 units, similar to the selected Box unit, with nominal capacities ranging from 315 to 480 MWe, a total of approximately 10,000 MWe. This represents 11% of the total market.

- Combustion Engineering sold 38 units, similar to the selected Box unit, with nominal capacities ranging from 100 to 660 MWe, for a total of 10,000 MWe. This represents a total market share of 11 percent.

Figure 3-19 shows the locations of existing oil and gas-fired boilers similar to those selected for the study.

TABLE 3-1

MARKET DATA FOR SELECTED UTILITY BOILERS

Unit Configuration	Close-Coupled Arch (CCA)	Close-Coupled Screen (CCS)	Box
Net capacity (MWe)[(1)]	850	600	400
Manufacturer	FW	C-E	C-E
No. of Mfr's similar units sold	14	20	38
Percent of Mfr's sales represented	50	30	34
Percent of total market represented	12	10	11
Percent of total market for all similar units[(2)]	11	21	15

(1) At full load

(2) Units sold by manufacturer and all competitors (Riley not included).

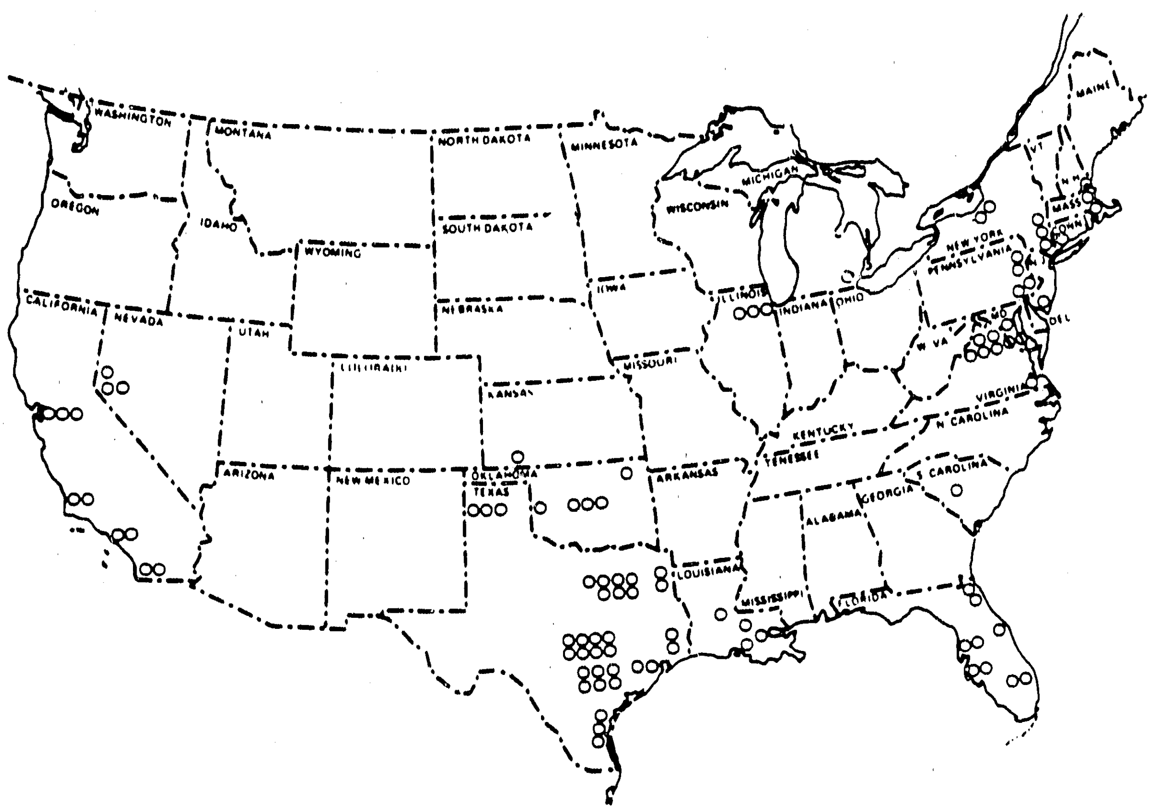


Figure 3-19 LOCATIONS OF OIL- AND GAS-FIRED BOILERS SIMILAR TO THE SELECTED BOILERS

3.2 INDUSTRIAL BOILER SELECTION

The total number of domestic industrial boilers in place as of 1977 is estimated to be about 1.8×10^6 units with a total firing capacity of about 4.5×10^{12} Btu/hr. Not included in these totals are residential heating units, utility steam generators and process heaters. Figure 3-20 breaks down the capacity in terms of industrial and commercial categories. These categories are subdivided into water tube, fire tube and cast iron designs. In water tube boilers, the water being heated flows through tubes with the hot gases flowing across the outside of the tubes. In fire tube boilers the opposite is done (gas inside and water outside the tubes). In cast iron boilers the gas is also contained inside the tubes, but the units are constructed of cast iron instead of steel. Figure 3-21 shows typical capacity ranges for the various boiler and fuel types. Figure 3-22 shows the population distribution as a function of unit size whereas Figure 3-23 illustrates the total firing capacity as a function of unit size. Although there are fewer water tube boilers, they are generally much larger than either the fire tube or cast iron designs and consequently represent the majority of the total firing capacity. Figure 3-24 shows the distribution of fuel type for the three boiler design types. Natural gas is the predominant fuel and accounts for about 45% of the total capacity. Oil firing accounts for an additional 37% and coal firing represents the remaining 18%. Forty percent of the capacity is in units in the 7 to 73 MW thermal range, 17% is in units larger than 73 MW thermal and 44% is in units below 7 MW thermal. Distribution of the industrial/commercial boiler capacity also shows that 57% are water tube, 23% are fire tube and 20% cast iron design units. (Figures 3-20 to 3-24 are from Reference 1.)

Given the significance of the water tube boiler classification, it is appropriate to examine details of the population. Water tube boilers were examined according to the following criteria in order to focus on units which represent potentially attractive CWF retrofit candidates.

- o Units are designed for oil and/or natural gas
- o Units represent 1965-1980 booking dates

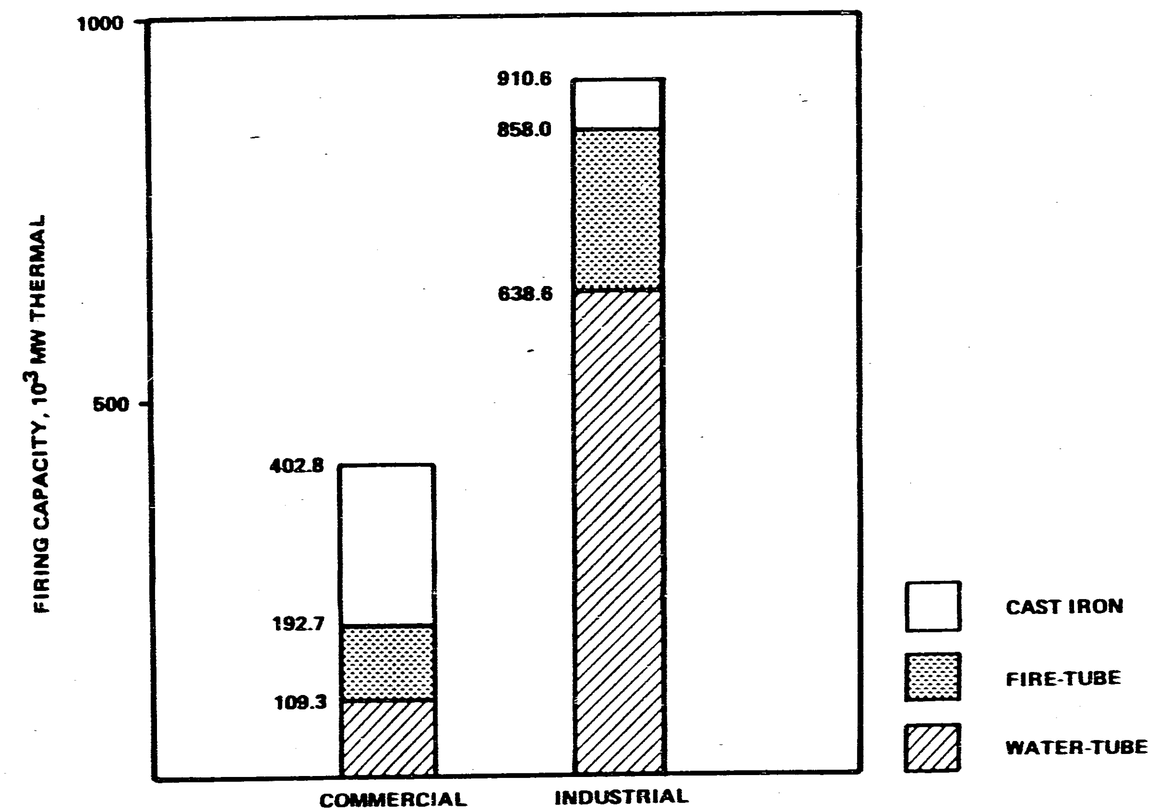


Figure 3-20 DISTRIBUTION OF COMMERCIAL AND INDUSTRIAL BOILER CAPACITY BY TYPE.(1)

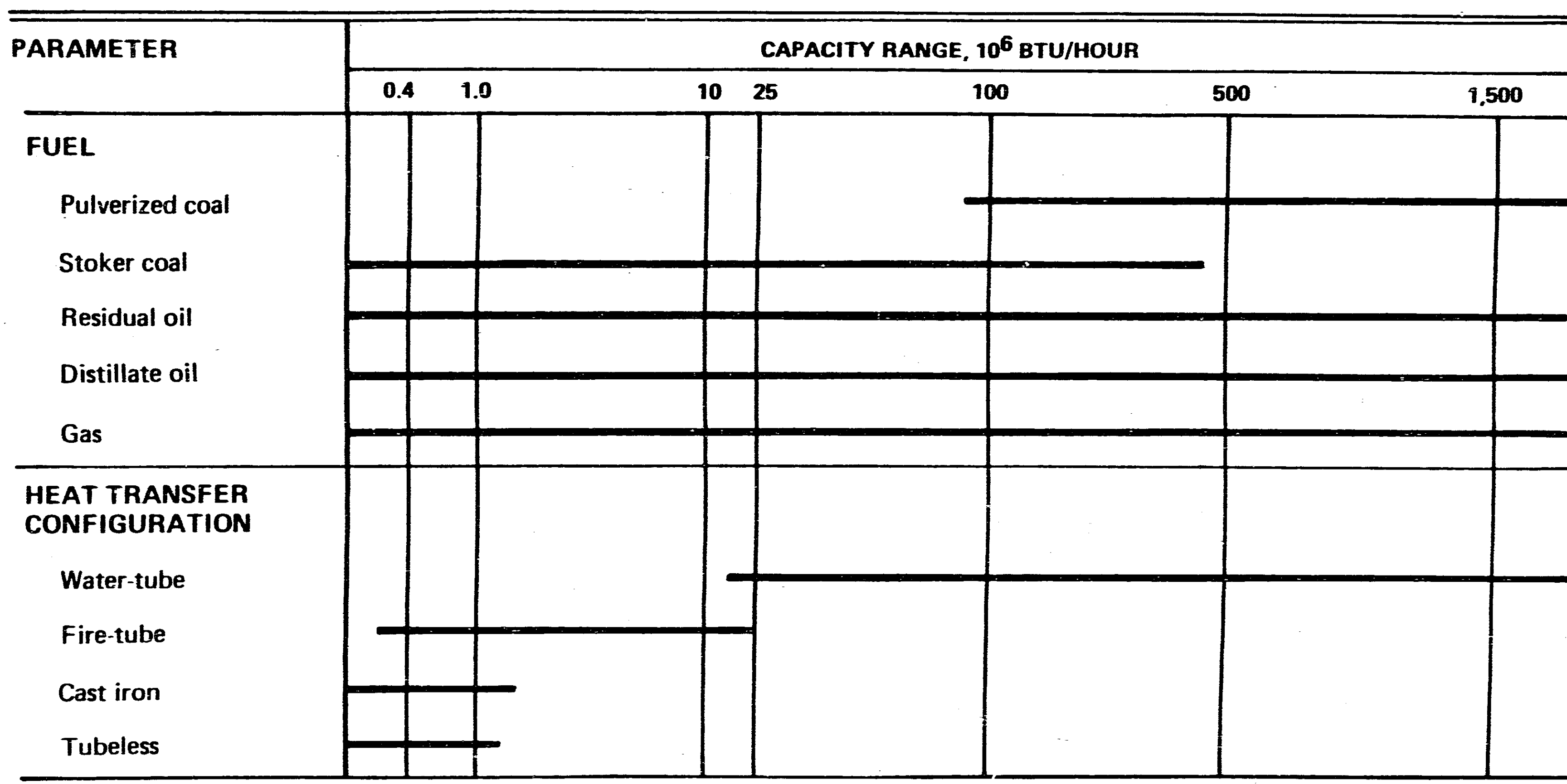


Figure 3-21 OCCURRENCE OF VARIOUS BOILER PARAMETERS BY CAPACITY RANGE.[1]

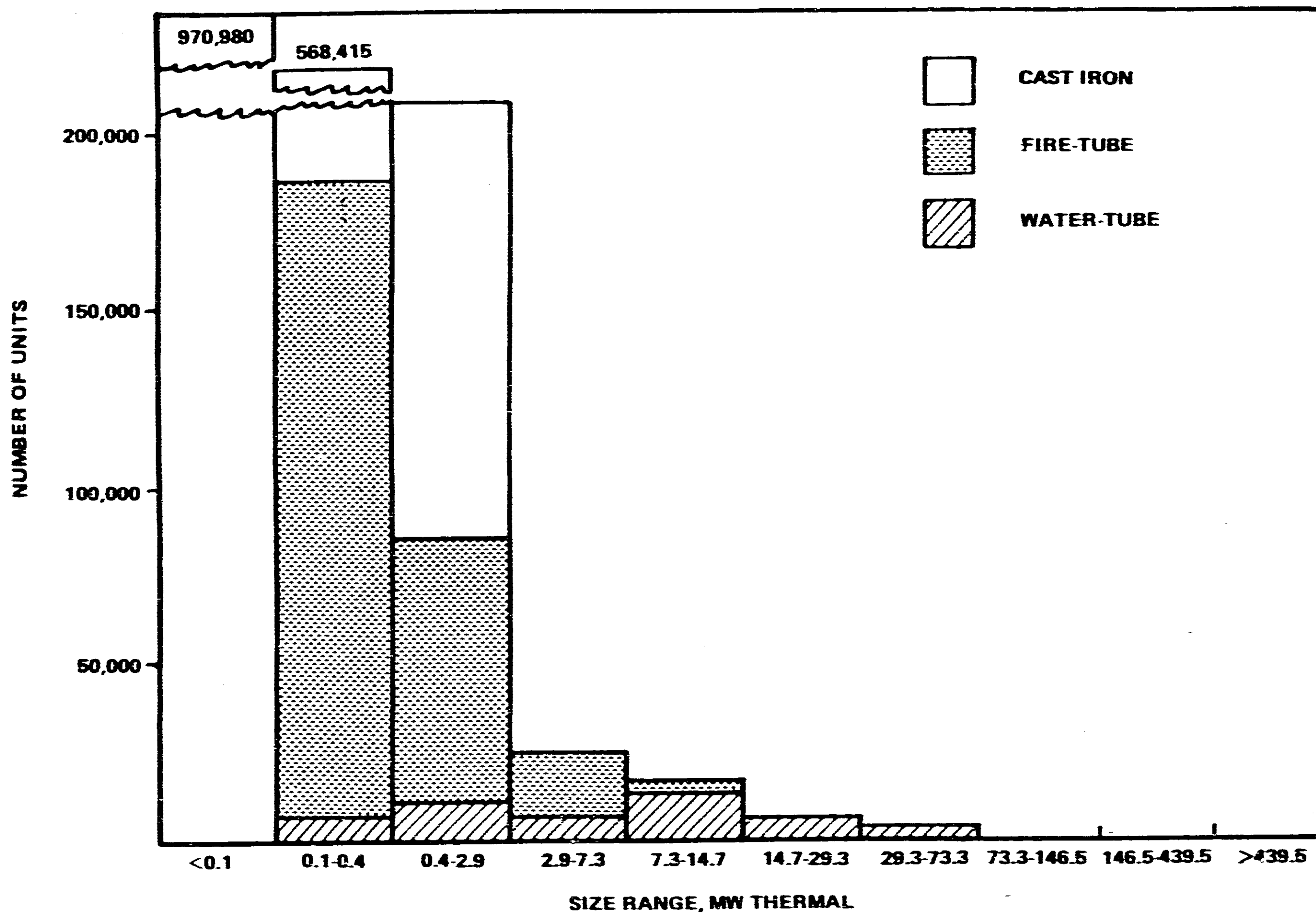


Figure 3-22 RELATIVE DISTRIBUTION OF THE NUMBER OF INDUSTRIAL/COMMERCIAL BOILERS BY TYPE AND SIZE RANGE.(1)

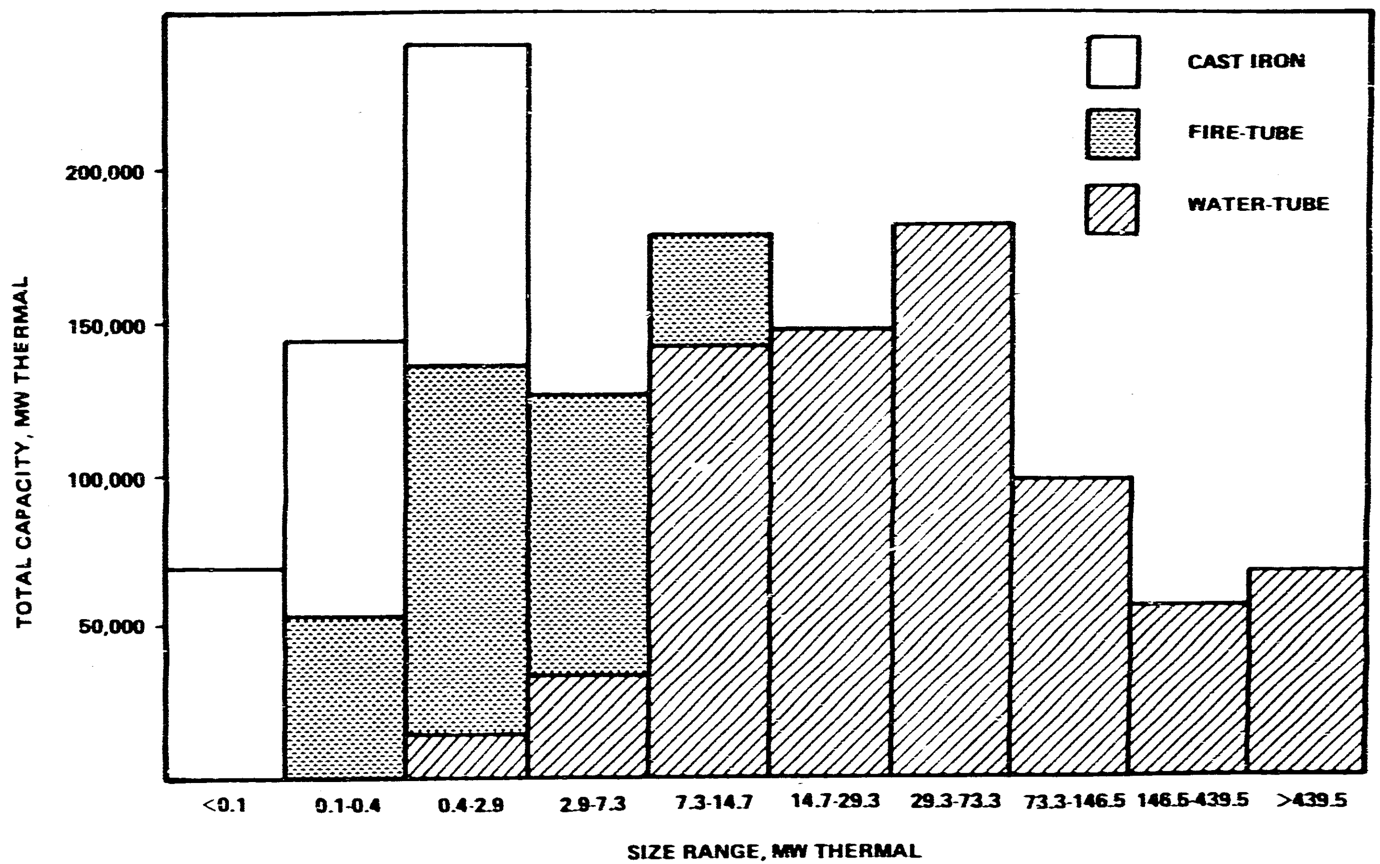
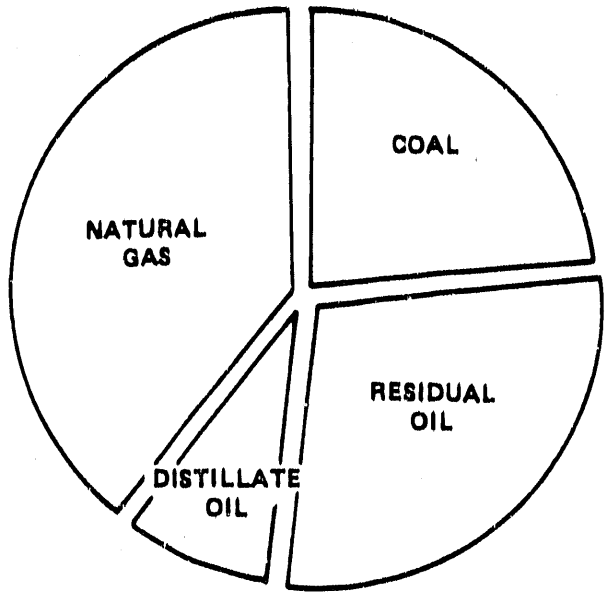
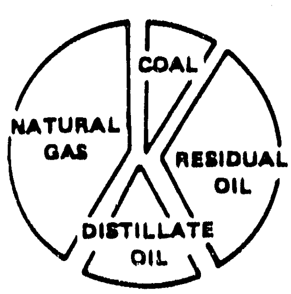


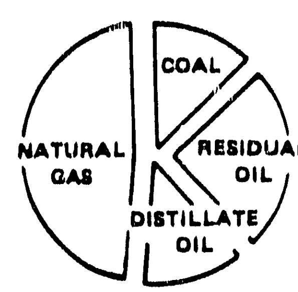
Figure 3-23 RELATIVE DISTRIBUTION OF THE CAPACITY OF THE INDUSTRIAL/COMMERCIAL BOILER POPULATION BY TYPE AND SIZE.(1)



WATER TUBE



FIRE TUBE



CAST IRON

Figure 3-24 RELATIVE DISTRIBUTION OF THE TOTAL CAPACITY BY FUEL TYPE IN EACH BOILER CLASS. (1)

These criteria reduce the population to about 10,000 units representing about 660×10^6 lb/hr of total steam generating capacity. The reduced boiler population was again grouped according to year of contract, fuel fired, and unit size. Figures 3-25 to 3-27 illustrate the total capacity profiles for all manufacturers with respect to the aforementioned variables. Almost 85% of the total capacity was in units sold from 1965 to 1974. Sixty-eight percent of the units were under 250,000 lb/hr of steam capacity.

Industrial water tube steam generators can be further classified in terms of fabrication method. There are three basic categories: shop-assembled, modular and field-erected.

Shop-assembled industrial boilers are available up to about 300,000 lb/hr. The principal size constraints arise from shipment limitations. Several different designs are available for shop-assembled boilers. Generally, the designs can be classified as either "A", "O" or "D" type units depending upon the location of the steam and water drums. Figure 3-28 shows the "A" and "D" type designs produced by C-E. In the C-E "A" boiler, a single steam drum is centered along the top of the unit. Two water drums are located at the bottom and run along the sides of the unit. The burners are located in the front wall. The combustion gases flow the full length of the unit and are then split to each side at the rear wall where they are turned 180 degrees and enter the convective sections. The convective sections are located above each water drum. Flue gas flows back toward the front wall in each convective section and exits vertically, where an economizer or air heater can be located.

In the "D" type boiler the steam and water drums are located along one side of the boiler. The burners are located in the front wall of the unit. The combustion gases are diverted at the rear of the furnace to the single convective pass located between the two drums. Combustion gases flow back toward the front wall in the convective pass and exit the unit to an economizer, air heater and stack.

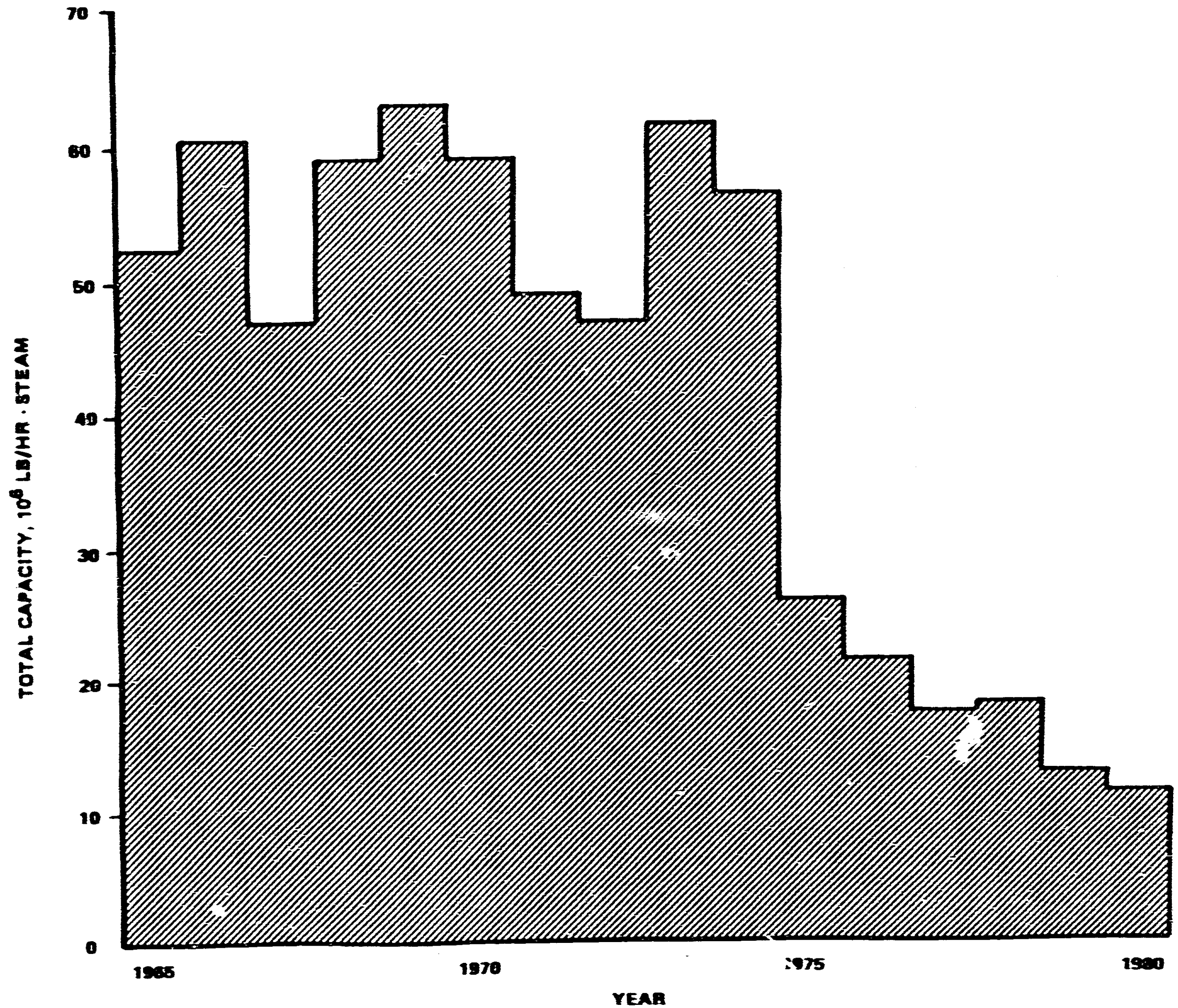


Figure 3-25 DOMESTIC INDUSTRIAL BOILER MARKET - OIL AND GAS FIRED UNITS
ALL MANUFACTURERS - WATER TUBE DESIGNS

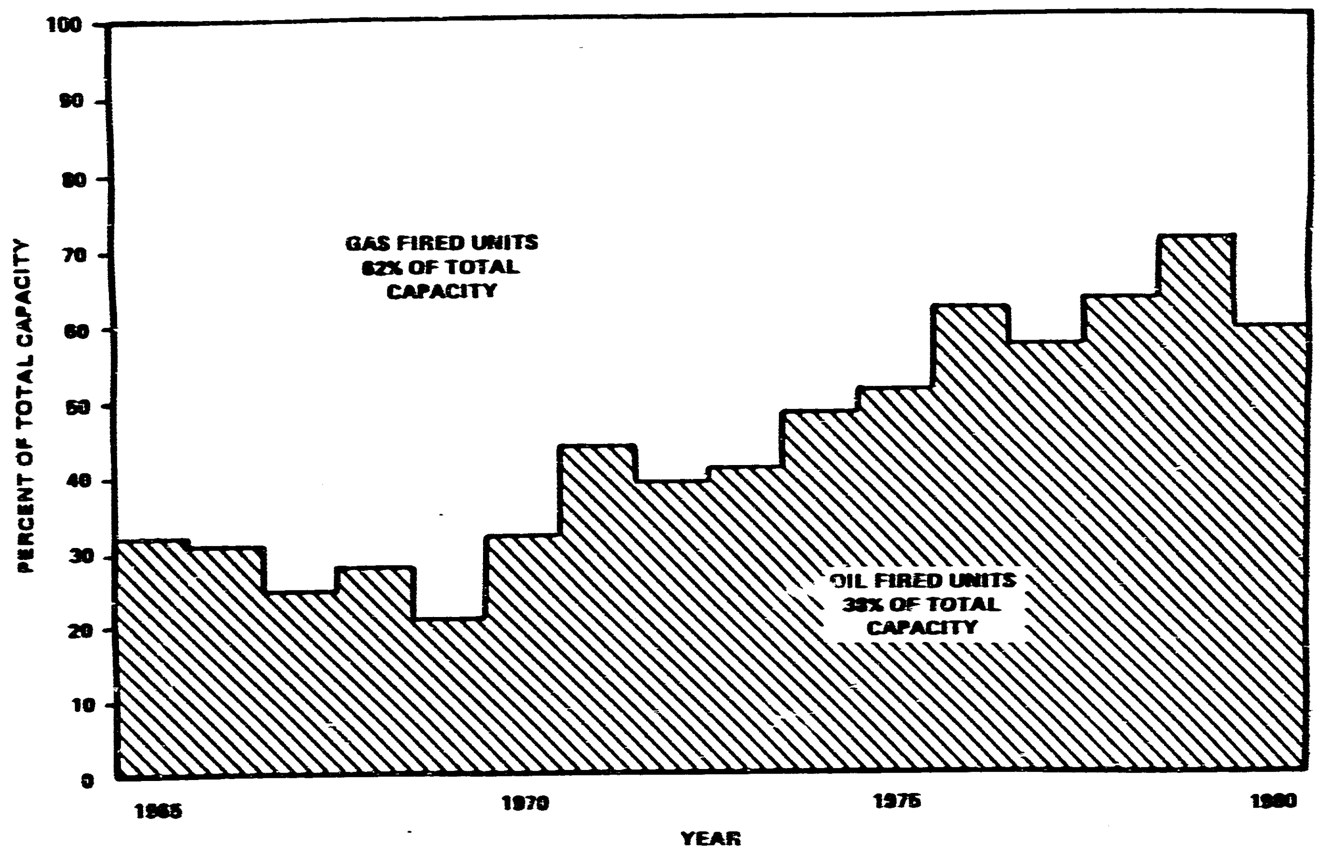


Figure 3-26 DOMESTIC INDUSTRIAL BOILER MARKET
OIL AND GAS FIRED UNITS
ALL MANUFACTURERS
WATER TUBE DESIGNS

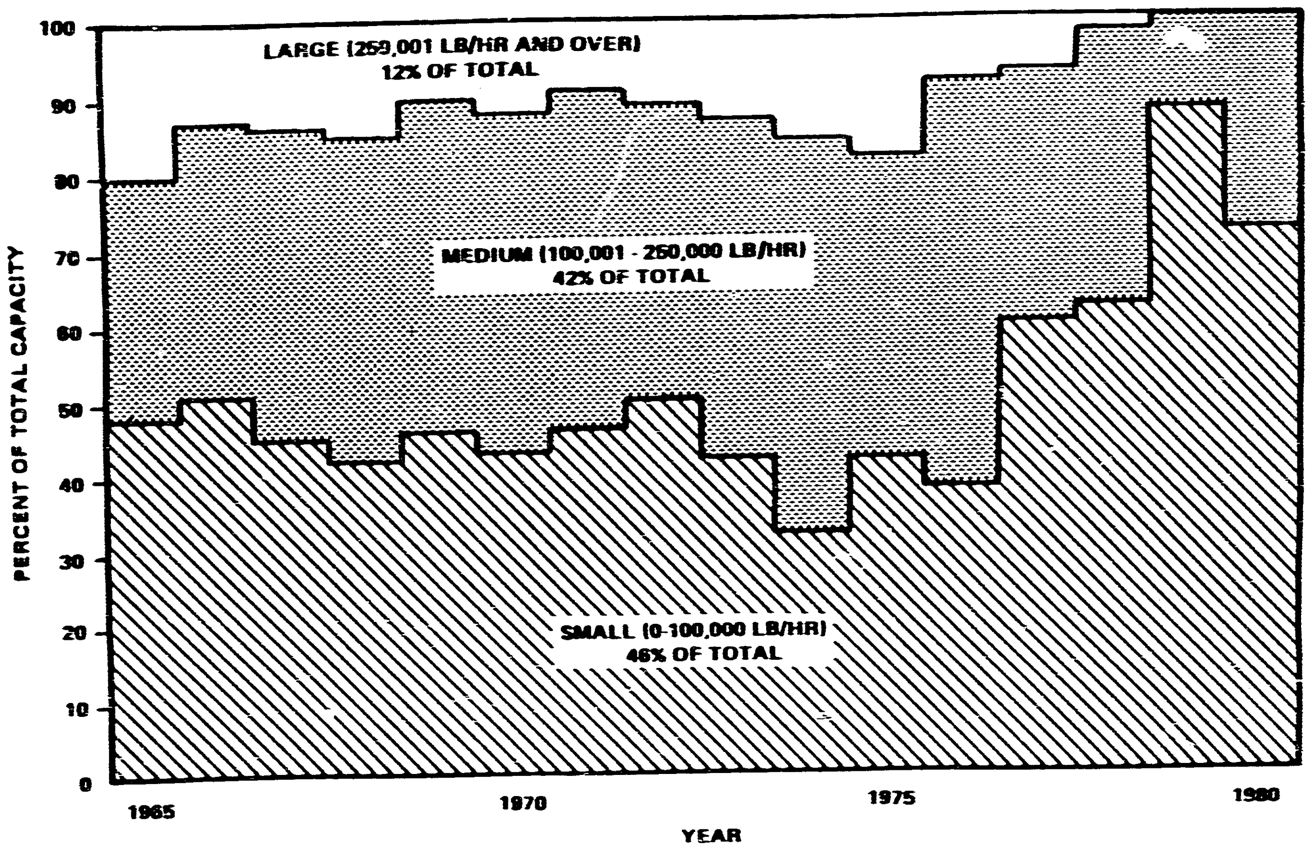


Figure 3-27 DOMESTIC INDUSTRIAL BOILER MARKET
OIL AND GAS FIRED UNITS
ALL MANUFACTURERS
WATER TUBE DESIGNS

C-E SHOP ASSEMBLED A BOILER

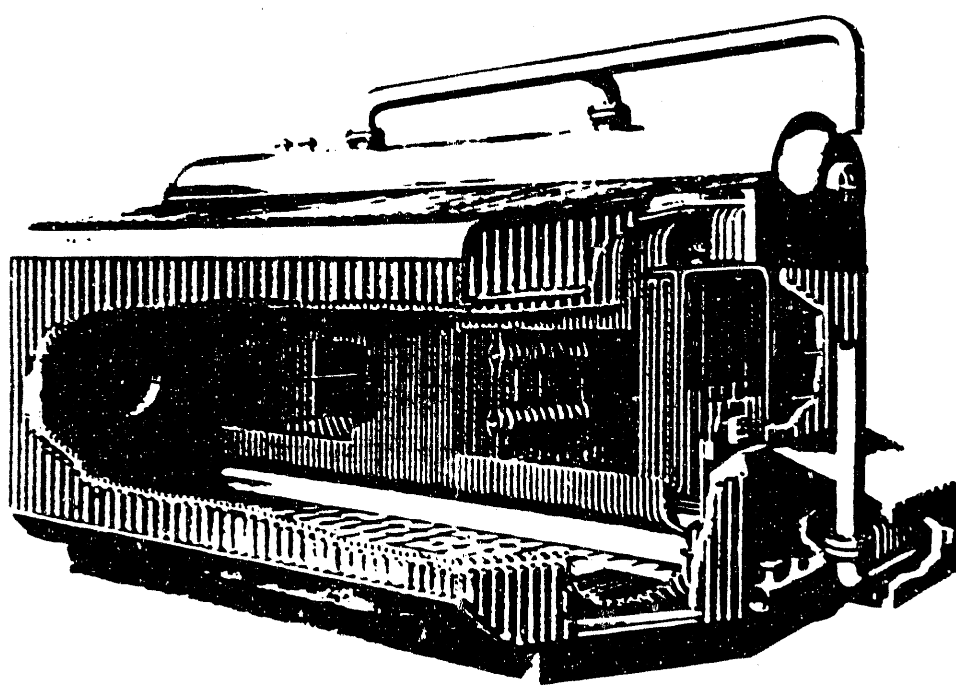


FIGURE 3-28
C-E SHOP ASSEMBLED VP BOILER (D-TYPE)

The "O" type boiler is similar to the "A". The bottom two side drums are replaced with a single drum at the bottom center of the unit. Various combustion gas flow paths are available in the "A" and "O" design classification depending on manufacturer.

Modular steam generators are available in ranges from 200,000 to 1,000,000 lb/hr. Figure 3-29 shows a C-E VU-60 type modular steam generator. These are bottom supported units built from pre-engineered components which are field assembled.

Field erected steam generators are top-supported units which are usually limited to large capacity units or to custom built units. Figure 3-30 shows a C-E VU-40 type field erected steam generator.

The C-E unit population profiles are shown in Figures 3-31 to 3-36. The market trends are very similar to those mentioned previously for the total market with respect to size and year. The "A" and VP (D type) shop-assembled units represent about 79% of the total capacity sold by C-E, whereas the VU-60 modular type units account for about 18% and the VU-40 field erected units represent about 3% of the sales in this category. Steam pressures under 1000 psig are predominant for the C-E shop-assembled units. The 0 to 200 psig and the 600 to 800 psig bands are the largest for the "A" boilers, whereas the 400 to 600 psig band dominates for the VP units. Fifty percent of the VU-60 units are represented in the 1200 to 1400 psig range and 83% of the VU-40 units are in the 800 to 900 psig range.

Approximately 50% of the C-E shop-assembled units are equipped with superheaters and 49% generate saturated steam. The remaining one percent are hot water units. All of the VU-60 and VU-40 type units are equipped with superheaters.

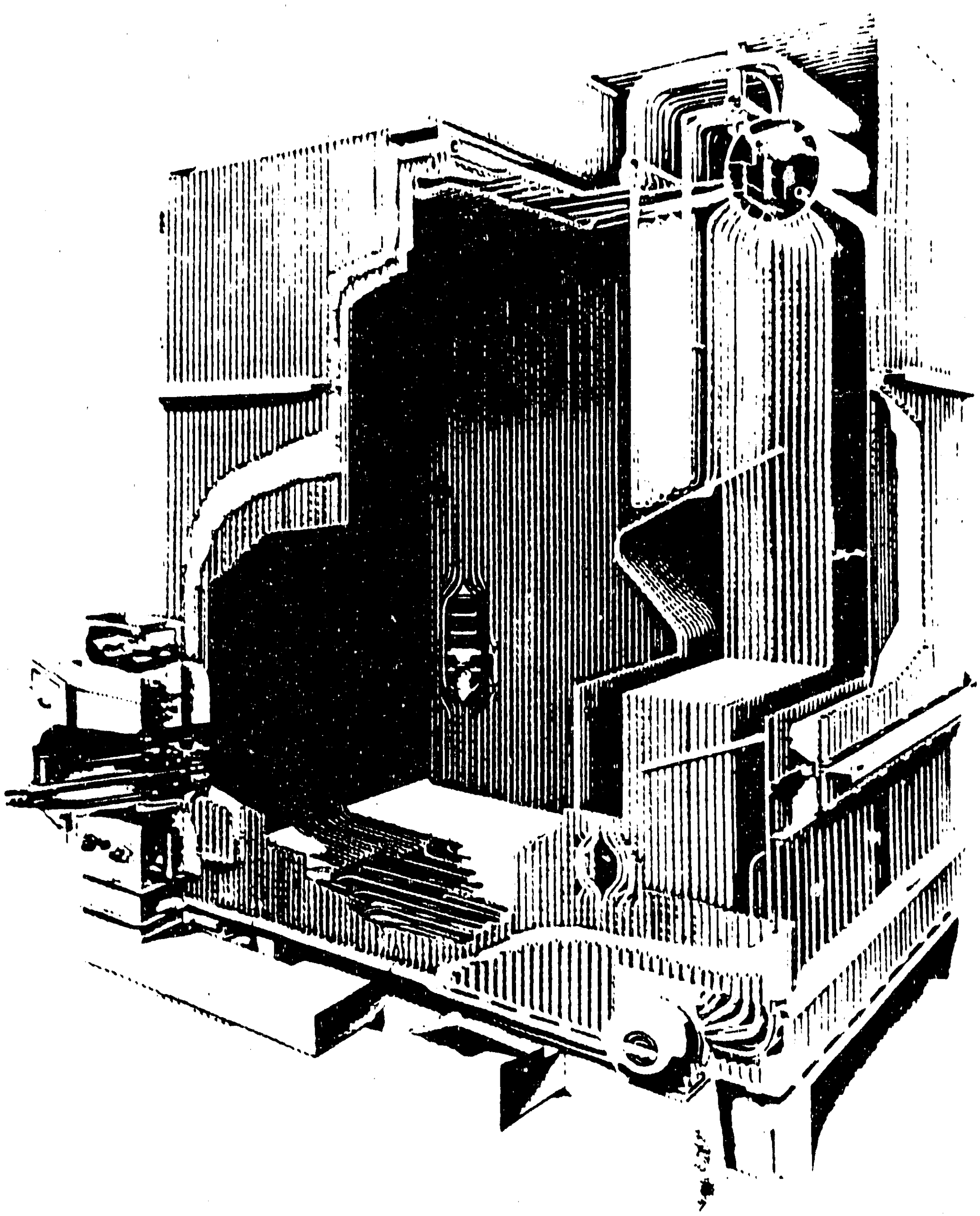


FIGURE 3-29
C-E MODULAR VU-60 BOILER

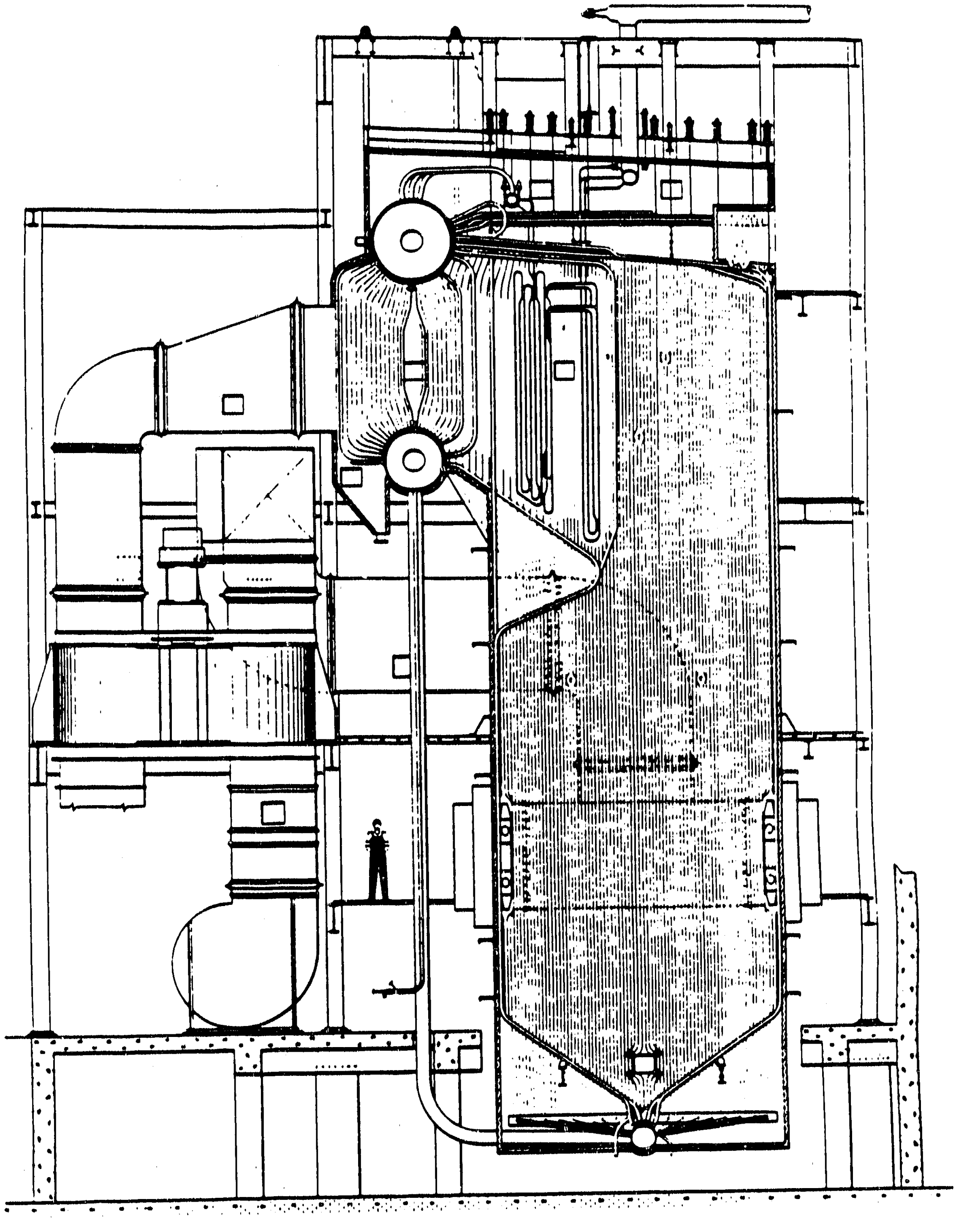


FIGURE 3-30
C-E FIELD ERECTED VU-40 BOILER

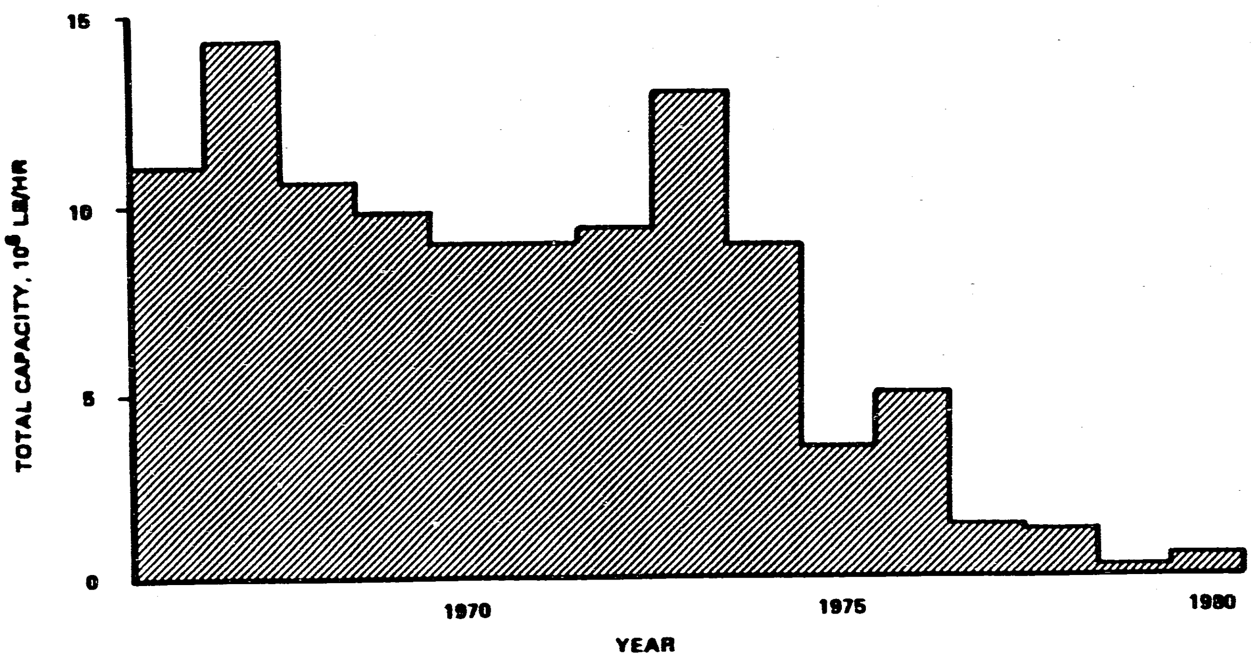


Figure 3-31 DOMESTIC INDUSTRIAL BOILER MARKET
C-E - OIL AND GAS FIRED UNITS
WATER TUBE DESIGNS

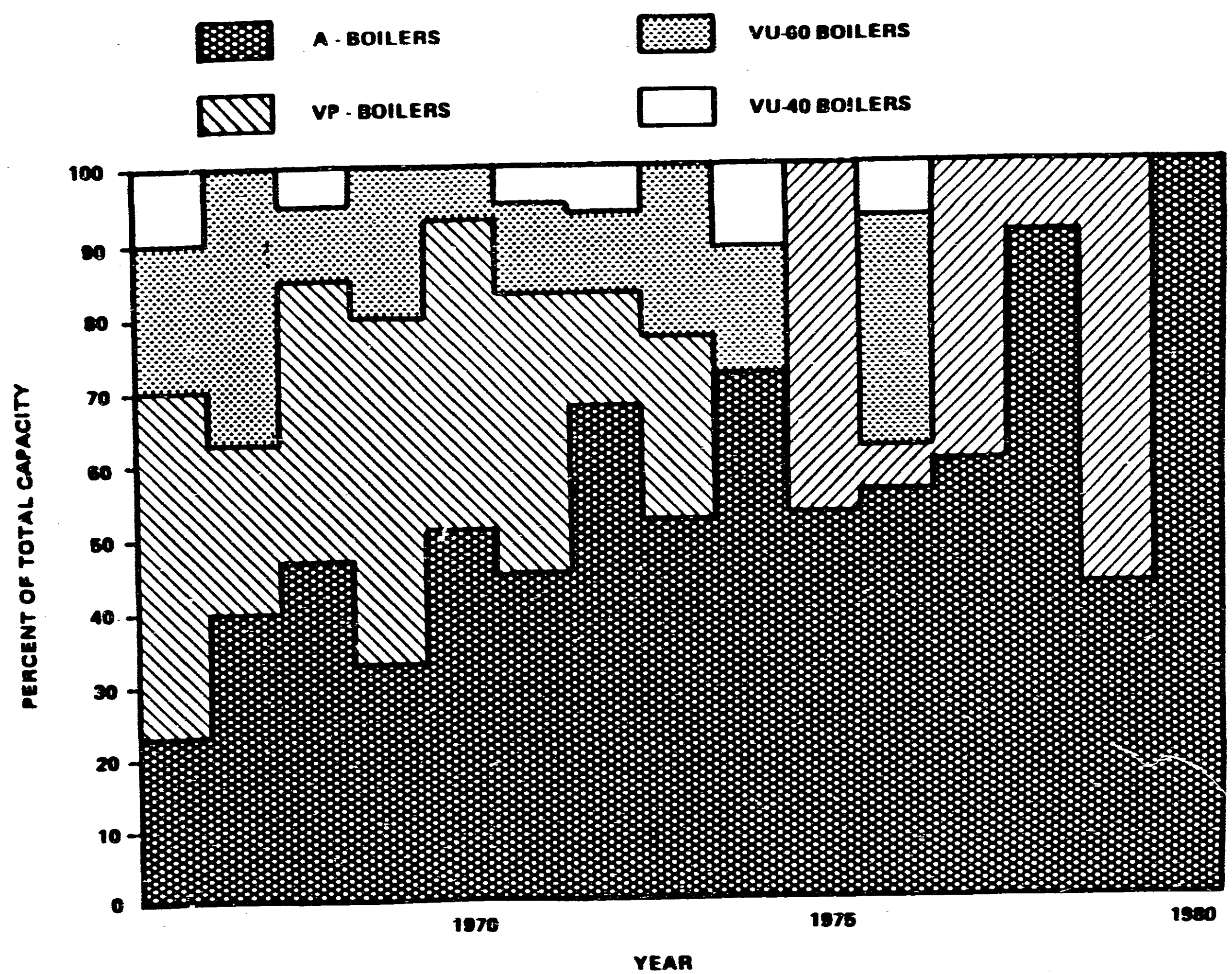


Figure 3-32 DOMESTIC INDUSTRIAL BOILER MARKET C-E OIL AND GAS FIRED UNITS

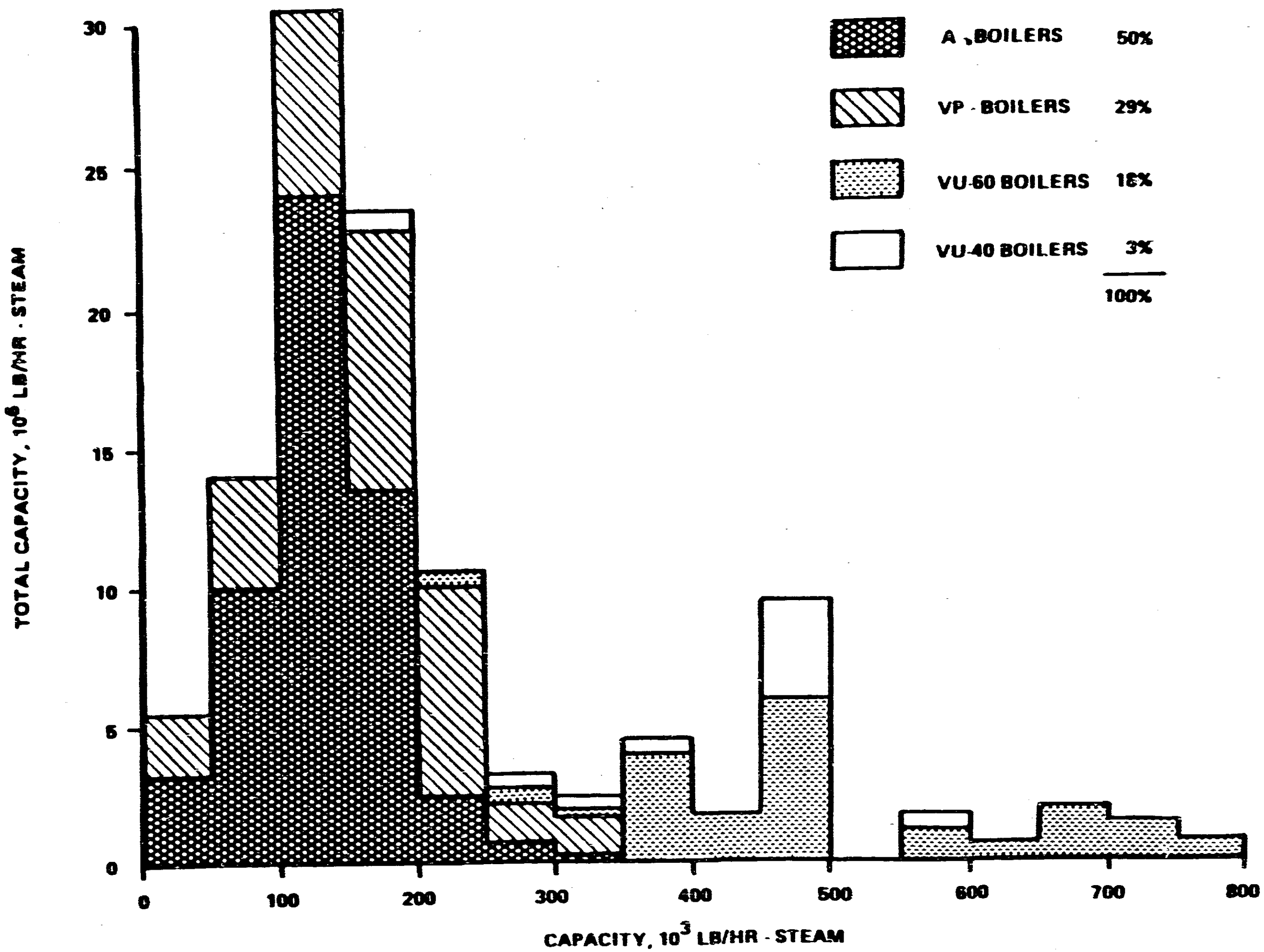


Figure 3-33 DOMESTIC INDUSTRIAL BOILER MARKET
C-E OIL AND GAS FIRED UNITS

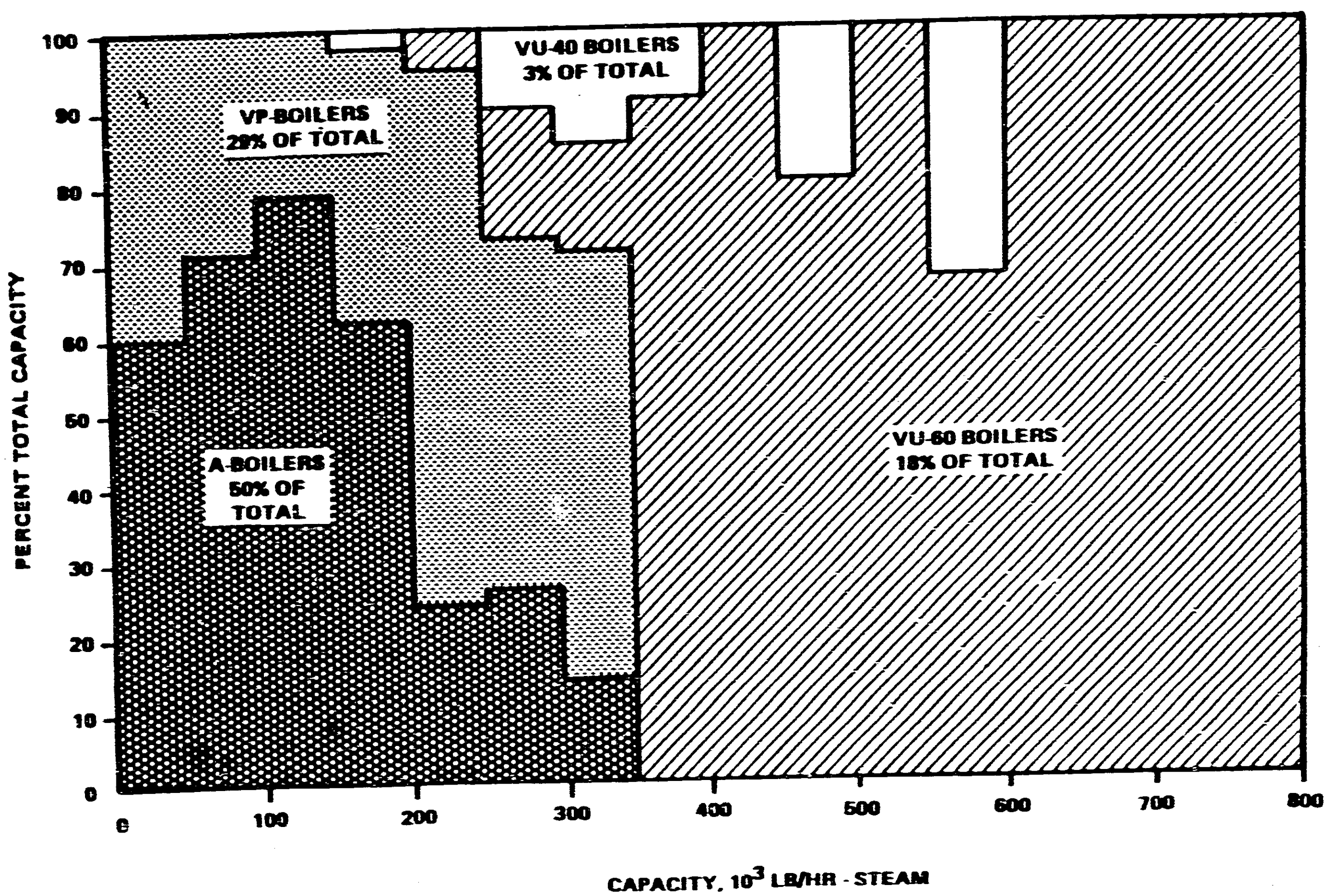


Figure 3-34 DOMESTIC INDUSTRIAL BOILER MARKET C-E OIL AND GAS FIRED UNITS

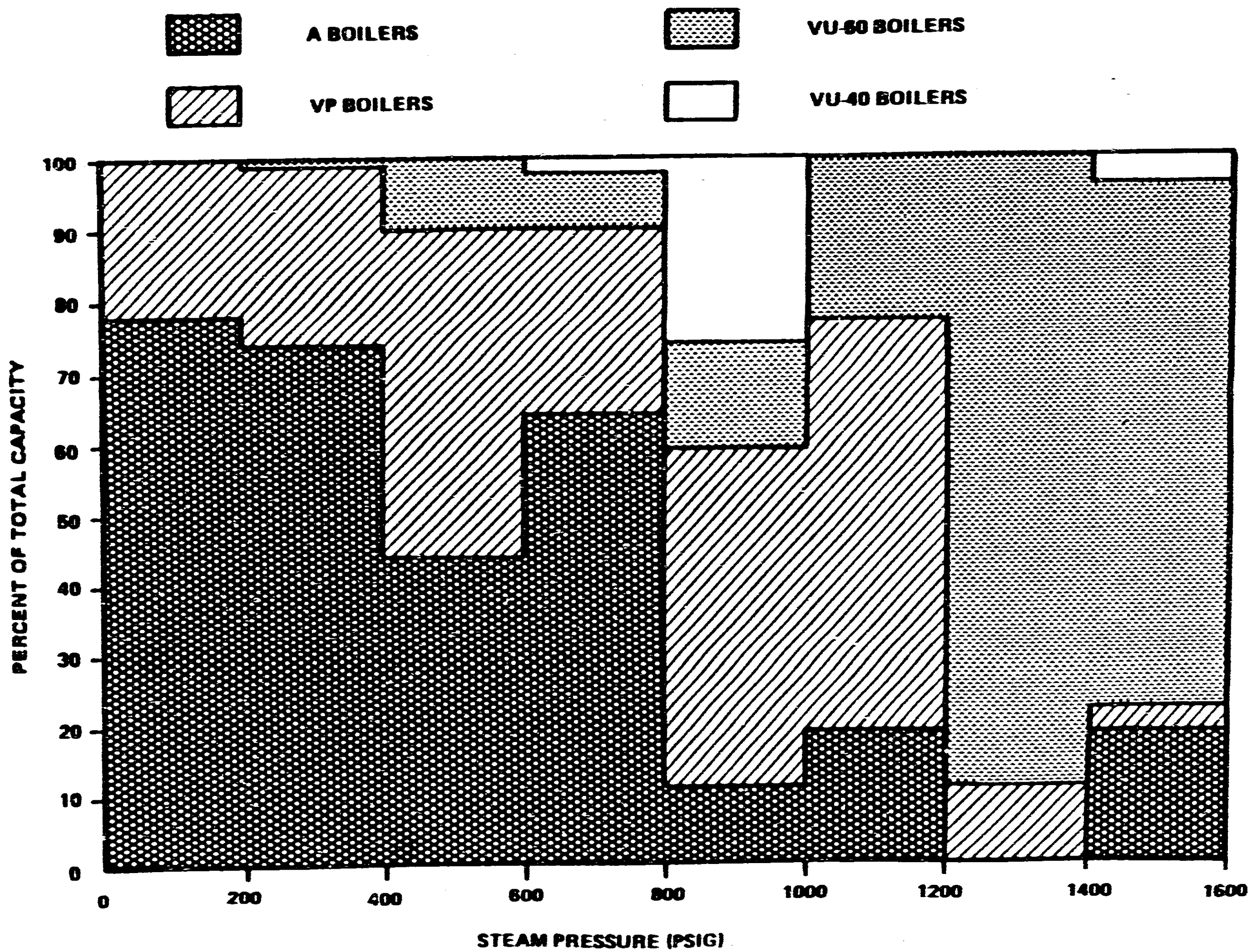


Figure 3-35 DOMESTIC INDUSTRIAL BOILER MARKET
C-E OIL AND GAS FIRED UNITS

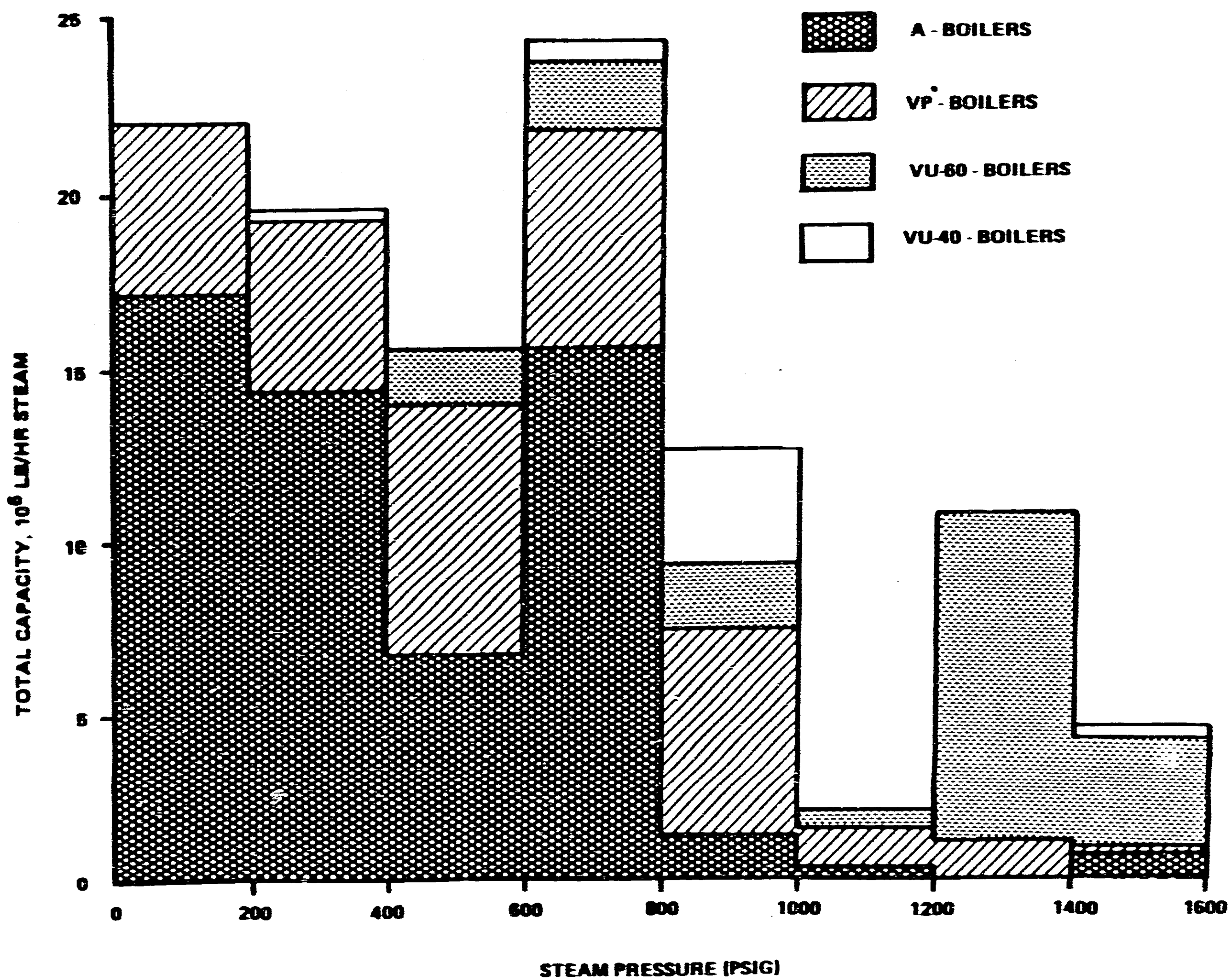


Figure 3-36 DOMESTIC INDUSTRIAL BOILER MARKET C-E OIL AND GAS FIRED UNITS

(The data on the total industrial commercial boiler market was taken from Reference 1. The American Boiler Makers Association Data Base is the source used for the total oil and gas-fired water tube boiler market data. The data specific to C-E units are taken from the C-E yearly industrial boiler contract listings.)

APPLICATION OF SELECTION CRITERIA AND MARKET SURVEY

The two units selected for the industrial boiler retrofit application study should represent as much of the market as possible. Table 3-2 indicates the variable ranges which will insure maximum market representation. By choosing one shop-assembled and one modular unit, two distinct design types can be studied. The large field erected VU-40 units were not selected because of the limited amount of capacity they represent in oil/gas designed units. The other variable ranges listed in Table 3-2 insure the selected study units will be representative of the specific unit type.

TABLE 3-2

APPLICATION OF SELECTION CRITERIA AND MARKET SURVEY

Unit Type	Shop Assembled	Modular-field Assembled
C-E Designation Type	A or VP	VU-60
Unit Size (10^3 lb/hr)	100-200	400-500
Booking Year	1966-1974	1966-1973
Steam Pressure (psig)	0-800	1200-1550
Steam Leaving	Superheated or Sat.	Superheated

3.4 PROCESS HEATER SELECTION

Process heaters vary widely in many aspects:

- o Size of individual units
- o Number of units or total capacity in the industry
- o Feasibility of burning difficult fuels

Coal conversion of feasibility was considered by an American Petroleum Institue (API) Task Force[2] in March 1977. They concluded that many services cannot be considered for various reasons:

- o Sensitivity to local overheating of the process liquid film at the inside tube wall
- o Corrosion of the high temperature tube metal by coal ash
- o Overheating of highly stressed high temperature tube metal

The energy consumption of the major process heaters is reported by Dr. Paul Marnell[3] in the proceedings of a workshop on the utilization of coal fuels in process heaters. The only major service that meets the API Task Force's criteria is atmospheric pressure crude distillation.

Other considerations suggested by the API Task Force involve problems associated with fuel ash. Existing process heaters which can best tolerate any appreciable ash are those designed for heavy oil firing.

Section 3.4.1 discusses Potential Industrial Process Heater Study Units based on References (2) and (3) above.

The criteria used for selection of test case units are:

- o Service is Atmospheric Crude distillation
- o Design fuel is oil
- o Unit must be large enough to install burners of at least 15 million Btu/hr capacity
- o Unit must be representative of designs common in the industry
- o Unit must be equipped with air preheat
- o Convection surface must be suitable for cleaning

Another study leading to the selection of two process heaters was done in 1985 by the Heat Transfer Systems unit of C-E Lummus, Bloomfield, NJ. Sections 3.4.2 through 3.4.5 are based on a final report released in December 1985 (Reference 4). These sections will in turn discuss the feasibility of coal-water fuels in existing industrial process heaters, compare basic parameters of electric utilities vs. hydrocarbon processing industries, briefly describe the development and evolution of process heater design, and list the selection of process heaters reviewed in this study.

3.4.1 POTENTIAL INDUSTRIAL PROCESS HEATER STUDY UNITS

A breakdown of the total domestic energy use by economic sector is shown in Table 3-3 with the industrial sector consuming about 19 Quads (10^{15} Btu's) or 26% of the total.

Table 3-3

Total Energy Consumption in 1976 by Economic Sector

Economic Sector	Quads (10^{15} Btu's)	%
Residential/Commercial	14.671	19.76
Industry	19.234	25.91
Transportation	19.054	25.66
Electric Utility	21.283	28.67
Total Energy Consumed	74.242	100.00

McClelland, R. H., "Industrial Fuel Gas Economic Perspective and Market Potential," CNG Energy Company, 1978.

Natural gas and petroleum fuels make up about 80% of the total industrial fuel use as shown in Table 3-4.

Table 3-4

Industrial Energy Consumption in 1976

Primary Source	Quads (10^{15} Btu's)	%
Coal	3.821	19.86
Natural Gas	8.843	45.98
Petroleum	6.537	33.99
Hydro	0.033	0.17
Total Consumed	19.234	100.00

McClelland, R. H., "Industrial Fuel Gas Economic Perspective and Market Potential," CNG Energy Company, 1978.

A breakdown of the gas and oil fuel use by industry is shown in Table 3-5 with the chemical and petroleum industries consuming about 60% of the total.

Table 3-5

Consumption (In Quads) Uses of Natural Gas and Oil In the Manufacturing Industries in 1974*

Industry	Functional Use: Boiler	Feedstock	Process Heat	Other	Total
Chemical	1.13	1.96	.83	.25	4.17
Petroleum	.63	-	2.21	.06	2.90
Primary Metals	.30	.10	1.10	.20	1.70
Paper	.70	-	.15	.13	.98
Stone, Clay, and Glass	.01	-	.78	-	.79
Food	.40	-	.10	.10	.60
Textiles	.13	-	.03	-	.16
Printing	-	-	.04	-	.04
All Other Manufacturing	.58	-	.63	-	1.19
TOTAL	3.86	2.06	5.87	0.74	12.53

*The Technical Feasibility of Coal Use in Industrial Process Heat Application.
Energy and Environmental Analysis, Arlington, Virginia. May 1978.

Process heat represents almost half of the total industrial premium fuel use and more than 50% of this usage is in the petroleum and chemical industries. The petroleum industry clearly represents the single largest process heat user, consuming nearly 40% of the total process heat generated.

The typical energy use pattern of a refinery is shown in Table 3-6.

Table 3-6

Typical Energy Use Pattern of a Refinery*

Process (Temp. Level)	Direct Heat	Steam	Electricity	Cooling Water	Total
Crude Distillation (700°F)	19.3	20.8	7.8	23.5	20.7
Vacuum Distillation (750°F)	8.0	25.6	6.0	21.9	12.7
Delayed Coking (850°F)	10.8	9.5	6.7	13.7	11.4
Naptha Hydrotreating (500°F)	3.8	3.8	6.5	2.2	4.6
Catalytic Reforming (1000°F)	27.5	-	19.6	11.5	23.8
Alkylation	12.2	0.6	3.9	9.0	10.2
Distillate Hydrotreating (500°F)	6.5	11.9	15.1	5.3	9.3
Catalytic Cracking (960°F)	11.9	-	25.4	12.9	0.3
Offsites	-	27.8	9.0	-	7.0
	100	100	100	100	100
% of Total Refinery Energy Use	78.3	9.8	10.5	1.4	100

*The potential for Energy Conservation in Nine Selected Industries, Vol. 2, Petroleum Refining. Gordian Associates, N.Y., N.Y. 1975.

These data reveal two major points: 1) Process heat is by far the largest consumer of energy in a refinery, accounting for more than 70% of the total; 2) The process heaters used in distillation, catalytic reforming and cracking, and alkylation consume about 80% of the refinery's process heat. Thus, it is relatively easy to focus on these few types of heaters which consume about 1.8 Quads of energy annually.

The first process heater study unit selected was a petroleum crude distillation heater. The two candidate process heater units represented the two most popular design configurations (vertical cylindrical; horizontal box), and either configuration would be acceptable.

In selecting a second process heater study unit the chemical industry appears to represent a significant market for consideration. Table 3-7 shows a breakdown of the major energy-consuming chemical processes.

Ammonia and ethylene production represent the most significant processes with respect to process heat consumption in the chemical industry. Total annual energy consumption related to ammonia production is about 0.358 Quads. Ethylene production consumes about 0.123 Quads annually. Each of these industries uses large process heaters and between them they consume 16% of the total energy used in the chemical industry. Unfortunately, however, there are technical reasons which eliminate these types of heaters from consideration for coal based firing.

Reference 2 categorizes process heaters based on the severity of the process service type. Three categories were defined and are shown below. The ammonia and ethylene heaters fall in category 1 which is the most severe service type.

1. Designs of heaters for high temperature process reactions or high pressures and elevated temperatures:

   (a) Require that metal pressure parts be at temperatures approaching the coal ash fusion point, implying severe corrosion problems;

Table 3-7

Energy* - Consuming Chemical Processes**

Chemical	Annual Energy Consumption 10^{12} Btu/yr	Specific Energy Consumed Btu/lb	Percent of total† for all Chemical Processes
1. Ammonia	358	14,500	11.9
2. Chlorine/Caustic(E)	335	17,500	11.2
3. Ethylene	123	10,000	4.1
4. Aluminum Oxide	96	8,000	3.2
5. Soda Ash	71	6,500	2.4
6. Rayon	60	62,200	2.0
7. Carbon Black	50	17,000	1.7
8. Nylon	49	26,000	1.6
9. Polyethylene	49	7,500	1.6
10. Polyester	46	20,000	1.5
11. Butadiene	45	14,500	1.5
12. Styrene	42	7,000	1.4
13. Phosphoric Acid	41		1.4
14. Phosphates	36		1.2
15. Titanium Oxide	31	19,500	1.0
16. Polyvinylchloride	31	6,000	1.0
17. Acrylic	30	47,000	1.0
18. Acetate	28	67,200	0.93
19. Phosphorus	26	23,500	0.87
20. Oxygen(E)	25	700	0.83
21. Acetylene	20	52,700	0.67
22. Methanol	16	2,500	0.53
23. Polybutadiens	13	19,000	0.43
24. Phenol	12	5,500	0.40
25. Nitrogen(E)	12	1,300	0.40

Table 3-7 (Cont.)

Energy* - Consuming Chemical Processes**

Chemical	Annual Energy Consumption 10^{12} Btu/yr	Specific Energy Consumed Btu/lb	Percent of total+ for all Chemical Processes
26. Polystyrene	11	2,200	0.37
27. Styrene Butadiene	11	4,300	0.37
28. Ethanol	11		0.37
29. Hydrogen	9.2	43,300	0.31
30. Cumene	8.8		0.29
Total	1,696		57

*Excludes energy value of feedstocks. Estimates are for 1972. Energy consumptions are totals for energy consumed through fuel use and purchased electrical power. Fuel use comprises process heating, steam generation, and power generation from internal combustion engines.

**Data for all chemicals except cumene were obtained from Draft Target and Support Document on Developing a Maximum Energy Efficiency Improvement Target for SIC 28: Chemicals and allied Products, Battelle Laboratories, prepared for the Federal Energy Administration, July, 1976. The cumene energy consumption was obtained from Energy Consumption: Fuel Utilization and Conservation in Industry, Dow Chemical Co., EPA Report #650/2-75-032-d.

+The annual total energy consumption (exclusive of feedstock use) was estimated, in the Battelle report, to be $3{,}000 \times 10^{12}$ Btu.

(E)Primarily electrical.

(b) Have metal pressure parts operating near the safe high temperature strength limit and require precise control of the heat flux to avoid overheating of these parts; and

(c) Commonly require many small burners in order to adequately control heat flux distribution.

Limited experience is available to identify the magnitude of the corrosion problem. However, studies of the effects of the (much milder) corrosive agents in oil fuels have led to the conclusion that sulfur and many metal salts, common to coal ash, will rapidly destroy the highly alloyed materials used in high temperature and/or pressure heaters. Also, detailed knowledge of heat transfer from coal flames, as required to design for and control precise heat flux distributions, is presently lacking. Therefore, we conclude that it is presently, and for the foreseeable future, impractical to design for coal firing in heaters designed for high temperature process reactions or for high pressures.

Heaters falling in the above class include those for ethylene pyrolysis, steam-hydrocarbon reforming, hydrocracking, and some hydrotreating. They are to be found predominantly in the chemical, petroleum, and fertilizer industries.

2. Designs that process fluids subject to thermal decomposition require close control of the temperature of the fluid adjacent to the heat absorbing surface (known as the fluid film). Overheating of the fluid film will lead to formation of decomposition products and plugging, and/or overheating of the tubes.

   Relatively close prediction and control of heat flux is required in order to obtain satisfactory run length and operational safety. Also, it is necessary to provide for rapid extinction of combustion for the case when thermal decomposition is detected. These factors will likely remove stoker-fired designs from consideration for these services.

Since adequate knowledge of the characteristics of pulverized coal flames to allow relatively precise heat flux prediction and control is lacking, we see the application of coal firing to this class of units as unattractive until proven in less severe services. Services susceptible to thermal decomposition include heaters in cokers, visbreakers, thermal crackers, and vacuum flashers in the petroleum refinery industry.

3. Designs for general process service are considered as first priority candidates for development of coal-firing designs. Current and traditional designs do not satisfy the fundamental technical requirements for burning coal as covered previously. In addition, we expect that larger combustion chambers and fewer burners of greater heat release, as compared to current designs, will be required for firing pulverized coal.

   Vertical upward firing, as currently applied with gas or oil fuels, which gives the most even heat distribution in economically-sized fireboxes will not be possible with coal fuel. Maintenance requirements on combustor, fuel, and ash systems may limit heater availability. Experience with coal-fired boilers indicates that stream factors are less than currently considered desirable in process applications.

   Existing coal-fired boiler technology and features are deemed directly transferrable to process heater design in the areas of coal handling, ash or slag handling, flue gas conditioning, and maintenance facilities. Improvement of pulverized coal firing control is possibly indicated. Problem areas requiring solution before general application of coal firing to process heaters can be attempted are

   (a) Obtain detailed knowledge of coal flame characteristics and heat transfer from coal flames.

   (b) Solve problems of slagging, fouling, and corrosion of high temperature pressure parts and refractory.

(c) Develop techniques for controlling heat flux distribution with coal firing. This includes consideration of fuel distribution, air distribution, and small burner development.

The petroleum crude distillation heater described previously fall into this third category in terms of process severity.

A second type of process heater which represents a potentially feasible application is commonly referred to as a "hot oil belt heater". This type of heater, also commonly used in refineries, uses an intermediate heat transfer media such as hot oil or an organic fluid which transfers its heat to the crude in a separate heat exchanger. C-E Lummus estimates this type of heater probably represents about 5 to 10% of the total refinery fuel consumption. The potential usage for this heater type is as high as 25% using present day technology. Future improvements in the maximum temperature level for the intermediate heat transfer fluid will increase the potential application for this type of unit. These types of units would be classified in category 3 in terms of process severity.

These units are also constructed in the vertical cylindrical and horizontal box type configurations and therefore could be selected in the opposite configuration of the crude distillation heater described previously. The unit configuration is an important parameter for consideration. Therefore, both types should be studied, if possible.

Another potentially significant market for CWF fuels could be in enhanced oil recovery steam generators. Since accurate numbers for the total number of enhanced recovery steam generators in the U.S. do not seem to be available, the numbers which we will have to concentrate on are from California. This will not introduce a large error in the estimate since well over 90% of all the U.S. enhanced oil steam generators are in California.

According to a 1979 publication by the California Air Resources Board there were 1049 active enhanced recovery steam generator permits. C-E Natco personnel estimate that there are currently approximately 1200 units in California (about 1,000 greater than 50×10^6 Btu/hr and 200 less than 50×10^6 Btu/hr).

Of these 1200 units we estimate at least 75% are presently firing oil with the remainder being fired by gas. Most of the units are equipped for both gas and oil firing and the oil companies switch back and forth depending upon fluctuations in gas and oil pricing and availability.

If we assume there are 1,000 - 50 MM Btu/hr units (62.5×10^6 Btu/hr heat release) and 200 - 25×10^6 Btu (31.25×10^6 Btu/hr heat release) the total annual oil consumption for the units will be about 0.4 Quads.

If it were assumed that all 1200 units were firing on oil, the annual oil consumption would be approximately 81,200,000 bbl (0.5 quad/yr) or roughly 10% of all the crude that the U.S. is currently importing (2.3×10^6 bbl/day imported crude).

3.4.2 BACKGROUND--EXPLORING THE FEASIBILITY OF FIRING COAL-WATER FUELS IN EXISTING INDUSTRIAL PROCESS HEATERS

Coal was fired in some early process heaters but was phased out of use about thirty years ago as inexpensive (and abundant) gas and oil supplies became available. In the 1970's the price of fuel gas and oil rose and supplies of these fuels became erratic. The American Petroleum Institute (API) in 1977 investigated the conversion of then existing process heaters to coal firing. The API concluded that existing process heaters, which had evolved between the 1950's and 1970's, and which were based on oil and gas firing, were not suitable for conversion to coal firing (5). The API based its conclusion on the available coal firing systems in the utility industry at that time (pulverized or stoker firing) and extrapolated problems with those firing system to process heaters. The API identified the following problem areas for converting process heaters to coal firing:

- High temperature service process heaters with metal parts which operate near the coal ash fusion point would be subject to corrosive agents in the coal ash.

- Heat absorption rate control and distribution.

- The need for rapid extinction of combustion when thermal decomposition in the process coil is detected (applicable to stoker firing only).

- The lack of detailed knowledge of coal flame characteristics and heat transfer as it pertains to process heater services.

- Slagging and fouling of pressure parts and refractories.

- Burner development

- Heater availability (on-stream time)

- Limited space around existing heaters for coal handling and storage and for flue gas clean-up equipment.

Since 1977, process heater designs have continued to evolve. New heater designs have also been developed that may permit pulverized coal firing (6), and at least two heaters employing such a design have been installed and have started operation. However, these two heaters do fire a fuel containing ash but the ash levels are comparable to typical fuel oils.

There has been no reported recent testing of coal firing (in pulverized, stoker or CWF form) in process heaters. The substitution of CWF firing in place of oil or gas in process heaters could have similar economic advantages compared to boilers provided the modifications needed are similar to boiler installations.

3.4.3 <u>A COMPARISON OF BASIC PARAMETERS OF ELECTRIC UTILITIES VS. HYDROCARBON PROCESSING INDUSTRIES</u>

Large, modern fossil fuel fired electric utility and hydrocarbon processing plants have comparable total heat input capacities - on the order of one to ten billion British thermal units (Btu) per hour. An electric utility plant's total heat input is supplied in one, or up to five large boilers. A hydrocarbon processing plant's total heat input is supplied in numerous process heaters (some plants can have more than 20 different, individual service heaters) and small industrial boilers. The heat input per unit in a processing plant can be one tenth to less than one twentieth of a utility boiler. The large number of relatively small heat input capacity process heaters are needed because of the many processing steps in the plant that require precise control to optimize the operation of the plant.

The numerous processing steps in a hydrocarbon processing facility require additional equipment besides the heaters. The equipment includes reactors, columns, vessels, heat exchangers, tanks, pumps, piping, valves, etc. The layout of a hydrocarbon facility must be compact and as simple as possible to reduce costs for piping and still allow adequate access to equipment. Free spaces around process heaters are either very limited, non-existent or are specifically set aside for maintenance requirements.

Modern designs for utility or industrial boilers and process heaters evolved from similar beginnings - old designs had heat absorbing tubes located away from refractory walls in the combustion chambers. The relatively simple process of heating, vaporizing and superheating a single component fluid (water) permitted the use of high radiant flux rates in boilers. The heating and vaporization of multi-component fluids (hydrocarbons) can cause decomposition of some components inside the heat absorbing tubes in a process heater. The decomposition of hydrocarbons inside a process coil is not desirable as it causes overheating of the metal which can lead to failures of the tubes. Hydrocarbon decomposition also reduces product yields which affect plant economics. (Overheating of boiler tubes also occurs, but a failure of a boiler tube does not introduce an uncontrolled, combustible fluid into the unit.)

The two fuels common to boilers and process heaters (gas and oil) produce no or low levels of deposits which can adhere to heat absorbing surfaces. Coal, because it contains mineral components, produces deposits which can adhere to heat absorbing surfaces. Deposits on these surfaces shift the heat absorption to different locations inside the unit.

The complex heating and vaporizing service in process heaters requires low flux rates (compared to boilers) and only small shifts in these rates. The simple heating and vaporization of water in boilers allows high flux rates and larger shifts in these rates. (Table 3-8 presents typical design factors for boilers and process heaters.) The fuels commonly fired in process heaters (oil and gas) help to satisfy the process heater operating requirements. The simpler requirements in a boiler have permitted the firing of less predictable fuels (such as coal).

The factors determining the economic viability of facilities in the electric utility industry and the hydrocarbon processing industry differ. A fossil fuel fired utility produces a single product (electricity) from the combustion of fuel using a relatively simple thermal cycle. The combustion of fuel produces steam at controlled conditions which then drives a turbine/generator. A power plant is designed around a fuel or fuels which are imported into the plant. Fuel is a direct factor in an electric utility plant's economics.

A hydrocarbon processing facility produces a variety of hydrocarbon products for a projected market from a variety of hydrocarbon sources using a variety of processing technologies. Fuel in a hydrocarbon processing plant is used to supply the energy needed for the process technology. Changes in feedstocks and operation conditions affect the yield of valuable or marketable products. No process technology or group of technologies can produce 100% yield of a single valuable product from a feed stock source.

TABLE 3-8

TYPICAL BOILER AND PROCESS HEATER DESIGN PARAMETERS

Design Parameter	Oil- or Gas-Fired Boiler	Coal-fired Boiler	Oil- or Gas-fired Process Heater
Average radiant absorption per unit circumferential tube area (Btu/hr.ft^2)	N.A.[a]	N.A.	12,000
Heat release rate per unit volume (Btu/hr.ft^3)	50,000	20,000	10,000
Heat release rate per unit wall area (Btu/hr.ft^2)	170,000	80,000	40,000
Maximum gas velocity in convection zone (ft/sec)	120	70	30

a Values not defined.

Fuel oil and gas in a hydrocarbon facility are by-products of the process technology and are generally less valuable than other products. In some cases these fuels may not have a market at all or may require additional processing equipment to upgrade the fuels into marketable products. The economics of a hydrocarbon facility are thus tied to the value and marketability of fuel produced in the facility along with the other products. Fuel has less direct impact on hydrocarbon processing facility economics because it is a by-product.

The operating requirements needed to meet the product demands of an electric power plant and a processing plant also differ. Electric power requirements vary seasonally, daily and hourly. Power plants are commonly called base load, stand-by and peaking. These terms and the plants they represent reflect the almost instantaneous change in demand for electricity from the market that a power plant may serve. Electricity cannot be stored economically so utilities build more capacity for a market than is actually needed for "average" conditions to insure demand is met at all times. This required overcapacity in the electric utility industry permits the ratio of useful production time in a given time period compared to the total time period to be around 80%, because excess capacity can help meet demand at any given time. This overcapacity also allows utility units to be out of operation for long periods of time if needed.

The product demands in a market area near a hydrocarbon processing facility are almost constant in most cases, or vary only seasonally. If slight changes in product yields are required, the operation of portions of the plant can be varied to meet changes. Additionally, hydrocarbons can be stored economically to prepare for anticipated changes in market demands. Hydrocarbon processing facilities are therefore designed for "average" or near-constant market conditions with little, if any, excess capacity. It is not economical to build excess capacity in a hydrocarbon facility and only use the excess capacity on an intermittent basis. If more capacity is required for an increase in market demand, existing plants are modified to increase capacity slightly or new plants are built. The lack of excess capacity in hydrocarbon processing plants requires that the numerous components in the plant, including the heaters, operate with high availability - well over 90% in most cases.

The high availability requirement of process heaters is a key factor in the operation of a hydrocarbon processing plant. If one heater is not operating, it may force the whole plant to be shut down because each processing step relies on the operation of another. Additionally, almost all process heaters using external equipment such as air preheat systems (to achieve high efficiency) and fans are capable of high capacity operation without the external equipment in operation. This allows the heater and plant to operate if mechanical equipment that is external to a heater is out of service for any period of time.

The acceptable pay-back time period (the ratio of total installed cost of a modification divided by the operational cost savings per year of a modification) for equipment modifications also differ between the electric utility industry and hydrocarbon processing industry. Acceptable electric utility industry pay-back periods are generally five years or longer while in the hydrocarbon processing industry, acceptable pay-back periods are generally two years or less.

3.4.4 HISTORY OF DEVELOPMENT AND EVOLUTION OF PROCESS HEATER DESIGN

There are many different hydrocarbon services and design requirements to which heater designs have been applied. There are also many different designs of process heaters. The design of process heaters has been based on reliability of operation, efficiency of heat recovery, type of fuel fired, burner technology used and price competition. The following brief discussion reviews the development and evolution of modern process heaters in areas as it pertains to the feasibility of firing coal-water fuels.

Early process heater designs were almost all of horizontal tube cabin configuration (refer to Figures 3-37 through 3-44). Tubes are located away from refractory walls to allow heat input to all sides of a tube at one time. This design feature is used to permit maximum utilization of the heat absorbing surface while minimizing local variations at each tube that could lead to decomposition of the hydrocarbon fluid. The flow of the products of combustion (flue gas) as it left the radiant combustion chamber and traversed to and across convective heat transfer surface (if it existed) varied between designs (refer again to Figures 3-37 through 3-44). Calculation procedures for the process and heat transfer of early designs were imprecise by today's standards. Early heater design was more an art than a science.

Experience gained from the actual operation of the early heaters was applied to "improved" designs. Heater flux rates (the heat transfer rate per square foot of tube surface) were revised upwards or downwards in designs until economically acceptable reliability or on-stream time parameters were met. Standards for certain portions of heaters were established for certain services.

Radiant combustion chambers of early heaters were large, with low heat release rates per cubic foot of chamber volume. Firing in early heaters was almost always horizontal. Fuels fired included oil and gas and occasionally pulverized coal or coke. The solid fuels were generally sprayed into or over oil flames. Horizontal firing of oil was used to

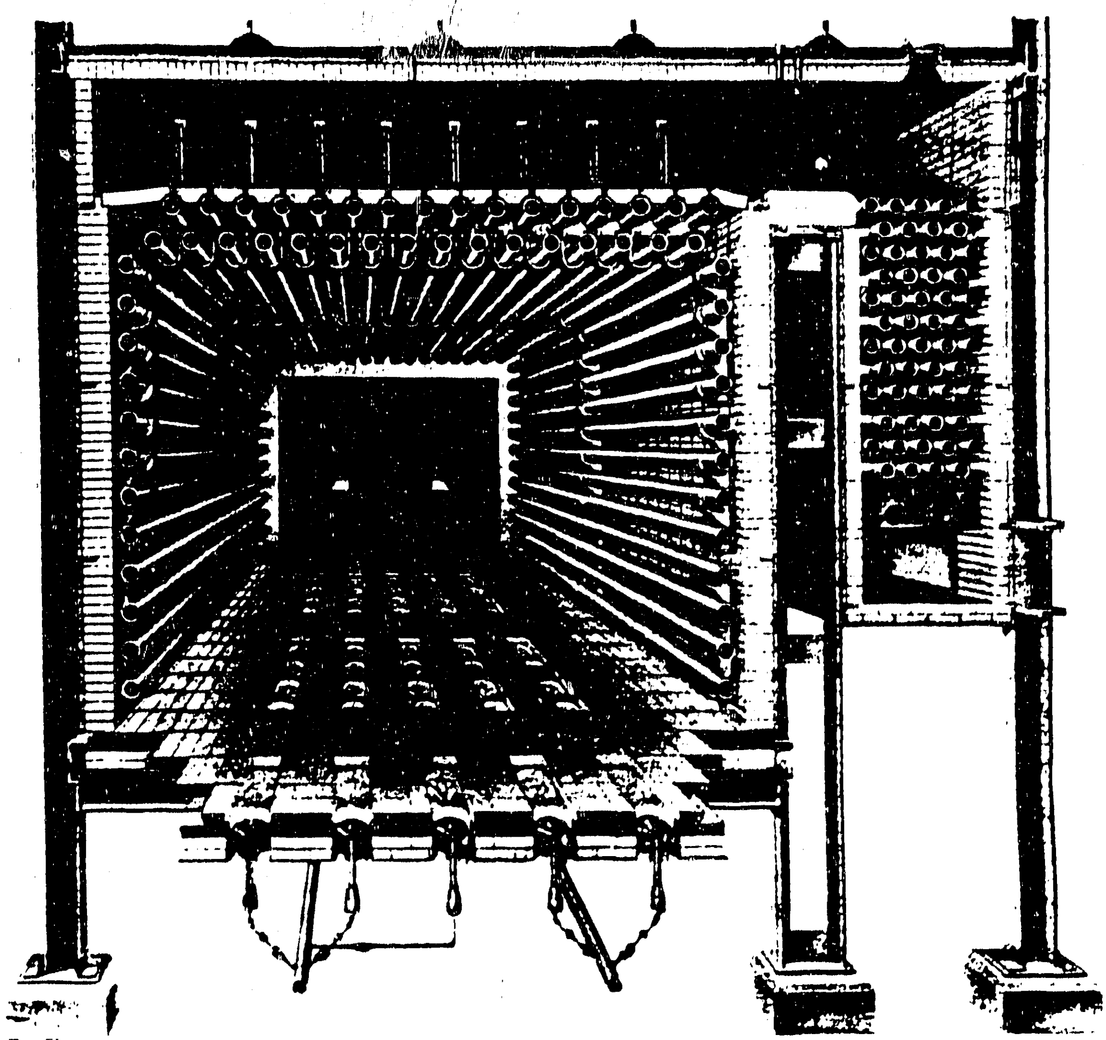


FIGURE 3-37
HORIZONTAL CABIN HEATER WITH SIDE MOUNTED DOWN FLOW CONVECTION

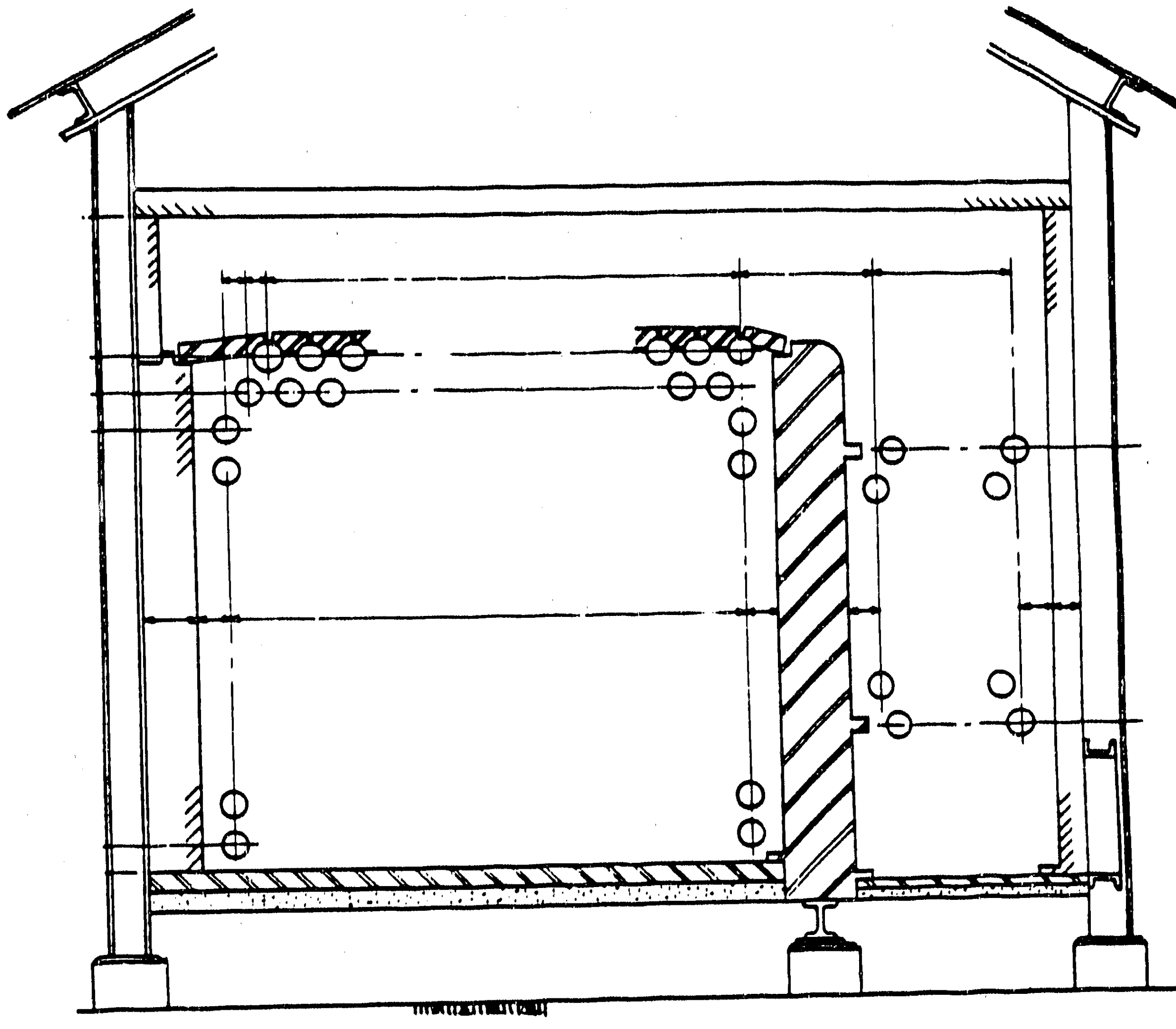


FIGURE 3-38
HORIZONTAL CABIN HEATER WITH SIDE MOUNTED DOWN FLOW CONVECTION

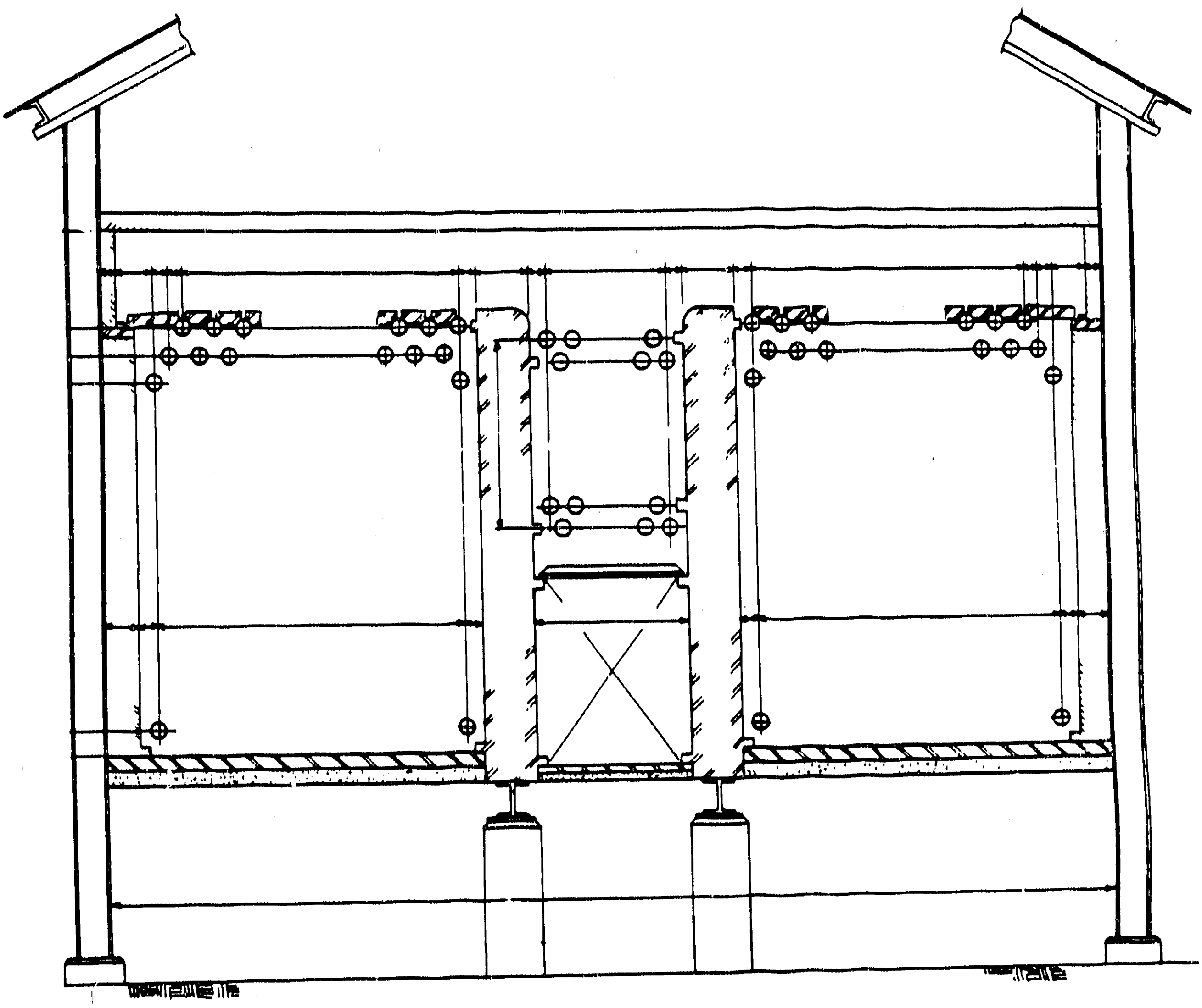


FIGURE 3-39
HORIZONTAL CABIN HEATER WITH CENTRAL DOWN FLOW CONVECTION

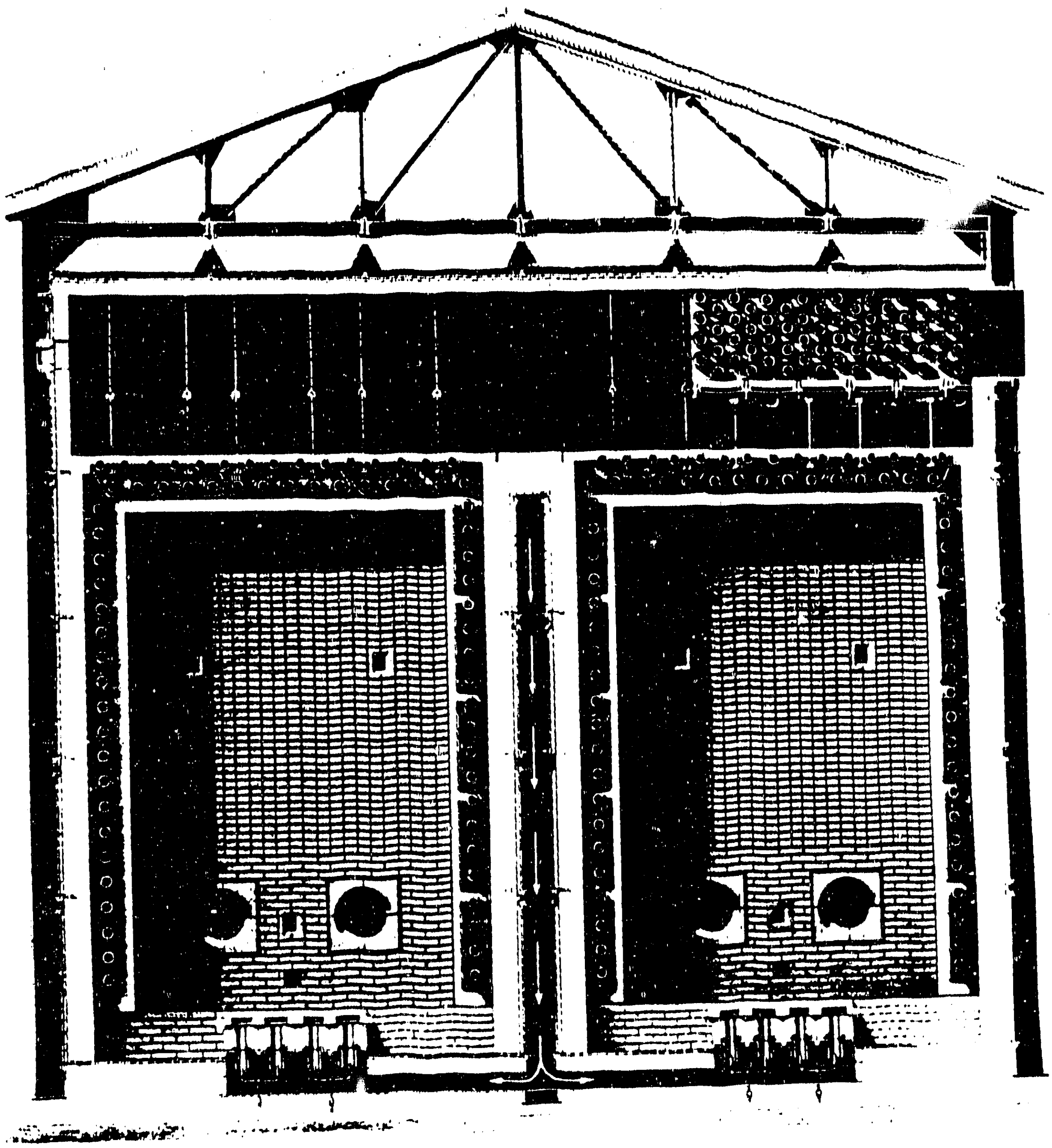


FIGURE 3-40
HORIZONTAL CABIN HEATER WITH OVERHEAD, SIDE FLOW CONVECTION

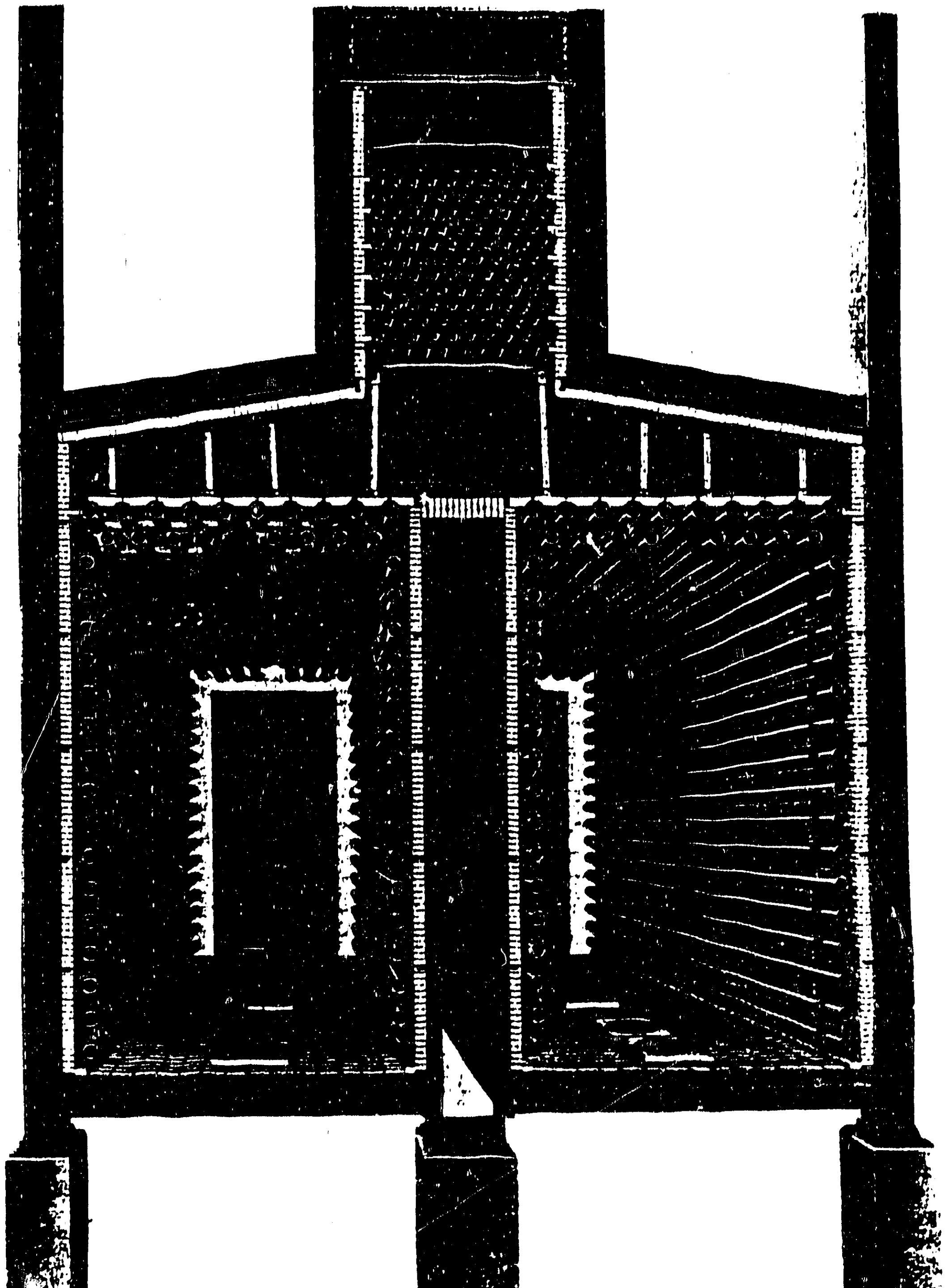


FIGURE 3-41
HORIZONTAL CABIN HEATER WITH OVERHEAD CONVECTION

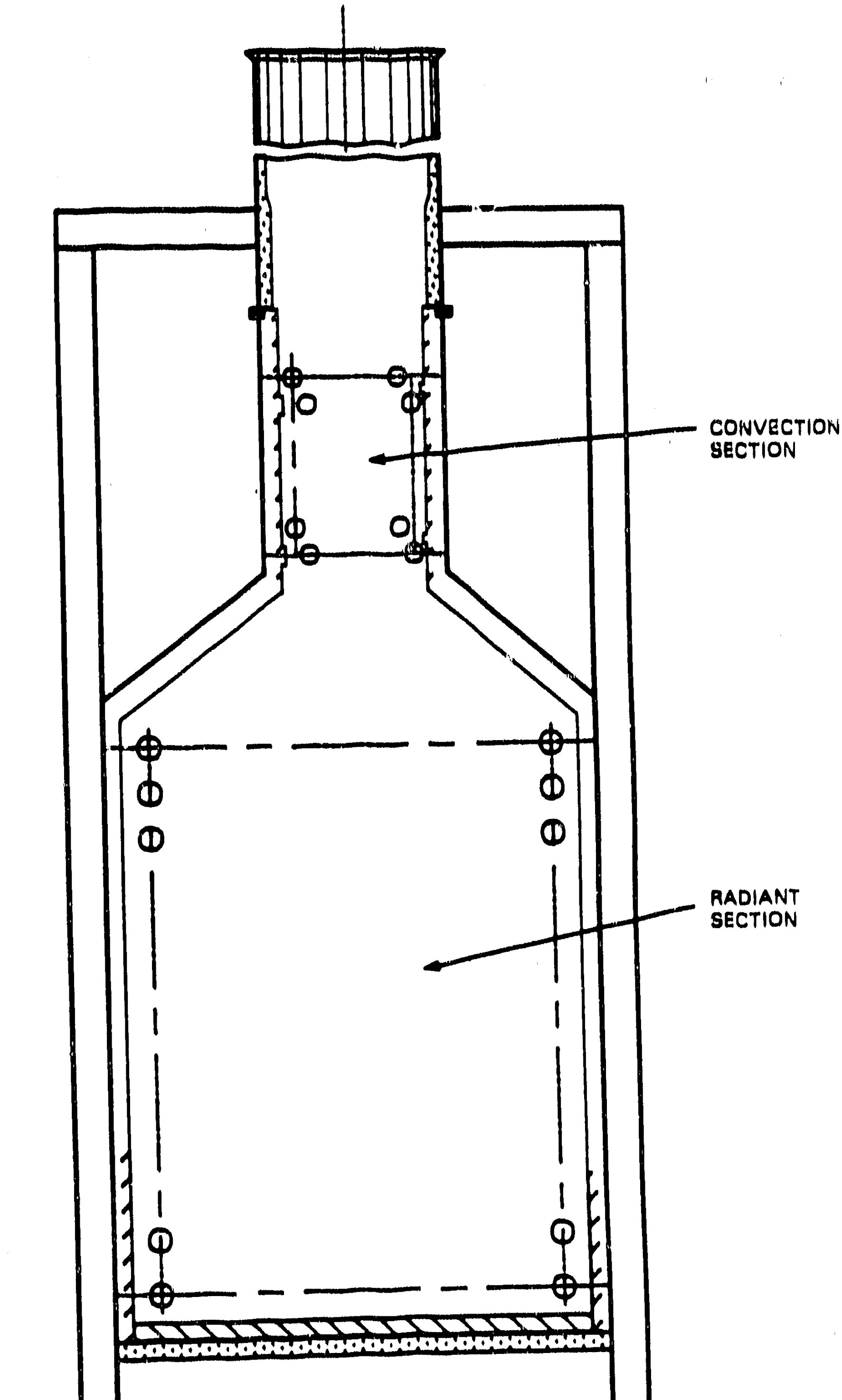


Figure 3-42. HORIZONTAL CABIN HEATER WITH OVERHEAD CONVECTION

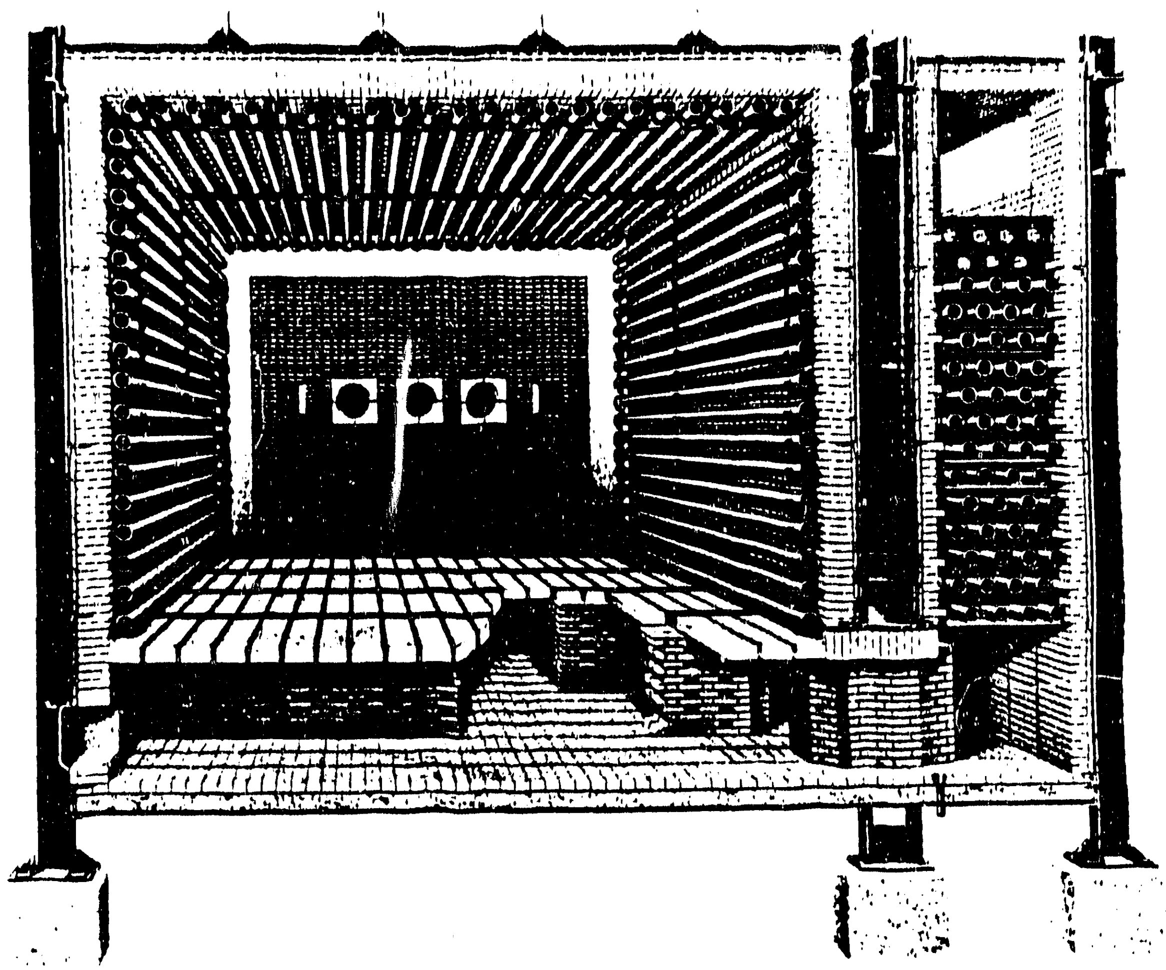


FIGURE 3-43
"HEAVY OIL" FIRED HEATER

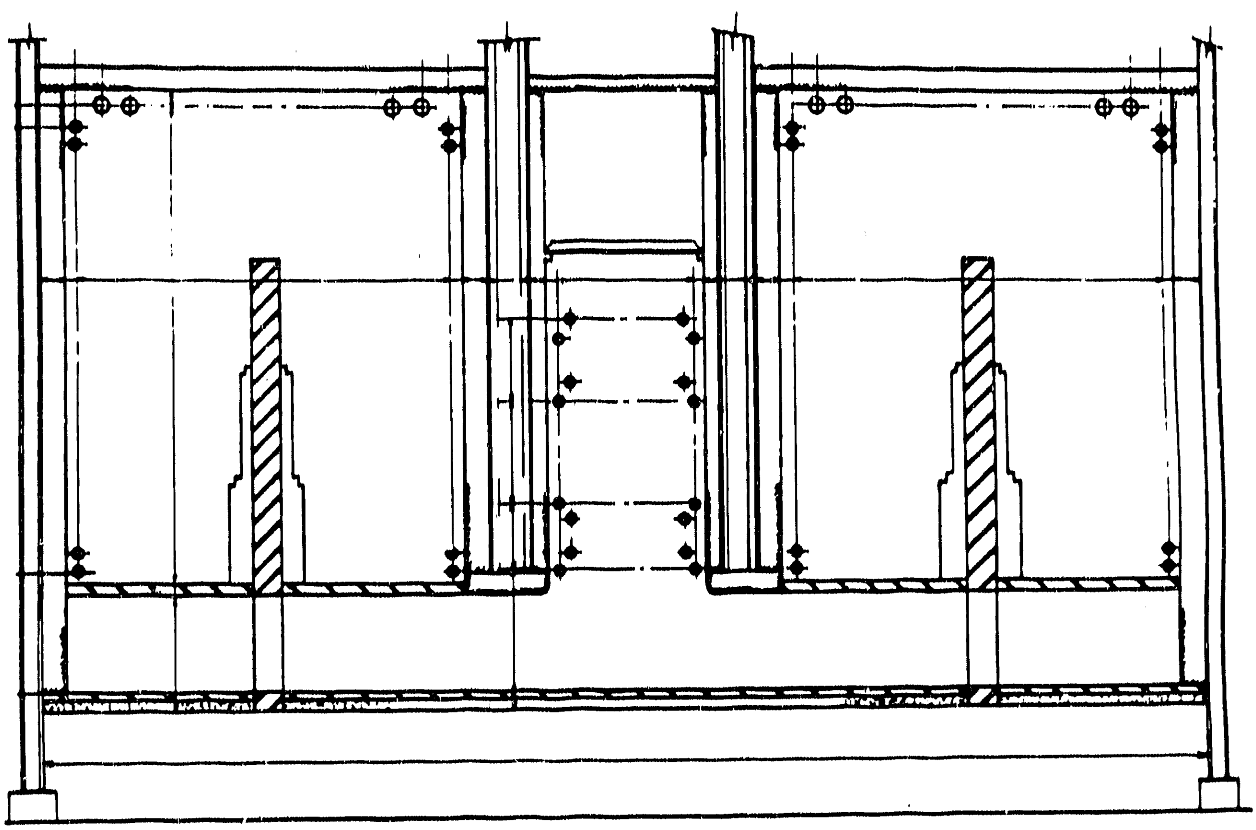


FIGURE 3-44
"HEAVY OIL" FIRED HEATER

avoid problems with fuel spills in overhead, vertically firing burners. Heaters firing "heavy" fuel oil (essentially No. 6 fuel oil), or oil and coal, usually had bare (no extended surface) tube convection sections with the convection sections located to the side of the combustion chamber. Flue gas exited the radiant chamber of these "heavy" oil fired heaters near grade and flowed through ducts below the combustion chamber to the convection section (refer to Figures 3-43 and 3-44). These ducts had access panels in them to permit ash removal. Ash, if it accumulated, was removed from the ducts only if it affected operation, or at scheduled plant shutdowns.

Improvements in burner technology greatly reduced the problems with oil spills and fuel tip clogging and thus permitted reliable vertical firing of fuel oils - even "heavy" oils. Better understanding of process flow regimes in the heater coils permitted the use of vertically disposed tubes in the radiant sections of some heaters and slightly higher radiant flux rates. These developments allowed heater manufacturers to design vertical cylindrical heaters - the most compact and economical heater design for many services (refer to Figures 3-45 and 3-46). Industry standards for fuel oils were also established with strict limits for ash content. Extended surface was used in convection sections of "heavy" oil fired heaters and was found to meet operating criteria. These standards, improvements and better understanding of heater technology essentially eliminated the heater designs with horizontal firing, bare tube convection sections and ash collection ducts under the radiant and convection sections, due to price competition.

Some modern heater designs are still horizontally fired from endwalls or sidewalls due to client preference, but these designs represent only a small fraction of the heaters in operation today. Vertical firing of coal was not tried in process heaters and coal firing was phased out of use as inexpensive gas supplies became available or as processing techniques respondea to different markets and produced more by-product fuel oil or gas which was fired in the heaters. The last coal or coke fired process heaters probably went out of service in the late 1940's or early 1950's.

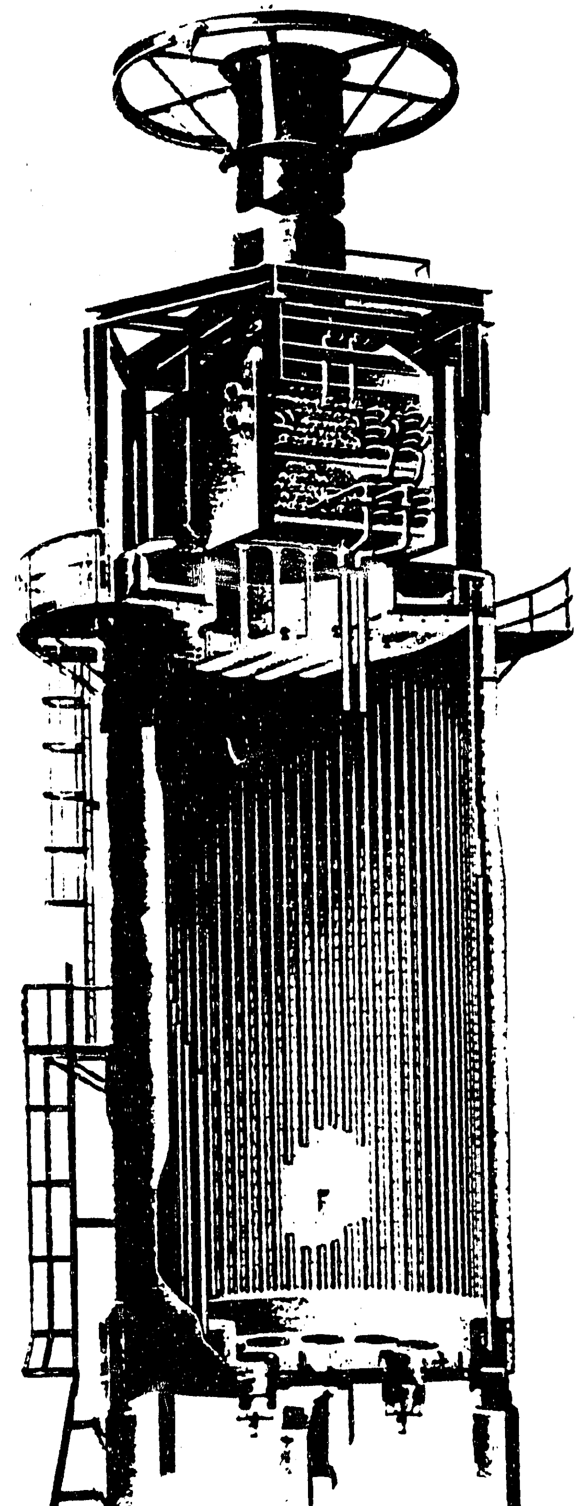


FIGURE 3-45
VERTICAL CYLINDRICAL HEATER

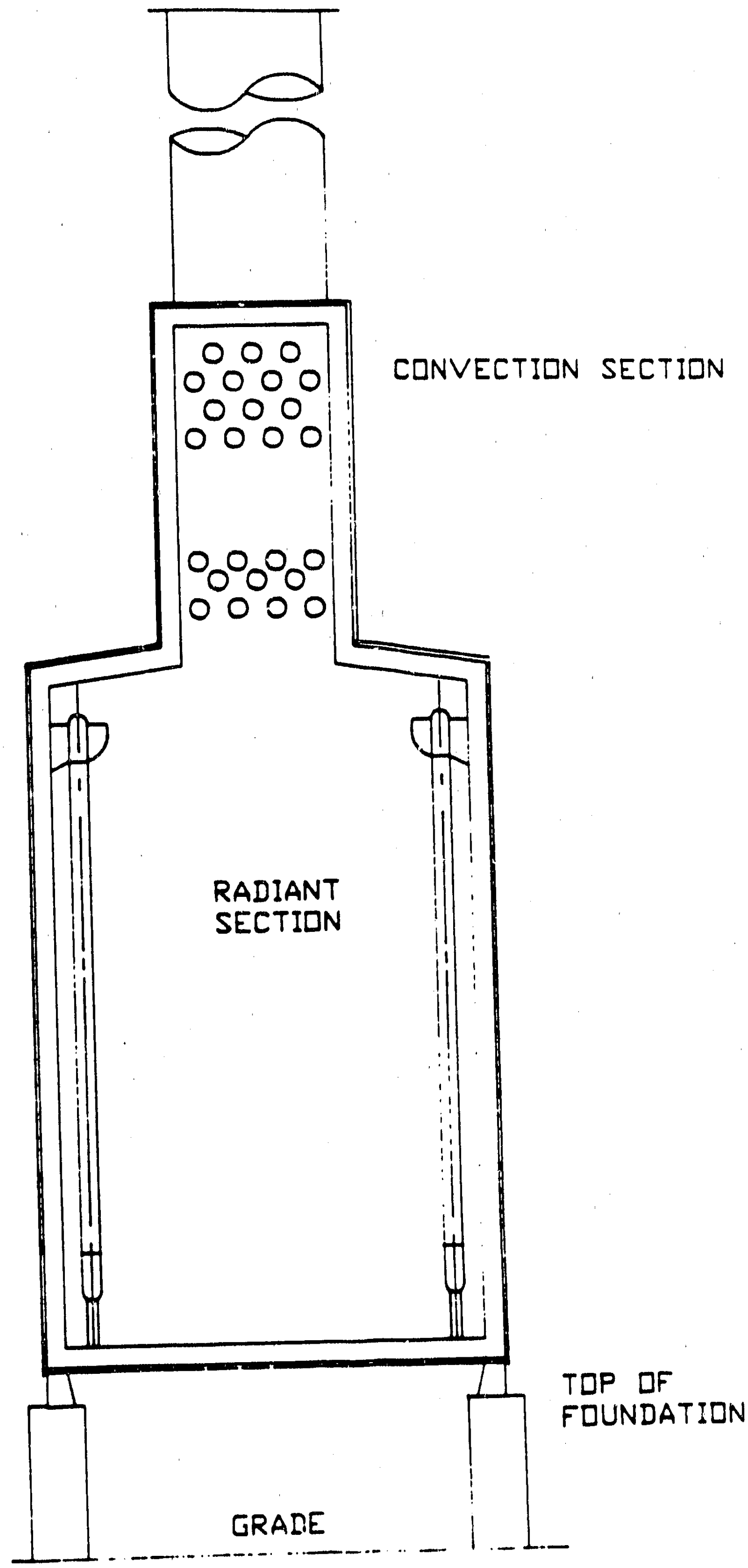


FIGURE 3-46
VERTICAL CYLINDRICAL HEATER

As experience in calculation procedures for radiative and convective heat transfer and inside the coil process mechanisms grew, fired heater sizes shrunk for a given heat absorption while maintaining reliability and on-stream time parameters. Higher thermal efficiency designs were made, air preheat systems came into use, new light weight refractories were developed and used and larger heaters in more complex plants were designed. Economics of a plant favored thermally efficient but compact heater designs. That trend was accelerated with the rise in the cost of fuels, feedstocks, materials and labor.

Modern process heater designs can be described as the near optimization of complex process technology and simple fuel combustion in a compact, highly reliable package. Modern designs are a blend of the old designs on the process side (inside the tube) along with reductions in the physical size of equipment due to component technology and heat transfer calculation technique improvements. Modern heaters are highly efficient thermally, cost effective and very reliable - on stream time for plants that use process heaters is commonly measured in years.

3.4.5 SELECTION OF PROCESS HEATERS FOR REVIEW IN THIS STUDY

Process heaters are categorized by two general and loosely fitting terms (service and configuration) that have become accepted throughout the hydrocarbon processing industry. Unfortunately, these two terms do no fully describe what happens to the feedstock (service) nor do they fully describe the arrangement of the heat absorbing coils, burner layout, fuels fired or, geometry (configuration) of a heater. Heaters are designed for specific services and as a consequence there are hundreds of process heater designs in service. Some heater configurations are suitable for more than one specific service but specific designs have been developed and used for specific services. Competitive costs, experience and owner preference generally determine what type of design is used for a given service.

A survey of over seven hundred process heaters manufactured by one supplier in the United States was made. The survey categorized the heaters by the two terms described above with the following sub-categories:

Configuration:	Vertical Cylindrical
	Horizontal tube Cabin
	Vertical tube Box
	Other
Service:	Vaporizing
	All liquid
	All vapor
	Pyrolysis
	Other

The survey also categorized the heaters by their total heat absorbing capacity (duty) and the decade they were designed.

It is noted that although two heater services (pyrolysis and other) were included in the survey of heaters, they are not considered adaptable to coal firing in any form. This is because these heaters involve high temperature processes and have metal parts which operate near the coal ash fusion temperature and thus would be subject to severe corrosion conditions when firing coal. These two heater services represent about 25% of all heaters and total duty in the survey.

The survey revealed trends in the duties of the heaters over time and trends in the use of configurations and services over time. The survey allowed the selection of two heaters as "typical" of a majority of the process heaters in the United States. The two selected heaters represent a major portion of the services and configurations of all process heaters in the survey and have duties close to the average duty of all heaters in the survey. The selected heaters have services which would not impose additional constraints for coal firing due to ash corrosion.

The two selected oil fired heaters, which were designed in the mid 1970's and are in operation today, are as follows:

Unit F

This heater is located in a Midwest refinery, and is a 54.4×10^6 Btu/hr, vertically fired, vertical cylindrical fractionator preheat (vaporizing service) heater. The heater shares a combustion air preheat system with another process heater of similar duty but different service. The heater was designed for a very compact plot area (thus requiring a vertical cylindrical design) inside the plant. The process fluid in the heater is a fraction of the total feedstock input into the plant and is ultimately made into gasoline. This heater relies on the operation of upstream equipment and produces one of the most valued products of the plant. The arrangement of this heater is similar to Figure 3-45.

Unit G

This heater is located on the West Coast and is a 103.8×10^6 Btu/hr vertically fired, horizontal tube cabin style crude (vaporizing service) heater. This heater also shares an air preheat system, with an identical service and duty heater. The horizontal design and maximum degree of prefabrication (narrow width) of the heater design were client design requirements to fit an open area of the plant near existing equipment, to allow tube pulling in a horizontal position and to reduce field erection costs and unit downtime. This heater is the initial processing step in the refinery. Every processing step downstream of this heater relies on its operation. The arrangement of this heater is similar to Figure 3-42.

These two heater designs were used as the basis for applying the data collected on coal-water fuel firing tests to determine if it is feasible to fire coal-water fuels in existing fired heaters. Data for these two heaters are contained in Table 3-9.

TABLE 3-9

COMPARISON TABLE - Typical Utility Boiler vs. Selected Vertical Cylindrical and Selected Horizontal Cabin Process Heaters

ITEM	TYPICAL UTILITY BOILER	UNIT F	UNIT G
Configuration	-	Vertical Cylindrical	Horizontal
Service	Generate & Superheat Steam	Vaporize Hydrocarbons	Cabin Vaporize Hydrocarbons
Fuel	Coal	Oil	Oil
Absorbed Duty, 10^6 Btu/Hr	-	54.4	103.8
Thermal Efficiency, %	-	91.85	89.0
Use of Preheat	Yes	Yes	Yes
Volumetric Release Btu/Hr-Ft^3	14,000-18,000	9040	6850
Firebox Temperature, °F	-	1660	1670
Heat Release/Surface Area (Btu/Hr-Ft^2)			
Heat Release/Floor Area (Btu/Hr-Ft^2)	2,000,000-2,200,000	352,500	182,000
Heat Absorption Rate (Btu/Hr-Ft^2)	Not Applic.	12,000	12,000
Firebox Residence Time (Sec)	1.0-1.5	7.3	9.1
Burners			
- Location	Walls and Corners	Hearth	Hearth
- Number	Various	8	20
- Release Rate 10^6 Btu/hr	Various	7.39	5.9
- Firing Direction	Horizontal	Vertical	Vertical
- Centerline to Tube, Ft	Not Applicable	4.25	5.08
- Arrangement*	Not Applicable	Circular	Straight Line
- Natural Draft Provisions	No	Yes	Yes
- Air Temp. to Burners, °F	Various	677	700

*Arrangement is pattern of burners at firing location

TABLE 3-9
COMPARISON TABLE (Cont'd)

ITEM	TYPICAL UTILITY BOILER	UNIT F	UNIT G
Insulation Type			
- In Radiant Section	Not Applic.	Dense Castable	Ceramic Fiber
- In Convection	Not Applic.	Dense Castable	Dense Castable
Cleaning Facilities			
Type	Sootblowers	Sootblowers	Sootblowers
Location	Radiant & Convection	Convection	Convection
Run Time	Various	1-2 Years	1-2 Years
Availability	80%	90+%	90+%
Convection Section Velocity			
$Lb/Hr\text{-}Ft^2$	Not Applic.	2200	1150
Ft/Sec Min	60	12	9
Max	80	30	18
Extended Surface			
Type	Fins	Fins	Fins
Height, in.	0.75	0.75	0.75
Thickness, in.	0.06	0.105	0.105
Number/in.	2.0	3.0	3.0
Convection Tube Layout	Square Pitch	Triangular Pitch	Triangular Pitch
Fin Tip Clearance, in.	2-3	3.875	2-4
General Dimensions (Radiant Section)	Not Applic.		
Height, Ft		39	27
Length, Ft		-	62
Width, Ft		-	10.33
Diameter, Ft		14.6	-

4. PERFORMANCE ANALYSIS GUIDELINES

The thermal performance of each of the seven study units was analyzed for each of four Coal-Water Fuels below. The four CWFs are among twelve CWFs which were tested as part of the DOE project. The four study fuels are:

* Upper Freeport 6.8% Ash (UF6.8)
* Splash Dam 5.7% Ash (SD5.7)
* Cedar Grove 7.9% Ash (CG7.9)
* Cedar Grove 4.8% Ash (CG4.8)

(The number associated with each fuel refers to the ash content of the fuel - dry basis.)

In addition, a fifth Coal-Water Fuel, Splash Dam 2.6 (SD2.6), was evaluated for Unit C. This fuel produced considerably less erosion of the test section in the Task 5 portion of the laboratory tests discussed below. Unit C was chosen as the one unit having the potential for the greatest load increase with this fuel. Unit B was capable of only a minor load increase, while the remaining units were limited by other criteria. A sixth Coal-Water Fuel, Alma 5.9 (AL5.9), was evaluated for utility units A and C and industrial Unit E. The fine grind version of this CWF produced considerably less erosion of the test section used in the Task 5 laboratory tests.

These particular fuels were chosen to provide a basis for studying the effects of:

* Ash Slagging and Fouling Characteristics
* Ash Quantity and the Effect of Coal Cleaning
* Erosion Potential

The detailed analysis of each fuel is tabulated on Table 4-1.

Each of the CWFs was tested in the C-E laboratory facilities under Tasks 4 and 5. Testing included:

* Slagging and Cleaning of Furnace Walls
* Fouling and Cleaning of Convection Banks
* Erosion of Test Section
* Carbon Conversion Efficiency Determination
* Atomization Variation
* Flame Stability and Turndown

Based on the results of the laboratory testing and on general principles which have been developed for CWF firing and operation, the following guidelines were defined for use in predicting the CWF performance of the units.

4.1 Furnace Performance

A. Furnace heat absorption rates and outlet temperatures are determined by the use of appropriate calculating procedures and computer programs. When appropriate, allowance is made in the calculations for:

1. Furnace wall slag thermal resistance (as indicated by results from the lab tests)

2. Furnace flame radiation characteristics (as indicated by results from the lab tests)

3. Estimated flame lengths (CWF relative to oil firing)

TABLE 4-1 ANALYSIS FOR EACH COAL WATER FUEL

Fuel Type	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Proximate, Wt. %						
Moisture (Total)	30.4	30.6	30.9	32.1	30.3	36.0
Volatile Matter	23.1	21.0	22.6	23.0	21.6	23.9
Fixed Carbon (Diff.)	41.8	44.4	41.0	41.5	46.3	36.3
Ash	4.7	4.0	5.5	3.3	1.8	3.8
Total	100.0	100.0	100.0	100.0	100.0	100.0
HHV, Btu/lb	9,785	10,125	9,410	9,680	10,535	8,803
LB Ash/MM Btu	4.8	3.9	5.8	3.4	1.7	4.3
Ultimate, Wt. %						
Moisture (Total)	30.4	30.6	30.9	32.1	30.3	36.0
Hydrogen	3.5	3.4	3.5	3.3	3.5	3.0
Carbon	55.0	56.8	53.7	54.3	59.7	50.6
Sulfur	1.2	0.5	.6	.5	0.5	1.0
Nitrogen	1.0	1.0	1.1	1.0	1.3	1.0
Oxygen (Diff.)	4.2	3.7	4.7	5.4	2.8	4.5
Ash	4.7	4.0	5.5	3.3	1.8	3.8
Total	100.0	100.0	100.0	100.0	100.0	100.0
Ash Fusibility, °F						
I.T.	1,980	2,390	2,350	2,350	2,270	1920
S.T.	2,270	2,770+	2,600	2,600	2,700+	2240
H.T.	2,390	2,770+	2,700+	2,700+	2,700+	2390
F.T.	2,460	2,770+	2,700+	2,700+	2,700+	2510
Ash Composition, Wt. %						
SiO_2	45.3	57.1	54.2	54.2	47.1	48.9
Al_2O_3	24.7	27.2	26.4	26.4	30.8	22.8
Fe_2O_3	21.5	7.4	8.8	8.8	11.7	18.0
CaO	1.6	0.9	2.0	2.0	2.2	3.9
MgO	0.7	0.8	1.0	1.0	0.6	0.7
Na_2O	0.4	0.8	.4	.4	1.9	0.7
K_2O	2.5	2.1	2.4	2.4	1.1	1.3
TiO_2	2.1	2.1	2.2	2.2	1.6	1.8
SO_3	0.6	1.4	1.2	1.2	1.4	1.0
Total	99.4	99.8	98.6	98.6	98.4	99.1

B. The furnace operating limits and parameters are as follows:

1. Excess Air (Normal Operation): 25%
(If unit loads could be raised by using higher air flow 30% excess air was used.)

2. Minimum Air Preheat Temp.: 300°F

3. Maximum Furnace Liberation (Q fired/furnace volume): 25,000 Btu/hr-ft^3
(This was limited to ensure adequate carbon conversion efficiency.)

4. Gas Recirculation - Was limited as a function of furnace liberation, excess air, and injection location to ensure that the gas recirculation did not adversely affect carbon conversion.

Maximum Allowable Gas Recirculation (GR)

i. For Furnace Liberation less than 20,000 Btu/hr-ft^3:

For 25% excess air: Max GR (thru Bottom) = 20%
Max GR (thru Windbox) = 15%

For 30% excess air: Max GR (thru Bottom) = 25%
Max GR (thru Windbox) = 20%

ii. For Furnace Liberation = 25,000 Btu/hr-ft^3 max:

For any excess air: Max GR = 0 % (for Bottom or Windbox)

iii. For Furnace Liberation less than 25,000 but greater than 20,000 Btu/hr-ft^3:

Use linear interpolation between these two points.

C. With the above operating limits met, carbon conversion efficiency (% of total carbon burned) was estimated to be 99%. This value was used for calculation of boiler efficiency and related operating parameters. For the fine grind AL5.9 CWF, carbon conversion efficiency was estimated to be 99.5%.

D. Additional furnace operating limits (related to avoiding excessive furnace slagging) were:

1. Net Heat Input/Plan Area: Less than 2.1×10^6 Btu/hr-ft^2

2. Burner Zone Heat Release: Less than 650×10^3 Btu/hr-ft^2

For the SD2.6 fuel, these limits were relaxed and allowed to increase to 2.36×10^6 Btu/hr-ft^2 and 860×10^3 Btu/hr-ft^2, respectively, because of the low ash content of this fuel. Relaxing these limits enabled us to take full advantage of the 129 ft/sec Gas Velocity Limit established for this SD2.6 CWF. (See 4.2 A below.)

4.2 Convection Bank Limits

A. Erosion Velocity Limit

Laboratory tests of erosion potential yielded the following Gas Velocity Limits (based on a 2 mil per 10,000 hr metal loss rate criterion):

	FUEL					
	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Velocity Limit (ft/sec):	69	79	51	76	129	84

These limits apply to cross flow conditions and are average velocities at the bank. In certain convection bank arrangements these limits are adjusted to allow for possible high local velocities relative to the average. In addition, allowable velocities are reduced by 10% for load-supporting tubes.

B. Clear Space Limits

To minimize convection bank plugging, limits were established for the maximum gas temperature entering the convection banks. The temperature limits are a function of the clear space between adjacent tube assemblies. These limits are based on lab test results and previous field experience with coal firing. The maximum allowable gas temperatures (for clear spaces of 16 inches or greater) are set as follows:

	FUEL					
	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Gas Temp. Limit (°F)						
Platens:	2300	2500	2500	2500	2500	2500
Non-Platens:	2200	2400	2400	2400	2400	2400

Gas temperature limits are reduced for clear spaces less than 16 inches. The smaller the clear space, the lower the temperature limit.

C. Convection Bank Heat Transfer

Based on lab test measurements, estimates were made of the heat transfer effectiveness of convection banks. The resulting corrections, relative to conditions for oil firing, were developed for the five CWFs:

	FUEL					
	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Convection Effectiveness						
Platens or Panels:	-4%	+19%	+14%	+15%	+19%	+15%
Non-Platens:	-1%	+6%	+5%	+5%	+6%	+5%

These factors were employed in running the heat transfer computer programs and other convection pass calculations.

D. Economizer Arrangement Requirements

The following economizer arrangements were considered acceptable for CWF firing:

* Continuous Finned Surface
* Bare Tube, either in-line or staggered
* Spiral Fin (Must be in-line, with no more than 2 fins per inch)

If it was determined that an economizer was not in compliance with these restrictions, it was considered to be replaced with an in-line spiral finned economizer with 2 fins per inch. Sufficient surface was assumed installed to match the original economizer performance for oil firing. If the economizer was replaced, the following minimum clear space requirements (fin tip-to-fin tip) were applied:

	FUEL					
	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Replacement Econ. Clear Space Req.(inches)	2	1-1/2	1-1/2	1-1/2	1-1/2	1-1/2

The reduced clear space requirements for SD5.7, CG7.9, CG4.8, SD2.6, and AL5.9 CWFs reflect the lower fouling tendencies observed with these fuels during the lab tests.

4.3 Other Operating Conditions and Limits

A. Minimum Duct Metal Temperatures

To avoid excessive corrosion due to acid condensation in the gas ducts downstream of the boiler, the following minimum gas temperatures must be maintained for the gases leaving the regenerative air preheater (or economizer or last heat transfer surface in the gas pass if there is no air heater):

	FUEL					
	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Minimum Duct Temps.(°F):	296	281	285	282	280	295

B. Minimum Average Air Heater Cold End Temperature (ACET)

The following minimum ACETs were imposed for protection of the regenerative air heater cold end elements:

	FUEL					
	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6	AL5.9
Minimum ACET (°F):	158	155	155	155	155	155

C. Tube Metal Temperature Limits

In determining the maximum loads for each CWF, metal temperature limits were observed. Limits were specified for both mid-wall and outside tube metal temperatures. Two levels of limits were defined:

1. Preferred - These limits are equivalent to what would be used to design and build a new unit. These limits were imposed for any <u>new</u> sections installed as part of the CWF conversion.

2. Maximum - These limits are less conservative (allow higher temperatures). These limits were allowed for <u>existing</u> components, with the recognition that somewhat less than full lifetime may be obtained with their use.

D. Maximum Temperature Difference Between Main Steam and Reheat Steam

In calculating performance on CWF the following criteria were observed:

1. The main steam outlet temperature is not allowed to exceed the reheat steam temperature by more than 50°F.

2. The reheat steam temperature is not allowed to exceed the main steam temperature by any amount.

The above restrictions reflect typical temperature differential limitations of steam turbines.

E. Ambient Air and Fuel Temperatures

For calculation purposes, the ambient air temperature and the as-fired CWF temperature were assumed to be 80°F.

F. Desuperheater Spray Limits

Desuperheater spray flows were not allowed to exceed a level which caused the steam temperature after spray to come any closer than 20°F above saturation. The same criteria also applies to reheater spray flows.

G. Emission Limits

The emission limits assumed for this study reflect general limits found throughout the country, rather than specific limits which may apply to each actual plant. This approach was taken so that the conclusions drawn concerning emission control requirements would reflect a generalized situation rather than a site-specific one.

The following generalized emission limits were applied to all units studied:

Substance	Limit
SO_2	1.2 lb/10^6 Btu
NO_x	0.7 lb/10^6 Btu
Particulate	0.2 lb/10^6 Btu

4.4 Conservatism of Guidelines

Due to the present lack of field test results to confirm the laboratory results, a somewhat conservative approach was taken in establishing the guidelines. Use of these guidelines would therefore be unlikely to result in serious overestimation of a particular unit's load carrying firing CWF. On the other hand, there is the distinct possibility that data from future field test programs will justify the use of more liberal load limit criteria. The economic analysis was therefore conducted for two loads with each fuel-unit combination.

* Load based on criteria defined in this section.

* Load based on assumption that a more liberal set of criteria might be valid (a 20% increase in load capacity over the conservative limit was generally assumed.)

5. RESULTS OF PERFORMANCE ANALYSIS

PRINCIPAL LOAD LIMITERS

Tables 5-1A and 5-1B summarize general results of performance analyses for six fuels applied to some or all of the seven units selected for this study. A total of 32 combinations were considered. The summary shows that the deratings ranged from zero (for the two process heaters) to 77% (for the Type-A shippable unit). The principal load limiters proved to be:

Gas Velocity Limit	-	12 cases
Clear Space Temperature Limit	-	13 cases
Furnace Liberation	-	3 cases
Burner Zone Release Rate Limit	-	2 cases
NONE	-	8 cases
TOTAL		38 cases*

*Note - the total of cases is greater than the total of combinations because on some combinations more than one limiter applied.

LOAD LIMITERS AS FUNCTION OF FUEL FIRED

In general, the UF6.8 fuel represented the most restrictive fuel. This was usually because of the Clear Space Temperature Limit for this fuel, which was 200°F lower than the Limit for the remaining fuels. In contrast, the SD2.6 fuel used for the special study on Unit C represented the best fuel from the derating standpoint due to the high allowable Gas Velocity Limit (129 ft/sec). The SD5.7 fuel caused the minimum derating of the remaining five fuels usually because of its high allowable Gas Velocity Limit (79 ft/sec) compared to most of the other fuels. The CG4.8 fuel usually came close to the SD5.7 fuel in maximum load since its slagging and fouling characteristics closely approximates SD5.7 and its allowable Gas Velocity Limit is almost the same (76 ft/sec). The AL5.9 fuel had deratings close to SD5.7 and CG4.8 for the three units in which it was studied (Units A, C, and E).

TABLE 5-1A GENERAL RESULTS OF PERFORMANCE ANALYSIS

UNIT	TYPE	CWF	MAX LOAD (%)	LOAD LIMITED BY
A	U	UF6.8	33*	Clear Space at Upper Finishing SH;
A	U	SD5.7	74	Clear Space at Upper Finishing SH; Gas velocities at RH Front Crossover, Rear LTRH, WW Screen
A	U	CG7.9	44	Gas velocity at RH Front Crossover, WW Screen, Rear LTRH
A	U	CG4.8	71	Clear Space at Upper Finishing SH; Gas velocity at RH Front Crossover, Rear LTRH, WW Screen.
A	U	AL5.9	73	Clear Space at Upper Finishing SH; Gas Velocities at RH Front Crossover, Rear LTRH, WW Screen
B	U	UF6.8	30	Clear Space at Finishing Reheater
B	U	SD5.7	50	Gas Velocity at Rear LTSH
B	U	CG7.9	31	Gas Velocity at Rear LTSH
B	U	CG4.8	48	Gas Velocity at Rear LTSH
C	U	UF6.8	45	Clear Space at SH Platen
C	U	SD5.7	73	Gas Velocity - LTSH Cold (SH pass), Horiz RH #2 (RH Pass) Burner Zone Release Rate Limit
C	U	CG7.9	46	Gas Velocity - Horiz RH #2 (RH pass)
C	U	CG4.8	70	Gas Velocity - LTSH Cold (SH pass), Horiz RH #2 (RH Pass)
C	U	SD2.6	95	Clear Space, SH Platen; Gas velocity, Horiz RH #2 (RH pass)
C	U	AL5.9	71	Gas Velocity - LTSH Cold (SH Pass), Horiz RH #2 (RH Pass); Burner Zone Release Rate
D	I	UF6.8	23	Clear Space at Boiler Bank
D	I	SD5.7	30	Furnace liberation (BTU fired/furnace volume)
D	I	CG7.9	29	Furnace liberation
D	I	CG4.8	30	Furnace liberation
E	I	UF6.8	33	Clear Space at Spaced SH
E	I	SD5.7	54	Clear Space at Spaced SH
E	I	CG7.9	52	Clear Space at Spaced SH
E	I	CG4.8	53	Clear Space at Spaced SH
E	I	AL5.9	52	Clear Space at Spaced SH
F	P	UF6.8	100	No Limit
F	P	SD5.7	100	No Limit
F	P	CG7.9	100	No Limit
F	P	CG4.8	100	No Limit
G	P	UF6.8	100	No Limit
G	P	SD5.7	100	No Limit
G	P	CG7.9	100	No Limit
G	P	CG4.8	100	No Limit

*Utilities (Units A, B, C) % maximum electrical output to grid. Industrial (Units D, E) % of MCR steam generated

**For this case the limits were not quite met. (See Discussion)

"TYPE" code: U = Utility I = Industrial P = Process Heater

TABLE 5-1B GENERAL SUMMARY OF OPERATING CONDITIONS FIRING CWF

UNIT	TYPE	CWF	LOAD %	MAIN STEAM FLOW (MMBtu/hr)	FIRING RATE (MMBtu/hr)	EXCESS AIR (%)	GAS RECIRC. (%)	BURNER TILT (DEG)	SHOT (°F)	RHOT (°F)
A	U	UF6.8	33	1386	2083	30	25	+23	1005	952
A	U	SD5.7	74	3024	4263	25	9	-18	1005	960
A	U	CG7.9	44	1806	2705	25	13	+30	1005	955
A	U	CCA.8	71	2898	4127	25	9	-12	1005	955
A	U	AL5.9	73	2967	4285	25	9	-21	1005	977
B	U	UF6.8	30	907	1442	30	0	+13	955	912
B	U	SD5.7	50	1388	2180	25	0	+13	955	930
B	U	CG7.9	31	907	2108	25	0	+30	955	943
B	U	CCA.8	48	1332	1456	25	0	+19	955	936
C	U	UF6.8	45	2709	3941	25	0	0	1005	1004
C	U	SD5.7	73	4410	6096	25	0	0	1005	1005
C	U	CG7.9	46	2835	4043	25	0	0	1006	958
C	U	CCA.8	70	4221	5890	25	0	0	1006	1007
C	U	SD2.6	95	5544	8057	25	9	0	1005	1005
C	U	AL5,9	71	4260	6081	25	0	0	1005	1005
D	I	UF6.8	23	21	26	25	0	0	388	-
D	I	SD5.7	30	28	33	25	0	0	388	-
D	I	CG7.9	29	27	33	25	0	0	388	-
D	I	CCA.8	30	26	33	25	0	0	388	-
E	I	UF6.8	33	132	176	25	0	0	910	-
E	I	SD5.7	54	215	288	25	0	0	910	-
E	I	CG7.9	52	209	283	25	0	0	910	-
E	I	CCA.8	53	210	283	25	0	0	910	-
E	I	AL5.9	52	208	282	25	0	0	910	-
F	P	UF6.8	100	494*	59	30	0	-	-	-
F	P	SD5.7	100	494*	59	30	0	-	-	-
F	P	CG7.9	100	494*	59	30	0	-	-	-
F	P	CCA.8	100	494*	59	30	0	-	-	-
G	P	UF6.8	100	466*	117	30	0	-	-	-
G	P	SD5.7	100	466*	117	30	0	-	-	-
G	P	CG7.9	100	466*	117	30	0	-	-	-
G	P	CCA.8	100	466*	117	30	0	-	-	-

* Denotes Process Fluid Flow
"TYPE" code: U = Utility I = Industrial P = Process Master

The CG7.9 fuel usually fell between the UF6.8 and CG4.8 fuels in derating. This was mainly because of its low (51 ft/sec) allowable Gas Velocity Limit compared to CG4.8 (76 ft/sec), its Clear Space Temperature Limit (which was 200°F higher than for the UF6.8 fuel).

Generally speaking, we would expect the AL5.9 CWF, in the absence of fine grinding, to have performance characteristics similar to UF6.8. Fine grinding, however, permits an improved allowable Gas Velocity Limit (84 ft/sec) compared to UF6.8 (69 ft/sec). Also, the Clear Space Temperature Limit is set at the same level as the Cedar Grove and Splash Dam - based fuels. It is likely that without fine grinding the Clear Space Temperature Limit would have been 150°F lower.

The results are summarized below:

FUEL	RESTRICTIONS
UF6.8	Clear Space Temperature Limits - all utility and industrial units. SHO - RHO ΔT limits occurred on Unit A.
SD5.7	Clear Space Temperature Limits on Units A and E. Gas Velocity Limits on all 3 utility units. Furnace Liberation on Unit D. Burner Zone Release Rate on Unit C.
CG7.9	Clear Space Temperature Limit on Unit E. Gas Velocity Limits on all 3 utility units. Furnace Liberation on Unit D. SHO - RHO ΔT limits occurred on Unit A.
CG4.8	Clear Space Temperature Limit on Unit E. Gas Velocity Limits on all 3 utility units. Furnace Liberation on Unit D.
SD2.6	-- Studied on Unit C only -- Clear Space Temperature Limit. Gas Velocity Limit (relaxed NHI/PA and Burner Zone Release Rate limits for this extra low ash fuel)
AL5.9	-- Studied on Units A, C, and E only -- Gas Velocity Limits on Units A and C. Clear Space Temperature Limits on Units A and E. Burner Zone Release Limit on Unit C.

LOAD LIMITERS AS FUNCTION OF BOILER TYPE

For five fuels - UF6.8, SD5.7, CG7.9, CG4.8 and AL5.9 - the Utility units showed a wide range of derating requirements ranging from 26% to as much as 70% load derating. This range reflects the wide variety of configurations which are encountered in this type of service. These units are not easily characterized and must be analyzed on a case by case basis. For the special study of SD2.6 fuel on Unit C, the derating was only 5% due to the extra low ash and low erosion potential of this fuel.

Both Industrial Units required significant load derating, due primarily to the high design furnace loadings which generally have been incorporated into these boilers since 1960. The load derating ranged from 46% to as much as 77%.

The process heaters appeared to require no derating. This is due to the very low design furnace loadings and gas velocities, which are generally characteristic of this equipment.

The results are summarized below:

TYPE	AVG CWF LOAD % MCR	PRINCIPAL LIMITERS	
Utility	57 Output to Grid	Gas Velocity Limit	- 12 cases
		Clear Space Temperature Limit	- 7 cases
		Burner Zone Release Rate Limit	- 2 cases
Industrial	40 Steam Generated	Clear Space Temperature Limit	- 6 cases
		Furnace Liberation	- 3 cases
Process Heaters	100	None	- 8 cases
		TOTAL	38 cases

DISCUSSION OF EACH UNIT DERATING

1. UNIT A:

a. GENERAL

Careful adjustment of gas recirculation and burner tilt was necessary in order to meet the Clear Space Temperature Limit for the SD5.7, CG4.8 and AL5.9 fuels, as well as the SHO - RHO steam temperature differential requirements for all the fuels. Velocity limits imposed by the Reheater Front Crossover tubes, the Waterwall Screen, and the Rear Low Temperature Reheater affected the fuel firing rates for the SD5.7, CG7.9, CG4.8, and AL5.9 fuels. In addition, a review of metal temperatures showed that the SH Lower Bank required a material upgrade when firing these four fuels. A substantial additional load derating would occur without making this upgrade. Also, use of these four fuels required that we open the transverse spacing perpendicular to the gas flow to 10 inches on the Reheater Front Crossover tubes in order to meet Gas Velocity Limits.

b. UPPER FREEPORT 6.8 --- MAXIMUM LOAD = 33% MCR OUTPUT TO GRID

Operation when firing this fuel is marginal. In order to operate with UF6.8, 30% excess air and 25% gas recirculation is required. It is very difficult to maintain both the required Clear Space Temperature Limit and the SHO - RHO steam temperature differential limits. Using a +23 degree burner tilt, it is possible to minimize the variance beyond the two limits as follows: predicted gas temperature of 1720°F vs 1705°F Clear Space Temperature Limit; Predicted SHO - RHO ΔT is 53°F vs. the 50°F allowable limit. Adjusting operating conditions to make one of the above parameters comply with guideline limits causes the other parameter deviation to get worse. Gas velocity limits were not approached. Review of metal temperatures show that no material changes are required.

c. SPLASH DAM 5.7 --- MAXIMUM LOAD = 74% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, 9% gas recirculation, and a -18 degree burner tilt. SHO - RHO steam temperature differential is 45°F.

d. CEDAR GROVE 7.9 --- MAXIMUM LOAD = 44% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, 13% gas recirculation, and a +30 degree burner tilt. SHO - RHO steam temperature differential is at the 50°F maximum limit.

e. CEDAR GROVE 4.8 --- MAXIMUM LOAD = 71% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, 9% gas recirculation, and a -12 degree burner tilt. SHO - RHO steam temperature differential is 50°F.

f. ALMA 5.9 --- MAXIMUM LOAD = 73% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, 9% gas recirculation, and a -21 degree burner tilt. SHO-RHO steam temperature differential is 28°F.

2. UNIT B:

a. UPPER FREEPORT 6.8 --- MAXIMUM LOAD = 30% MCR OUTPUT TO GRID

The unit is operated at 30% excess air and a +13 degree burner tilt. The unit has no gas recirculation capability, but some gas recirculation would probably have been useful if it had been available. This fuel was different from the remaining three because the maximum load was limited by the Clear Space Temperature Limit at the Finishing Reheater which is 200°F lower than for the other fuels. Excess air had to be raised to 30% in order to bring the SHO RHO steam temperature differential within the 50°F permitted while maximizing load and maintaining the Clear Space Temperature Limit on the Spaced Finishing Reheater. The Reheat outlet steam temperature was increased 10°F above that attained using 25 % excess air.

b. SPLASH DAM 5.7 --- MAXIMUM LOAD = 50% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, no gas recirculation, and a +13 degree burner tilt. The load was restricted by the Gas Velocity Limit in the Rear LTSH. The SHO - RHO steam temperature differential is 25°F or half the permitted maximum. If burner tilt were to be raised much further, metal temperature limits would be reached.

c. CEDAR GROVE 7.9 --- MAXIMUM LOAD = 31% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, no gas recirculation, and a +30 degree burner tilt. The load was restricted by the Gas Velocity Limit in the Rear LTSH. It was possible to raise the tilts to the maximum limit of +30 degrees and get nearly the full reheat temperature. The SHO - RHO steam temperature differential was 12°F.

d. CEDAR GROVE 4.8 --- MAXIMUM LOAD = 48% MCR OUTPUT TO GRID

The unit is operated at 25% excess air, no gas recirculation, and a +19 degree burner tilt. The load was restricted by the Gas Velocity Limit in the Rear LTSH. It was possible to raise burner tilts 6 degrees higher than the setting for SD5.7 and reduce the SHO - RHO steam temperature differential to 19°F, compared to 25°F for the SD5.7 fuel.

3. UNIT C:

a. GENERAL:

Six fuels were evaluated on this unit. For the four fuels evaluated on the other units (UF6.8, SD5.7, CG5.7, CG4.8, and AL5.9), excess air was 25%, there was no gas recirculation, and burners were horizontally fixed at 0 degrees tilt. The very low ash version of the Splash Dam slurry, (SD2.6), was a special case and is discussed in item 3f below.

b. UPPER FREEPORT 6.8 --- MAXIMUM LOAD = 45% MCR OUTPUT TO GRID

Load was restricted due to Clear Space Temperature Limit on the Cold Finishing Superheater. There was no restriction due to Gas Velocity Limit at this load. Ratio of gas flow, superheater pass and reheater pass was, 36.0% to 64.0%. SHO - RHO steam temperature differential was 1°F.

c. SPLASH DAM 5.7 --- MAXIMUM LOAD = 73% MCR OUTPUT TO GRID

Load was restricted due to the Gas Velocity Limit, both on the Cold LTSH in the superheater pass, and the Horizontal Reheater No. 2 in the reheater pass. The furnace was also at a Burner Zone Release Rate Limit (Btu fired/sqft). Ratio of gas flow, superheater pass and reheater pass was, 40.7% to 59.3%. SHO - RHO steam temperatures were exactly matched at 1005°F apiece.

d. CEDAR GROVE 7.9 --- MAXIMUM LOAD = 46% MCR OUTPUT TO GRID

Load was restricted due to the Gas Velocity Limit on the Horizontal Reheater No. 2 in the reheater pass. The SHO - RHO steam temperature differential was forced to remain at 48°F, because of the low Gas Velocity Limit (49.4 ft/sec). The ratio of gas flow, superheater pass and reheater pass, was 39.0% to 61.0%.

e. CEDAR GROVE 4.8 --- MAXIMUM LOAD = 70% MCR OUTPUT TO GRID

Load was restricted due to the Gas Velocity Limit, both on the Cold LTSH in the superheater pass, and the Horizontal Reheater No. 2 in the reheater pass. SHO - RHO steam temperature differential was within 1°F. Ratio of gas flow, superheater pass and reheater pass, was 40.6% to 59.4%.

f. SPLASH DAM 2.6 --- MAXIMUM LOAD = 95% MCR OUTPUT TO GRID

The low erosion potential of this fuel permitted Gas Velocity Limits substantially higher than the other four fuels. This Velocity Limit at first seemed to be a major advantage. It was soon evident that easing of this major limiting factor introduced other restrictions which were not encountered on any of the other fuels or other units. As a result, the derating, while not severe, was determined only after overcoming a number of complexities. The findings are as follows:

Load was restricted by a Clear Space Temperature Limit at the SH Platen. It soon became evident that the SHO - RHO steam temperature differential could be reduced to 0°F. However, care had to be taken so that feedwater leaving the economizer section in the superheater pass had sufficient subcooling prior to entering the drum. Thus it was necessary to bias gas flow into the reheater pass up to the Gas Velocity Limit permitted by the Horizontal Reheater No. 2. RHO steam temperature usually exceeded SHO steam temperature by a substantial amount, thus reheater spray was introduced to maintain a SHO - RHO steam temperature match. It turned out that the only way to make maximum use of the high Gas Velocity Limit and also simultaneously maintain the Clear Space Temperature Limit at the SH Platen, was to increase Gas Recirculation to 9%. Ratio of gas flow, superheater pass to reheater pass, was adjusted to 38.6% and 61.4%, respectively. Because the SD2.6 fuel was considerably cleaner than the other fuels in the study, and in order to take advantage of the high Gas Velocity Limit, two furnace Heat Release Rate Limits were relaxed for this fuel: NHI/PA (10^6 Btu/hr-sqft) was increased to 2.31 from the Limit of 2.1, and the Burner Zone Release Rate (10^3 Btu Fired/sqft) was increased to 860 from the Limit of 650.

A review of steam temperatures shows that, for the most part, steam temperatures obtained using the SD2.6 fuel run close to the values measured on firing oil. The largest deviation were 37°F above test data temperatures for the outlet of the Cold LTSH and inlet of the Hot LTSH, and 54°F above test data temperatures at the outlet of the Hot LTSH. The materials originally selected for superheater surfaces in these locations would be capable of this increase in temperature service.

g. ALMA 5.9 --- MAXIMUM LOAD = 71% MCR OUTPUT TO GRID

Firing rate was set at the Burner Zone Release Rate Limit. Load was also restricted due to the Gas Velocity Limit, both on the cold LTSH in the superheater pass, and the Horizontal Reheater No. 2 in the reheater pass. SHO-RHO steam temperature were matched at 1005°F. The ratio of gas flow, superheater pass to reheater pass was 40.3% to 59.7%. A small amount of reheat spray was required to control RHO steam temperature.

A review of steam temperatures shows that steam temperatures obtained using AL5.9 fuel run close to the values measured while firing oil. The largest deviations were 20°F above test data temperatures for the outlet of the cold LTSH and inlet of the hot LTSH, and 32°F above test data temperatures at the outlet of the hot LTSH. The materials originally selected for superheater surfaces in these locations would be capable of this increase in temperature service.

4. UNIT D:

a. GENERAL:

For all four fuels evaluated for this industrial unit, excess air was 25%, there was no gas recirculation system installed, and the burners were horizontally fixed with no tilt provision. Gas Velocity Limits were not encountered on this unit.

b. UPPER FREEPORT 6.8 --- MAXIMUM LOAD = 23% MCR STEAM GENERATED

The load limiter for this fuel was the Clear Space Temperature Limit at the Boiler Bank of the unit, which was 200°F lower than that for the other three fuels.

c. SPLASH DAM 5.7 --- MAXIMUM LOAD = 30% MCR STEAM GENERATED

d. CEDAR GROVE 7.9 --- MAXIMUM LOAD = 29% MCR STEAM GENERATED

e. CEDAR GROVE 4.8 --- MAXIMUM LOAD = 30% MCR STEAM GENERATED

The load limiter for these three fuels was the Furnace Liberation Limit (Btu fired/furnace volume). This caused the firing rate (10^6 BTU/hr) for these three fuels to be set at a fixed maximum permissible value. The steam generation (lbs/hr) obtained using these fixed firing rates determined the maximum derated load rates.

5. UNIT E

a. GENERAL

For all five fuels studied on this industrial unit, excess air was set at 25%, there was no gas recirculation system installed and the burners were horizontally fixed with no tilt provision.

b. UPPER FREEPORT 6.8 --- MAXIMUM LOAD = 33% MCR STEAM GENERATED
c. SPLASH DAM 5.7 --- MAXIMUM LOAD = 54% MCR STEAM GENERATED
d. CEDAR GROVE 7.9 --- MAXIMUM LOAD = 52% MCR STEAM GENERATED
e. CEDAR GROVE 4.8 --- MAXIMUM LOAD = 53% MCR STEAM GENERATED
f. ALMA 5.9 --- MAXIMUM LOAD = 52% MCR STEAM GENERATED

The single load limiter for the five fuels was the Clear Space Temperature Limit at the Spaced Superheater. The unit was derated substantially more for the UF6.8 fuel because the Clear Space Temperature Limit was 200°F lower for this fuel than the other four. Physical clear space between tubes was tight at only 2.00 inches, permitting only a 1615°F maximum gas temperature for UF6.8 fuel, and 1815°F for the other four fuels.

6. UNIT F

Full load (100% MCR) capacity was deemed attainable for this Vertical Cylindrical process heater, firing any of the four fuels. One criterion which had to be met was the ability to maintain full load capability in process fluid heating for extended periods of time, since there is little or no excess plant or heater capacity for use in backup service in case the process heater loses capacity or goes into a forced outage.

Due to inherent design features, no Guideline Limits were reached. The 30% excess air is also used to operate this unit when firing low grade petroleum-based fuel. There is no gas recirculation required, and firing in this cylindrical furnace is done with a single large-capacity CWF burner fixed in the straight up vertical direction.

7. UNIT G

Full load (100% MCR) capacity was also deemed attainable for this Horizontal Cabin process heater, firing any of the four fuels. As in the case of Unit F, one criterion which had to be met was the ability to maintain full load capability to heat process fluids for extended periods of time.

Due to design features built into the original Horizontal Cabin heater, no Guideline Limits were reached. The 30% excess air is also used when operating this unit firing low grade petroleum-based fuel. No gas recirculation is required, and firing in this furnace is done by horizontally fixed (0 degree tilt) burners relocated to the end walls.

SPECIFIC OBSERVATIONS OF HOW WELL GUIDELINES ARE BEING MET

The following discusses how some of the more important Guideline Limits were reached while determining the maximum load capabilities using the various CWFs.

GAS VELOCITY LIMITS

Gas Velocity Limits were reached on some fuels on all three Utility Units. No velocity limits were reached on either the Industrial Units or Process Heaters. The location and type of heat transfer section affected by the Gas Velocity Limits is best illustrated on the side arrangement drawing for each unit. The heat transfer sections affected by velocity limits for a particular fuel are shown in Table 5-2.

TABLE 5-2 HEAT TRANSFER SECTIONS AFFECTED BY GAS VELOCITY LIMITS

UNIT	CWF	HEAT TRANSFER SECTION	REF. SIDE ELEVATION DWG.	GAS VELOCITY (ft/sec) PRED.	LIMIT
A	UF6.8	- - -	- - - -	-	-
A	SD5.7	RH Front Crossover	Figure 3-1	80	79
		Rear LTRH		80	79
		WW Screen		71	71
A	CG7.9	RH Front Crossover	Figure 3-1	51	51
		Rear LTRH		51	51
		WW Screen		45	46
A	CG4.8	RH Front Crossover	Figure 3-1	77	76
		Rear LTRH		77	76
		WW Screen		68	68
A	AL5.9	RH Front Crossover	Figure 3-1	84	84
		Rear LTRH		85	84
		WW Screen		75	76
B	UF6.8	- - -	- - - -	-	-
B	SD5.7	Rear LTSH	Figure 3-2	80	79
B	CG7.9	Rear LTSH	Figure 3-2	52	51
B	CG4.8	Rear LTSH	Figure 3-2	77	76
C	UF6.8	- - -	- - - -	-	-
C	SD5.7	LTSH Cold (SH Pass)	Figure 3-3	65	64
		Horiz RH No. 2 (RH Pass)		76	76
C	CG7.9	Horiz RH No. 2 (RH Pass)	Figure 3-3	49	49
C	CG4.8	LTSH Cold (SH Pass)	Figure 3-3	63	62
		Horiz RH No. 2 (RH Pass)		74	74
C	SD2.6	Horiz RH No. 2 (RH Pass)	Figure 3-3	124	125
C	AL5.9	LTSH Cold (SH Pass)	Figure 3-3	68	69
		Horiz RH No. 2 (RH Pass)		81	81

NOTE: Tolerance on Gas Velocity Limit is plus or minus 1 ft/sec.

CLEAR SPACE TEMPERATURE LIMIT

On some fuels, Clear Space Temperature Limits were reached on all three Utility Units, and both Industrial Units. No Clear Space Limits were reached on the Process Units. As above, the location and type of heat transfer section affected by the Clear Space Limits is best illustrated on the arrangement drawing for each unit affected. The heat transfer sections affected by a Clear Space Temperature Limit for a particular fuel are shown in Table 5-3.

FURNACE LIBERATION RATE

Table 5-4A shows predicted Furnace Liberation (Btu/hr-cuft) compared to the Guideline Limit of 25,000. The only unit which encountered this limit as a load limiter was the A-type Boiler, Unit D, for the SD5.7, CG7.9, and CG4.8 fuels.

GAS RECIRCULATION AS A FUNCTION OF FURNACE LIBERATION RATE

None of the units had predicted Furnace Liberation rates which required a reduction of permissible percent gas recirculation (GR). The A-type Boiler, Unit D, had furnace liberation at the Guideline Limit for three fuels; however, no gas recirculation was installed. For the remainder of fuels and units, highest furnace liberation was below 20000 Btu/hr-cuft which meant that there would have been no cutback on permissible gas recirculation if high GR percentage rates had been required (maximum of 20% GR through bottom, 15% GR premixed through windbox when using 25% excess air; 5% additional GR permissible when using 30% excess air). Unit A required 25% GR for the UF6.8 fuel, but the Furnace Liberation was only 7,500 Btu/hr-cuft, easily permitting this level of gas recirculation.

AIR PREHEAT TEMPERATURE INTO FURNACE (°F)

Table 5-4B shows that air preheat temperature was predicted at or above the minimum limit of 300°F for all units in the study.

TABLE 5-3 HEAT TRANSFER SECTIONS AFFECTED BY CLEAR SPACE TEMPERATURE LIMITS

UNIT	CWF	HEAT TRANSFER SECTION	REF. SIDE ELEVATION DWG.	CLEAR SPACE TEMPERATURE PRED.	CLEAR SPACE TEMPERATURE LIMIT
A	UF6.8	Upper Finishing SH	Figure 3-1	1704	1705
A	SD5.7	Upper Finishing SH	Figure 3-1	1901	1905
A	CG7.9	- - -	- - -	- - -	- - -
A	CG4.8	Upper Finishing SH	Figure 3-1	1901	1905
A	AL5.9	Upper Finishing SH	Figure 3-1	1903	1905
B	UF6.8	Finishing Reheater	Figure 3-2	1791	1790
B	SD5.7	- - -	- - -	- - -	- - -
B	CG7.9	- - -	- - -	- - -	- - -
B	CG4.8	- - -	- - -	- - -	- - -
C	UF6.8	Superheater Platen	Figure 3-3	2231	2230
C	SD5.7	- - -	- - -	- - -	- - -
C	CG7.9	- - -	- - -	- - -	- - -
C	CG4.8	- - -	- - -	- - -	- - -
C	SD2.6	Superheater Platen	Figure 3-3	2431	2230
D	UF6.8	Boiler Bank	Figure 3-4	1469	1470
D	SD5.7	- - -	- - -	- - -	- - -
D	CG7.9	- - -	- - -	- - -	- - -
D	CG4.8	- - -	- - -	- - -	- - -
E	UF6.8	Spaced SH	Figure 3-5	1617	1615
E	SD5.7	Spaced SH	Figure 3-5	1818	1815
E	CG7.9	Spaced SH	Figure 3-5	1816	1815
E	CG4.8	Spaced SH	Figure 3-5	1814	1815
E	AL5.9	Spaced SH	Figure 3-5	1818	1815

NOTE: Tolerance for Clear Space Temperature Limit is plus or minus 5°F.

NET HEAT INPUT / PLAN AREA (10^6 Btu/hr sqft)

Table 5-4C compares the predicted Net Heat Input/Plan Area (NHI/PA) to the Guideline Limit of 2.1×10^6 Btu/hr-sqft. Because of the derating the Utility and Industrial Units experienced for five of the fuels, the NHI/PA values were well below the Guideline Limit. Due to the fuel's low ash content, an exception was made for the SD2.6 fuel studied for use on Utility Unit C. If the NHI/PA were not permitted to increase, a substantial reduction in potential load would have occurred. Output to grid would have been cut by about 11 percentage points, reducing it to 84% MCR from the predicted 95% MCR.

The Process Units are at very low NHI/PA levels in spite of being run at 100% MCR because they are not generating steam; instead they are heating a petroleum-based process liquid at low heat flux rates.

BURNER ZONE RELEASE RATE (10^3 Btu/hr-sqft)

Table 5-4D compares the predicted Burner Zone Release Rate (BZRR) to the Guideline Limit of 650×10^3 Btu/hr-sqft. In the majority of cases, the release rates are well below the Guideline limits. There are three exceptions (all on Unit C). Two cases are SD5.7 and AL5.9 on Unit C where the predicted BZRR is at the Limit. The other case is also on Unit C for the special study of SD2.6 fuel, where an exception is made due to the low ash content of the fuel, and the predicted burner zone release rate is 860. If the BZRR were not permitted to increase, a substantial reduction in potential load would have occurred, and the low ash virtue of the SD2.6 fuel would have been neutralized. Output to grid would have been cut by about 25 percentage points, reducing it to 70% MCR from the predicted 95% MCR. In contrast, the SD5.7 fuel was optimized at 73% MCR, and AL5.9 was optimized at 71%.

TABLE 5-4
A. COMPARISON OF PREDICTED FURNACE LIBERATION RATES
B. PREDICTED AIR PREHEAT TEMPERATURE INTO WINDBOX
C. PREDICTED NET HEAT INPUT/PLAN AREA COMPARISON
D. PREDICTED BURNER ZONE RELEASE RATE COMPARISON

			A Btu/hr cuft	B Deg. F	C 10^6 Btu/hr-sqft	D 10^3 Btu/hr-sqft
A	U	UF6.8	7500	420	.85	253
A	U	SD5.7	15300	422	1.72	519
A	U	CG7.9	9700	410	1.09	329
A	U	CG4.8	14800	422	1.65	506
A	U	AL5.9	15400	430	1.72	521
B	U	UF6.8	9130	300*	.67	329
B	U	SD5.7	13800	300*	1.02	497
B	U	CG7.9	9200	300*	.68	332
B	U	CG4.8	13350	300*	.98	481
C	U	UF6.8	9600	551	1.11	421
C	U	SD5.7	14850	586	1.74	651
C	U	CG7.9	9850	535	1.14	432
C	U	CG4.8	14350	585	1.67	629
C	U	SD2.6	19630	627	2.36**	861**
C	U	AL5.9	14830	593	1.73	650
D	I	UF6.8	19600	300*	.38	DNA
D	I	SD5.7	25000*	300*	.48	DNA
D	I	CG7.9	25000*	300*	.48	DNA
D	I	CG4.8	25000*	300*	.48	DNA
E	I	UF6.8	8900	582	.30	142
E	I	SD5.7	14200	586	.49	226
E	I	CG7.9	14300	588	.48	228
E	I	CG4.8	14300	587	.48	228
E	I	AL5.9	14300	592	.48	228
F	P	UF6.8	9040	677	.35	DNA
F	P	SD5.7	9040	677	.35	DNA
F	P	CG7.9	9040	677	.35	DNA
F	P	CG4.8	9040	677	.35	DNA
G	P	UF6.8	6850	700	.18	DNA
G	P	SD5.7	6850	700	.18	DNA
G	P	CG7.9	6850	700	.18	DNA
G	P	CG4.8	6850	700	.18	DNA
		GUIDELINE LIMITS	25000 max	300 min	2.10 max	650 max

* = At Guideline limit

** = Max Limit relaxed because of low ash content of SD 2.6 fuel.

DNA = Does not apply to this unit design.

MINIMUM DUCT METAL PROTECTION TEMPERATURE (°F)

Table 5-5 shows that the predicted duct metal protection temperature was at or above the minimum Guideline Limit prescribed for each fuel. The temperature referred to is the gas temperature leaving the air heater, on units having regenerative air preheaters, or gas temperature leaving the last heat transfer section in the gas pass on units not having regenerative air preheaters. This temperature must be maintained above a minimum value so that acid condensation and resulting corrosion does not occur on metal surfaces forming the gas ducts to the stack and the stack liner. This minimum temperature value is set at the gas dew point temperature +10°F.

AVERAGE COLD END TEMPERATURE (°F)

Table 5-6 shows that the Average Cold End Temperature (ACET) for regenerative air preheaters was well above the minimum required Guideline Limit. For the units having this type of air preheater (unit A, C, E, F, G), the Minimum Duct Metal Protection Temperature Guideline automatically assured that the average of the air temperature entering the air heater and the gas temperature leaving the air heater was above the ACET minimum requirements. Units B and D had steam air heaters for which this Guideline did not apply.

SUPERHEATER SPRAY LIMIT

Table 5-7 shows the amount of desuperheating spray required to maintain required superheater outlet temperature set point, and whether the desuperheater outlet temperature was above the minimum 20°F above saturation temperature corresponding to pressure at that location. On Unit C, there were two spray stations in the superheater circuit. The spray flows were set so that equal flows went to each spray station.

TABLE 5-5 MINIMUM DUCT METAL PROTECTION TEMPERATURE

UNIT	TYPE	CWF	MINIMUM DUCT METAL PROTECTION TEMPERATURE (°F) PREDICTED	MINIMUM LIMIT
A	U	UF6.8	296	296
A	U	SD5.7	300	281
A	U	CG7.9	287	285
A	U	CG4.8	297	282
A	U	AL5.9	308	295
B	U	UF6.8	369	296
B	U	SD5.7	406	281
B	U	CG7.9	358	285
B	U	CG4.8	404	282
C	U	UF6.8	294	296
C	U	SD5.7	309	281
C	U	CG7.9	291	285
C	U	CG4.8	311	282
C	U	SD2.6	322	280
C	U	AL5.9	314	295
D	I	UF6.8	314	296
D	I	SD5.7	306	281
D	I	CG7.9	310	285
D	I	CG4.8	309	282
E	I	UF6.8	295	296
E	I	SD5.7	282	281
E	I	CG7.9	286	285
E	I	CG4.8	282	282
E	I	AL5.9	295	295
F	P	UF6.8	310	296
F	P	SD5.7	310	281
F	P	CG7.9	310	285
F	P	CG4.8	310	282
G	P	UF6.8	323	296
G	P	SD5.7	323	281
G	P	CG7.9	323	285
G	P	CG4.8	323	282

"TYPE" code: U = Utility I = Industrial P = Process Heater

TOLERANCE: Plus or minus 2°F

Minimum Duct Metal Temperature is set at gas dew point temperature +10°F.

TABLE 5-6 AVERAGE COLD END TEMPERATURE COMPARISON

UNIT	TYPE	CWF	AVERAGE COLD END TEMPERATURE (°F) PREDICTED	MINIMUM LIMIT
A	U	UF6.8	229	158
A	U	SD5.7	193	155
A	U	CG7.9	209	155
A	U	CG4.8	191	155
A	U	AL5.9	197	155
B	U	UF6.8	SAH	158
B	U	SD5.7	SAH	155
B	U	CG7.9	SAH	155
B	U	CG4.8	SAH	155
C	U	UF6.8	238	158
C	U	SD5.7	237	155
C	U	CG7.9	236	155
C	U	CG4.8	240	155
C	U	SD2.6	232	155
C	U	AL5.9	239	155
D	I	UF6.8	SAH	158
D	I	SD5.7	SAH	155
D	I	CG7.9	SAH	155
D	I	CG4.8	SAH	155
E	I	UF6.8	243	158
E	I	SD5.7	218	155
E	I	CG7.9	221	155
E	I	CG4.8	217	155
E	I	AL5.9	231	155
F	P	UF6.8	185	158
F	P	SD5.7	185	155
F	P	CG7.9	185	155
F	P	CG4.8	185	155
G	P	UF6.8	197	158
G	P	SD5.7	197	155
G	P	CG7.9	197	155
G	P	CG4.8	197	155

"TYPE" code: U = Utility I = Industrial P = Process Heater

"SAH" denotes "Steam Air Heater"

TABLE 5-7 DESUPERHEATER SPRAY QUANTITY LIMIT

			DESUPERHEATER SPRAY REQUIREMENTS		
				DESUPERHEATER OUTLET TEMPERATURE ABOVE SATURATION TEMPERATURE (°F)	
UNIT	TYPE	CWF	PREDICTED SPRAY	PREDICTED	MINIMUM LIMIT
A	U	UF6.8	14.6%	69	20
A	U	SD5.7	4.0%	90	20
A	U	CG7.9	17.5%	60	20
A	U	CG4.8	5.1%	87	20
A	U	AL5.9	5.9%	81	20
B	U	UF6.8	5.5%	221	20
B	U	SD5.7	8.4%	213	20
B	U	CG7.9	9.5%	198	20
B	U	CG4.8	9.2%	210	20
C	U	UF6.8	12.7%	79 and 88	20
C	U	SD5.7	12.2%	77 and 89	20
C	U	CG7.9	12.7%	68 and 84	20
C	U	CG4.8	11.8%	80 and 91	20
C	U	SD2.6	16.0%	91 and 77	20
C	U	AL5.9	13.9%	87 and 88	20
D	I	UF6.8	NO SUPERHEATERS INSTALLED ON THIS UNIT		
D	I	SD5.7			
D	I	CG7.9			
D	I	CG4.8			
E	I	UF6.8	9.6%	82	20
E	I	SD5.7	15.6%	59	20
E	I	CG7.9	16.2%	53	20
E	I	CG4.8	15.5%	58	20
E	I	AL5.9	17.2%	51	20
F	P	UF6.8	NO SUPERHEATERS INSTALLED ON THIS UNIT		
F	P	SD5.7			
F	P	CG7.9			
F	P	CG4.8			
G	P	UF6.8	NO SUPERHEATERS INSTALLED ON THIS UNIT		
G	P	SD5.7			
G	P	CG7.9			
G	P	CG4.8			

"TYPE" code: U = Utility I = Industrial P = Process Heater

REHEATER SPRAY LIMIT

The SD2.6 fuel used in the special study on Unit C required using reheater spray. Spray requirements to maintain proper SHO and RHO temperature were 7%, and the temperature at the spray station outlet was 67°F above saturation temperature, which is well above the minimum 20°F above saturation temperature corresponding to pressure at the spray station outlet. The AL5.9 fuel also required a small amount of reheater spray. Spray requirements were 2-1/2%, and the spray temperature at the spray station outlet was 124°F above saturation temperature.

COMPLIANCE WITH NO_x EMISSIONS REQUIREMENTS

Table 5-8 shows the levels of NO_x emissions predicted compared to the maximum permissible limit of 0.700 $lb/10^6 Btu$ fired. The Table shows that the NO_x Guideline can be met; however, several comments should be made:

1. The CWF's have not been field tested on full scale units.

2. A number of the units included in this study are significantly different from the large four-, and five-level tangentially fired utility units used to develop the NO_x calculation procedure. Two units are wall fired (Units C and D), one is end wall fired (Unit G), one is fired vertically upwards (Unit F), and four of the units (Units D, E, F, G) are small industrial or process heaters.

TABLE 5-8 COMPLIANCE WITH NOX EMISSIONS REQUIREMENTS

UNIT	TYPE	CWF	NOX EMISSIONS PREDICTED	(LB/MM BTU. FIRED) MAXIMUM LIMIT
A	U	UF6.8	0.530	0.700
A	U	SD5.7	0.503	0.700
A	U	CG7.9	0.590	0.700
A	U	CG4.8	0.526	0.700
A	U	AL5.9	0.554	0.700
B	U	UF6.8	0.533	0.700
B	U	SD5.7	0.507	0.700
B	U	CG7.9	0.594	0.700
B	U	CG4.8	0.536	0.700
C	U	UF6.8	0.448	0.700
C	U	SD5.7	0.464	0.700
C	U	CG7.9	0.544	0.700
C	U	CG4.8	0.525	0.700
C	U	SD2.6	0.514	0.700
C	U	AL5.9	0.561	0.700
D	I	UF6.8	0.700*	0.700
D	I	SD5.7	0.700*	0.700
D	I	CG7.9	0.700*	0.700
D	I	CG4.8	0.700*	0.700
E	I	UF6.8	0.531	0.700
E	I	SD5.7	0.500	0.700
E	I	CG7.9	0.590	0.700
E	I	CG4.8	0.524	0.700
E	I	AL5.9	0.551	0.700
F	P	UF6.8	0.700*	0.700
F	P	SD5.7	0.700*	0.700
F	P	CG7.9	0.700*	0.700
F	P	CG4.8	0.700*	0.700
G	P	UF6.8	0.700*	0.700
G	P	SD5.7	0.700*	0.700
G	P	CG7.9	0.700*	0.700
G	P	CG4.8	0.700*	0.700

"TYPE" code: U = Utility I = Industrial P = Process Heater

* No field test data available for this type of unit but modifications necessary to comply would not represent a significant capital cost.

6. GUIDELINES FOR RETROFIT SELECTION

In converting a plant to fire a Coal-Water Fuel, the ash content of the fuel is a major factor. A large portion of the cost of most retrofits can be attributed to the ash in the fuel. Other factors which can be significant include: Burner and windbox modifications, SO_2 removal requirements, metal temperature limitations, controls, and fuel supply and storage equipment. The guidelines presented below were used in specifying the retrofit requirements for the above-mentioned areas, as well as for other miscellaneous areas:

1. The retrofit requirements were assessed separately for each CWF, as if only one primary fuel was to be fired. (This rule was sometimes waived for certain components when multifuel capability could be achieved with only minor additional cost.)

2. After conversion to CWF firing the unit must be capable of operation at MCR with the original fuel with original performance (efficiency, steam temperatures, etc.).

3. Furnace Bottom Modifications.
   For top-supported units, a furnace bottom slope of 55 degrees (with a 36 inch hopper opening) is preferred. If the unit does not meet this requirement the following rules apply:

   A. If the existing slope is less than 35 degrees, rebuild it to a slope of at least 50 degrees (55 degrees preferred) with a 36 inch hopper opening.

   B. If the existing slope is between 35 degrees and 45 degrees, leave the slope unchanged and install a jet system to move the ash down the slopes.

   C. If the existing slope is 45 degrees to 50 degrees, do not change slope or add a jet system. Be prepared, however, to add a jet system at some future time should it prove to be needed.

D. Regardless of hopper slope, hopper opening should be rebuilt to 36 inches if existing opening is less than 33 inches.

E. Make provision for collection of ash below the hopper. Often the headroom below the hopper will be minimal. The use of a submerged scraper conveyor (SSC) ash removal device will sometimes be specified when its use will avoid the need for excavation below the furnace.

F. On units which have gas recirculation through the furnace bottom, the ducts will have to be modified to be compatible with the new furnace bottom configuration. This will generally call for introduction of the recirculation gas through the slope of the hopper near the bottom opening.

G. Make proper allowance for sealing the connection between the furnace bottom and the ash collection system (SSC or water-impounded intermittent removal hopper). This will sometimes require installation of seal plates and drip shields.

H. On bottom-supported units the furnace hopper slopes are generally shallow. No slope changes will be attempted. The principal means of ash removal will be a jet system combined with one or more screw ash conveyors to pull the ash out from under the boiler.

4. Furnace wall blowers and convection pass soot blowers would be installed in accordance with general coal-fired design practice. Recognition of the higher slagging tendencies of the UF6.8 and CG7.9 fuels were made when selecting the locations for wall blowers. Recognition of the higher fouling tendencies for the UF6.8 fuel were made in selecting convection pass soot blower locations.

5. New burners and possible windbox modifications were specified as necessary to meet the following requirements:

A. If feasible, burners are to be able to fire the CWF at 1.2 times the rate associated with the maximum CWF load. This extra tolerance is included to allow for uncertainties in estimating the true maximum CWF load. For example, tube metal erosion rates might prove to be lower than expected, or fouling tendencies may be less intense than predicted.

B. Burners must be able to fire the original fuel at full MCR rating.

6. Convective surface revisions may be made to permit higher loads to be achieved with CWF firing. The replacement of large banks can be impractical from a cost-benefit standpoint. In certain cases, however, changes can be justified. Revisions might be made for any of the following reasons:

A. Revisions which increase the free gas area at a section. This will reduce the gas velocities at that location.

B. Revisions which increase the transverse spacing between assemblies. This will permit operation at higher local gas temperatures within the clear space limit.

C. Revisions which include installation of higher grade tube materials. This will permit operation at higher gas temperatures and flow rates within allowable metal temperature limits.

7. Superheater or Reheater spray capacity increase. A general tendency in conversion to CWF firing is to require a greater quantity of superheat spray flow. In some cases the spray requirement exceeds the existing spray capacity. In these cases, installation of larger spray control valves may be required.

8. Increased air heating capacity using a steam coil may be required for any of several reasons:

A. To attain the minimum required air preheat temperature at 300°F.

B. To attain the minimum duct metal temperature downstream of the regenerative air preheater (or economizer when there is no air preheater).

C. To attain the minimum air preheater average cold end temperature.

9. Economizer replacement may be required if the existing economizer configuration does not meet the requirements for CWF firing (See Part 4.2 D). Due to the high costs associated with economizer replacement, it may be worth omitting the economizer replacement for initial operation on CWF. If economizer fouling is not excessive it may be possible to avoid the economizer replacement. Of course, operation with CWF may prove that the economizer must be replaced. In that case a second outage would be required to install the new economizer. A decision of this question would have to be made on a case-by-case basis.

10. Ash hopper revisions will often be required, due to the increased ash loadings associated with CWF firing. Aside from revisions to the furnace bottom area, revisions and/or additional hoppers may be required at:

    Economizer Outlet
    Gas Recirculation Duct
    Air Preheater Outlet Duct.

    The sizing of these hoppers would be in accordance with standard design criteria for coal firing. An allowance for possible future load increases will be provided by designing for an ash loading of 1.2 times the calculated maximum CWF load.

11. Existing fan capacity is usually sufficient to handle the CWF conditions. This is because the maximum loads on CWF are usually well below the original MCR rating. The major exception to this trend is found in the process heaters, where ID and FD fan replacement is likely. In addition, the GR fan (if installed) may require revision to handle high ash content gas streams if it is to be operated during CWF firing.

12. Furnace wall penetration seal replacement or modification may be required on some units with pressurized furnaces.

13. Controls revisions would be required for most cases. The actual extent of the control revisions will depend, however, on the age, condition, and sophistication of the existing plant controls. For purposes of this study, it will generally be assumed that existing firing system controls must be replaced for CWF firing.

14. Depending on the unit design and expected gas velocities, it may be desirable to install gas baffling and/or erosion shields at selected locations to reduce local velocity peaks or shield tubes from direct contact with flyash.

15. Structural support changes would sometimes be required when revisions to the unit result in increased weights or loads on structural members.

16. Particulate removal equipment would be required for all units which presently do not have such equipment. The three utility units do have existing electrostatic precipitators, some of which may prove to have sufficient collector efficiency to avoid the need for additional equipment.

REQUIRED TOTAL PARTICULATE COLLECTION EFFICIENCY (%)

Fuel:	UF6.8	SD5.7	CG7.9	CG4.8	SD2.6
Efficiency (%)	96.3	95.6	96.9	95.0	91.2

17. SO_2 scrubbers will be required at all plants for two of the CWFs: UF6.8 and CG7.9.

REQUIRED SCRUBBER EFFICIENCY (%)

Fuel	UF6.8	CG7.9
Efficiency (%):	51.1	5.9

18. New Ductwork would be required for most cases. Situations which call for ductwork include:

    A. Installation of a scrubber or a particulate collector

    B. Relocation of the ID fan

    C. Ductwork around windbox

    D. Revised GR ductwork

    Duct sizes and arrangements would be such that full load capability on original fuel is maintained and existing fan capacities are not overtaxed.

19. An ash removal system would be included in the conversion. For purposes of this study it will be assumed that ash will be trucked to a disposal site.

20. Coal-Water Fuel supply and storage requirements were included in the conversion. Criteria for selection include:

A. It is assumed that existing oil off-loading facilities are available.

B. A new storage tank with a ten day capacity would be built.

C. New CWF transfer pumps and pipelines would be installed to allow availability of the original fuel to be maintained.

21. For some cases new or upgraded refractory would be required.

22. Excavation and foundation work would be required for some cases:

A. Excavation beneath the furnace bottom to permit installation of ash handling equipment (a minimum of 10 feet headroom is required for top-supported units).

B. Foundation work for--

Ash Handling Equipment
Particulate Collecting Equipment
SO_2 Scrubbers
Fans (if moved or increased in size)
New Ductwork
Fuel Storage and Supply Facilities

23. Waste Water Disposal. For this study it was assumed that any additional waste water generated by the CWF conversion would be handled by the existing plant waste water treatment system.

24. Makeup Water. For this study it was assumed that no capital costs would be associated with the additional makeup water requirements from soot blowing, fuel atomization, bottom ash handling, CWF system flushing, and related items.

25. Auxiliary steam will be required for:

CWF atomizing
CWF heating
Steam coil air heaters (if required)
Wall and soot blowers

In some cases this steam may be taken from the unit. In other cases the steam may be taken from auxiliary boilers.

26. Auxiliary Power. For this study it was assumed that any additional power loads can be handled with the existing plant auxiliary transformers.

27. Service and Instrument Air. In general, air requirements would be handled by existing plant sources. Any exceptions would be on a case by case basis.

7. RESULTS OF RETROFIT SELECTION

Each of the seven units has been analyzed for the requirements of conversion to CWF firing using the guidelines outlined in Part 6. The scope of work varies from unit to unit and from fuel to fuel. Table 7-1 summarizes the major conversion work required for each unit. The major changes to the "boiler island" are also shown in Figures 7-1 through 7-7.

TABLE 7-1

MAJOR CWF CONVERSION WORK

Key: X - applies to all four CWFs (five on Units A & E, six on Unit C)
1 - applies to UF6.8
2 - applies to SD5.7
3 - applies to CG7.9
4 - applies to CG4.8
5 - applies to SD2.6
6 - applies to AL5.9

	UNIT						
	A	B	C	D	E	F	G
Furnace							
Change Hopper Slope	--	X	-	-	-	-	-
Jet System	X	-	X	X	X	-	-
GR Ducts	X	-	-	-	-	-	-
Ash Hopper	-	-	-	-	-	X	X
Blowers							
Wall Blowers	X	X	X	X	X	X	X
Retract Blowers	X	X	X	-	X	-	-
Rotary Blowers	-	-	-	X	-	-	-
Fixed Blowers	-	-	-	-	-	X	X
Firing System							
New Burners	X	X	X	X	X	X	X
Windbox Work	246	24	-	-	X	X	X
Pressure Part Work	X	24	2456	-	X	-	-
New Ignitors	X	X	X	X	X	X	X
New Scanners	X	X	X	X	-	X	X
OFA Ductwork	-	-	-	-	X	-	-

Table 7-1 (Cont'd)

	UNIT						
	A	B	C	D	E	F	G
Convection Sections							
Change for Vel. Limit	2346	-	-	-	-	-	-
Change for Metal Temps.	13	-	-	-	-	-	-
Change for Clear Space	-	-	-	X	-	-	-
Replace with In-Line	-	-	-	-	-	X	X
SH or RH Spray							
Increase SH Spray Capacity	X	-	-	-	-	-	-
Economizer							
Replace Existing	X	X	-	X	-	-	-
Add Additional	-	X	-	-	-	-	-
Ash Hopper Revisions							
Economizer Outlet	X	X	-	-	-	-	-
GR Duct	X	-	-	-	-	-	-
Boiler Bank	-	-	-	X	X	-	-
Air Preheater Outlet	-	-	X	-	-	-	-
Horiz. Duct Runs	-	-	-	-	-	X	X
Steam Air Heater							
Add New Heater	-	-	-	-	X	-	-
Supplement Heater	-	X	-	-	-	-	-
Controls							
Extensive Revision	X	X	X	X	X	-	-
Minor Revision	-	-	-	-	-	X	X
Erosion Protection							
Baffles	X	X	X	-	-	-	-
Shields	X	X	X	-	-	-	-
Fans							
FD	-	-	-	-	-	X	X
ID	-	-	-	-	-	X	X
Standby FD	-	-	-	-	-	X	X
GR Flyash Protection	X	-	5	-	-	-	-

Table 7-1 (Cont'd)

	UNIT						
	A	B	C	D	E	F	G
Structural Support							
Screen Tubes	X	-	-	-	-	-	-
Hanger Rods	X	-	-	-	-	-	-
For Part. Collector	26	-	-	-	X	X	X
For Scrubber	13	13	136	13	136	13	13
For Economizer	X	X	-	X	-	-	-
Radiant Tube Supports	-	-	-	-	-	-	X
Particulate Collector							
Addition to ESP Surface	26	-	-	-	-	-	-
Dry Scrubber/ESP	-	-	-	-	136	-	-
Wet Scrubber	-	-	-	X	-	X	X
New ESP	-	-	-	-	24	-	-
SO_2 Removal							
Dry Scrubber	136	13	136	-	-	-	-
Dry Scrubber/ESP	-	-	-	-	136	-	-
Wet Scrubber	-	-	-	13	-	13	13
Ductwork							
For Add'l Economizer	-	X	-	-	X	-	-
For Part. Collector	26	-	-	X	X	X	X
For Scrubber	136	13	136	13	136	13	13
For Steam Air Heater	-	X	-	X	-	-	-
GR Duct	X	-	-	-	-	-	-
Air Preheater Bypass	-	-	-	-	X	-	-
Ash Removal Equipment							
SSC	X	X	-	-	-	-	-
Screw Conveyor	-	-	-	X	X	-	-
Vacuum System	X	X	X	-	-	-	-
Mechanical System	-	-	-	X	X	X	X
Fuel Supply/Storage							
Storage Tank	X	X	X	X	X	X	X
Pipelines	X	X	X	X	X	X	X
Pumps	X	X	X	X	X	X	X
Refractory Work							
Furnace Bottom	-	-	-	X	-	-	-
Radiant Section	-	-	-	-	-	-	X

Table 7-1 (Cont'd)

	UNIT						
	A	B	C	D	E	F	G
Excavation/Foundation Work							
For Part. Collector	26	-	-	X	X	X	X
For Scrubber	136	13	136	13	136	13	13
For Ductwork	X	X	X	X	X	X	X
For Fuel Supply/Storage	X	X	X	X	X	X	X
For New Fans	-	-	-	-	-	X	X
For SSC Under Furnace	-	X	-	-	-	-	-
For Add'l Economizer	-	X	-	-	-	-	-
Auxiliary Items							
Steam Piping	X	X	X	X	X	X	X
Air Compressor	-	-	-	-	X	-	-
Air Preheater							
Modify for Flyash Serv.	-	-	-	-	-	X	X

HIGHLIGHTS OF RETROFIT SELECTION - UNIT "A"
600 MW CLOSE-COUPLED SCREEN TYPE
FIGURE 7-1

1. FURNACE -- all five fuels studied

The hopper slope is sufficient not to require modification. However, other changes are required as follows:

Install a gas recirculation inlet into the rear side of the hopper mouth. Set back every other tube 12 inches to provide inlet. Modify rear hopper support system to accommodate and support new gas recirculation duct and maintain support of rear lower drum to support tubing from drum, and install new horizontal main buckstay support struts and lateral support beams in the rear lower drum area.

Install gas recirculation duct in dead space between rear furnace slope and furnace rear wall tubes running vertically from rear lower drum. Line with refractory and insulation, and support with hanger rods. Provide two shut-off dampers in GR duct outside of dead space. Run two separate ducts into a single divided duct which connects to existing GR duct. Provide ash collection hoppers at bottom end of GR duct. Install 5 small hoppers having 55 degree slopes to avoid excavation work. Also remove existing GR "box" and duct, relocate seals at outlet of hopper to provide for wet ash collection system, and relocate platform.

Install "jet system" to assist bottom ash to move down hopper slopes to hopper mouth. Install 3 plenums on each hopper slope. Plenums are 4-inch OD tube 57 feet long welded to back side of hamper slope tubes. Drill 1/4-inch diameter holes in fusion welded fins in hopper slope and weld deflector plate over each hole to deflect jet down the slope. Install supply lines, main shut-off valve, on-off control valves, distribution headers, and control panel. Blowing medium is to be steam taken from existing plant steam supply.

2. BLOWERS

New soot blowers, plus pressure parts work at the new sites are required as follows:

Furnace Wall Blowers - 72 for UF6.8, CG7.9; 50 for SD5.7, CG4.8, AL5.9
Double side retract blowers - 10 for all five fuels.

3. FIRING SYSTEM

For all five fuels, convert existing 5 elevations (EL) of oil burners to 6 elevations of combined oil/cwf burners. The existing windbox opening can be used for firing UF6.8 and CG7.9 fuels, but will have to be 4'4" taller for the remaining fuels. Compartment partition plates have to be relocated, and new secondary air control dampers are required. New openings have to be made in waterwalls to accommodate new and/or relocated ignitors. About 20 waterwall tubes have to be modified for the taller windbox used for the CG4.8, SD5.7 and AL5.9 fuels.

4. CONVECTION SECTION MODIFICATIONS

Revise RH crossover arrangement to reduce gas velocities for SD5.7, CG7.9, CG4.8, and AL5.9 fuels. Change material of SH Front Horizontal Spaced Lower Assemblies to accommodate higher metal temperatures as follows: SA 213 TP 304 H for UF6.8 and CG7.9.

5. SH or RH Spray

Install larger capacity SH spray control valves.

6. ECONOMIZER

Replace the existing bank by a taller in-line spiral finned bank with wider horizontal spacing between tubes. Replace both inlet and outlet economizer headers.

7. ASH HOPPER REVISIONS

Fabricate new ash hoppers at economizer outlet and in the Gas Recirculation duct.

8. STRUCTURAL SUPPORT

Stiffen support steel in economizer hanger attachment area.
Install support steel for ESP addition (SD5.7 and AL5.9).
Install support steel for scrubbers required for UF6.8, CG7.9, and AL5.9.
Install support steel for revised gas recirculation duct system as discussed in Item 1.

9. PARTICULATE COLLECTOR

For the SD5.7 and AL5.9 fuels install a 20% addition to the existing electrostatic precipitator (ESP). The remaining three fuels do not require changes to the ESP.

10. SO_2 REMOVAL EQUIPMENT

Install a new Dry Scrubber upstream of the existing ESP for the UF6.8 and CG7.9, and AL5.9 fuels.

11. DUCTWORK

Install new duct segments to accomodate addition to existing ESP for SD5.7 and AL5.9. For UF6.8, CG7.9 and AL5.9 install new ductwork to new scrubber located upstream of existing ESP. Install connecting ductwork from scrubber to ESP, and provide new shut-off dampers so that scrubber can be isolated when firing oil.

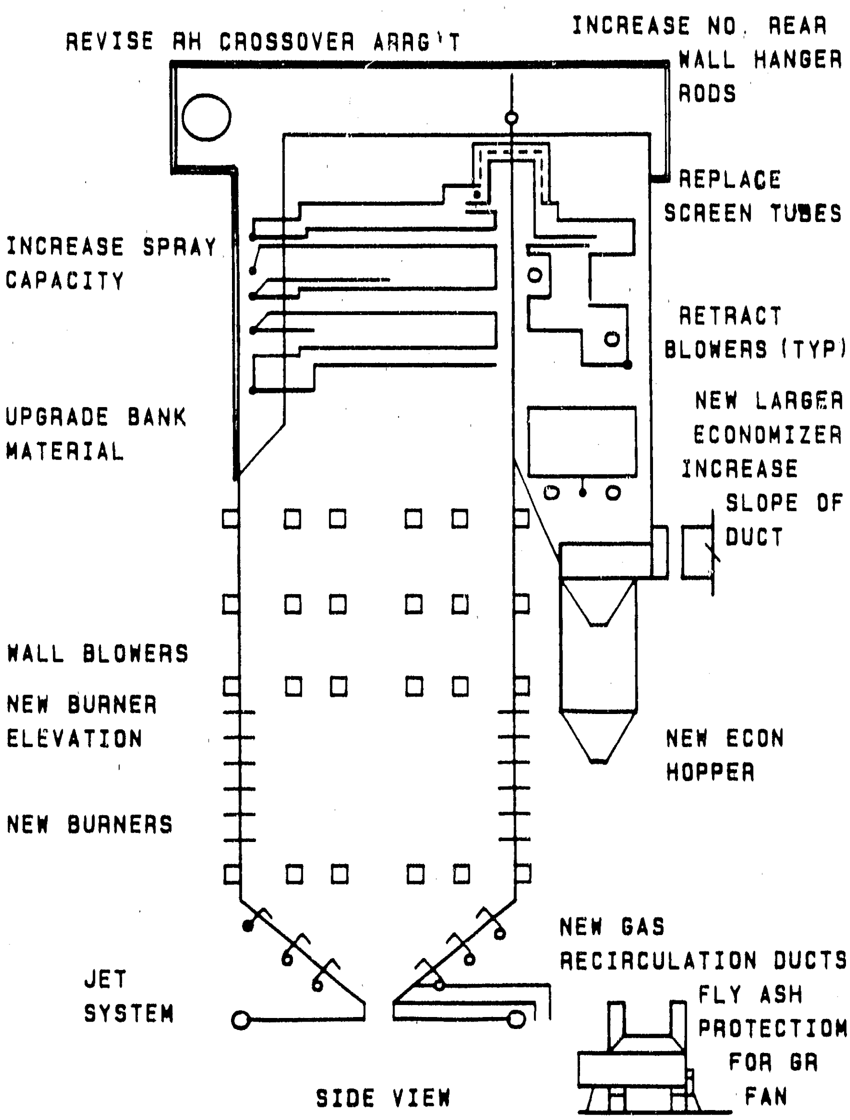


FIGURE 7-1
UNIT A
MAJOR BOILER ISLAND MODIFICATIONS

HIGHLIGHTS OF RETROFIT SELECTION -- UNIT "B"
400 MW BOX TYPE
FIGURE 7-2

1. FURNACE

The existing hopper has a slope of 30 degrees which will require revision to 50 degrees, plus a 3 foot opening for bottom ash removal. Scope of work is summarized below.

Remove existing ash hopper. Cut sidewalls just above inlet header, and cut sidewall inlet header links. Remove sidewall inlet headers. Cut floor tubes at hopper bend line and at inlet header connection. Cut front and rear wall inlet header connecting links and remove headers. Remove hopper structural support members. Cut 8 downcomers at EL 48' and remove. Remove hopper floor tubes. Excavate about 10 feet, and provide foundation for submerged scraper conveyor. Install new hopper floor tubes, inlet headers, and structural support system for hopper floor, headers and links. Install old downcomers with new 13 feet 9 inch extension piping. Install new sidewall panels and inlet headers. Install new horizontal buckstay at EL 24'. Provide new insulation, lagging, and side plates at opening for wet ash removal system.

2. SOOT BLOWERS

Install 3 elevations of wall blowers above burners and one elevation below burners - total of 60 (UF6.8, CG7.9). Install 3 elevations of wall blowers above burners - total of 44 (SD5.7, UF4.8). Install pairs of retractable soot blowers above and below bottom economizer bank in backpass, plus a pair of retractable soot blowers upstream of additional economizer bank installed in new ductwork (6 soot blowers in all).

3. FIRING SYSTEM

Present windbox width is sufficient for all four fuels studied. For SD5.7 and CG4.8 extend waterwall tube opening height by 30 inches. Relocate existing IFM ignitor openings from the existing 56-inch centerlines to new 64-inch centerlines - thus 12 ignitor openings will be modified for these two fuels. No windbox pressure part modifications are required for UF6.8 and CG7.9 fuels. For SD5.7 and CG 4.8 fuels, windbox height will have to be extended by 30 inches on top, 6 inches on bottom. Modify associated connecting ductwork to accommodate larger windbox. Install new damper linkages. Install new tilt drives for all four fuels.

4. ECONOMIZER

Replace the two existing spiral finned 3 fins/inch staggered-tube economizer banks with three banks having spiral finned 2 fins/inch in-line-tube arrangement. The additional vertical height requirements associated with the in-line arrangement require the third bank be installed in a new duct downstream of the existing backpass location. Also extend the economizer inlet link to connect with the 3rd bank. Run connecting link between 3rd bank and bottom bank in backpass. The 3rd bank is to be bottom supported, and a support structure will also be required for the new ductwork.

5. STEAM AIR HEATER

Install a new steam coil air heater downstream of the existing steam coil air heater in vertical air duct so that air can be heated to 300°F (minimum for CWF firing). Steam source to be boiler drum. Provide steam piping from drum to coil, and condensate piping from coil to condenser hot well.

6. SO_2 REMOVAL EQUIPMENT

Install a new Dry Scrubber upstream of the existing ESP for the UF6.8 and CG7.9 fuels.

7. NEW DUCTWORK

Provide enclosure for new 3rd bank of economizer. Run new ductwork from 3rd economizer to new scrubber (UF6.8, CG7.9). Provide bypass duct around scrubber and supply shut-off dampers to isolate scrubber when firing original oil fuel. Install new ductwork for new steam coil air heater.

8. ASH REMOVAL EQUIPMENT

Because of tight clearances under the furnace hopper throat, install a Submerged Scraper Conveyor (SSC). A 10-foot excavation would be required for the SSC.

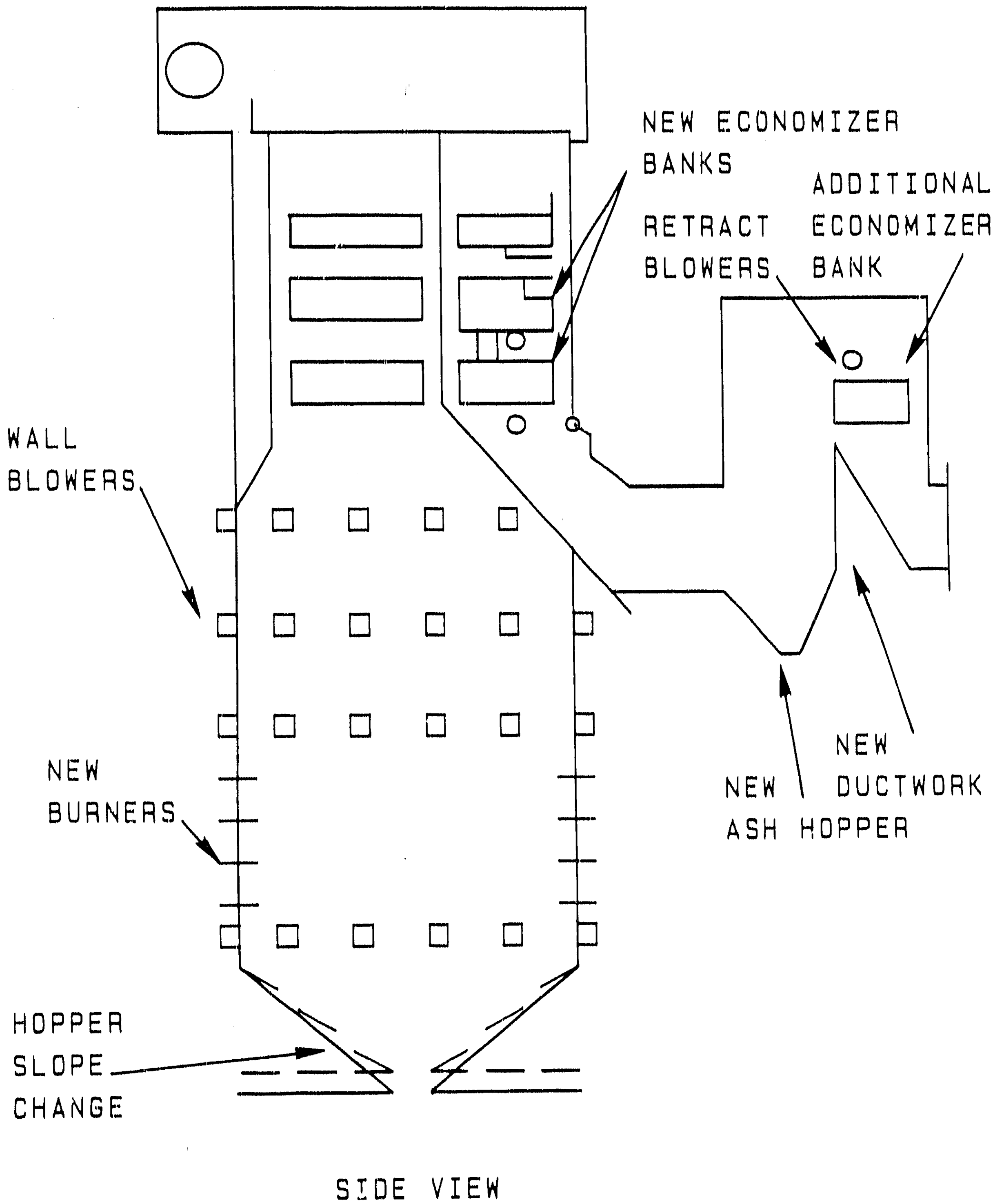


FIGURE 7-2
UNIT B
MAJOR BOILER ISLAND MODIFICATIONS

HIGHLIGHTS OF RETROFIT SELECTION -- Unit "C"
850 MW CLOSE-COUPLED ARCH TYPE
FIGURE 7-3

1. FURNACE

Install "jet system" to assist bottom ash to move down hopper slopes to hopper mouth. Install 3 plenums on each hopper slope. Plenums are 4-inch OD tubes 82 feet long welded to back side of hopper slope tubes. Drill 1/4-inch diameter holes in fusion welded fins in hopper slope and weld deflector plate over each hole to deflect jet down the the slope. Install supply lines, main shut-off valve, on-off control valves, distribution headers, and control panel. Blowing medium to be steam taken from existing plant steam supply.

2. BLOWERS

Install wall blowers: for all fuels, 62 installed in the furnace walls, and for UF6.8 and CG7.9 fuels, 3 additional blowers in each side wall below the burner zone. These 6 additional blowers must pass through a 19 foot windbox.

Also install two additional double sided retract blowers just above the economizer bank, plus a double sided retract blower just under the furnace nose (6 retracts total). Pressure part work will be required for all wall blowers and the two retract blowers installed under the furnace nose. Install a soot blower control panel for automatic sequencing in the control room. Steam supply to be taken from the plant auxiliary supply.

3. FIRING SYSTEM

For UF6.8 and CG7.9 fuels, existing openings have sufficient size. Equipment required is: wall-fired CWF burners and guns, flame scanners, light oil or gas pipe ignitors (32 each). For SD5.7, CG4.8, and AL5.9 fuels, enlarge burner openings up to 69 inches from existing 48 inches at 32 locations. Eighteen tubes need to be removed and rerouted at each location. For all fuels, new equipment required is: wall-fired CWF burners and guns, flame scanners, light oil or gas pipe ignitors (32 each). For the SD2.6 fuel, enlarge burner openings up to 74 inches from the existing 48 inches size at 32 locations. About 22 tubes need to be removed and rerouted at each locations.

4. ASH HOPPER

Existing furnace bottom and economizer ash hoppers appear to have sufficient capacity for CWF firing. However, rebuild existing ash hopper at outlet of air heater. Since vertical clearances to floor are tight, install two parallel rows of 16 hoppers apiece. Each of the hoppers to be about 7 feet high, and 7 x 7 feet in plan area.

5. SO_2 REMOVAL EQUIPMENT

Install a new Dry Scrubber upstream of the existing ESP for the UF6.8, CG7.9, and AL5.9 fuels.

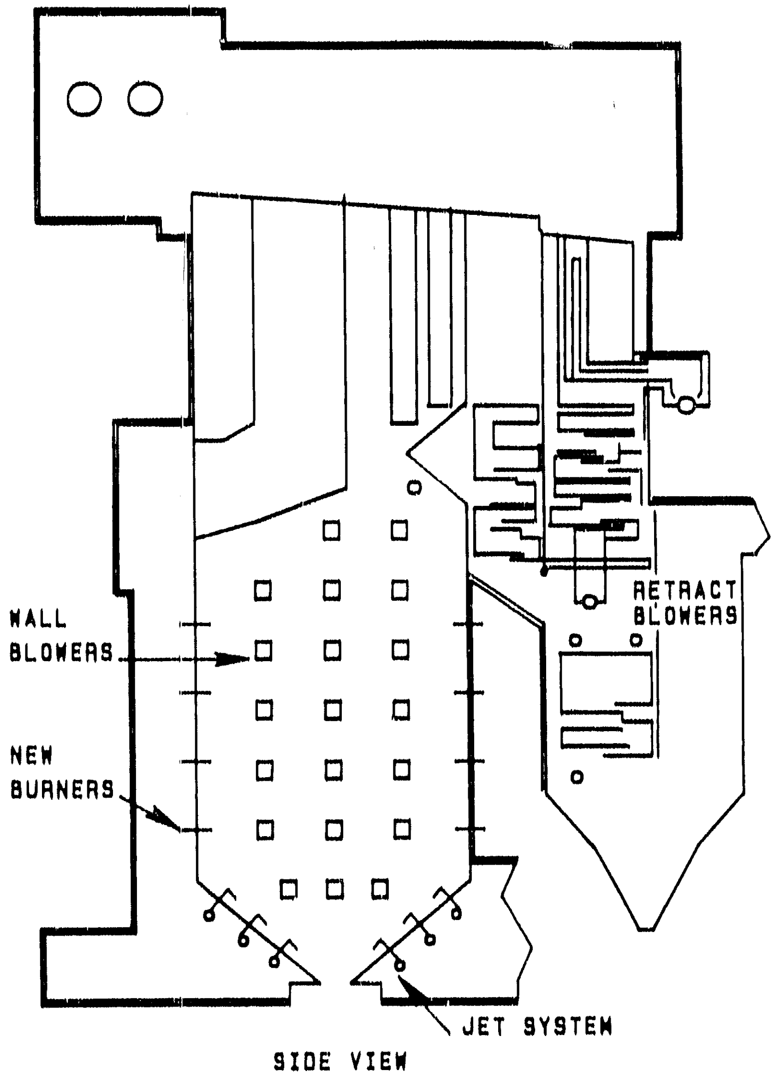


FIGURE 7-3
UNIT C
MAJOR BOILER ISLAND MODIFICATIONS

HIGHLIGHTS OF RETROFIT SELECTION -- UNIT "D"
SHOP-ASSEMBLED INDUSTRIAL BOILER
FIGURE 7-4

1. FURNACE

This boiler is of the "Type A" design and is a very compact unit. The furnace has a refractory tile floor and is fired horizontally from burners in one end. To convert the furnace to CWF firing a steam jet system will be installed on the furnace floor. Remove existing boiler casing under furnace (which may require jacking up entire boiler to gain working access). Remove existing tile floor of furnace. Install castable refractory gas barrier and replace existing tiles with RAM 90 refractory. Install series of about 20 stainless steel "jetting blocks" along centerline of furnace. Install 20 connector lines between new steam supply header pipe and jetting blocks. Install new casing/hopper beneath furnace with two ash collection hoppers, each with a 2-inch screw conveyor to pull out bottom ash. Install new insulation over bottom area.

2. BLOWERS

Add two wall blowers - one on each side above/or below existing rotary soot blower locations. Pressure part work consists of penetration of peg-fin outer tube wall and tangent tube furnace wall tubes.

Add two rotary soot blowers, one on each side, inserted at a new location in the boiler bank. Pressure part work includes penetrating outer tube wall and bending 8 boiler bank tubes aside to provide blower lance access.

The new economizer bank (See Item 5 below) requires rotary soot blowers 8 blowers for the UF 6.8 fuel, 6 blowers for the remaining three fuels studied.

Blowers are supplied by steam from the existing drum connection. The new blowers require new supply piping, control valves, and controls.

3. FIRING SYSTEM

Existing windbox and refractory endwalls are acceptable for CWF conversion. Install two new CWF burners (replacing existing two oil burners), one Safe Scan Flame Scanner, and two pipe ignitors. Update control system for operation with the new firing system.

4. CONVECTION SECTIONS

For all four fuels studied, remove all boiler bank tubes back as far as existing retract soot blower location, but not the 10 finned tubes on each side, running along each side wall. Remove 9 spaced baffle wall tubes - 4 on left, 5 on right - (UF6.8). Remove 4 spaced baffle wall tubes - 2 on left, 2 on right - for the other three fuels.

5. ECONOMIZER

Remove existing staggered economizer. Install in-line spiral finned economizer having 1-1/2 inch OD tubes with 3-1/2 inch OD fins at 2 fins/inch. Gas flow is up, water flow is down. Installed surface to be sufficient to compensate for removal of the selected boiler bank tubes.

6. ASH HOPPER REVISION

Add an ash hopper at the bottom of each side of the boiler bank. Each hopper is to have a 2-inch screw conveyor. Install new insulation/lagging.

7. STEAM AIR HEATER

Install a steam air heater to raise combustion air temperature to 300°F minimum. Saturated steam is to be supplied by the drum. Coil layout must be such that full load air flow will not create excessive draft loss.

8. STRUCTURAL SUPPORT

Reinforce structural steel supporting the replacement spiral finned economizer to be mounted on top of the boiler.

9. PARTICULATE COLLECTOR AND SO_2 REMOVAL

A wet scrubber will perform the dual function of particulate and SO_2 removal. Install the wet scrubber between the economizer and stack on a bypass duct (all four fuels). The wet scrubber will only operate when firing CWF. When firing oil, the wet scrubber will be isolated.

10. NEW DUCTWORK

Run a new transition piece between the boiler outlet and inlet to the new spiral finned economizer. Erect a new bypass duct to direct the gases to the wet scrubber. Include a junction leaving the economizer with isolation dampers on the outlet leg. Run ducts to wet scrubber and back to outlet tee junction. Provide isolation damper on inlet from wet scrubber. The existing stack is to be relocated on top of this tee.

11. ASH REMOVAL

A mechanical ash removal system will be installed to handle ash from the various hoppers. Ash disposal to be off site.

12. FOUNDATION WORK

Foundation work for wet scrubber, new ductwork, ash handling system, fuel supply and storage facilities.

13. FUEL SUPPLY AND STORAGE

Install to comply with the retrofit Guidelines.

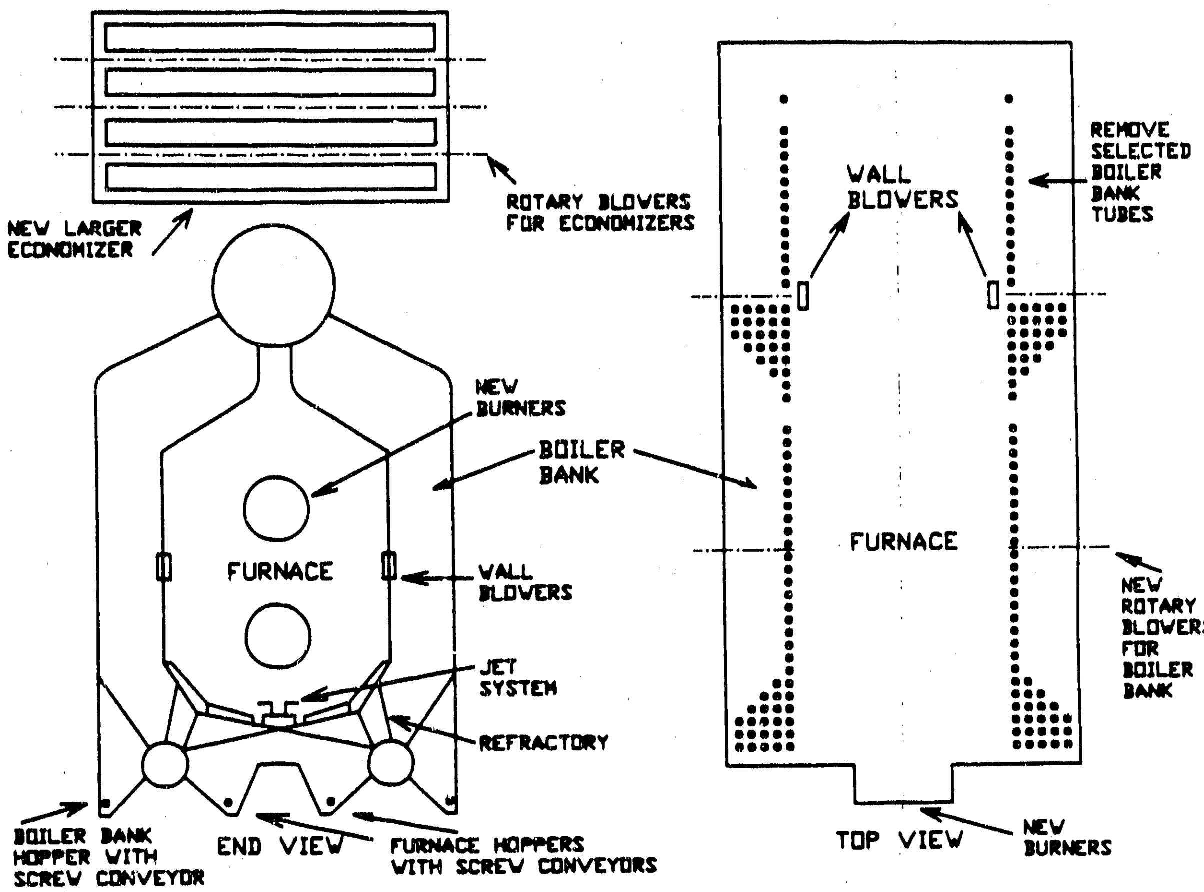


FIGURE 7-4
UNIT D
MAJOR BOILER ISLAND MODIFICATION

HIGHLIGHTS OF RETROFIT SELECTION -- UNIT "E"
FIELD ASSEMBLED INDUSTRIAL BOILER
FIGURE 7-5

1. FURNACE

Install grate blocks over furnace floor tubes. Every third row of grate blocks to have a jetting block supplied from new headers installed below the furnace floor. The jet system will push the ash toward the furnace floor hopper located adjacent to the lower drum.

2. BLOWERS

Install two elevations of wall blowers above the burners. There will be a total of twelve wall blowers required for the unit - four in each wall. Install two new single side retractable soot blowers between the superheater banks. Make necessary pressure parts alterations at each wall and soot blower penetration. Install new control panel equipment and controls.

3. FIRING SYSTEM

Open existing windbox width from 14 to 16 inches wide. Relocate about six tubes and rework shell and casing on one side of each windbox. Relocate existing 3-inch pipe ignitors to intermediate auxiliary compartment and aim at CWF guns. Open the four existing 10 inch diameter overfire air ports, and run duct to them from main windbox. Upgrade the control system to accommodate the new firing system.

4. ASH HOPPER

Install ash hopper at the gas outlet adjacent to the boiler bank outlet.

5. PARTICULATE COLLECTOR AND SO_2 REMOVAL

Install an electrostatic precipitator (ESP) for the two fuels which do not require scrubbers (SD5.7 and CG4.8). For the remaining three fuels (UF6.8, CG7.9 and AL5.9) install a "Dry Scrubber/ESP". This device will remove the flyash from the gas stream at the same time it removes the SO_2. A bypass duct will permit the boiler to operate on oil at MCR without passing the gases through the ESP or dry scrubber/ESP.

6. NEW DUCTWORK

Install new bypass ductwork and damper box around air preheater. Remove existing dust collector and relocate stack. Run new ductwork to electrostatic precipitator (ESP) (CG4.8 and SD5.7). Run new ductwork to ESP and scrubber (UF6.8, CG7.9 and AL5.9). Install ductwork to bypass the new scrubber when original design fuels are in use. Install damper boxes in ductwork to control bypass flow around scrubber when original fuels are in use. The ESP, scrubber, and stack serve two units. Install shut-off dampers for situation when only one of the units is operating.

7. MODIFICATIONS TO EXISTING DUCTWORK

The UF6.8, CG7.9 and AL5.9 fuels require new scrubbers. Modify the existing vertical duct running from the air heater outlet to the lower Electrostatic Precipitators (ESP's) as follows: install a take-off tee in the right and left vertical sidewall of the duct just below the existing lower ESP, so that gas can be passed horizontally to each of the new scrubbers erected to the right and left of the ESP. Above the lower pair of take-off tees, install a pair of return tees to handle the gas downstream of the scrubbers. Install isolation dampers in each take-off and return tee. Adjacent to the tees, install reducer sections configured so that 20 x 20 foot ductwork can be run to and from the scrubbers. Install about 200 running feet of ductwork, including 8 expansion joints. Provide structural support for the duct runs approximately 70 feet above grade, plus insulation and lagging.

8. ASH REMOVAL

Install a mechanical ash removal system to handle ash from the various hoppers, ESP or dry scrubber/ESP. Ash disposal is to be off site.

9. FUEL SUPPLY AND STORAGE

Install to comply with retrofit Guidelines.

HIGHLIGHTS OF RETROFIT SELECTION -- UNIT "F"
VERTICAL CYLINDRICAL PROCESS HEATER
FIGURE 7-6

1. FURNACE

Note that this furnace is a cylindrical chamber. Modify the bottom to accept ash removal equipment since ash will collect at the bottom when firing CWF. Since a vertical CWF burner is to be centered in the bottom of the radiant chamber, the ash hopper must form an annulus around the burner.

2. BLOWERS

Install radiant chamber wall blowers - using the same design as in conventional coal-fired utility-type units. The dense castable refractory behind the wall tubes can withstand the wall blowing duty and does not need to be changed. Four levels of blowers are required. These blowers will keep the tube surfaces clean in order to avoid heat flux rate changes and possible decomposition of the process fluid in the tubes.

3. FIRING SYSTEM

Horizontal firing in the vertical cylindrical heater presents a problem, as there is no wall without tubes in front of it and the diameter of the tube circle is not large enough to insure that flame impingement does not occur on the tubes opposite the burner. From a search of the literature, it does not appear that vertical firing of coal has as yet been attempted in process heaters. It is probable that such firing would be successful, however, since C-E's Fireside Performance Test Facility fires pulverized coal and CWF in a vertical burner and has logged many hours of satisfactory operation.

Install a single large-capacity burner centered in the bottom of the radiant chamber. Make provision for dual fuel burner capability (CWF and stand-by oil), and provide a system to insure rapid transition from CWF firing to oil. Provide a new windbox for the burner which must be compatible with the annular ash hopper equipment. Also provide new ignitor and scanner.

This design would permit near optimum uniformity of heat input into the process tubes while allowing maximum room for ash collection.

4. CONVECTION SECTION CHANGES

Although the tube and fin tip clearances and flue gas velocities in the convection sections of both heaters are within the Guidelines, the fin spacing per inch and the staggered arrangement are not.

Replace existing spiral finned staggered-tube banks with shop-fabricated spiral finned in-line banks with fin spacing meeting Guidelines. The new convection section designs are to meet full load oil performance.

5. ASH HOPPER REVISIONS

Since soot blowers will be installed in the air preheaters to provide adequate cleaning, add a new ash collection hopper at the air preheater outlet.

6. FANS

Replace the existing induced draft (ID) and forced draft (FD) fans. The new flue gas cleanup equipment increases the static pressure requirements for the ID fan. The high pressure drop characteristic of the new burner increases the FD fan static pressure requirement. Also install a new standby full capacity FD fan with a different drive to provide standby firing capability should the primary FD fan go out of service.

7. DUCTWORK REVISIONS

Since ductwork was designed for low velocities (30 fps), and there are horizontal sections where flyash can settle, install ash collection hoppers at strategic locations in these ducts. Additional ducts, connecting the new flue gas cleanup equipment to the existing equipment, are also required.

8. PARTICULATE COLLECTOR/SO_2 REMOVAL

The most economical choice of equipment is a wet scrubber which is capable of handling both particulate removal and SO_2 removal where required.

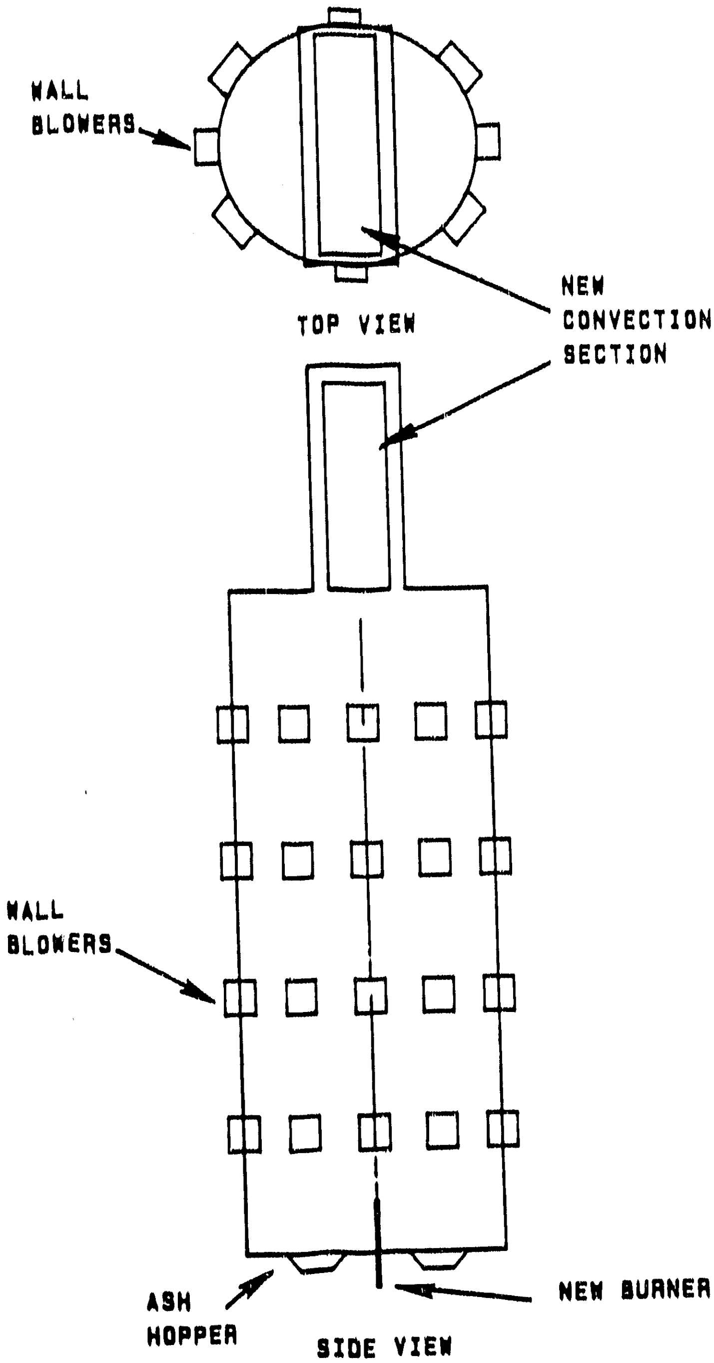


FIGURE 7-6
UNIT F
MAJOR BOILER ISLAND MODIFICATIONS

HIGHLIGHTS OF RETROFIT SELECTION -- UNIT "G"
HORIZONTAL CABIN PROCESS HEATER
FIGURE 7-7

1. FURNACE

Modify the bottom to accept ash removal equipment. Note that the vertical burners, formerly located in the furnace floor, are to be removed, and the firing system will be relocated in the end walls (see Firing System below).

2. BLOWERS

Install three levels of wall blowers in both side walls - blowers to be conventional coal-fired utility-type units. Remove the ceramic fiber blanket insulation behind the radiant sidewall tubes. This low weight insulation cannot withstand the force of soot blowing and must be replaced with castable insulation. Since the castable insulation doesn't have the low thermal conductivity characteristic of the former ceramic fiber blanket, the castable refractory has to be substantially thicker. Provide new supports for the radiant sidewall tubes which locate the tubes further from the outside furnace casing plate, but the same distance from the refractory face as originally used with the ceramic fiber blanket. This relocation of the tubes allows radiant heat transfer to the back sides of the tubes, as in the original design, so that the critical heat flux rates are maintained. If this relocation was not made, the effective radiant chamber heat absorbing surface would be reduced, leading to higher local maximum rates and possible decomposition of the process fluid. The castable refractory weighs more than the ceramic fiber blanket, thus additional structural support must be provided.

3. FIRING SYSTEM

Remove the existing firing system from the bottom of the unit. Install two new CWF burners apiece in both end walls, one burner located directly over the other. No pressure part work is required since the end walls are refractory lined and contain no tubes. Aim the burners along the axis of the radiant chamber from each end wall, designing the burners to produce horizontal long, narrow shaped flames. This layout produces uniform heat input per tube length, similar to conventional heaters using endwall firing. Make provision for dual fuel burner capability (CWF and stand-by oil), and provide a system to insure rapid transition from CWF firing to oil. Provide new windboxes for the burners. Also provide new ignitors and scanners. Ash produced would enter the overhead convection section or fall to the furnace bottom area.

4. CONVECTION SECTION CHANGES

Although the tube and fin tip clearances and flue gas velocities in the convection sections of both heaters are within the Guidelines, the fin spacing per inch and the staggered arrangement are not.

Replace existing spiral finned staggered tube banks with shop-fabricated spiral finned in-line banks with fin spacing meeting Guidelines. The new convection section designs are to meet full load oil performance.

5. ASH HOPPER REVISIONS

Since soot blowers would be installed in the air preheaters to provide adequate cleaning, add a new ash collection hopper at the air preheater outlet.

6. FANS

Replace the existing induced draft (ID) and forced draft (FD) fans. The new flue gas cleanup equipment increases the static pressure requirements for the ID fan. The high pressure drop characteristic of the new burners increases the FD fan static pressure requirement. Also install a new stand-by full capacity FD fan with a different drive to provide stand-by firing capability should the primary FD fan go out of service.

7. DUCTWORK REVISIONS

Since ductwork was designed for low (30fps) velocities, and there are horizontal sections where flyash can settle, install ash collection hoppers at strategic locations in these ducts. Additional ducts, connecting the new flue gas cleanup equipment to the existing equipment, are also required.

8. PARTICULATE COLLECTOR/SO_2 REMOVAL

The most economical choice of equipment is a wet scrubber which is capable of handling both particulate removal and SO_2 removal where required.

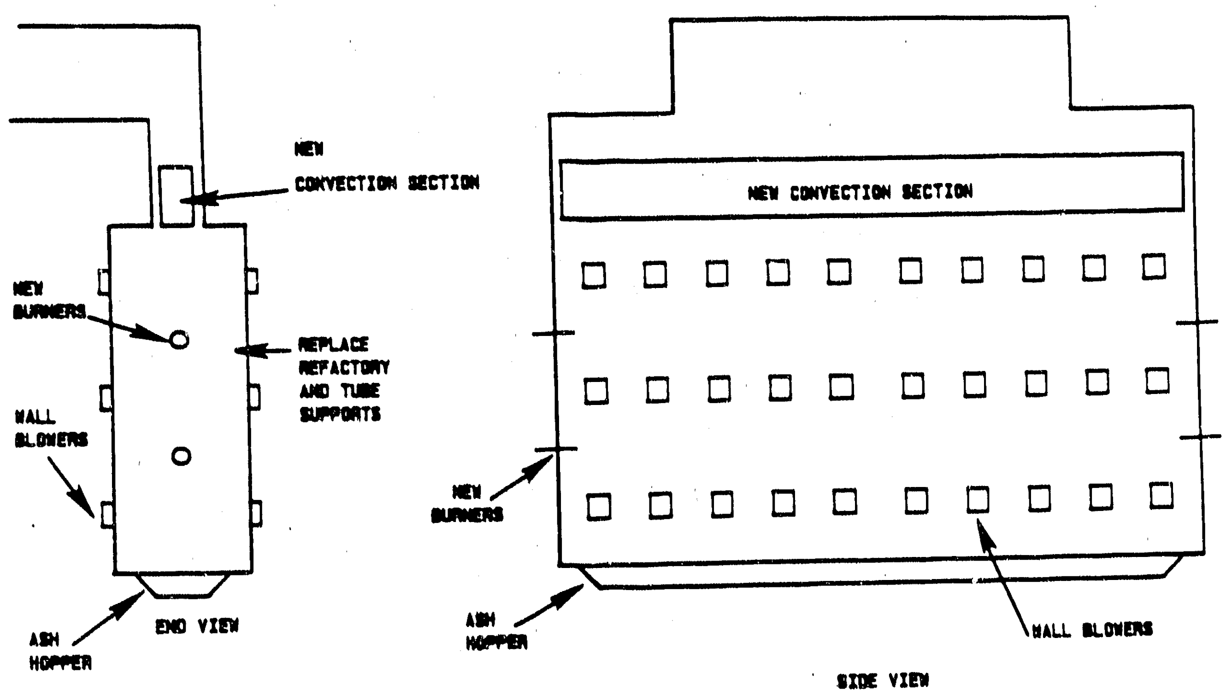


FIGURE 7-7
UNIT G
MAJOR BOILER ISLAND MODIFICATIONS

8. CWF RETROFIT COST ESTIMATES AND ECONOMIC EVALUATIONS

This section describes the approach for developing capital costs and operating and maintenance cost estimates for the CWF retrofit of seven major fuel burning installations considered in this study. The procedures used in making this evaluation were taken from Reference (7) with minor modifications where appropriate. These procedures are discussed briefly in this report. An economic evaluation is presented for the seven units. This evaluation defines the incremental costs and savings as a result of the use of CWF as a substitute fuel for oil. The economic results are presented both as first year and levelized costs. The first year incremental operation and maintenance cost savings and the total capital requirement are used to determine a simplified payback period for all seven units. Also calculated for the utility units only are the total levelized annual revenue savings, specific levelized revenue savings, and incremental levelized cost of electricity savings.

There are several uncertainties involved in a study of this type. Two of the major uncertainties are the maximum load capability with CWF and the fuel costs. The load capability predictions and required assumptions were described previously in Sections 4 and 5. The predicted load capabilities described in Section 5 were calculated based on a set of Guidelines briefly outlined in Section 4. Much of the data used to develop the Performance Guidelines were developed in a small laboratory facility ($4x10^6$ Btu/hr heat input). Data from this laboratory test unit was used to predict slagging, fouling, and erosion behavior for the wide range of unit types, and sizes in this study. These fuels have not been fired in units of the sizes or configurations of those used in this study. Because of this, many of the procedures used to develop the Performance Guidelines are not confirmed. Knowing these uncertainties, the developed Guidelines and the predicted load capabilities may be somewhat conservative. For these reasons the economic evaluation presented in this section also considers the sensitivity of higher than predicted load capability and its effect on economic feasibility. Economic evaluation results are presented for both the predicted loads and predicted loads with a 20% increase in firing rate.

The costs for producing CWF fuels in the quantities required for large scale commercial usage here are not well established. Also the fairly rapid fluctuations in oil prices make it difficult to set fuel prices which would be appropriate. Because of these two uncertainties, sensitivities of the payback period and total levelized annual revenue savings to a range of differential fuel costs are presented.

For the units which experience a load derating (utility and industrial) the mode of operation is an important consideration. For the utility units two basic modes of operation are possible with CWF firing. In the first mode the retrofitted plant is assumed to burn CWF, but switches completely to fuel oil at peak demand. This operating mode assumes that the plant is derated on CWF but can regain its maximum capacity when switched to fuel oil.

By designing the retrofit modifications with this dual fuel capability, it is possible to eliminate the necessity for the utility to purchase additional generating capacity to make up for the loss of capacity due to the derating.

Another possible operating mode would be having the retrofitted plant burn CWF for 100% of its operating time without switching to oil. In this mode the utility would have to purchase additional generating capacity.

There is a trade off to be made in comparing these two operating modes. In the second mode (no oil switching) capital costs would be higher due to the purchase of the additional generating capacity. However, since the unit is not required to switch to oil in periods of peak demand, the annual power generation with CWF would be higher and therefore fuel cost savings would be greater.

It was beyond the scope of this study to consider both operating modes for utility units. Only the oil switching operating mode has been studied in comparison to the base case where the unit burns fuel oil 100% of its operating time.

For the industrial steam generator units, results for two potential operating modes are considered. In the first operating mode (Case I) it is assumed the customer can afford to operate the derated unit on CWF 100% of its operating time with no need to switch to oil at peak load demand. Also, no additional capacity is assumed to be purchased. In the second operating mode (Case II) it is assumed the customer must switch back to oil firing about 50% of the operating time, during which time the unit operates at its original maximum continuous rating. These two cases are compared to the base case where the unit is fired with fuel oil 100% of its operating time.

For the process heaters, for which there was no derating, the basis of the calculations assumes the heaters operate 95% of any calendar year (95% overall availability). A second assumption is that the total number of hours per year that the heaters operate while firing CWF and utilizing the air preheat system and flue gas clean up equipment is 90% of a calendar year (90% availability). A third assumption is that the number of hours that the heaters operate while firing fuel oil and without the air preheat system and flue gas cleanup equipment in operation is 5% of any calendar year. Thus the total availability of the heaters is 95% overall.

Besides the primary 90%CWF-5% oil availability assumption, some pay-out period studies were done using 85%CWF-10% oil and 80%CWF-15% oil alternate availability assumptions. Results are discussed and plotted further on in this report. The economic evaluation results for the units are presented in terms of simplified payback period.

CAPITAL COST ESTIMATES

Capital cost estimates for the CWF retrofit of seven major fuel burning installations were developed. The capital cost estimates for retrofitting are divided into the following six basic categories:

- CWF Storage
- CWF Transfer
- Boiler Island
- Particulate Removal System
- Flue Gas Desulfurization System
- Ash Handling System

The capital costs estimates were developed using various sources depending on unit type (Utility, Industrial or Process heater).For the utility units, budget capital cost estimates (±20%) were developed for the Boiler Island, Particulate Removal System and Flue Gas Desulfurization System based on drawings, specifications and equipment lists.

The remaining categories for the utility units (CWF Storage, CWF Transfer, and Ash Handling System) were estimated using generalized cost plots as provided in Reference 7. In Reference 7, capital costs including direct costs, distributables, engineering services, and total contingency were plotted as a function of capacity for the various equipment groups. For this study these generalized costs were escalated from 2nd quarter 1983 to mid-1985 (about 12%).

For the industrial units and process heaters the generalized costs were used only for CWF Storage and CWF Transfer with the remaining categories requiring new estimates.

Because of the preliminary nature of this retrofit feasibility study, the developed cost estimates are similar to the Class II preliminary estimate defined in the EPRI "Premises". All estimates are based on mid 1985 wage and price levels.

Tables 8-1 to 8-6 define the capital costs for the three utility units, Tables 8-7 to 8-10 for the industrial units, and Tables 8-11 and 8-12 for the process heaters. These tables show the capital costs for each unit with each of the four fuels (five fuels for Units A and E, six fuels for Unit C) and at the two loads (predicted and predicted + 20% increase in firing rate with a limit at 100% load where applicable). The total plant investment for all the predicted load +20% firing rate cases was assumed the same as for the predicted load cases. This was possible since retrofit specification tolerances were large enough. Preproduction costs, however, change slightly. These tables present the total plant investment, preproduction costs, and total capital requirements for the retrofit specifications described in Section 7.

The total plant investment (TPI) includes direct costs, distributables, engineering services and total contingency. Direct costs represent the largest part of the total plant investment and include field construction of permanent plant equipment, materials, subcontracts, and construction labor. Distributables are those cost items that cannot be ascribed separately to direct cost items of the facility, and thus are accounted for separately. The distributables cover costs of a temporary nature at the construction site such as field supervision, temporary construction facilities, temporary utilities, and construction equipment and tools.

The engineering services include engineering costs and other home office costs and fees. Engineering includes preliminary engineering, optimization studies, specifications, detail engineering, vendor drawing review, site investigations, and support to vendors. Other home office costs are comprised of procurement, estimating and schedule services, and construction and project management.

Total contingency consists of a process contingency, which covers the uncertainty in the design and cost of CWF commercial-scale equipment, and a project contingency, which covers additional equipment or other costs that would result from a more detailed design of an explicitly defined project at an actual site. The total contingency for this study is included in each capital cost grouping at 25% of the estimated capital costs.

Table 8-1

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT A
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	FUEL				
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	AL-5.9
CWF STORAGE	3260.	4700.	3805.	4710.	4950.
CWF TRANSFER	5160.	7410.	6010.	7450.	7810.
BOILER ISLAND MODIFICATIONS	12340.	11730.	13190.	11720.	11720.
PARTICULATE REMOVAL	0.	28030.	0.	0.	28030.
FLUE GAS DESULFURIZATION	23390.	0.	30300.	0.	46100.
ASH HANDLING SYSTEM	18825.	20730.	20270.	20250.	20690.
TOTAL PLANT INVESTMENT	62975.	72600.	73575.	44130.	119300.
PREPRODUCTION COSTS	2519.	4076.	3124.	3418.	5021.
TOTAL CAPITAL REQUIREMENT	65494.	76676.	76699.	47548.	124321.
SPECIFIC CAPITAL REQUIREMENT					
($/KW-MCR)	111.	130.	130.	80.	210.
($/KW-DERATED)	339.	176.	293.	113.	287.

Table 8-2

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT A
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	FUEL				
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	AL-5.9
CWF STORAGE	3260.	4700.	3805.	4710.	4950.
CWF TRANSFER	5160.	7410.	6010.	7450.	7810.
BOILER ISLAND MODIFICATIONS	12340.	11730.	13190.	11720.	11720.
PARTICULATE REMOVAL	0.	28030.	0.	0.	28030.
FLUE GAS DESULFURIZATION	23390.	0.	30300.	0.	46100.
ASH HANDLING SYSTEM	18825.	20730.	20270.	20250.	20690.
TOTAL PLANT INVESTMENT	62975.	72600.	73575.	44130.	119300.
PREPRODUCTION COSTS	2781.	4606.	3464.	3931.	5554.
TOTAL CAPITAL REQUIREMENT	65756.	77206.	77039.	48061.	124854.
SPECIFIC CAPITAL REQUIREMENT					
($/KW-MCR)	111.	130.	130.	81.	211.
($/KW-DERATED)	273.	147.	238.	95.	239.

Table 8-3

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT 8
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	FUEL			
	UF-6.8	SD-5.7	CG-7.9	CG-4.8
CWF STORAGE	2490.	3000.	2550.	3020.
CWF TRANSFER	3920.	4740.	4020.	4770.
BOILER ISLAND MODIFICATIONS	10330.	10110.	10250.	10080.
PARTICULATE REMOVAL	0.	0.	0.	0.
FLUE GAS DESULFURIZATION	14660.	0.	14690.	0.
ASH HANDLING SYSTEM	18340.	18030.	17725.	17530.
TOTAL PLANT INVESTMENT	49740.	35880.	49235.	35400.
PREPRODUCTION COSTS	1859.	2043.	1859.	1986.
TOTAL CAPITAL REQUIREMENT	51599.	37923.	51094.	37386.
SPECIFIC CAPITAL REQUIREMENT				
($/KW-MCR)	127.	93.	125.	92.
($/KW-DERATED)	421.	186.	411.	192.

Table 8-4

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT 8
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	FUEL			
	UF-6.8	SD-5.7	CG-7.9	CG-4.8
CWF STORAGE	2490.	3000.	2550.	3020.
CWF TRANSFER	3920.	4740.	4020.	4770.
BOILER ISLAND MODIFICATIONS	10330.	10110.	10250.	10080.
PARTICULATE REMOVAL	0.	0.	0.	0.
FLUE GAS DESULFURIZATION	14660.	0.	14690.	0.
ASH HANDLING SYSTEM	18340.	18030.	17725.	17530.
TOTAL PLANT INVESTMENT	49740.	35880.	49235.	35400.
PREPRODUCTION COSTS	2040.	2315.	2042.	2249.
TOTAL CAPITAL REQUIREMENT	51780.	38195.	51277.	37649.
SPECIFIC CAPITAL REQUIREMENT				
($/KW-MCR)	127.	94.	126.	92.
($/KW-DERATED)	336.	153.	328.	156.

Table 8-5

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT C
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	FUEL					
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	SD-2.6	AL-5.9
CWF STORAGE	4480.	5560.	4670.	5560.	5540.	5900.
CWF TRANSFER	7080.	8770.	7380.	8775.	9600.	9310.
BOILER ISLAND MODIFICATIONS	6050.	6460.	6060.	6290.	6500.	6350.
PARTICULATE REMOVAL	0.	0.	0.	0.	0.	0.
FLUE GAS DESULFURIZATION	48230.	0.	48230.	0.	0.	66410.
ASH HANDLING SYSTEM	20860.	21885.	21650.	21270.	21185.	23280.
TOTAL PLANT INVESTMENT	86700.	42675.	87990.	41895.	42825.	111250.
PREPRODUCTION COSTS	4131.	4592.	4223.	4445.	5781.	5949.
TOTAL CAPITAL REQUIREMENT	90831.	47267.	92213.	46340.	48606.	117199.
SPECIFIC CAPITAL REQUIREMENT						
($/KW-MCR)	109.	57.	111.	56.	59.	141.
($/KW-DERATED)	245.	78.	243.	80.	62.	198.

Table 8-6

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT C
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	FUEL					
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	SD-2.6	AL-5.9
CWF STORAGE	4480.	5560.	4670.	5560.	5540.	5900.
CWF TRANSFER	7080.	8770.	7380.	8775.	9600.	9310.
BOILER ISLAND MODIFICATIONS	6050.	6460.	6060.	6290.	6500.	6350.
PARTICULATE REMOVAL	0.	0.	0.	0.	0.	0.
FLUE GAS DESULFURIZATION	48230.	0.	48230.	0.	0.	66410.
ASH HANDLING SYSTEM	20860.	21885.	21650.	21270.	21185.	23280.
TOTAL PLANT INVESTMENT	86700.	42675.	87990.	41895.	42825.	111250.
PREPRODUCTION COSTS	4625.	5347.	4730.	5174.	6052.	6702.
TOTAL CAPITAL REQUIREMENT	91325.	48022.	92720.	47069.	48877.	117952.
SPECIFIC CAPITAL REQUIREMENT						
($/KW-MCR)	110.	58.	112.	57.	59.	142.
($/KW-DERATED)	199.	66.	198.	67.	59.	165.

Table 8-7

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT D
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
CWF STORAGE	363.	363.	403.	403.	418.	418.	412.	412.
CWF TRANSFER	573.	573.	636.	636.	660.	660.	651.	651.
BOILER ISLAND MODIFICATIONS	1474.	1474.	1475.	1475.	1474.	1474.	1475.	1475.
PARTICULATE REMOVAL	0.	0.	0.	0.	0.	0.	0.	0.
FLUE GAS DESULFURIZATION	210.	210.	210.	210.	210.	210.	210.	210.
ASH HANDLING SYSTEM	139.	139.	178.	178.	178.	178.	178.	178.
TOTAL PLANT INVESTMENT	2759.	2759.	2902.	2902.	2940.	2940.	2926.	2926.
PREPRODUCTION COSTS	80.	78.	88.	85.	89.	86.	88.	86.
TOTAL CAPITAL REQUIREMENT	2839.	2837.	2990.	2987.	3029.	3026.	3014.	3012.
SPECIFIC CAPITAL REQUIREMENT								
($/LB STEAM/HR-MCR)	28.4	28.4	29.9	29.9	30.3	30.3	30.1	30.1
($/LB STEAM/HR-DERATED)	123.3	123.2	100.7	100.6	102.9	102.8	102.1	102.0

Table 8-8

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT D
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
CWF STORAGE	363.	363.	403.	403.	418.	418.	412.	412.
CWF TRANSFER	573.	573.	636.	636.	660.	660.	651.	651.
BOILER ISLAND MODIFICATIONS	1474.	1474.	1475.	1475.	1474.	1474.	1475.	1475.
PARTICULATE REMOVAL	0.	0.	0.	0.	0.	0.	0.	0.
FLUE GAS DESULFURIZATION	210.	210.	210.	210.	210.	210.	210.	210.
ASH HANDLING SYSTEM	139.	139.	178.	178.	178.	178.	178.	178.
TOTAL PLANT INVESTMENT	2759.	2759.	2902.	2902.	2940.	2940.	2926.	2926.
PREPRODUCTION COSTS	83.	81.	92.	89.	93.	90.	93.	90.
TOTAL CAPITAL REQUIREMENT	2842.	2840.	2994.	2991.	3033.	3030.	3019.	3016.
SPECIFIC CAPITAL REQUIREMENT								
($/LB STEAM/HR-MCR)	28.4	28.4	29.9	29.9	30.3	30.3	30.2	30.2
($/LB STEAM/HR-DERATED)	102.9	102.8	84.0	83.9	85.9	85.8	85.2	85.1

Table 8-9

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT E
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
CWF STORAGE	673.	673.	835.	835.	870.	870.	855.	855.	898.	898.
CWF TRANSFER	1063.	1063.	1315.	1315.	1370.	1370.	1350.	1350.	1455.	1455.
BOILER ISLAND MODIFICATIONS	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1250.
PARTICULATE REMOVAL	0.	0.	4725.	4725.	0.	0.	4680.	4680.	7370.	7370.
FLUE GAS DESULFURIZATION	5963.	5963.	0.	0.	7370.	7370.	0.	0.	0.	0.
ASH HANDLING SYSTEM	1405.	1405.	1313.	1313.	1405.	1405.	1313.	1313.	1405.	1405.
TOTAL PLANT INVESTMENT	10353.	10353.	9438.	9438.	12265.	12265.	9448.	9448.	12378.	12378.
PREPRODUCTION COSTS	351.	339.	406.	387.	466.	447.	402.	384.	467.	449.
TOTAL CAPITAL REQUIREMENT	10703.	10692.	9843.	9825.	12731.	12712.	9850.	9831.	12845.	12827.
SPECIFIC CAPITAL REQUIREMENT										
($/LB STEAM/HR-MCR)	26.8	26.7	24.6	24.6	31.8	31.8	24.6	24.6	32.1	32.1
($/LB STEAM/HR-DERATED)	81.1	81.0	45.8	45.7	60.9	60.8	46.9	46.8	61.8	61.7

Table 8-10

RETROFIT CAPITAL COST SUMMARY
($1000S; MID 1985 WAGE & PRICE LEVEL)
UNIT-UNIT E
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
CWF STORAGE	673.	673.	835.	835.	870.	870.	855.	855.	898.	898.
CWF TRANSFER	1063.	1063.	1315.	1315.	1370.	1370.	1350.	1350.	1455.	1455.
BOILER ISLAND MODIFICATIONS	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1250.
PARTICULATE REMOVAL	0.	0.	4725.	4725.	0.	0.	4680.	4680.	7370.	7370.
FLUE GAS DESULFURIZATION	5963.	5963.	0.	0.	7370.	7370.	0.	0.	0.	0.
ASH HANDLING SYSTEM	1405.	1405.	1313.	1313.	1405.	1405.	1313.	1313.	1405.	1405.
TOTAL PLANT INVESTMENT	10353.	10353.	9438.	9438.	12265.	12265.	9448.	9448.	12378.	12378.
PREPRODUCTION COSTS	375.	361.	445.	422.	505.	482.	440.	419.	505.	484.
TOTAL CAPITAL REQUIREMENT	10727.	10713.	9882.	9860.	12770.	12747.	9888.	9866.	12883.	12861.
SPECIFIC CAPITAL REQUIREMENT										
($/LB STEAM/HR-MCR)	26.8	26.8	24.7	24.6	31.9	31.9	24.7	24.7	32.2	32.2
($/LB STEAM/HR-DERATED)	67.7	67.6	38.3	38.2	50.9	50.8	39.2	39.2	51.6	51.5

TABLE 8-11

RETROFIT CAPITAL COST SUMMARY AT PREDICTED LOAD

VERTICAL CYLINDRICAL DESIGNED HEATERS

UNIT F

	Single Heater	Twin Heaters
Heater Modifications Including CWF Storage & Transfer	$4,285,000	$5,655,000
ASH/SO_x Removal Equipment	$ 500,000	$ 620,000
ASH Handling Equipment	$ 500,000	$ 670,000
TOTAL PLANT INVESTMENT	$5,285,000	$6,946,000
Preproduction Costs	$ 148,000	$ 216,000
TOTAL CAPITAL REQUIREMENTS (TOTAL INSTALLED COSTS)	$5,433,000	$7,161,000

TABLE 8-12

RETROFIT CAPITAL COST SUMMARY AT PREDICTED LOAD

HORIZONTAL CABIN DESIGNED HEATERS

UNIT G

	Single Heater	Twin Heaters
Heater Modifications Including CWF Storage & Transfer	$6,030,000	$ 8,655,000
ASH/SO_x Removal Equipment	$ 875,000	$ 1,250,000
ASH Handling Equipment	$ 770,000	$ 1,025,000
TOTAL PLANT INVESTMENT	$7,675,000	$10,930,000
Preproduction Costs	$ 230,000	$ 362,000
TOTAL CAPITAL REQUIREMENTS (TOTAL INSTALLED COSTS)	$7,905,000	$11,292,000

The total capital requirement represents all the capital needed to complete the project and is the sum of the TPI plus the preproduction costs.

Preproduction costs are expenditures incurred for initial training of plant operators, preoperational testing and major modifications to plant equipment, inefficient use of materials at startup, and miscellaneous administrative and support labor. Preproduction costs are estimated as the sum of one month's fixed and variable operating costs (defined later) at full derated capacity (excluding CWF fuel), 25% of full derated capacity CWF fuel cost for one month, and 2% of TPI.

The total installed cost for modifying each selected process heater for CWF firing as described earlier was estimated and is contained in Tables 8-11 and 8-12. Single and twin process heater modification costs were developed because each selected heater has a near identical twin heater with which it shares a common air preheat system and stack and so that size scaling factors could be determined. The modification costs in the tables apply to any of the four selected CWF's for the following reasons:

1. The modification costs (exclusive of fly ash collection and SO_x removal equipment) for each heater type were identical (within the accuracy of the estimate) for each fuel.

2. The costs of wet scrubbing systems for combined SO_x removal and fly ash collection for each heater type were identical (within the accuracy of the estimate) for each fuel. All four CWF's require fly ash collection equipment, but only two (Upper Freeport 6.8 and Cedar Grove 7.9) require SO_x removal equipment. It may therefore seem that the installation of a wet scrubber for the two low sulfur CWF's (Cedar Grove 4.8 and Splash Dam 5.7) is excessive or not justified but a wet scrubber was considerably less costly for these fuels than an electrostatic precipitator.

SPECIFIC CAPITAL REQUIREMENTS

Figure 8-1 compares Specific Capital Requirements (SCRs) for the three utility units. The SCR ranges from about \$60/KW-derated to about \$420/KW-derated depending primarily on the load capability, or between about \$60 to 140 based on the nameplate capacity of the unit. The SCR plots for the microfine AL5.9 fuel lie significantly above the other data for Units A and C respectively. The larger scrubber and the ESP addition contribute to the higher SCR for Unit A, while the larger scrubber requirement on Unit C raises its SCR.

Figure 8-2 shows a similar comparison for the industrial units. Costs range from about \$40 to \$125/lb steam/hr-derated, or from about \$25 to \$32/lb steam/hr based on the nameplate capacity. The primary dependence for the specific capital cost requirement is again load capability. The SCR plots for the microfine AL5.9 fuel lie within the band of of other data since changes in retrofit costs are relatively small regardless of the CWF in this study. Figure 8-3 compares all the unit SCRs on a Btu Fired basis. The smaller industrial units require about 1.5 to 2 times more capital per Btu Fired than do the utility units. The SCR plots for the microfine AL5.9 fuel lie above the band for Utility Units A and C, and within the band for Industrial Unit E.

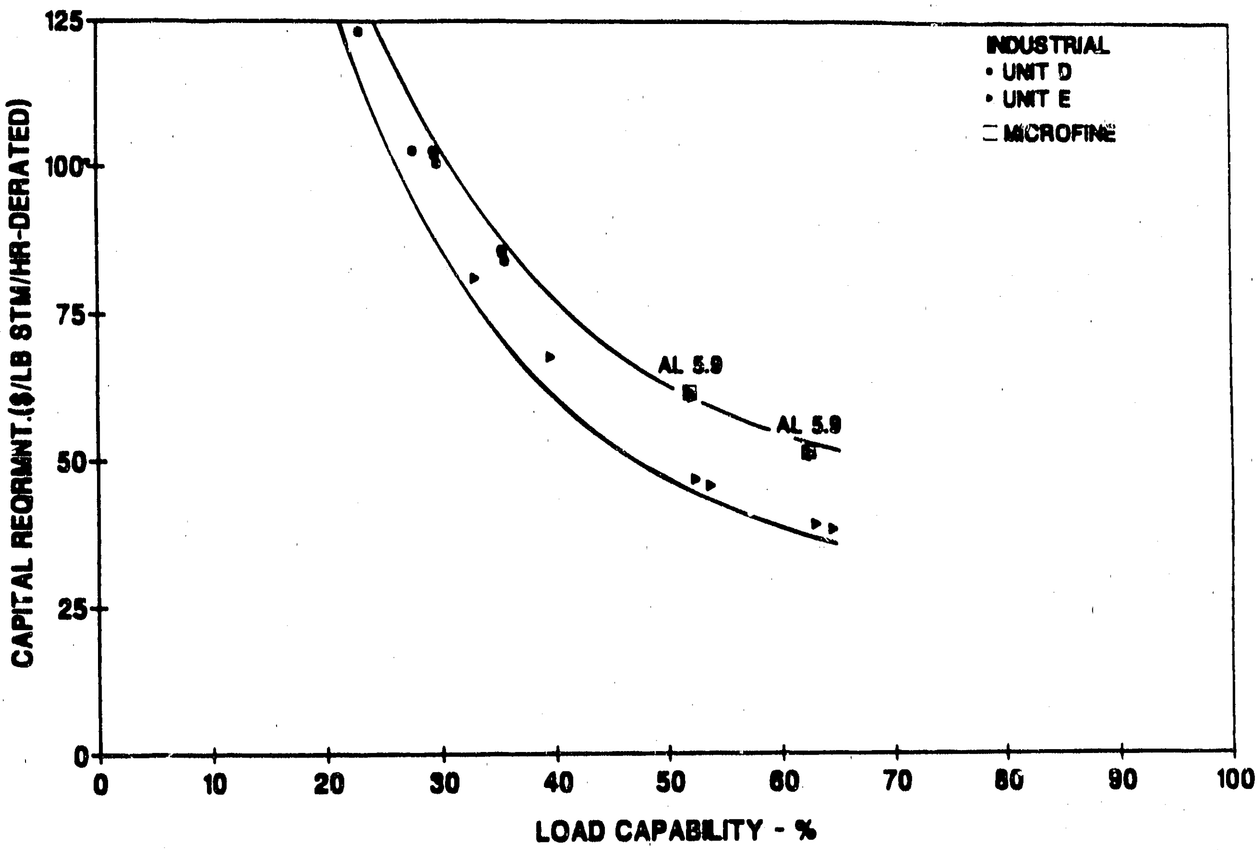


FIGURE 8-2
SPECIFIC CAPITAL REQUIREMENT VS. LOAD CAPABILITY

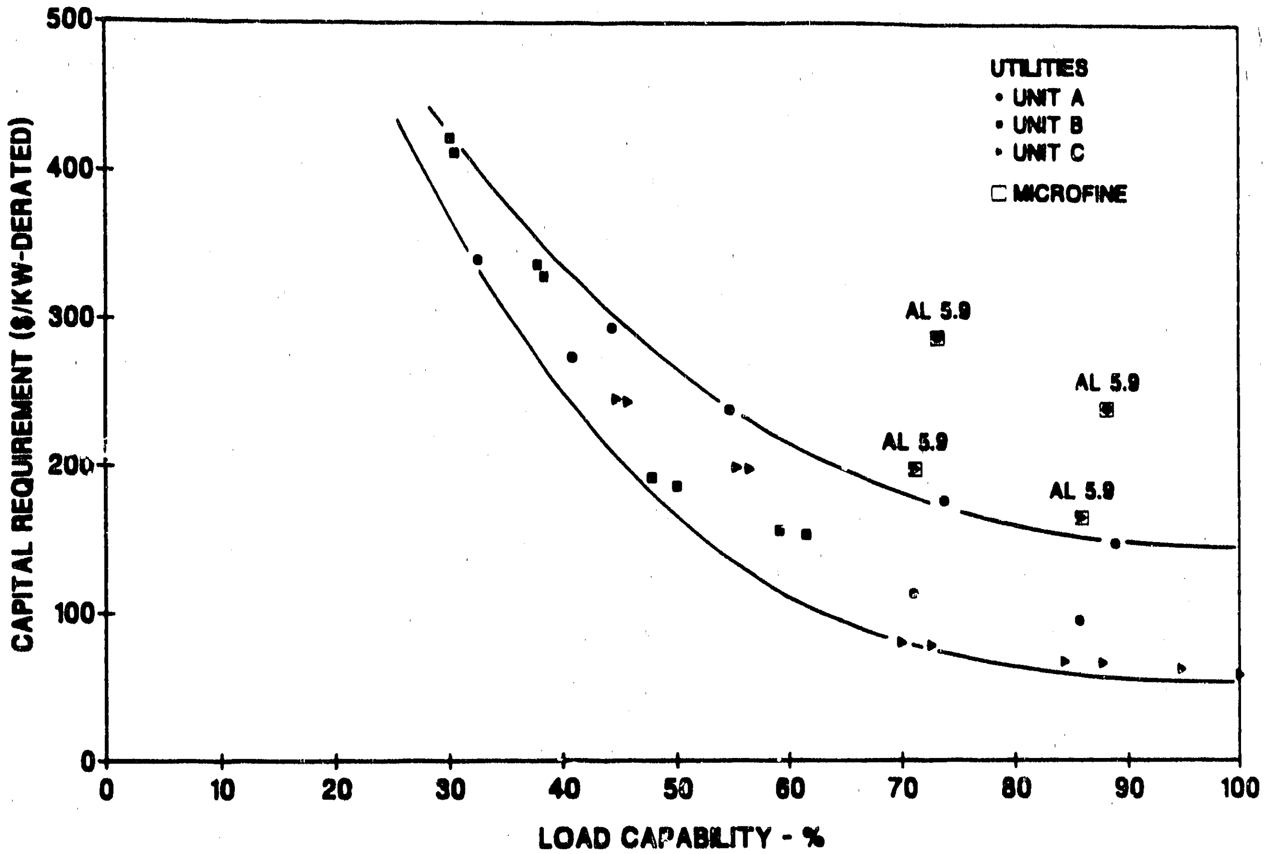


FIGURE 8-1
SPECIFIC CAPITAL REQUIREMENT VS. LOAD CAPABILITY

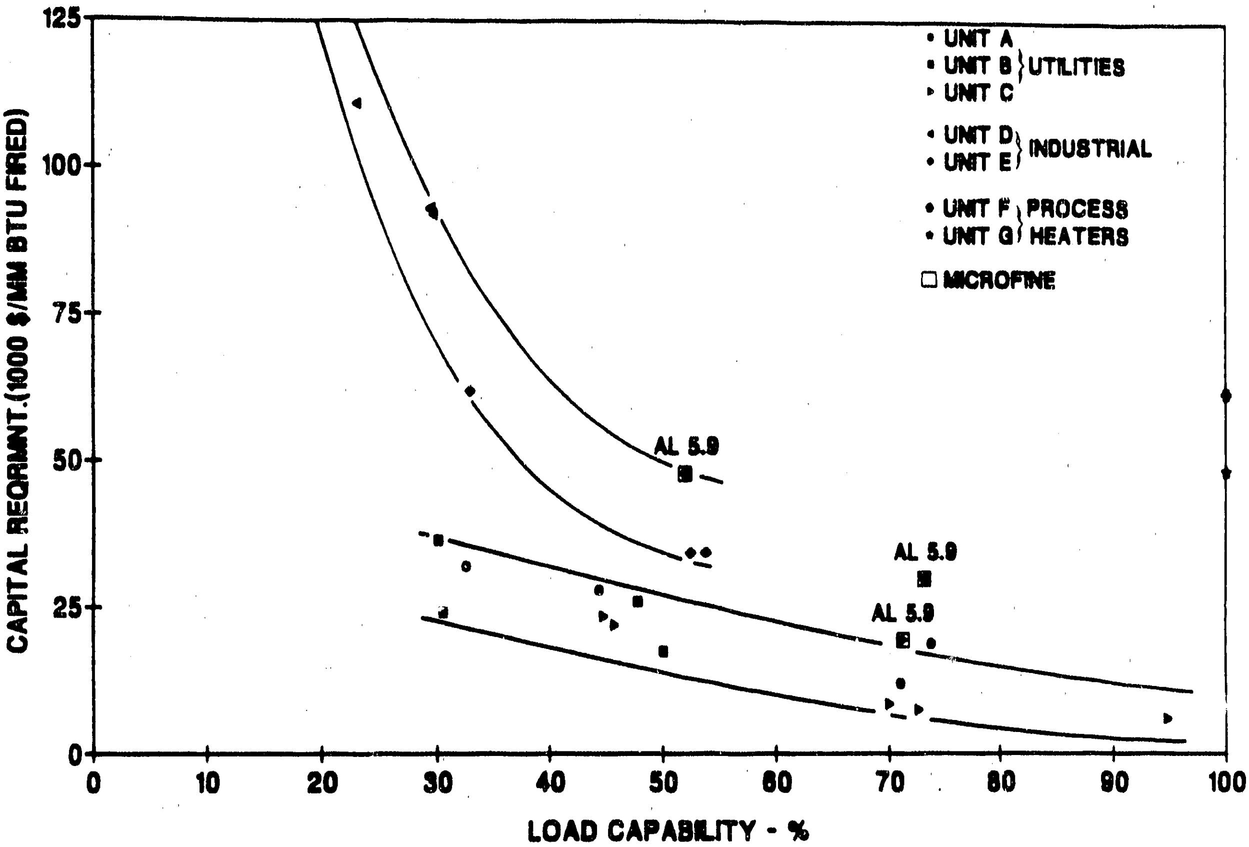


FIGURE 8-3
SPECIFIC CAPITAL REQUIREMENT VS. LOAD CAPABILITY

ANNUAL OPERATING AND MAINTENANCE COST ESTIMATES

The annual operating and maintenance (O&M) cost estimate is based on mid 1985 price and wage levels and is structured with two estimate components - total O&M costs and credits. The first component, total O&M cost, is the incurred O&M cost due to CWF retrofitting. The second cost component, credits due to CWF retrofitting, is the savings realized by not burning fuel oil. The final objective of the cost estimate is to determine how the CWF option compares with fuel oil firing on an annual basis. Thus, the incremental O&M cost or savings for CWF is determined simply by the difference of total O&M cost and credits. The basis for estimating is described briefly below and in more detail in Reference 7.

The total O&M cost consists of three or four cost items depending on the unit type. These are fixed O&M costs, variable O&M costs, and fuel costs associated with all units, and replacement power costs for the utility units only.

The fixed O&M cost represents the incremental increase in plant operating and maintenance labor and material due to CWF retrofitting over the fuel-oil designed power plant. Only the change in fixed O&M is required to compare cost and credits.

In estimating the incremental fixed O&M cost, it is assumed that converting from fuel oil firing to CWF firing will not increase or decrease the operating labor cost or the annual overhead charges, which include administrative and support labor cost. Therefore, the only incremental fixed O&M cost due to CWF burning consists of the additional maintenance material and labor costs of CWF over fuel oil burning. This incremental cost is estimated at 4% of the CWF retrofit process capital cost. A typical maintenance labor/material split ratio of 40/60 is estimated.

Variable O&M costs include expenses for water, chemicals, other consumables necessary for power or steam generation, and other expenses necessary for waste disposal. Cost calculations for the variable O&M cost are based on plant capacity factors for each plant as defined later.

For this cost study, the annual variable O&M costs associated with CWF are included in the estimates as a summation of the following two cost items:

- For the utility units the water and chemical costs required to generate 1 kilowatt hour of electricity are based on an estimated unit cost of 1.8 mills per kilowatt hour. This charge was calculated based on annual power generated for both CWF and fuel oil. For industrial units a cost of 0.25 mills per pound of steam generated is used.

- Ash disposal cost was estimated at $5.60 per short ton of dry ash produced from CWF firing. The amount of disposable ash is again calculated based on annual fuel consumption. The small amount of ash from the fuel oil burning has been neglected in the cost calculation.

The annual fuel consumption and associated fuel costs are calculated based on unit capacity and unit capacity factor for each of the seven units. For this study period, three differential fuel costs have been assumed as shown in Table 8-13. These three differential fuel costs have sufficient range so that economic trends can be clearly identified. A more detailed study of CWF cost is given by Reference (8) and is included in Section 11.

TABLE 8-13

DIFFERENTIAL FUEL COSTS ($\$/10^6$BTU)

Oil Cost	CWF Cost	Differential Fuel Cost
4.00	3.00	1.00
4.50	3.00	1.50
5.00	3.00	2.00

Because of the lower capacity factor generally expected when utility units are switched from firing fuel oil 100% of the time to firing CWF at derated capacity, replacement power will be needed to meet the plant yearly load demand. The replacement power is assumed to be generated by dispatching other oil-fired units. The cost of replacement power is calculated by assuming the same oil fired net plant heat rate as the plant in question and the same variable O&M cost.

To complete the estimate, credits from burning CWF are required. Credits represent the savings achieved by not burning fuel oil. The credit consists of two items - fuel oil savings and variable O&M savings. The credit represents an annual savings. The fuel oil credit, which will be deducted from other O&M costs, is obtained simply by multiplying the annual fuel oil requirement for the Base Case by the fuel unit prices listed previously.

The variable O&M credit, which includes savings from makeup water and chemicals reductions due to lower annual outputs with CWF burning, is calculated based on 1.8 mills/kWhr and the annual power generated for the Base Case of the respective utility boilers. For the industrial units 0.25 mills per pound of steam and the annual steam generated are used.

The above discussion forms the basis of the annual operating and maintenance cost and savings estimate. The results indicated are the incremental annual O&M costs of CWF firing compared to fuel oil firing. The incremental annual O&M savings thus calculated are used to calculate the total economic impact of a CWF conversion over the life of the boiler plant.

In order to estimate the economic impact of CWF fuel retrofitting, several tables summarizing plant operating data are shown. Tables 8-14 to 8-19 describe plant operating data for the three utility units. There are two tables for each unit. One table is calculated at the predicted loads for the fuels and the second table is calculated at the predicted load with 20% increase in firing rate (100% load for Unit C with SD2.6 Fuel). Included in these tables are the following items.

Maximum plant output is the maximum net electrical power generated by the plant when the unit is fired with the respective fuel.

Table 8-14

PLANT OPERATING DATA
UNIT-UNIT A
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	FUEL					
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	AL-5.9	BASE-OIL
MAXIMUM PLANT OUTPUT..................(KW)	193201.	436570.	262158.	420370.	433105.	591900.
DERATED CAPACITY................(FRACTION)	0.326	0.738	0.443	0.710	0.732	
CAPACITY FACTOR CWF.............(FRACTION)	0.141	0.351	0.201	0.337	0.348	
CAPACITY FACTOR OIL.............(FRACTION)	0.065	0.053	0.062	0.054	0.053	0.537
ANNUAL POWER GEN. BY CWF...(10**6 KWHR/YR)	733.52	1820.79	1041.59	1748.42	1805.31	
ANNUAL POWER GEN. BY OIL...(10**6 KWHR/YR)	338.11	274.15	319.98	278.41	275.06	2784.37
ANNUAL REPLACEMENT POWER...(10**6 KWHR/YR)	1712.74	689.43	1422.80	757.54	704.00	
NET PLANT HEAT RATE CWF.........(BTU/KWHR)	10781.5	9765.5	10318.6	9817.3	9893.8	
NET PLANT HEAT RATE OIL.........(BTU/KWHR)	9243.6	9243.6	9243.6	9243.6	9243.6	9243.6
ANNUAL FUEL CONS. CWF......(10**12 BTU/YR)	7.908	17.781	10.748	17.165	17.861	
ANNUAL FUEL CONS. OIL......(10**12 BTU/YR)	3.125	2.534	2.958	2.573	2.543	25.738
ANNUAL ASH FIRED CWF............(TONS/YR)	18993.	35123.	31409.	29258.	38551.	
ANNUAL FLYASH CWF...............(TONS/YR)	15195.	28098.	25128.	23406.	30841.	

Table 8-15

PLANT OPERATING DATA
UNIT-UNIT A
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	FUEL					
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	AL-5.9	BASE-OIL
MAXIMUM PLANT OUTPUT..................(KW)	241274.	525959.	323605.	507112.	521832.	591900.
DERATED CAPACITY................(FRACTION)	0.408	0.889	0.547	0.857	0.882	
CAPACITY FACTOR CWF.............(FRACTION)	0.183	0.428	0.254	0.412	0.425	
CAPACITY FACTOR OIL.............(FRACTION)	0.063	0.048	0.059	0.049	0.049	0.537
ANNUAL POWER GEN. BY CWF...(10**6 KWHR/YR)	948.29	2220.15	1316.11	2135.95	2201.71	
ANNUAL POWER GEN. BY OIL...(10**6 KWHR/YR)	325.47	250.66	303.83	255.61	251.74	2784.37
ANNUAL REPLACEMENT POWER...(10**6 KWHR/YR)	1510.61	313.56	1164.42	392.81	330.92	
NET PLANT HEAT RATE CWF.........(BTU/KWHR)	10358.1	9727.0	10030.4	9765.6	9854.7	
NET PLANT HEAT RATE OIL.........(BTU/KWHR)	9243.6	9243.6	9243.6	9243.6	9243.6	9243.6
ANNUAL FUEL CONS. CWF......(10**12 BTU/YR)	9.822	21.595	13.201	20.859	21.697	
ANNUAL FUEL CONS. OIL......(10**12 BTU/YR)	3.009	2.317	2.809	2.363	2.327	25.738
ANNUAL ASH FIRED CWF............(TONS/YR)	23590.	42658.	38579.	35555.	46830.	
ANNUAL FLYASH CWF...............(TONS/YR)	18872.	34126.	30863.	28444.	37464.	

Table 8-16

PLANT OPERATING DATA
UNIT-UNIT B
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	FUEL				
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	BASE-OIL
MAXIMUM PLANT OUTPUT..................(KW)	122673.	203808.	124429.	194683.	407400.
DERATED CAPACITY................(FRACTION)	0.301	0.500	0.305	0.478	
CAPACITY FACTOR CWF.............(FRACTION)	0.129	0.230	0.131	0.219	
CAPACITY FACTOR OIL.............(FRACTION)	0.066	0.060	0.066	0.061	0.537
ANNUAL POWER GEN. BY CWF...(10**6 KWHR/YR)	458.83	821.31	466.68	780.54	
ANNUAL POWER GEN. BY OIL...(10**6 KWHR/YR)	235.42	214.10	234.96	216.50	1916.46
ANNUAL REPLACEMENT POWER...(10**6 KWHR/YR)	1222.20	881.05	1214.82	919.41	
NET PLANT HEAT RATE CWF.........(BTU/KWHR)	11752.2	10698.9	11695.6	10823.6	
NET PLANT HEAT RATE OIL.........(BTU/KWHR)	10101.9	10101.9	10101.9	10101.9	10101.9
ANNUAL FUEL CONS. CWF......(10**12 BTU/YR)	5.392	8.787	5.458	8.448	
ANNUAL FUEL CONS. OIL......(10**12 BTU/YR)	2.378	2.163	2.374	2.187	19.360
ANNUAL ASH FIRED CWF.............(TONS/YR)	12950.	17357.	15951.	14401.	
ANNUAL FLYASH CWF................(TONS/YR)	10360.	13886.	12761.	11520.	

Table 8-17

PLANT OPERATING DATA
UNIT-UNIT B
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	FUEL				
	UF-6.8	SD-5.7	CG-7.9	CG-4.8	BASE-OIL
MAXIMUM PLANT OUTPUT..................(KW)	154197.	250414.	156364.	240882.	407400.
DERATED CAPACITY................(FRACTION)	0.378	0.615	0.384	0.591	
CAPACITY FACTOR CWF.............(FRACTION)	0.168	0.288	0.171	0.277	
CAPACITY FACTOR OIL.............(FRACTION)	0.064	0.057	0.063	0.057	0.537
ANNUAL POWER GEN. BY CWF...(10**6 KWHR/YR)	599.67	1029.53	609.35	986.94	
ANNUAL POWER GEN. BY OIL...(10**6 KWHR/YR)	227.14	201.85	226.57	204.36	1916.46
ANNUAL REPLACEMENT POWER...(10**6 KWHR/YR)	1089.65	685.08	1080.54	725.16	
NET PLANT HEAT RATE CWF.........(BTU/KWHR)	11222.4	10449.2	11168.4	10498.2	
NET PLANT HEAT RATE OIL.........(BTU/KWHR)	10101.9	10101.9	10101.9	10101.9	10101.9
ANNUAL FUEL CONS. CWF......(10**12 BTU/YR)	6.730	10.758	6.805	10.361	
ANNUAL FUEL CONS. OIL......(10**12 BTU/YR)	2.295	2.039	2.289	2.064	19.360
ANNUAL ASH FIRED CWF.............(TONS/YR)	16162.	21250.	19888.	17661.	
ANNUAL FLYASH CWF................(TONS/YR)	12930.	17000.	15911.	14129.	

Table 8-18

PLANT OPERATING DATA
UNIT-UNIT C
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	FUEL UF-6.8	SD-5.7	CG-7.9	CG-4.8	SD-2.6	AL-5.9	BASE-OIL
MAXIMUM PLANT OUTPUT..................(KW)	371404.	603547.	379144.	581273.	786958.	591046.	830000.
DERATED CAPACITY................(FRACTION)	0.447	0.727	0.457	0.700	0.948	0.712	
CAPACITY FACTOR CWF.............(FRACTION)	0.203	0.346	0.208	0.332	0.459	0.338	
CAPACITY FACTOR OIL.............(FRACTION)	0.062	0.053	0.061	0.054	0.047	0.054	0.537
ANNUAL POWER GEN. BY CWF...(10**6 KWHR/YR)	1477.52	2514.64	1512.09	2415.13	3334.04	2458.79	
ANNUAL POWER GEN. BY OIL...(10**6 KWHR/YR)	447.70	386.70	445.67	392.55	338.50	389.98	3904.42
ANNUAL REPLACEMENT POWER...(10**6 KWHR/YR)	1979.20	1003.08	1946.66	1096.74	231.88	1055.65	
NET PLANT HEAT RATE CWF.........(BTU/KWHR)	10611.5	10100.0	10664.4	10133.7	10238.0	10288.4	
NET PLANT HEAT RATE OIL.........(BTU/KWHR)	9772.1	9772.1	9772.1	9772.1	9772.1	9772.1	9772.1
ANNUAL FUEL CONS. CWF......(10**12 BTU/YR)	15.679	25.398	16.125	24.474	34.134	25.297	
ANNUAL FUEL CONS. OIL......(10**12 BTU/YR)	4.375	3.779	4.355	3.836	3.308	3.811	38.154
ANNUAL ASH FIRED CWF.............(TONS/YR)	37655.	50168.	47126.	41718.	29161.	54600.	
ANNUAL FLYASH CWF................(TONS/YR)	30124.	40135.	37700.	33374.	23328.	43680.	

Table 8-19

PLANT OPERATING DATA
UNIT-UNIT C
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	FUEL UF-6.8	SD-5.7	CG-7.9	CG-4.8	SD-2.6	AL-5.9	BASE-OIL
MAXIMUM PLANT OUTPUT..................(KW)	458854.	727107.	468419.	700366.	830000.	713064.	830000.
DERATED CAPACITY................(FRACTION)	0.553	0.876	0.564	0.844	1.000	0.859	
CAPACITY FACTOR CWF.............(FRACTION)	0.257	0.422	0.263	0.405	0.485	0.413	
CAPACITY FACTOR OIL.............(FRACTION)	0.058	0.049	0.058	0.050	0.045	0.049	0.537
ANNUAL POWER GEN. BY CWF...(10**6 KWHR/YR)	1868.21	3066.65	1910.94	2947.18	3526.34	3003.91	
ANNUAL POWER GEN. BY OIL...(10**6 KWHR/YR)	424.72	354.23	422.21	361.25	327.19	357.92	3904.42
ANNUAL REPLACEMENT POWER...(10**6 KWHR/YR)	1611.49	483.54	1571.27	595.98	50.90	542.59	
NET PLANT HEAT RATE CWF.........(BTU/KWHR)	10307.5	10059.8	10358.2	10093.3	10238.0	10233.8	
NET PLANT HEAT RATE OIL.........(BTU/KWHR)	9772.1	9772.1	9772.1	9772.1	9772.1	9772.1	9772.1
ANNUAL FUEL CONS. CWF......(10**12 BTU/YR)	19.257	30.850	19.794	29.747	36.103	30.741	
ANNUAL FUEL CONS. OIL......(10**12 BTU/YR)	4.150	3.462	4.126	3.530	3.197	3.498	38.154
ANNUAL ASH FIRED CWF.............(TONS/YR)	46247.	60938.	57846.	50705.	30842.	66351.	
ANNUAL FLYASH CWF................(TONS/YR)	36998.	48750.	46277.	40564.	24674.	53081.	

Derated capacity is the percent of of oil fired maximum plant output the plant can generate when firing CWF.

The plant capacity factor is an average over the year and is defined as follows:

$$\text{capacity factor} = \frac{\text{(Annual kWh actually generated)}}{\text{(kWh generated if the plant operates at 100\% load on oil for 8,760 hours/year)}}$$

The capacity factor is determined both by unit availability and by economic dispatch of the utility system (estimated based on the EPRI Regional Systems), and thus depends on the fuel fired, the plant mode of operation, the plant nameplate capacity and the capacity derating on CWF. Appendix B of Reference (7) outlines the methodology used to estimate the capacity factors for firing oil or CWF from the load duration curves given in the EPRI Regional Systems. Figure 8-4 shows the capacity factor as a function of the unit derating. The capacity factors calculated for each of the three boilers studied are listed. The annual power generated has been calculated based on the derated capacity and on the plant capacity factor described previously.

To make up the difference between the yearly power output for the Base Case and the power outputs for CWF, replacement power is assumed to be generated by dispatching other existing oil-fired units. For simplicity, these units will be assumed to burn the same fuel oil and to have the same heat rate as that of the Base Case oil-fired plant of each three utility boilers studied.

In order to compare the Base Case with CWF firing on equal basis, the annual replacement power cost is added to the O&M cost of CWF firing. In this way the total yearly kilowatt hours generated are the same for the Base Case and the CWF option.

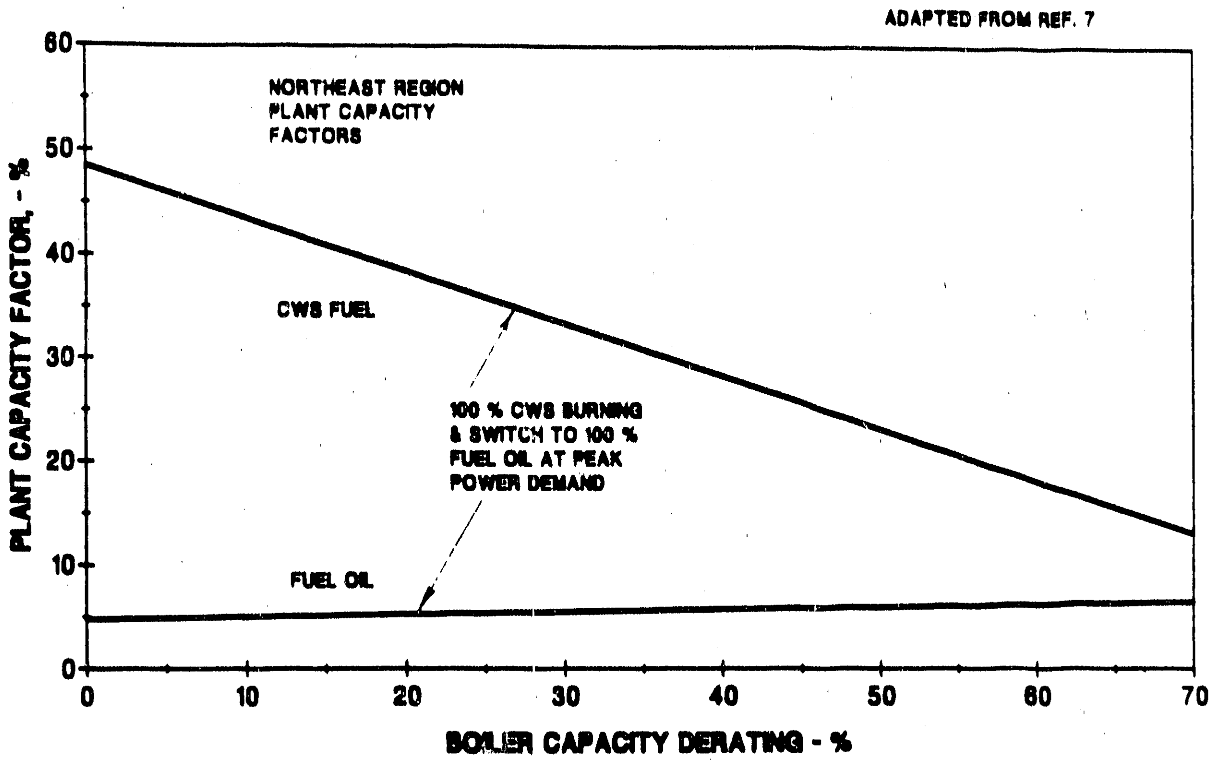


FIGURE 8-4
EFFECT OF BOILER CAPACITY DERATING ON PLANT CAPACITY FACTORS

The net plant heat rate is defined as the ratio of the fuel heat input to the net plant output, expressed in Btu/kWhr. The plant heat rate when the unit is firing No. 6 fuel oil is based on actual plant data. When firing CWF, the heat rate is calculated based on predictions of variation in boiler and turbogenerator efficiencies due to variations in the maximum load and steam condition when the unit is converted from oil to CWF firing. When the retrofitted unit is switched from CWF to oil firing to meet peak load demand, it is assumed that the original plant heat rate on oil can be obtained.

The annual fuel consumption values are calculated based on the annual power generation and the respective net plant heat rate.

Similarly, Tables 8-20 to 8-23 describe unit operating data for the two industrial steam generators.

The calculation procedures for determining annual operating cost savings for each process heater follow the economic guidelines established for this study. The assumed operating conditions of the heaters are contained in Table 8-24. Breakdowns of operating costs for each heater are contained in Tables 8-25 and 8-26. In addition, total annual operating cost savings plus payback period for the heaters are contained in these tables. Definitions of the items unique to these tables follows:

- Total Operating Time, Hrs/yr

  This is the total number of hours per year that the heaters operate. The basis of the calculations assumes the heaters operate 95% of any calendar year (95% overall availability).

- Operating Time on CWF, Hrs/yr

  This is the total number of hours per year that the heaters operate on CWF with the air preheat system and flue gas clean-up equipment in operation. This time was set by the guidelines to be 90% of any calendar year (90% availability).

Table 8-20

PLANT OPERATING DATA
UNIT-UNIT D
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
MAXIMUM STEAM OUTPUT (OIL)....(1000 LB/HR)	100.	100.	100.	100.	100.	100.	100.	100.
MAXIMUM STEAM OUTPUT (CWF)....(1000 LB/HR)	23.	23.	30.	30.	29.	29.	30.	30.
DERATED CAPACITY (CWF)..........(FRACTION)	0.230	0.230	0.297	0.297	0.294	0.294	0.295	0.295
CAPACITY FACTOR CWF.............(FRACTION)	0.207	0.104	0.267	0.134	0.265	0.132	0.266	0.133
CAPACITY FACTOR OIL SWITCHING...(FRACTION)	0.000	0.450	0.000	0.450	0.000	0.450	0.000	0.450
BASE OIL CAPACITY FACTOR........(FRACTION)	0.207	0.554	0.267	0.584	0.265	0.582	0.266	0.583
ANNUAL STEAM GEN. BY CWF.......(MM LBM/YR)	181.51	90.75	234.11	117.05	231.97	115.99	232.85	116.43
ANNUAL STEAM GEN. BY OIL.......(MM LBM/YR)	0.00	394.20	0.00	394.20	0.00	394.20	0.00	394.20
BASE OIL ANNUAL STEAM GEN......(MM LBM/YR)	181.51	484.95	234.11	511.25	231.97	510.19	232.85	510.63
BOILER EFFICIENCY CWF...........(FRACTION)	0.8864	0.8864	0.8975	0.8975	0.8893	0.8893	0.8927	0.8927
BOILER EFFICIENCY OIL...........(FRACTION)	0.8695	0.8695	0.8695	0.8695	0.8695	0.8695	0.8695	0.8695
ANNUAL FUEL CONS. CWF..........(MM BTU/YR)	202228.	101114.	257610.	128805.	257612.	128806.	257608.	128804.
ANNUAL FUEL CONS. OIL SWITCH...(MM BTU/YR)	0.	447742.	0.	447742.	0.	447742.	0.	447742.
BASE OIL ANNUAL FUEL CONS......(MM BTU/YR)	206158.	550822.	265905.	580695.	263478.	579481.	264481.	579983.
ANNUAL ASH FIRED CWF............(TONS/YR)	486.	243.	509.	254.	753.	376.	439.	220.
ANNUAL FLYASH CWF...............(TONS/YR)	389.	194.	407.	204.	602.	301.	351.	176.

Table 8-21

PLANT OPERATING DATA
UNIT-UNIT D
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
MAXIMUM STEAM OUTPUT (OIL)....(1000 LB/HR)	100.	100.	100.	100.	100.	100.	100.	100.
MAXIMUM STEAM OUTPUT (CWF)....(1000 LB/HR)	28.	28.	36.	36.	35.	35.	35.	35.
DERATED CAPACITY (CWF)..........(FRACTION)	0.276	0.276	0.356	0.356	0.353	0.353	0.354	0.354
CAPACITY FACTOR CWF.............(FRACTION)	0.249	0.124	0.321	0.160	0.318	0.159	0.319	0.159
CAPACITY FACTOR OIL SWITCHING...(FRACTION)	0.000	0.450	0.000	0.450	0.000	0.450	0.000	0.450
BASE OIL CAPACITY FACTOR........(FRACTION)	0.249	0.574	0.321	0.610	0.318	0.609	0.319	0.609
ANNUAL STEAM GEN. BY CWF.......(MM LBM/YR)	217.80	108.90	280.93	140.47	278.37	139.18	279.42	139.71
ANNUAL STEAM GEN. BY OIL.......(MM LBM/YR)	0.00	394.20	0.00	394.20	0.00	394.20	0.00	394.20
BASE OIL ANNUAL STEAM GEN......(MM LBM/YR)	217.80	503.10	280.93	534.67	278.37	533.38	279.42	533.91
BOILER EFFICIENCY CWF...........(FRACTION)	0.8864	0.8864	0.8975	0.8975	0.8893	0.8893	0.8927	0.8927
BOILER EFFICIENCY OIL...........(FRACTION)	0.8695	0.8695	0.8695	0.8695	0.8695	0.8695	0.8695	0.8695
ANNUAL FUEL CONS. CWF..........(MM BTU/YR)	242670.	121335.	309133.	154567.	309138.	154569.	309129.	154565.
ANNUAL FUEL CONS. OIL SWITCH...(MM BTU/YR)	0.	447742.	0.	447742.	0.	447742.	0.	447742.
BASE OIL ANNUAL FUEL CONS......(MM BTU/YR)	247387.	571436.	319088.	607286.	316178.	605831.	317378.	606431.
ANNUAL ASH FIRED CWF.............(TONS/YR)	583.	291.	611.	305.	903.	452.	527.	263.
ANNUAL FLYASH CWF................(TONS/YR)	466.	233.	489.	244.	723.	361.	422.	211.

TABLE 8-22

PLANT OPERATING DATA
UNIT-UNIT E
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
MAXIMUM STEAM OUTPUT (OIL)....(1000 LB/HR)	400.	400.	400.	400.	400.	400.	400.	400.	400.	400.
MAXIMUM STEAM OUTPUT (CWF)....(1000 LB/HR)	132.	132.	215.	215.	209.	209.	210.	210.	208.	208.
DERATED CAPACITY (CWF)..........(FRACTION)	0.330	0.330	0.538	0.538	0.522	0.522	0.525	0.525	0.520	0.520
CAPACITY FACTOR CWF.............(FRACTION)	0.297	0.148	0.484	0.242	0.470	0.235	0.472	0.236	0.468	0.234
CAPACITY FACTOR OIL SWITCHING...(FRACTION)	0.000	0.450	0.000	0.450	0.000	0.450	0.000	0.450	0.000	0.450
BASE OIL CAPACITY FACTOR........(FRACTION)	0.297	0.599	0.484	0.692	0.470	0.685	0.472	0.686	0.468	0.684
ANNUAL STEAM GEN. BY CWF.......(MM LBM/YR)	1040.69	520.34	1695.06	847.53	1647.76	823.88	1655.64	827.82	1639.87	819.94
ANNUAL STEAM GEN. BY OIL.......(MM LBM/YR)	0.00	1576.80	0.00	1576.80	0.00	1576.80	0.00	1576.80	0.00	1576.80
BASE OIL ANNUAL STEAM GEN......(MM LBM/YR)	1040.69	2097.14	1695.06	2424.33	1647.76	2400.68	1655.64	2404.62	1639.87	2396.74
BOILER EFFICIENCY CWF...........(FRACTION)	0.8845	0.8845	0.8817	0.8817	0.8732	0.8732	0.877[illegible]	0.8773	0.8710	0.8710
BOILER EFFICIENCY OIL...........(FRACTION)	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963
ANNUAL FUEL CONS. CWF..........(MM BTU/YR)	1389780.	694890.	2270846.	1135423.	2228962.	1114481.	2229160.	1114580.	2223900.	1111950.
ANNUAL FUEL CONS. OIL SWITCH...(MM BTU/YR)	0.	2078005.	0.	2078005.	0.	2078005.	0.	2078005.	0.	2078005.
BASE OIL ANNUAL FUEL CONS......(MM BTU/YR)	1371483.	2763747.	2233856.	3194933.	2171515.	3163763.	2181905.	3168958.	2161125.	3158568.
ANNUAL ASH FIRED CWF.............(TONS/YR)	3338.	1669.	4486.	2243.	6514.	3257.	3800.	1900.	4800.	2400.
ANNUAL FLYASH CWF................(TONS/YR)	2670.	1335.	3588.	1794.	5211.	2606.	3040.	1520.	3840.	1920.

TABLE 8-23

PLANT OPERATING DATA
UNIT-UNIT E
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
MAXIMUM STEAM OUTPUT (OIL)....(1000 LB/HR)	400.	400.	400.	400.	400.	400.	400.	400.	400.	400.
MAXIMUM STEAM OUTPUT (CWF)....(1000 LB/HR)	158.	158.	258.	258.	251.	251.	252.	252.	250.	250.
DERATED CAPACITY (CWF)..........(FRACTION)	0.396	0.396	0.645	0.645	0.627	0.627	0.630	0.630	0.624	0.624
CAPACITY FACTOR CWF.............(FRACTION)	0.356	0.178	0.580	0.290	0.564	0.282	0.567	0.283	0.562	0.281
CAPACITY FACTOR OIL SWITCHING...(FRACTION)	0.000	0.450	0.000	0.450	0.000	0.450	0.000	0.450	0.000	0.450
BASE OIL CAPACITY FACTOR........(FRACTION)	0.356	0.628	0.580	0.740	0.564	0.732	0.567	0.734	0.562	0.731
ANNUAL STEAM GEN. BY CWF........(MM LBM/YR)	1248.83	624.41	2034.07	1017.04	1977.31	988.65	1986.77	993.38	1967.85	983.92
ANNUAL STEAM GEN. BY OIL........(MM LBM/YR)	0.00	1576.80	0.00	1576.80	0.00	1576.80	0.00	1576.80	0.00	1576.80
BASE OIL ANNUAL STEAM GEN.......(MM LBM/YR)	1248.83	2201.21	2034.07	2593.84	1977.31	2565.45	1986.77	2570.18	1967.85	2560.72
BOILER EFFICIENCY CWF...........(FRACTION)	0.8845	0.8845	0.8817	0.8817	0.8732	0.8732	0.8773	0.8773	0.8710	0.8710
BOILER EFFICIENCY OIL...........(FRACTION)	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963	0.8963
ANNUAL FUEL CONS. CWF..........(MM BTU/YR)	1667736.	833868.	2725015.	1362507.	2674754.	1337377.	2674992.	1337496.	2668680.	1334340.
ANNUAL FUEL CONS. OIL SWITCH...(MM BTU/YR)	0.	2078005.	0.	2078005.	0.	2078005.	0.	2078005.	0.	2078005.
BASE OIL ANNUAL FUEL CONS......(MM BTU/YR)	1645780.	2900895.	2680627.	3418319.	2605818.	3380915.	2618286.	3387148.	2593351.	3374680.
ANNUAL ASH FIRED CWF............(TONS/YR)	4005.	2003.	5383.	2691.	7817.	3908.	4560.	2280.	5760.	2880.
ANNUAL FLYASH CWF...............(TONS/YR)	3204.	1602.	4306.	2153.	6253.	3127.	3648.	1824.	4608.	2304.

TABLE 8-24

OPERATING CONDITIONS FOR PROCESS HEATERS

	Unit F (Vertical Cylindrical)*	Unit G (Horizontal Cabin)*
Total Operating, (1) Hrs/yr	8322	8322
Operating Time on CWF, (2) Hrs/yr	7884	7884
Operating Time on Fuel Oil, (3) Hrs/yr	438	438
Absorbed Duty, (4) 10^6 Btu/hr	54.4	103.8
Fuel Consumption, 10^6 Btu/hr		
Operating on CWF, (2)	59.22	116.63
Operating on Fuel Oil, (3)	71.2	142.2

* Per Heater Basis

(1) Overall availability assumed at 95%

(2) Operation of heater with air preheat system (high thermal efficiency) and flue gas clean-up equipment.
Assumed 90% availability.

(3) Operation of heater without air preheat system (lower thermal efficiency) and without flue gas clean-up equipment.
Fuel oil firing is required for this condition due to air pollution regulations and lack of preheated air for combustion of CWFs.
Assumed 5% availability.

(4) Heat load (absorbed duty) was assumed to be constant for all operating times.

TABLE 8-25

PLANT OPERATING COST DATA AT PREDICTED LOAD

VERTICAL CYLINDRICAL DESIGNED HEATERS (UNIT F)

1. Annual Fuel Savings

Fuel Cost Difference	Single Heater	Twin Heaters
$1.0/10^6$ Btu	$466,890	$ 933,781
$1.5/10^6$ Btu	$700,335	$1,400,672
$2.0/10^6$ Btu	$933,781	$1,867,562

2. Fixed Operating & Maintenance Costs	$147,980	$ 194,460
3. Variable Operating & Maintenance Costs	$ 10,000	$ 20,000

4. Annual Operating Cost Savings Summary

Fuel Cost Difference	Single Heater	Twin Heaters
$1.0/10^6$ Btu	$308,910	$ 719,321
$1.5/10^6$ Btu	$542,335	$1,186,212
$2.0/10^6$ Btu	$775,801	$1,653,102

5. Payback Period (Years)

Fuel Cost Difference	Single Heater	Twin Heaters
$1.0/10^6$ Btu	17.6	10.0
$1.5/10^6$ Btu	10.0	6.0
$2.0/10^6$ Btu	7.0	4.3

TABLE 8-26

PLANT OPERATING COST DATA AT PREDICTED LOAD

HORIZONTAL CABIN DESIGNED HEATERS (UNIT G)

1. Annual Fuel Savings

Fuel Cost Difference	Single Heater	Twin Heaters
$\$1.0/10^6$ Btu	\$ 919,511	\$1,839,022
$\$1.5/10^6$ Btu	\$1,379,267	\$2,758,533
$\$2.0/10^6$ Btu	\$1,839,022	\$3,678,044

2. Fixed Operating & Maintenance Costs	\$ 214,900	\$ 306,040
3. Variable Operating & Maintenance Costs	\$ 20,000	\$ 40,000

4. Annual Operating Cost Savings Summary

Fuel Cost Difference	Single Heater	Twin Heaters
$\$1.0/10^6$ Btu	\$ 684,611	\$1,492,982
$\$1.5/10^6$ Btu	\$1,144,367	\$2,412,493
$\$2.0/10^6$ Btu	\$1,604,122	\$3,332,004

5. Payback Period (Years)

Fuel Cost Difference	Single Heater	Twin Heaters
$\$1.0/10^6$ Btu	11.5	7.6
$\$1.5/10^6$ Btu	6.9	4.7
$\$2.0/10^6$ Btu	4.9	3.4

- Operating Time of Fuel Oil., Hrs/yr

  This time is the total number of hours per year that the heaters operate on fuel oil without the air preheat system and flue gas clean-up equipment in operation. This time was set to be 5% of any calendar year so that the total availability of the heaters is 95%.

- Absorbed Duty, 10^6 Btu/hr

  This is the design heat absorbing capacity of each heater. This duty was assumed to be constant for all operating time (no derating).

- Fuel Consumption, 10^6 Btu/hr

  This is the fuel consumption required for the operating case times HHV (CWF or fuel oil). For CWF, the heaters operate at high thermal efficiency (with air preheat) while for fuel oil, the heaters operate at low thermal efficiency (no air preheat).

REVENUE SAVINGS AND PAYBACK PERIOD

Using the previously described O&M cost estimating procedures and the plant operating data, the impact of CWF firing is presented in two different ways. First, a simplified payback period is calculated by dividing the total capital requirement by the first year incremental annual O&M cost savings. Also presented is the total levelized revenue savings (for utility units only).

The levelized revenue method is one of several discounted cash flow methods used to compare options. Estimates of first year costs or savings are escalated over the project life, sometimes with different escalation rates for various parts of the cost/savings. Levelizing factors from EPRI tables are used to levelize capital and annual costs. The resulting cost or saving is an annual figure, which can be compared to other investment options with similar bases.

The levelized revenue requirement is defined as a summation of the levelized fixed charge and the levelized incremental annual O&M cost (savings).

Levelized cost is a convenient way of measuring the present value of revenue requirements over the life of the plant with a single levelized value. The methodology used in levelization of cost is discussed in detail in Appendix A. of Reference (7).

The levelized fixed charge is the levelized annual cost necessary to support a return on the investment (total capital requirement) under certain economic assumptions.

The LFC required for the CWF retrofit is defined as follows:

$$LFC = (LFCR)_n \ (TCR)$$

where

LFC	=	n-year levelized fixed charge
$(LFCR)_n$	=	n-year levelized fixed charge rate
(TCR)	=	total capital requirement for CWF retrofit

The appropriate $(LFCR)_n$ for the current study is computed based on a number of economic assumptions that take into account the utility financing method, inflation, weighted cost of capital and debt, income and property taxes, and the book and tax life of the plant. Further details of the methodology to compute the LFCR are discussed in EPRI's Technical Assessment Guide (TAG), EPRI P-2410-SR (May 1982). Based on the economic assumptions, a 30-year levelized fixed charge rate of 15.3% is computed.

The annual estimated O&M cost is levelized based on the following general formula:

$$LOM = (LOMF)_n \ (AOM)$$

where

LOM	=	n-year levelized annual O&M cost
$(LOMF)_n$	=	n-year levelized O&M cost factor
(AOM)	=	estimated annual O&M cost factor

In this study, various criteria were used to compute the levelization factors associated with different O&M cost items. Table 8-27 lists the computed 30-year levelization factors associated with each O&M cost item. Appendix A of Reference (7) presents the economic criteria and formula used to compute these factors.

Table 8-28

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT A
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL									
		UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:											
FIXED O&M	2.314	1763.	4080.	2033.	4704.	2060.	4767.	1236.	2859.	3340.	7730.
VARIABLE O&M	2.314	2035.	4710.	3968.	9181.	2627.	6078.	3812.	8821.	3961.	9165.
FUEL COSTS:											
CWF FUEL COST	2.388	23725.	56656.	53343.	127383.	32243.	76997.	51494.	122968.	53584.	127959.
OIL FUEL COST	3.026	12501.	37829.	10136.	30673.	11831.	35801.	10294.	31149.	10170.	30775.
REPLACEMENT POWER	3.000	66411.	199232.	26732.	80196.	55168.	165504.	29373.	88120.	27297.	81891.
TOTAL O&M COST		106436.	302506.	96212.	252137.	103929.	289147.	96209.	253918.	98352.	257519.
CREDITS DUE TO CWF BURNING											
VARIABLE O&M	2.314	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.
FUEL OIL	3.026	102950.	311527.	102950.	311527.	102950.	311527.	102950.	311527.	102950.	311527.
TOTAL CREDITS		107962.	323125.	107962.	323125.	107962.	323125.	107962.	323125.	107962.	323125.
INCREMENTAL ANNUAL O&M COST		-1526.	-20618.	-11750.	-70987.	-4033.	-33978.	-11753.	-69207.	-9610.	-65606.
LEVELIZED FIXED CHARGE			10021.		11731.		11735.		7275.		19021.
LEVELIZED REVENUE SAVINGS			-10598.		-59256.		-22243.		-61932.		-46585.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-17.9		-100.1		-37.6		-104.6		-78.7
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-3.8		-21.3		-8.0		-22.2		-16.7
TOTAL CAPITAL REQUIREMENT		65494.		76676.		76699.		47548.		124321.	
PAYBACK PERIOD (YRS)		42.9		6.5		19.0		4.0		12.9	

TABLE 8-27

THIRTY-YEAR LEVELIZATION FACTORS[a]

Annual O&M Cost Items	Levelization Factor
Fixed O&M	2.314
Variable O&M	2.314
Fuel	
o CWS	2.388
o Fuel oil	3.026
Replacement power	3.000

(a) Basis: Inflation rate, 8.5%; discount rate, 12.5%, real escalation rate for fuel oil, 2.0%; real escalation rate for coal, 1.7%.

The levelized revenue requirement has been computed by adding the levelized fixed charge and levelized O&M cost (savings).

Tables 8-28 to 8-45 show O&M costs, levelized revenue savings and simplified payback periods for the three utility units. Tables 8-46 to 8-57 show these same items (excluding levelized costs) for the two industrial units.

Six results tables are presented for each utility and industrial unit. The first three are calculated at the predicted load and at the three differential fuel costs discussed previously. The second three tables are calculated assuming the predicted load plus 20% and again at the three differential fuel costs.

The pay back periods for each process heater type and quantity are calculated by dividing the total capital costs in Tables 8-11 and 8-12 by the annual operating cost savings in Tables 8-25 and 8-26. The pay back

Table 8-29

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT A
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED	AL-5.9 FIRST YR	AL-5.9 LEVELIZED
ANNUAL O&M COSTS:											
FIXED O&M	2.314	1763.	4080.	2033.	4704.	2060.	4767.	1236.	2859.	3340.	7730.
VARIABLE O&M	2.314	2035.	4710.	3966.	9181.	2627.	6078.	3812.	8821.	3961.	9165.
FUEL COSTS:											
CWF FUEL COST	2.388	23725.	56656.	53343.	127383.	32243.	76997.	51494.	122968.	53584.	127959.
OIL FUEL COST	3.026	14064.	42557.	11403.	34507.	13310.	40276.	11581.	35043.	11441.	34622.
REPLACEMENT POWER	3.000	74326.	222979.	29918.	89755.	61744.	185231.	32874.	98623.	30551.	91652.
TOTAL O&M COST		115914.	330983.	100665.	265531.	111984.	313350.	100997.	268315.	102877.	271127.
CREDITS DUE TO CWF BURNING											
VARIABLE O&M	2.314	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.
FUEL OIL	3.026	115819.	350468.	115819.	350468.	115819.	350468.	115819.	350468.	115819.	350468.
TOTAL CREDITS		120831.	362066.	120831.	362066.	120831.	362066.	120831.	362066.	120831.	362066.
INCREMENTAL ANNUAL O&M COST		-4917.	-31083.	-20165.	-96535.	-8847.	-48716.	-19834.	-93751.	-17954.	-90939.
LEVELIZED FIXED CHARGE			10021.		11731.		11735.		7275.		19021.
LEVELIZED REVENUE SAVINGS			-21062.		-84804.		-36981.		-86476.		-71917.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-35.6		-143.3		-62.5		-146.1		-121.5
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-7.6		-30.5		-13.3		-31.1		-25.8
TOTAL CAPITAL REQUIREMENT		65494.		76676.		76699.		47548.		124321.	
PAYBACK PERIOD (YRS)		13.3		3.8		8.7		2.4		6.9	

Table 8-30

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT A
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL									
		UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:											
FIXED O&M	2.314	1763.	4080.	2033.	4704.	2060.	4767.	1236.	2859.	3340.	7730.
VARIABLE O&M	2.314	2035.	4710.	3968.	9181.	2627.	6078.	3812.	8821.	3961.	9165.
FUEL COSTS:											
CWF FUEL COST	2.388	23725.	56656.	53343.	127383.	32243.	76997.	51494.	122968.	53584.	127959.
OIL FUEL COST	3.026	15627.	47286.	12671.	38341.	14789.	44751.	12867.	38936.	12713.	38468.
REPLACEMENT POWER	3.000	82242.	246727.	33105.	99315.	68320.	204959.	36376.	109127.	33804.	101413.
TOTAL O&M COST		125393.	359459.	105119.	278924.	120039.	337552.	105785.	282712.	107402.	284735.
CREDITS DUE TO CWF BURNING											
VARIABLE O&M	2.314	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.
FUEL OIL	3.026	128688.	389409.	128688.	389409.	128688.	389409.	128688.	389409.	128688.	389409.
TOTAL CREDITS		133700.	401006.	133700.	401006.	133700.	401006.	133700.	401006.	133700.	401006.
INCREMENTAL ANNUAL O&M COST		-8307.	-41547.	-28581.	-122083.	-13661.	-63454.	-27915.	-118294.	-26297.	-116271.
LEVELIZED FIXED CHARGE			10021.		11731.		11735.		7275.		19021.
LEVELIZED REVENUE SAVINGS			-31527.		-110351.		-51719.		-111019.		-97250.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-53.3		-186.4		-87.4		-187.6		-164.3
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-11.3		-39.6		-18.6		-39.9		-34.9
TOTAL CAPITAL REQUIREMENT		65494.		76676.		76699.		47548.		124321.	
PAYBACK PERIOD (YRS)		7.9		2.7		5.6		1.7		4.7	

Table 8-31

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT A
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED	AL-5.9 FIRST YR	AL-5.9 LEVELIZED
ANNUAL O&M COSTS:											
FIXED O&M	2.314	1763.	4080.	2033.	4704.	2060.	4767.	1236.	2859.	3340.	7730.
VARIABLE O&M	2.314	2425.	5611.	4686.	10844.	3132.	7247.	4504.	10422.	4678.	10826.
FUEL COSTS:											
CWF FUEL COST	2.388	29467.	70368.	64786.	154709.	39603.	94573.	625[illegible]7.	149433.	65092.	155439.
OIL FUEL COST	3.026	12034.	36415.	9268.	28045.	11234.	33994.	9451.	28599.	9308.	28166.
REPLACEMENT POWER	3.000	58573.	175719.	12158.	36475.	45150.	135449.	15231.	45693.	12831.	38493.
TOTAL O&M COST		104263.	292194.	92931.	234777.	101179.	276031.	92998.	237006.	95250.	240654.
CREDITS DUE TO CWF BURNING											
VARIABLE O&M	2.314	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.
FUEL OIL	3.026	102950.	311527.	102950.	311527.	102950.	311527.	102950.	311527.	102950.	311527.
TOTAL CREDITS		107962.	323125.	107962.	323125.	107962.	323125.	107962.	323125.	107962.	323125.
INCREMENTAL ANNUAL O&M COST		-3699.	-30931.	-15031.	-88348.	-6783.	-47094.	-14964.	-86119.	-12712.	-82471.
LEVELIZED FIXED CHARGE			10061.		11813.		11787.		7353.		19103.
LEVELIZED REVENUE SAVINGS			-20870.		-76535.		-35307.		-78765.		-63368.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-35.3		-129.3		-59.7		-133.1		-107.1
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-7.5		-27.5		-12.7		-28.3		-22.8
TOTAL CAPITAL REQUIREMENT		65756.		77206.		77039.		48061.		124854.	
PAYBACK PERIOD (YRS)		17.8		5.1		11.4		3.2		9.8	

Table 8-32

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT A
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL									
		UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZ	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:											
FIXED O&M	2.314	1763.	4080.	2033.	4704.	2060.	4767.	1236.	2859.	3340.	7730.
VARIABLE O&M	2.314	2425.	5611.	4686.	10844.	3132.	7247.	4504.	10422.	4678.	10826.
FUEL COSTS:											
CWF FUEL COST	2.388	29467.	70368.	[illegible]	154709.	39603.	94573.	62577.	149433.	65092.	155439.
OIL FUEL COST	3.026	13538.	40967.	1042[illegible].	31550.	12638.	38244.	10632.	32174.	10471.	31687.
REPLACEMENT POWER	3.000	65555.	196664.	13608.	40823.	50531.	151594.	17047.	51140.	14360.	43081.
TOTAL O&M COST		112749.	317691.	95539.	242630.	107965.	296425.	95995.	246027.	97943.	248763.
CREDITS DUE TO CWF BURNING											
VARIABLE O&M	2.314	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.
FUEL OIL	3.026	115819.	350468.	115819.	350468.	115819.	350468.	115819.	350468.	115819.	350468.
TOTAL CREDITS		120831.	362066.	120831.	362066.	120831.	362066.	120831.	362066.	120831.	362066.
INCREMENTAL ANNUAL O&M COST		-8082.	-44375.	-25292.	-119435.	-12866.	-65641.	-24836.	-116038.	-22888.	-113303.
LEVELIZED FIXED CHARGE			10061.		11813.		11787.		7353.		19103.
LEVELIZED REVENUE SAVINGS			-34314.		-107623.		-53854.		-108685.		-94200.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-58.0		-181.8		-91.0		-183.6		-159.1
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-12.3		-38.7		-19.3		-39.0		-33.8
TOTAL CAPITAL REQUIREMENT		65756.		77206.		77039.		48061.		124854.	
PAYBACK PERIOD (YRS)		8.1		3.1		6.0		1.9		5.5	

Table 8-33

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT A
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL									
		UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:											
FIXED O&M	2.314	1763.	4080.	2033.	4704.	2060.	4767.	1236.	2859.	3340.	7730.
VARIABLE O&M	2.314	2425.	5611.	4686.	10844.	3132.	7247.	4504.	10422.	4678.	10826.
FUEL COSTS:											
CWF FUEL COST	2.388	29467.	70368.	64786.	154709.	39603.	94573.	62577.	149433.	65092.	155439.
OIL FUEL COST	3.026	15043.	45519.	11585.	35056.	14043.	42493.	11814.	35748.	11635.	35207.
REPLACEMENT POWER	3.000	72536.	217609.	15057.	45170.	55913.	167739.	18862.	56586.	15890.	47670.
TOTAL O&M COST		121235.	343188.	98147.	250483.	114751.	316819.	98992.	255049.	100636.	256872.
CREDITS DUE TO CWF BURNING											
VARIABLE O&M	2.314	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.	5012.	11597.
FUEL OIL	3.026	128688.	389409.	128688.	389409.	128688.	389409.	128688.	389409.	128688.	389409.
TOTAL CREDITS		133700.	401006.	133700.	401006.	133700.	401006.	133700.	401006.	133700.	401006.
INCREMENTAL ANNUAL O&M COST		-12465.	-57819.	-35553.	-150523.	-18949.	-84187.	-34708.	-145958.	-33064.	-144134.
LEVELIZED FIXED CHARGE			10061.		11813.		11787.		7353.		19103.
LEVELIZED REVENUE SAVINGS			-47758.		-138711.		-72400.		-138604.		-125032.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-80.7		-234.3		-122.3		-234.2		-211.2
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-17.2		-49.8		-26.0		-49.8		-44.9
TOTAL CAPITAL REQUIREMENT		65756.		77206.		77039.		48061.		124854.	
PAYBACK PERIOD (YRS)		5.3		2.2		4.1		1.4		3.8	

Table 8-34

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT B
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED
ANNUAL O&M COSTS:									
FIXED O&M	2.314	1393.	3223.	1005.	2325.	1379.	3190.	991.	2294.
VARIABLE O&M	2.314	1322.	3060.	1961.	4538.	1352.	3129.	1875.	4339.
FUEL COSTS:									
CWF FUEL COST	2.388	16177.	38631.	26361.	62951.	16374.	39102.	25345.	60524.
OIL FUEL COST	3.026	9513.	28786.	8651.	26179.	9494.	28730.	8748.	26472.
REPLACEMENT POWER	3.000	51586.	154759.	37187.	111561.	51275.	153824.	38806.	116419.
TOTAL O&M COST		79991.	228458.	75165.	207554.	79874.	227975.	75766.	210048.
CREDITS DUE TO CWF BURNING									
VARIABLE O&M	2.314	3450.	7982.	3450.	7982.	3450.	7982.	3450.	7982.
FUEL OIL	3.026	77440.	234333.	77440.	234333.	77440.	234333.	77440.	234333.
TOTAL CREDITS		80889.	242315.	80889.	242315.	80889.	242315.	80889.	242315.
INCREMENTAL ANNUAL O&M COST		-898.	-13857.	-5724.	-34762.	-1015.	-14340.	-5123.	-32267.
LEVELIZED FIXED CHARGE			7895.		5802.		7817.		5720.
LEVELIZED REVENUE SAVINGS			-5962.		-28960.		-6523.		-26547.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-14.6		-71.1		-16.0		-65.2
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-3.1		-15.1		-3.4		-13.9
TOTAL CAPITAL REQUIREMENT		51599.		37923.		51094.		37386.	
PAYBACK PERIOD (YRS)		57.1		6.6		50.3		7.3	

Table 8-35

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT B
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED
ANNUAL O&M COSTS:									
FIXED O&M	2.314	1393.	3223.	1005.	2325.	1379.	3190.	991.	2294.
VARIABLE O&M	2.314	1322.	3060.	1961.	4538.	1352.	3129.	1875.	4339.
FUEL COSTS:									
CWF FUEL COST	2.388	16177.	38631.	26361.	62951.	16374.	39102.	25345.	60524.
OIL FUEL COST	3.026	10702.	32384.	9733.	29451.	10681.	32321.	9842.	29781.
REPLACEMENT POWER	3.000	57760.	173279.	41637.	124911.	57411.	172232.	43450.	130351.
TOTAL O&M COST		87354.	250576.	80697.	224176.	87197.	249974.	81504.	227289.
CREDITS DUE TO CWF BURNING									
VARIABLE O&M	2.314	3450.	7982.	3450.	7982.	3450.	7982.	3450.	7982.
FUEL OIL	3.026	87120.	263624.	87120.	263624.	87120.	263624.	87120.	263624.
TOTAL CREDITS		90569.	271607.	90569.	271607.	90569.	271607.	90569.	271607.
INCREMENTAL ANNUAL O&M COST		-3216.	-21031.	-9872.	-47431.	-3372.	-21633.	-9066.	-44318.
LEVELIZED FIXED CHARGE			7895.		5802.		7817.		5720.
LEVELIZED REVENUE SAVINGS			-13136.		-41628.		-13815.		-38598.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-32.2		-102.2		-33.9		-94.7
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-6.9		-21.7		-7.2		-20.1
TOTAL CAPITAL REQUIREMENT		51599.		37923.		51094.		37386.	
PAYBACK PERIOD (YRS)		16.0		3.8		15.2		4.1	

Table 8-36

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT B
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED
ANNUAL O&M COSTS:									
FIXED O&M	2.314	1393.	3223.	1005.	2325.	1379.	3190.	991.	2294.
VARIABLE O&M	2.314	1322.	3060.	1961.	4538.	1352.	3129.	1875.	4339.
FUEL COSTS:									
CWF FUEL COST	2.388	16177.	38631.	26361.	62951.	16374.	39102.	25345.	60524.
OIL FUEL COST	3.026	11891.	35983.	108[illegible]4.	32724.	11868.	35912.	10935.	33090.
REPLACEMENT POWER	3.000	63933.	191799.	46087.	138262.	63547.	190640.	48094.	144283.
TOTAL O&M COST		94716.	272695.	86229.	240799.	94520.	271974.	87241.	244530.
CREDITS DUE TO CWF BURNING									
VARIABLE O&M	2.314	3450.	7982.	3450.	7982.	3450.	7982.	3450.	7982.
FUEL OIL	3.026	96800.	292916.	96800.	292916.	96800.	292916.	96800.	292916.
TOTAL CREDITS		100249.	300898.	100249.	300898.	100249.	300898.	100249.	300898.
INCREMENTAL ANNUAL O&M COST		-5533.	-28204	-14021.	-60099.	-5730.	-28925.	-13008.	-56369.
LEVELIZED FIXED CHARGE			7895.		5802.		7817.		5720.
LEVELIZED REVENUE SAVINGS			-20309.		-54297.		-21108.		-50649.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-49.9		-133.3		-51.8		-124.3
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-10.6		-28.3		-11.0		-26.4
TOTAL CAPITAL REQUIREMENT		51599.		37923.		51094.		37386.	
PAYBACK PERIOD (YRS)		9.3		2.7		8.9		2.9	

Table 8-37

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.9$/MMBTU)
UNIT-UNIT B
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL							
		UF-6.8		SD-5.7		CG-7.9		CG-4.8	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:									
FIXED O&M	2.314	1393.	3223.	1005.	2325.	1379.	3190.	991.	2294.
VARIABLE O&M	2.314	1579.	3653.	2335.	5404.	1616.	3740.	2243.	5191.
FUEL COSTS:									
CWF FUEL COST	2.388	20189.	48212.	32273.	77069.	20416.	48754.	31083.	74227.
OIL FUEL COST	3.026	9178.	27773.	8156.	24681.	9155.	27704.	8258.	24988.
REPLACEMENT POWER	3.000	45992.	137975.	28916.	86747.	45607.	136821.	30607.	91822.
TOTAL O&M COST		78331.	220836.	72686.	156226.	78173.	220209.	73183.	198521.
CREDITS DUE TO CWF BURNING									
VARIABLE O&M	2.314	3450.	7982.	3450.	7982.	3450.	7982.	3450.	7982.
FUEL OIL	3.026	77440.	234333.	77440.	234333.	77440.	234333.	77440.	234333.
TOTAL CREDITS		80889.	242315.	80889.	242315.	80889.	242315.	80889.	242315.
INCREMENTAL ANNUAL O&M COST		-2559.	-21479.	-8204.	-46089.	-2716.	-22107.	-7707.	-43794.
LEVELIZED FIXED CHARGE			7922.		5844.		7845.		5760.
LEVELIZED REVENUE SAVINGS			-13557.		-40245.		-14261.		-38034.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-33.3		-98.8		-35.0		-93.4
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-7.1		-21.0		-7.4		-19.8
TOTAL CAPITAL REQUIREMENT		51780.		38195.		51277.		37649.	
PAYBACK PERIOD (YRS)		20.2		4.7		18.9		4.9	

Table 8-38

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL: DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT B
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED
ANNUAL O&M COSTS:									
FIXED O&M	2.314	1393.	3223.	1005.	2325.	1379.	3190.	991.	2294.
VARIABLE O&M	2.314	1579.	3653.	2335.	5404.	1616.	3740.	2243.	5191.
FUEL COSTS:									
CWF FUEL COST	2.388	20189.	48212.	32273.	77069.	20416.	48754.	31083.	74227.
OIL FUEL COST	3.026	10325.	31245.	9176.	27767.	10300.	31166.	9290.	28111.
REPLACEMENT POWER	3.000	51495.	154486.	32376.	97128.	51065.	153195.	34270.	102810.
TOTAL O&M COST		84982.	240819.	77165.	209692.	84775.	240045.	77878.	212633.
CREDITS DUE TO CWF BURNING									
VARIABLE O&M	2.314	3450.	7982.	3450.	7982.	3450.	7982.	3450.	7982.
FUEL OIL	3.026	87120.	263624.	87120.	263624.	87120.	263624.	87120.	263624.
TOTAL CREDITS		90569.	271607.	90569.	271607.	90569.	271607.	90569.	271607.
INCREMENTAL ANNUAL O&M COST		-5588.	-30788.	-13404.	-61915.	-5794.	-31562.	-12692.	-58974.
LEVELIZED FIXED CHARGE			7922.		5844.		7845.		5760.
LEVELIZED REVENUE SAVINGS			-22866.		-56071.		-23717.		-53214.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-56.1		-137.6		-58.2		-130.6
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-11.9		-29.3		-12.4		-27.8
TOTAL CAPITAL REQUIREMENT		51780.		38195.		51277.		37649.	
PAYBACK PERIOD (YRS)		9.3		2.8		8.8		3.0	

Table 8-39

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT B
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED
ANNUAL O&M COSTS:									
FIXED O&M	2.314	1393.	3223.	1005.	2325.	1379.	3190.	991.	2294.
VARIABLE O&M	2.314	1579.	3653.	2335.	5404.	1616.	3740.	2243.	5191.
FUEL COSTS:									
CWF FUEL COST	2.388	20189.	48212.	32273.	77069.	20416.	48754.	31083.	74227.
OIL FUEL COST	3.026	11473.	34716.	10196.	30852.	11444.	34629.	10322.	31235.
REPLACEMENT POWER	3.000	56999.	170997.	35836.	107509.	56523.	169568.	37933.	113798.
TOTAL O&M COST		91633.	260802.	81645.	223158.	91378.	259881.	82573.	226745.
CREDITS DUE TO CWF BURNING									
VARIABLE O&M	2.314	3450.	7982.	3450.	7982.	3450.	7982.	3450.	7982.
FUEL OIL	3.026	96800.	292916.	96800.	292916.	96800.	292916.	96800.	292916.
TOTAL CREDITS		100249.	300898.	100249.	300898.	100249.	300898.	100249.	300898.
INCREMENTAL ANNUAL O&M COST		-8617.	-40096.	-18604.	-77740.	-8872.	-41017.	-17677.	-74154.
LEVELIZED FIXED CHARGE			7922.		5844.		7845.		5760.
LEVELIZED REVENUE SAVINGS			-32174.		-71897.		-33172.		-68393.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-79.0		-176.5		-81.4		-167.9
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-16.8		-37.5		-17.3		-35.7
TOTAL CAPITAL REQUIREMENT		51780.		38195.		51277.		37649.	
PAYBACK PERIOD (YRS)		6.0		2.1		5.8		2.1	

TABLE 8-40

E'CONOMI(EVALUATION RESULTS SUMMARY
O&M COST SUMMARY: LEVELIZED REVENUE SAVINGS: AND PAYBACK PERIOD
($1000S, MID 1985 WAGE & PRICE LEVEL: DIFFERENTIAL FUEL COST= 1.05/MMBTU)
UNIT-UNIT C
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	UF-6.8		SD-5.7		CG-7.9		CG-4.8		SD-2.6		AL-5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:													
FIXED O&M	2.314	2428.	5617.	1195.	2765.	2464.	5701.	1173.	2714.	1199.	2775.	3115.	7269.
VARIABLE O&M	2.314	3676.	8507.	5503.	12735.	3788.	8765.	5287.	12235.	6774.	15675.	5434.	12573.
FUEL COSTS:													
CWF FUEL COST	2.388	47036.	112323.	76193.	181950.	48377.	115523.	73423.	175334.	102402.	244536	75891.	181228
OIL FUEL COST	3.026	17500.	52955.	15115.	45739.	17421.	52715.	15344.	46432.	13231.	40038.	15244.	46128
REPLACEMENT POWER	3.000	80926.	242779.	41014.	123043.	79596.	238787.	44844.	134532.	9481.	28443.	43164.	129491
TOTAL O&M COST		151566.	422181.	139021.	364232.	151644.	421491.	140071.	371247.	133087.	331467.	142847.	376629
CREDITS DUE TO CWF BURNING													
VARIABLE O&M	2.314	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028	16263.	7028.	16263.
FUEL OIL	3.026	152617.	461820.	152617.	461820.	152617.	461820.	152617.	461820.	152617.	461820.	152617.	461828.
TOTAL CREDITS		159645.	478083.	159645.	478083.	159645.	478083.	159645.	478083	159645.	478083.	159645.	478083.
INCREMENTAL ANNUAL O&M COST		-8079.	-55902.	-20624.	-111851.	-8001.	-56592.	-19574.	-106836	-26558.	-146616	-16798.	-101454.
LEVELIZED FIXED CHARGE			13897.		7232.		14109.		7090.		7437.		17931.
LEVELIZED REVENUE SAVINGS			-42005.		-104619.		-42484.		-99746.		-139179.		-83523.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-50.6		-126.0		-51.2		-120.2		-167.7		-100.6
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-10.8		-26.8		-10.9		-25.5		-35.6		-21.4
TOTAL CAPITAL REQUIREMENT		90831.		47267.		92213.		46340.		48606.		117199.	
PAYBACK PERIOD (YRS)		11.2		2.3		11.5		2.4		1.8		7.0	

TABLE 8-41

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY: LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT C
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL											
		UF-6.8		SD-5.7		CG-7.9		CG-4.8		SD-2.6		AL-5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:													
FIXED O&M	2.314	2428.	5617.	1195.	2765.	2464.	5781.	1173.	2714.	1199.	2775.	3115.	7208.
VARIABLE O&M	2.314	3676.	8507.	5503.	12735.	3788.	8765.	5287.	12235.	6774.	15675.	5436.	12573.
FUEL COSTS:													
CWF FUEL COST	2.388	47036.	112323.	76193.	181950.	48377.	115523.	73423.	175334.	102402.	244536.	75891.	181228.
OIL FUEL COST	3.026	19688.	59575.	17005.	51457.	19598.	59304.	17262.	52235.	14885.	45043.	17149.	51894.
REPLACEMENT POWER	3.000	90597.	271790.	45916.	137747.	89107.	267321.	50203.	150608.	10614.	31842.	48322.	144965.
TOTAL O&M COST		163424.	457811.	145812.	386653.	163333.	456614.	147348.	393127.	135874.	339871.	149911.	397868.
CREDITS DUE TO CWF BURNING													
VARIABLE O&M	2.314	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.
FUEL OIL	3.026	171695.	519548.	171695.	519548.	171695.	519548.	171695.	519548.	171695.	519548.	171695.	519548.
TOTAL CREDITS		178723.	535811.	178723.	535811.	178723.	535811.	178723.	535811.	178723.	535811.	178723.	535811.
INCREMENTAL ANNUAL O&M COST		-15298.	-77999.	-32911.	-149158.	-15389.	-79196.	-31374.	-142684.	-42848.	-195940.	-28812.	-137942.
LEVELIZED FIXED CHARGE			13897.		7232.		14189.		7090.		7437.		17931.
LEVELIZED REVENUE SAVINGS			-64102.		-141926.		-65088.		-135594.		-188503.		-120011.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-77.2		-171.0		-72.4		-163.4		-227.1		-144.6
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-16.4		-36.4		-16.7		-34.7		-48.3		-30.7
TOTAL CAPITAL REQUIREMENT		90831.		47267.		92213.		46340.		48606.		117199.	
PAYBACK PERIOD (YRS)		5.9		1.4		6.0		1.5		1.1		4.1	

TABLE 8-42

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY, LEVELIZED REVENUE SAVINGS, AND PAYBACK PERIOD
($1000S, MID 1985 WAGE & PRICE LEVEL, DIFFERENTIAL FUEL COST= 2 [illegible]/MMBTU)
UNIT UNIT C
LOAD-PREDICTED
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED	SD-2.6 FIRST YR	SD-2.6 LEVELIZED	AL-5.9 FIRST YR	AL-5.9 LEVELIZED
ANNUAL O&M COSTS:													
FIXED O&M	2.314	2428.	5617.	1195.	2765.	2464.	5701.	1173.	2714.	1199.	2775.	3115	7208
VARIABLE O&M	2.314	3676.	8507.	5503.	12735.	3788.	8765.	5287.	12235.	6774.	15675.	5434	12573
FUEL COSTS:													
CWF FUEL COST	2.388	47036.	112323.	76193	181952	48377.	115523.	73423.	175334.	102402	244536.	75891	181228.
OIL FUEL COST	3.026	21875.	66194.	18894	57174.	21776.	65893.	19380.	58639	16539.	50047.	19055	57660
REPLACEMENT POWER	3.000	100267.	300801.	50817	152450	98619.	295856	55561.	166684.	11747.	35241.	53480	160439.
TOTAL O&M COST		175282.	493442.	152603.	407074.	175022.	491738.	154625.	415007.	138661	348274.	156974	419108.
CREDITS DUE TO CWF BURNING													
VARIABLE O&M	2.314	7028.	16263.	7028	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028	16263
FUEL OIL	3.026	190772.	577275.	190772.	577275.	190772.	577275.	190772.	577275.	190772.	577275.	190772	577275.
TOTAL CREDITS		197800.	593538.	197800.	593538.	197800.	593538.	197800.	593538.	197800.	593538	197800	593538
INCREMENTAL ANNUAL O&M COST		-22517	-100096.	-45197.	-186464.	-22777.	-101800.	-43175.	-178531	-59138.	-245264.	-40826	-174430
LEVELIZED FIXED CHARGE			13897.		7232.		14109.		7090		7437.		17931
LEVELIZED REVENUE SAVINGS			-86199.		-179233.		-87691.		-171441.		-237827.		-156498
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-103.9		-215.9		-105.7		-206.6		-286.5		-188.6
LEVELIZED INCREMENTAL COST OF ELEC. SVGS (MILLS/KWHR)			-22.1		-45.9		-22.5		-43.9		-60.9		-40.1
TOTAL CAPITAL REQUIREMENT		90831		47267.		92213.		46340.		48606.		117149	
PAYBACK PERIOD (YRS)		4.0		1.0		4.0		1.1		0.8		2.9	

TABLE 8-43

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT C
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UF-6.8 FIRST YR	UF-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED	SD-2.6 FIRST YR	SD-2.6 LEVELIZED	AL-5.9 FIRST YR	AL-5.9 LEVELIZED
ANNUAL O&M COSTS:													
FIXED O&M	2.314	2428.	5617.	1195.	2765.	2464.	5701.	1173.	2714.	1199.	2775.	3115.	7208.
VARIABLE O&M	2.314	4366.	10150.	6499.	15038.	4524.	10468.	6239.	14437.	7109.	16450.	6423.	14863.
FUEL COSTS:													
CWF FUEL COST	2.388	57770.	137954.	92549.	221008.	59382.	141804.	89241.	213107.	108308.	258640.	92224.	220232.
OIL FUEL COST	3.026	16602.	50237.	13846.	41898.	16503.	49940.	14121.	42730.	12789.	38700.	13990.	42335.
REPLACEMENT POWER	3.000	65891.	197674.	19771.	59313.	64247.	192740.	24369.	73106.	2081.	6243.	22186.	66557.
TOTAL O&M COST		147076.	401632.	133860.	340023.	147119.	400652.	135142.	346095.	131487.	322808.	137938.	351194.
CREDITS DUE TO CWF BURNING													
VARIABLE O&M	2.314	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.
FUEL OIL	3.026	152617.	461820.	152617.	461820.	152617.	461820.	152617.	461820.	152617.	461820.	152617.	461820.
TOTAL CREDITS		159645.	478083.	159645.	478083.	159645.	478083.	159645.	478083.	159645.	478083.	159645.	478083.
INCREMENTAL ANNUAL O&M COST		-12569.	-76451.	-25785.	-138060.	-12526.	-77431.	-24503.	-131988.	-28159.	-155275.	-21707.	-126889.
LEVELIZED FIXED CHARGE			13973.		7347.		14186.		7202.		7478.		18047.
LEVELIZED REVENUE SAVINGS			-62479.		-130713.		-63245.		-124787.		-147797.		-108842.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-75.3		-157.5		-76.2		-150.3		-178.1		-131.1
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-16.0		-33.5		-16.2		-32.0		-37.9		-27.9
TOTAL CAPITAL REQUIREMENT		91325.		48022.		92720.		47069.		48877.		117952.	
PAYBACK PERIOD (YRS)		7.3		1.9		7.4		1.9		1.7		5.4	

TABLE 8-44

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT C
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL											
		UF-6.8		SD-5.7		CG-7.9		CG-4.8		SD-2.6		AL-5.9	
		FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED	FIRST YR	LEVELIZED
ANNUAL O&M COSTS:													
FIXED O&M	2.314	2428.	5617.	1195.	2765.	2464.	5701.	1173.	2714.	1199.	2775.	3115.	7208.
VARIABLE O&M	2.314	4386.	10150.	6499.	15038.	4524.	10468.	6239.	14437.	7109.	16450.	6423.	14863.
FUEL COSTS:													
CWF FUEL COST	2.388	57770.	137954.	92549.	221008.	59382.	141804.	89241.	213107.	108308.	258640.	92224.	220232.
OIL FUEL COST	3.026	18677.	56516.	15577.	47136.	18566.	56182.	15886.	48071.	14388.	43538.	15739	47627.
REPLACEMENT POWER	3.000	73765.	221295.	22134.	66401.	71924.	215772.	27281.	81842.	2330.	6989.	24837.	74510.
TOTAL O&M COST		157025.	431533.	137954.	352348.	156860.	429926.	139820.	360172.	133334.	328392.	142338.	364439.
CREDITS DUE TO CWF BURNING													
VARIABLE O&M	2.314	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.
FUEL OIL	3.026	171695.	519548.	171695.	519548.	171695.	519548.	171695.	519548.	171695.	519548.	171695.	519548.
TOTAL CREDITS		178723.	535811.	178723.	535811.	178723.	535811.	178723.	535811.	178723.	535811.	178723.	535811.
INCREMENTAL ANNUAL O&M COST		-21697.	-104278.	-40769.	-183462.	-21863.	-105884.	-38903.	-175639.	-45389.	-207419.	-36384.	-171371.
LEVELIZED FIXED CHANGE			13973.		7347.		14186.		7202.		7478.		18047.
LEVELIZED REVENUE SAVINGS			-90305.		-176115.		-91698.		-168437.		-199941.		-153324.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-108.8		-212.2		-110.5		-202.9		-240.9		-184.7
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-23.1		-45.1		-23.5		-43.1		-51.2		-39.3
TOTAL CAPITAL REQUIREMENT		91325.		48022.		92720.		47069.		48877.		117952.	
PAYBACK PERIOD (YRS)		4.2		1.2		4.2		1.2		1.1		3.2	

TABLE 8-45

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; LEVELIZED REVENUE SAVINGS; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT C
LOAD-PREDICTED +20%
TYPE-ELECTRIC UTILITY

	LEVELIZATION FACTOR	FUEL: UP-6.8 FIRST YR	UP-6.8 LEVELIZED	SD-5.7 FIRST YR	SD-5.7 LEVELIZED	CG-7.9 FIRST YR	CG-7.9 LEVELIZED	CG-4.8 FIRST YR	CG-4.8 LEVELIZED	SD-2.6 FIRST YR	SD-2.6 LEVELIZED	AL-5.9 FIRST YR	AL-5.9 LEVELIZED
ANNUAL O&M COSTS:													
FIXED O&M	2.314	2428.	5617.	1195.	2765.	2464.	5701.	1173.	2714.	1199.	2773.	3115.	7208.
VARIABLE O&M	2.314	4386.	10150.	6499.	15038.	4524.	10468.	6239.	14437.	7109.	16450.	6423.	14863.
FUEL COSTS:													
CWF FUEL COST	2.388	57770.	137954.	92549.	221008.	59382.	141804.	89241.	213107.	108308.	258640.	92224.	220232.
OIL FUEL COST	3.026	20752.	62796.	17308.	52373.	20629.	62424.	17651.	53412.	15986.	48375.	17488.	52919.
REPLACEMENT POWER	3.000	81639.	244916.	24496.	73489.	79601.	238804.	30193.	90578.	2578.	7735.	27488.	82463.
TOTAL O&M COST		166974.	461434.	142047.	364673.	166600.	459201.	144497.	374249.	135181.	333975.	146738.	377685.
CREDITS DUE TO CWF BURNING													
VARIABLE O&M	2.314	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.	7028.	16263.
FUEL OIL	3.026	190772.	577275.	190772.	577275.	190772.	577275.	190772.	577275.	190772.	577275.	190772.	577275.
TOTAL CREDITS		197800.	593538.	197800.	593538.	197800.	593538.	197800.	593538.	197800.	593538.	197800.	593538.
INCREMENTAL ANNUAL O&M COST		-30825.	-132104.	-55753.	-228865.	-31200.	-134337.	-53303.	-219289.	-62619.	-259563.	-51062.	-215853.
LEVELIZED FIXED CHARGE			13973.		7347.		14186.		7202.		7478.		18047.
LEVELIZED REVENUE SAVINGS			-118132.		-221517.		-120151.		-212088.		-252085.		-197807.
SPECIFIC LEVELIZED REVENUE SAVINGS ($/KW)			-142.3		-266.9		-144.8		-255.5		-303.7		-238.3
LEVELIZED INCREMENTAL COST OF ELEC. SVGS.(MILLS/KWHR)			-30.3		-56.7		-30.8		-54.3		-64.6		-50.7
TOTAL CAPITAL REQUIREMENT		91325.		48022.		92720.		47069.		48877.		117952.	
PAYBACK PERIOD (YRS)		3.0		0.9		3.0		0.9		0.8		2.3	

Table 8-46

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT D
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:								
FIXED O&M	77.	77.	81.	81.	82.	82.	82.	82.
VARIABLE O&M	48.	123.	61.	129.	62.	130.	61.	129.
FUEL COSTS:								
CWF FUEL COST	607.	303.	773.	386.	773.	386.	773.	386.
OIL FUEL COST	0.	1791.	0.	1791.	0.	1791.	0.	1791.
TOTAL O&M COST	732.	2294.	915.	2388.	917.	2389.	915.	2388.
CREDITS DUE TO CWF BURNING								
VARIABLE O&M	45.	121.	59.	128.	58.	128.	58.	128.
FUEL OIL	825.	2203.	1064.	2323.	1054.	2318.	1058.	2320.
TOTAL CREDITS	870.	2325.	1122.	2451.	1112.	2445.	1116.	2448.
INCREMENTAL ANNUAL O&M COST	-138.	-30.	-207.	-63.	-195.	-56.	-201.	-59.
TOTAL CAPITAL REQUIREMENT	2839.	2837.	2990.	2987.	3029.	3026.	3014.	3012.
PAYBACK PERIOD (YRS)	20.6	93.4	14.5	47.6	15.6	53.9	15.0	50.7

Table 8-47

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT D
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:								
FIXED O&M	77.	77.	81.	81.	82.	82.	82.	82.
VARIABLE O&M	48.	123.	61.	129.	62.	130.	61.	129.
FUEL COSTS:								
CWF FUEL COST	607.	303.	773.	386.	773.	386.	773.	386.
OIL FUEL COST	0.	2015.	0.	2015.	0.	2015.	0.	2015.
TOTAL O&M COST	732.	2518.	915.	2612.	917.	2613.	915.	2612.
CREDITS DUE TO CWF BURNING								
VARIABLE O&M	45.	121.	59.	128.	58.	128.	58.	128.
FUEL OIL	928.	2479.	1197.	2613.	1186.	2608.	1190.	2610.
TOTAL CREDITS	973.	2600.	1255.	2741.	1244.	2735.	1248.	2738.
INCREMENTAL ANNUAL O&M COST	-241.	-82.	-340.	-129.	-326.	-122.	-333.	-126.
TOTAL CAPITAL REQUIREMENT	2839.	2837.	2990.	2987.	3029.	3026.	3014.	3012.
PAYBACK PERIOD (YRS)	11.8	34.6	8.8	23.1	9.3	24.8	9.1	24.0

Table 8-48

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY; AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT D
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:								
FIXED O&M	77.	77.	81.	81.	82.	82.	82.	82.
VARIABLE O&M	48.	123.	61.	129.	62.	130.	61.	129.
FUEL COSTS:								
CWF FUEL COST	607.	303.	773.	386.	773.	386.	773.	386.
OIL FUEL COST	0.	2239.	0.	2239.	0.	2239.	0.	2239.
TOTAL O&M COST	732.	2742.	915.	2836.	917.	2837.	915.	2836.
CREDITS DUE TO CWF BURNING								
VARIABLE O&M	45.	121.	59.	128.	58.	128.	58.	128.
FUEL OIL	1031.	2754.	1330.	2903.	1317.	2897.	1322.	2900.
TOTAL CREDITS	1076.	2875.	1388.	3031.	1375.	3025.	1381.	3028.
INCREMENTAL ANNUAL O&M COST	-344.	-133.	-473.	-196.	-458.	-188.	-465.	-192.
TOTAL CAPITAL REQUIREMENT	2839.	2837.	2990.	2987.	3029.	3026.	3014.	3012.
PAYBACK PERIOD (YRS)	8.2	21.3	6.3	15.3	6.6	16.1	6.5	15.7

Table 8-49

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT D
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.5	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:								
FIXED O&M	77.	77.	81.	81.	82.	82.	82.	82.
VARIABLE O&M	58.	127.	74.	135.	75.	136.	73.	135.
FUEL COSTS:								
CWF FUEL COST	728.	364.	927.	464.	927.	464.	927.	464.
OIL FUEL COST	0.	1791.	0.	1791.	0.	1791.	0.	1791.
TOTAL O&M COST	863.	2360.	1082.	2471.	1084.	2473.	1082.	2472.
CREDITS DUE TO CWF BURNING								
VARIABLE O&M	54.	126.	70.	134.	70.	133.	70.	133.
FUEL OIL	990.	2286.	1276.	2429.	1265.	2423.	1270.	2426.
TOTAL CREDITS	1044.	2412.	1347.	2563.	1334.	2557.	1339.	2559.
INCREMENTAL ANNUAL O&M COST	-181.	-52.	-264.	-92.	-250.	-84.	-257.	-88.
TOTAL CAPITAL REQUIREMENT	2842.	2840.	2994.	2991.	3033.	3030.	3019.	3016.
PAYBACK PERIOD (YRS)	15.7	54.7	11.3	32.7	12.1	36.2	11.7	34.4

Table 8-50

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT D
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:								
FIXED O&M	77.	77.	81.	81.	82.	82.	82.	82.
VARIABLE O&M	58.	127.	74.	135.	75.	136.	73.	135.
FUEL COSTS:								
CWF FUEL COST	728.	364.	927.	464.	927.	464.	927.	464.
OIL FUEL COST	0.	2015.	0.	2015.	0.	2015.	0.	2015.
TOTAL O&M COST	863.	2584.	1082.	2695.	1084.	2697.	1082.	2695.
CREDITS DUE TO CWF BURNING								
VARIABLE O&M	54.	126.	70.	134.	70.	133.	70.	133.
FUEL OIL	1113.	2571.	1436.	2733.	1423.	2726.	1428.	2729.
TOTAL CREDITS	1168.	2697.	1506.	2866.	1492.	2860.	1498.	2862.
INCREMENTAL ANNUAL O&M COST	-305.	-114.	-424.	-171.	-408.	-163.	-416.	-167.
TOTAL CAPITAL REQUIREMENT	2842.	2840.	2994.	2991.	3033.	3030.	3019.	3016.
PAYBACK PERIOD (YRS)	9.3	25.0	7.1	17.5	7.4	18.6	7.3	18.1

Table 8-51

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT D
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL							
	UF-6.8		SD-5.7		CG-7.9		CG-4.8	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:								
FIXED O&M	77.	77.	81.	81.	82.	82.	82.	82.
VARIABLE O&M	58.	127.	74.	135.	75.	136.	73.	135.
FUEL COSTS:								
CWF FUEL COST	728.	364.	927.	464.	927.	464.	927.	464.
OIL FUEL COST	0.	2239.	0.	2239.	0.	2239.	0.	2239.
TOTAL O&M COST	863.	2807.	1082.	2919.	1084.	2921.	1082.	2919.
CREDITS DUE TO CWF BURNING								
VARIABLE O&M	54.	126.	70.	134.	70.	133.	70.	133.
FUEL OIL	1237.	2857.	1595.	3036.	1581.	3029.	1587.	3032.
TOTAL CREDITS	1291.	2983.	1666.	3170.	1650.	3163.	1657.	3166.
INCREMENTAL ANNUAL O&M COST	-428.	-176.	-583.	-251.	-566.	-242.	-575.	-246.
TOTAL CAPITAL REQUIREMENT	2842.	2840.	2994.	2991.	3033.	3030.	3019.	3016.
PAYBACK PERIOD (YRS)	6.6	16.2	5.1	11.9	5.4	12.5	5.3	12.2

Table 8-52

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY:AND PAYBACK PERIOD
($1000S: MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT E
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:										
FIXED O&M	290.	290.	264.	264.	343.	343.	265.	265.	347.	347.
VARIABLE O&M	279.	534.	449.	619.	448.	618.	435.	612.	437.	613.
FUEL COSTS:										
CWF FUEL COST	4169.	2085.	6813.	3406.	6687.	3343.	6687.	3344.	6672.	3336.
OIL FUEL COST	0.	8312.	0.	8312.	0.	8312.	0.	8312.	0.	8312.
TOTAL O&M COST	4738.	11220.	7526.	12601.	7479.	12617.	7387.	12532.	7455.	12607.
CREDITS DUE TO CWF BURNING										
VARIABLE O&M	260.	524.	424.	606.	412.	600.	414.	601.	410.	599.
FUEL OIL	5486.	11055.	8935.	12780.	8686.	12655.	8728.	12676.	8645.	12634.
TOTAL CREDITS	5746.	11579.	9359.	13386.	9098.	13255.	9142.	13277.	9054.	13233.
INCREMENTAL ANNUAL O&M COST	-1008.	-359.	-1834.	-785.	-1619.	-638.	-1754.	-745.	-1599.	-626.
TOTAL CAPITAL REQUIREMENT	10703.	10692.	9843.	9825.	12731.	12712.	9850.	9831.	12845.	12827.
PAYBACK PERIOD (YRS)	10.6	29.8	5.4	12.5	7.9	19.9	5.6	13.2	8.0	20.5

Table 8-53

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT E
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:										
FIXED O&M	290.	290.	264.	264.	343.	343.	265.	265.	347.	347.
VARIABLE O&M	279.	534.	449.	619.	448.	618.	435.	612.	437.	613.
FUEL COSTS:										
CWF FUEL COST	4169.	2085.	6813.	3406.	6687.	3343.	6687.	3344.	6672.	3336.
OIL FUEL COST	0.	9351.	0.	9351.	0.	9351.	0.	9351.	0.	9351.
TOTAL O&M COST	4738.	12259.	7526.	13640.	7479.	13656.	7387.	13571.	7455.	13646.
CREDITS DUE TO CWF BURNING										
VARIABLE O&M	260.	524.	424.	606.	412.	600.	414.	601.	410.	599.
FUEL OIL	6172.	12437.	10052.	14377.	9772.	14237.	9819.	14260.	9725.	14214.
TOTAL CREDITS	6432.	12961.	10476.	14983.	10184.	14837.	10232.	14861.	10135.	14813.
INCREMENTAL ANNUAL O&M COST	-1694.	-702.	-2950.	-1343.	-2705.	-1181.	-2845.	-1290.	-2680.	-1167.
TOTAL CAPITAL REQUIREMENT	10703.	10692.	9843.	9825.	12731.	12712.	9850.	9831.	12845.	12827.
PAYBACK PERIOD (YRS)	6.3	15.2	3.3	7.3	4.7	10.8	3.5	7.6	4.8	11.0

Table 8-54

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S: MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 2.0$/MMBTU)
UNIT-UNIT E
LOAD-PREDICTED
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:										
FIXED O&M	290.	290.	264.	264.	343.	343.	265.	265.	347.	347.
VARIABLE O&M	279.	534.	449.	619.	448.	618.	435.	612.	437.	613.
FUEL COSTS:										
CWF FUEL COST	4169.	2085.	6813.	3406.	6687.	3343.	6687.	3344.	5672.	3336.
OIL FUEL COST	0.	10390.	0.	10390.	0.	10390.	0.	10390.	0.	10390.
TOTAL O&M COST	4738.	13298.	7526.	14679.	7479.	14695.	7387.	14610.	7455.	14685.
CREDITS DUE TO CWF BURNING										
VARIABLE O&M	260.	524.	424.	606.	412.	600.	414.	601.	410.	599.
FUEL OIL	6857.	13819.	11169.	15975.	10858.	15819.	10910.	15845.	10806.	15793.
TOTAL CREDITS	7118.	14343.	11593.	16581.	11270.	16419.	11323.	16446.	11216.	16392.
INCREMENTAL ANNUAL O&M COST	-2380.	-1045.	-4067.	-1902.	-3791.	-1724.	-3936.	-1836.	-3760.	-1707.
TOTAL CAPITAL REQUIREMENT	10703.	10692.	9843.	9825.	12731.	12712.	9850.	9831.	12845.	12827.
PAYBACK PERIOD (YRS)	4.5	10.2	2.4	5.2	3.4	7.4	2.5	5.4	3.4	7.5

Table 8-55

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.0$/MMBTU)
UNIT-UNIT E
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:										
FIXED O&M	290.	290.	264.	264.	343.	343.	265.	265.	347.	347.
VARIABLE O&M	335.	562.	539.	664.	538.	663.	522.	655.	524.	656.
FUEL COSTS:										
CWF FUEL COST	5003.	2502.	8175.	4088.	8024.	4012.	8025.	4012.	8006.	4003.
OIL FUEL COST	0.	8312.	0.	8312.	0.	8312.	0.	8312.	0.	8312.
TOTAL O&M COST	5628.	11665.	8978.	13327.	8906.	13331.	8812.	13244.	8877.	13318.
CREDITS DUE TO CWF BURNING										
VARIABLE O&M	312.	550.	509.	648.	494.	641.	497.	643.	492.	640.
FUEL OIL	6583.	11604.	10723.	13673.	10423.	13524.	10473.	13549.	10373.	13499.
TOTAL CREDITS	6895.	12154.	11231.	14322.	10918.	14165.	10970.	14191.	10865.	14139.
INCREMENTAL ANNUAL O&M COST	-1268.	-489.	-2253.	-994.	-2012.	-8[illegible]	-2158.	-947.	-1989.	-821.
TOTAL CAPITAL REQUIREMENT	10727.	10713.	9882.	9860.	12770.	12747.	9888.	9866.	12883.	12861.
PAYBACK PERIOD (YRS)	8.5	21.9	4.4	9.9	6.3	15.3	4.6	10.4	6.5	15.7

Table 8-56

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY;AND PAYBACK PERIOD
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= 1.5$/MMBTU)
UNIT-UNIT E
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UF-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:										
FIXED O&M	290.	290.	264.	264.	343.	343.	265.	265.	347.	347.
VARIABLE O&M	335.	562.	539.	664.	538.	663.	522.	655.	524.	656.
FUEL COSTS:										
CWF FUEL COST	5003.	2502.	8175.	4088.	8024.	4012.	8025.	4012.	8006.	4003.
OIL FUEL COST	0.	9351.	0.	9351.	0.	9351.	0.	9351.	0.	9351.
TOTAL O&M COST	5628.	12704.	8978.	14366.	8906.	14370.	8812.	14283.	8877.	14357.
CREDITS DUE TO CWF BURNING										
VARIABLE O&M	312.	550.	509.	648.	494.	641.	497.	643.	492.	640.
FUEL OIL	7406.	13054.	12063.	15382.	11726.	15214.	11782.	15242.	11670.	15186.
TOTAL CREDITS	7718.	13604.	12571.	16031.	12221.	15855.	12279.	15885.	12162.	15826.
INCREMENTAL ANNUAL O&M COST	-2091.	-900.	-3593.	-1665.	-3315.	-1486.	-3467.	-1601.	-3285.	-1469.
TOTAL CAPITAL REQUIREMENT	10727.	10713.	9882.	9860.	12770.	12747.	9886.	9866.	12883.	12861.
PAYBACK PERIOD (YRS)	5.1	11.9	2.8	5.9	3.9	8.6	2.9	6.2	3.9	8.8

Table 8-57

ECONOMIC EVALUATION RESULTS SUMMARY
O&M COST SUMMARY~~;AND PAYBACK PERIOD~~
($1000S; MID 1985 WAGE & PRICE LEVEL; DIFFERENTIAL FUEL COST= ~~2.09/MMBTU)~~
UNIT-UNIT E
LOAD-PREDICTED +20%
TYPE-INDUSTRIAL STEAM GENERATOR

	FUEL									
	UP-6.8		SD-5.7		CG-7.9		CG-4.8		AL-5.9	
OPER. MODE	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II	CASE I	CASE II
ANNUAL O&M COSTS:										
FIXED O&M	290.	290.	264.	264.	343.	343.	265.	265.	347.	347.
VARIABLE O&M	335.	562.	539.	664.	538.	663.	522.	655.	524.	656.
FUEL COSTS:										
CWF FUEL COST	5003.	2502.	8175.	4088.	8024.	4012.	8025.	4012.	8006.	4003.
OIL FUEL COST	0.	10390.	0.	10390.	0.	10390.	0.	10390.	0.	10390.
TOTAL O&M COST	5628.	13743.	8978.	15405.	8906.	15409.	8812.	15322.	8877.	15396.
CREDITS DUE TO CWF BURNING										
VARIABLE O&M	312.	550.	509.	648.	494.	641.	497.	643.	492.	648.
FUEL OIL	8229.	14504.	13403.	17092.	13029.	16905.	13091.	16936.	12967.	16873.
TOTAL CREDITS	8541.	15055.	13912.	17740.	13523.	17546.	13588.	17578.	13459.	17514.
INCREMENTAL ANNUAL O&M COST	-2913.	-1312.	-4934.	-2335.	-4618.	-2137.	-4776.	-2256.	-4582.	-2118.
TOTAL CAPITAL REQUIREMENT	10727.	10713.	9882.	9860.	12770.	12747.	9888.	9866.	12883.	12861.
PAYBACK PERIOD (YRS)	3.7	8.2	2.0	4.2	2.8	6.0	2.1	4.4	2.8	6.1

periods for each fuel cost differential are shown in Figures 8-23 to 8-26 and apply to each selected CWF. As noted previously, these pay back periods assume the heaters operate 95% of the calendar year at constant load (95% availability) with 90% availability with CWF firing and 5% availability with fuel oil firing.

Two additional pay back period Tables 8-58 and 8-59 are also included for reference. These tables show the effects of the degree of heater availability with regard to fuel use. In these cases, it was assumed that the total availability of the heaters is still 95% (as used earlier), however, the availability to fire CWF and fuel oil with their corresponding fuel consumption is varied from 90% to 85% and to 80%. Figures 8-27 and 8-28 illustrate these payback period sensitivities.

TABLE 8-58

PAYBACK PERIODS

VERTICAL CYLINDRICAL HEATER (UNIT F)

SINGLE HEATER

Fuel Cost Difference	Availability Factors (1)		
	90-5	85-10	80-15
$1.0/10^6 Btu	17.6	20.7	25.3
$1.5/10^6 Btu	10.0	11.3	13.0
$2.0/10^6 Btu	7.0	7.8	8.8

TWIN HEATERS

Fuel Cost Difference	Availability Factors (1)		
	90-5	85-10	80-15
$1.0/10^6 Btu	10.0	11.4	13.5
$1.5/10^6 Btu	6.0	6.7	7.7
$2.0/10^6 Btu	4.3	4.8	5.3

(1) Total availability is constant 95%
First number is percent of time with CWF and air preheat in operation.
Second number is percent of time heaters operated with stand-by fuel (oil) and without air preheat.

TABLE 8-59

PAYBACK PERIODS

VERTICAL CYLINDRICAL HEATER (UNIT G)

SINGLE HEATER

Fuel Cost Difference	Availability Factors (1)		
	90-5	85-10	80-15
$1.0/10^6 Btu	11.5	13.4	16.0
$1.5/10^6 Btu	6.9	7.8	8.9
$2.0/10^6 Btu	4.9	5.5	6.1

TWIN HEATERS

Fuel Cost Difference	Availability Factors (1)		
	90-5	85-10	80-15
$1.0/10^6 Btu	7.6	8.7	10.2
$1.5/10^6 Btu	4.7	5.2	5.9
$2.0/10^6 Btu	3.4	3.7	4.2

(1) Total availability is constant 95%
First number is percent of time with CWF and air preheat in operation.
Second number is percent of time heaters operated with stand-by fuel (oil) and without air preheat.

ECONOMIC RESULTS EVALUATION

The economics of conversion to CWF are dependent on many variables. In this evaluation some of the key variables have been identified. The driving force for conversion is the anticipated fuel cost differential between oil and CWF. Other important factors which affect conversion economics are the retrofit modification capital costs, the derated load capability, the unit capacity factor on CWF, and the unit operating mode.

The basic scope of this economic evaluation is defined in Table 8-60.

TABLE 8-60

SCOPE OF ECONOMIC EVALUATION

	Utility	Industrial	Process heater	Total
No. Units	3	2	2	7
No. Fuels	4/5/6*	4/5*	4	4/5/6*
No. Fuel Costs	3	3	3	3
No. Loads	2	2	1**	2/1**
No. Operating Modes	1	2	1	2/1
No. Evaluation Cases	96	108	24	228

*Note 1: A fifth fuel (SD2.6) was evaluated for Unit C. A sixth fuel (AL5.9) was evaluated for Utility Units A and C, and Industrial Unit E. All units were evaluated at "predicted" and "predicted + 20%" load points (maximum of 100% MCR on Unit C).

**Note 2: The process heaters are predicted not to require any load capability derating due to CWF conversion. The "predicted +20%" load case does not apply.

Some of the results of this evaluation are presented graphically in terms of plotting simplified payback period as a function of several of the more important study variables. Levelized results are also shown for the utility units.

Figures 8-5 to 8-7 show payback periods for the three utility units for the study fuels as a function of Differential Fuel Costs (DFC). Figures 8-8 to 8-10 show these same results in a slightly different manner by plotting payback period as a function of load capability for the three DFC's. The top and bottom symbols correspond to DFCs of $1\$/10^6$ Btu and $2\$/10^6$ Btu, respectively. The payback periods run longer for the AL5.9 CWF vs. the others because of the larger scrubber system requirements (Units A and C) and ESP addition on Unit A. Figure 8-11 combines Figures 8-8 to 8-10 and attempts to generalize these limited results by showing bands for payback period as a function of load capability at DFCs of $1\$/10^6$Btu and $2\$/10^6$Btu. This indicates the relative importance of load capability on the economic feasibility of conversion.

With a DFC of $1\$/10^6$Btu, payback periods ranging from about 2 to 9 years are shown at load capabilities above 60%. At load capabilities below 50%, payback periods increase sharply as load capability is reduced. At the 50% load point, the band indicates payback periods from about 7 to 14 years. The band width is relatively narrow (about 3 years) at loads above 60%. The variations which cause this band width are due to site or fuel specific differences such as the requirement for a retrofit electrostatic precipitator or flue gas desulfurization system as well as significant differences in unit sizes which reflect some economy of scale.

Results at the $2\$/10^6$Btu DFC show less variation with payback periods below 6 years at loads above 40%. The band width at this DFC is reduced to about 2 years.

Figure 8-12 shows a similar analysis using the levelized results. Levelized Incremental Cost of Electricity Savings (LICOES) are plotted as a function of load capability for two DFC's. The LICOES is calculated by

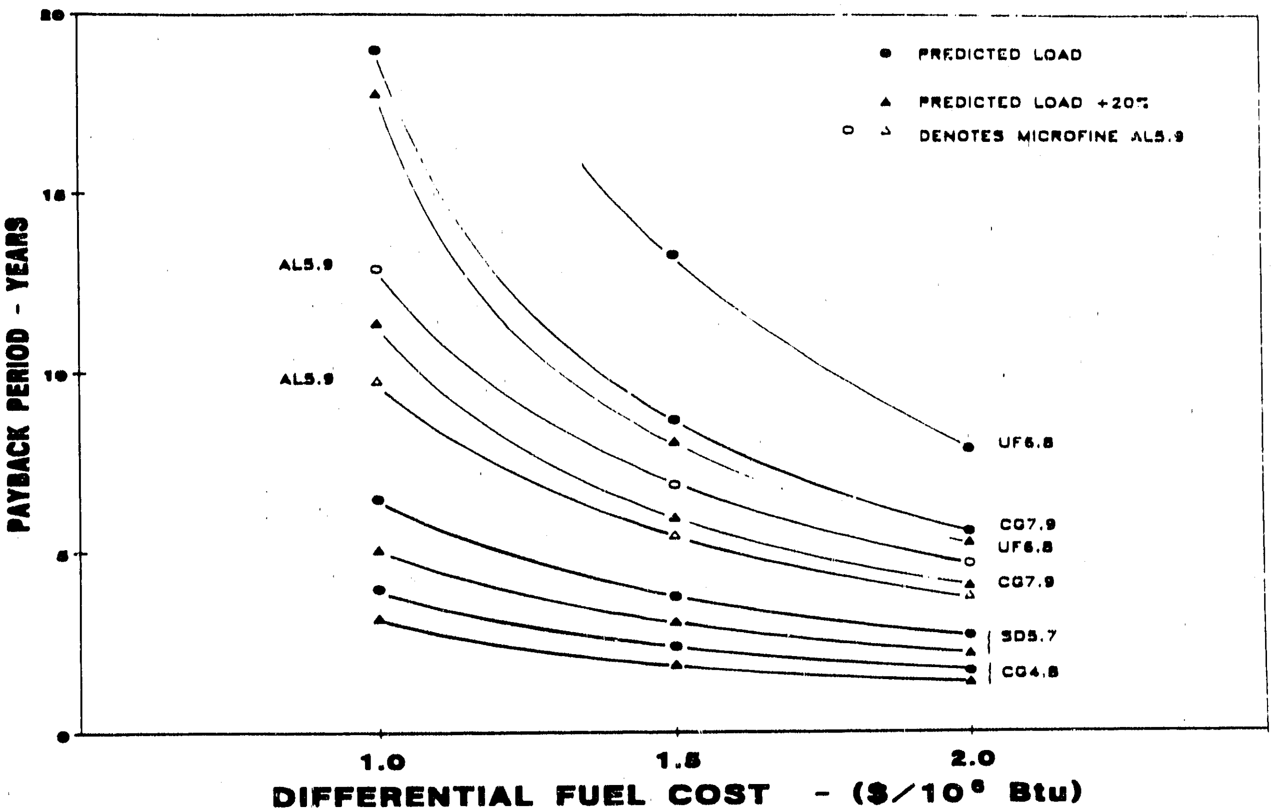


FIGURE 8-5
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT A

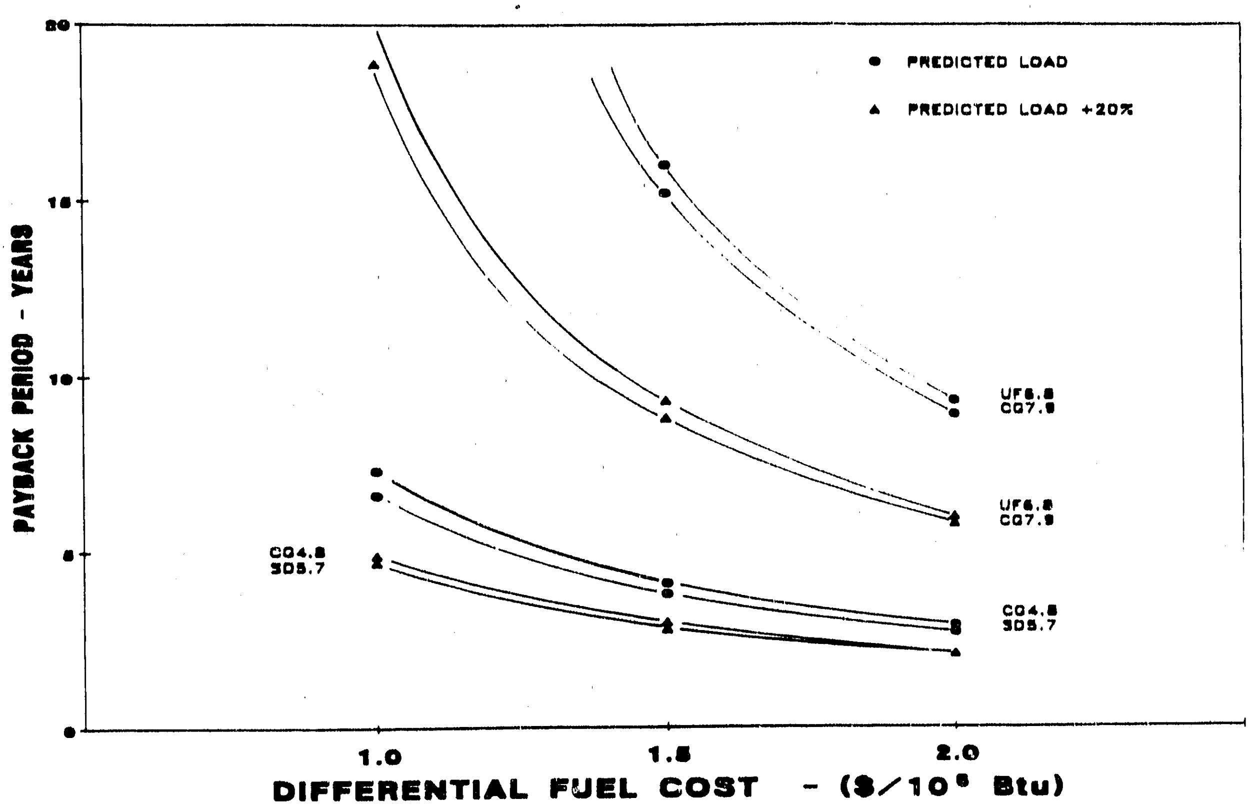


FIGURE 8-6
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT B

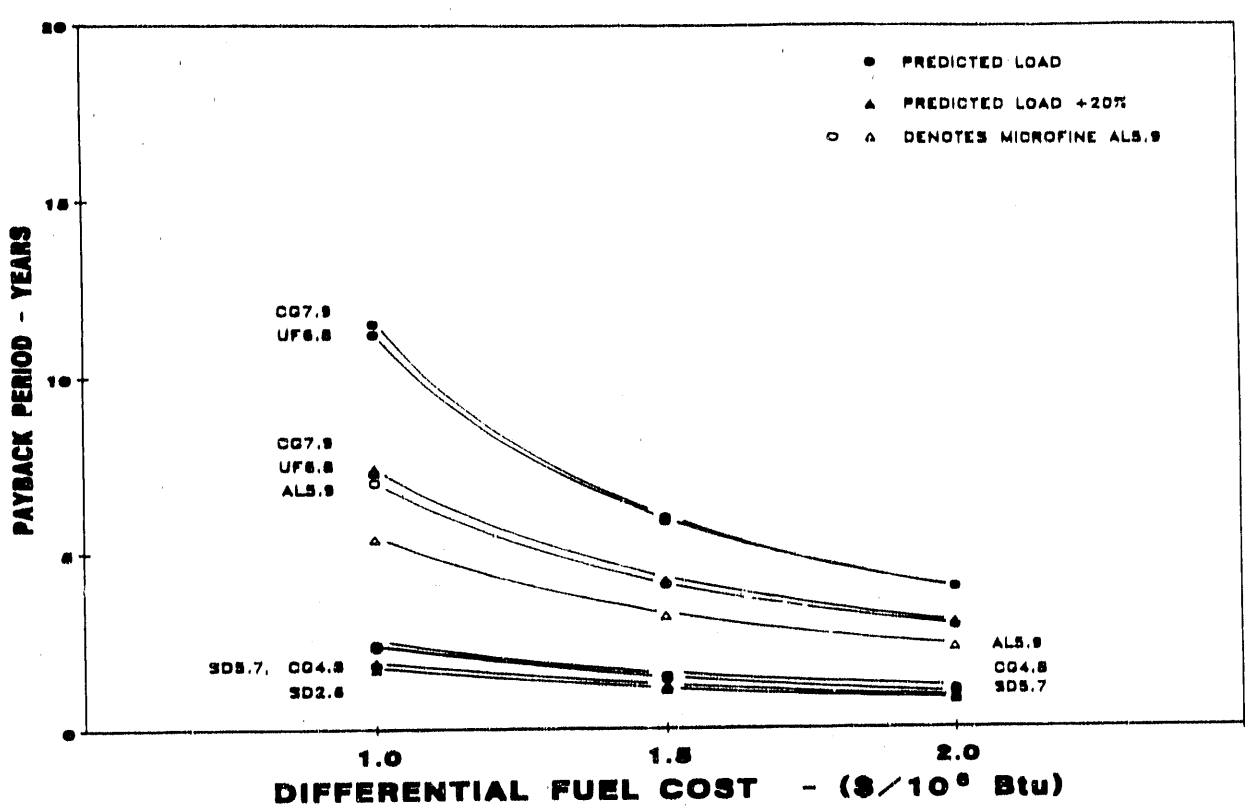


FIGURE 8-7
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT C

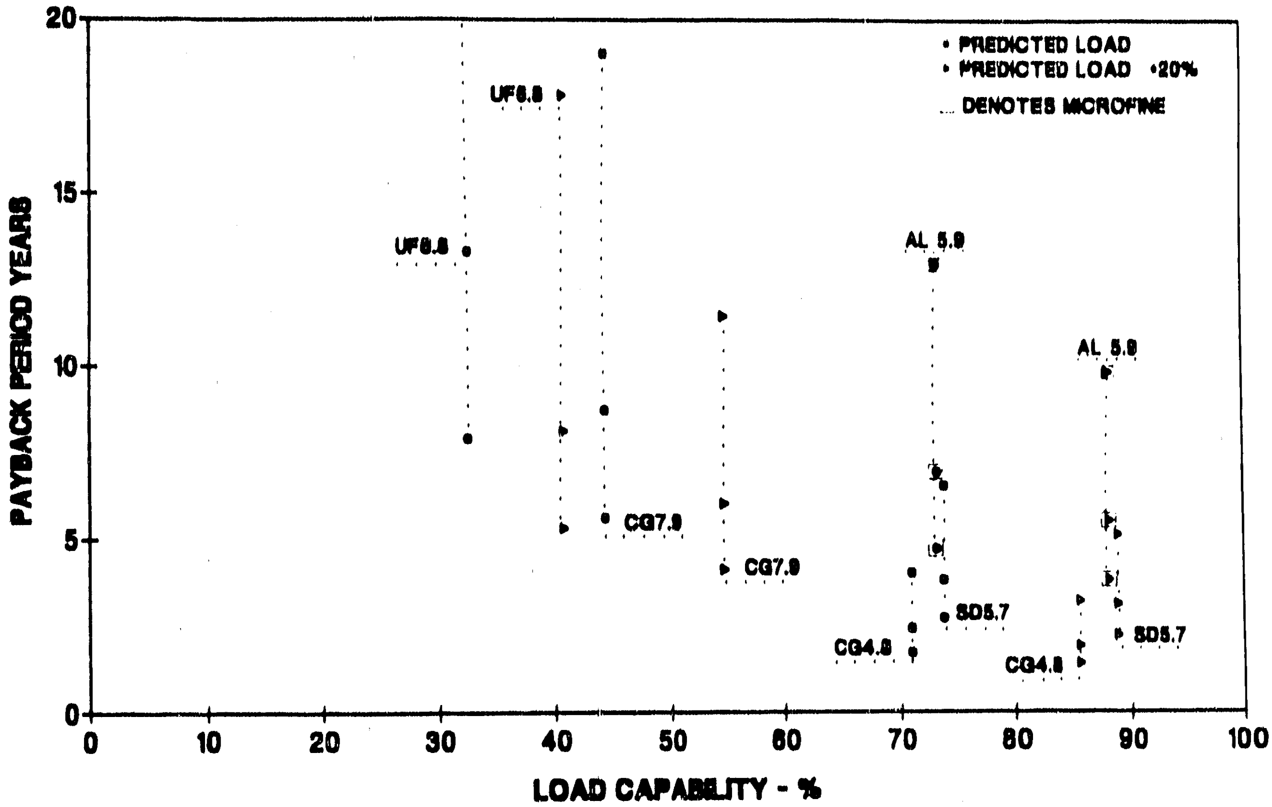


FIGURE 8-8
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT A

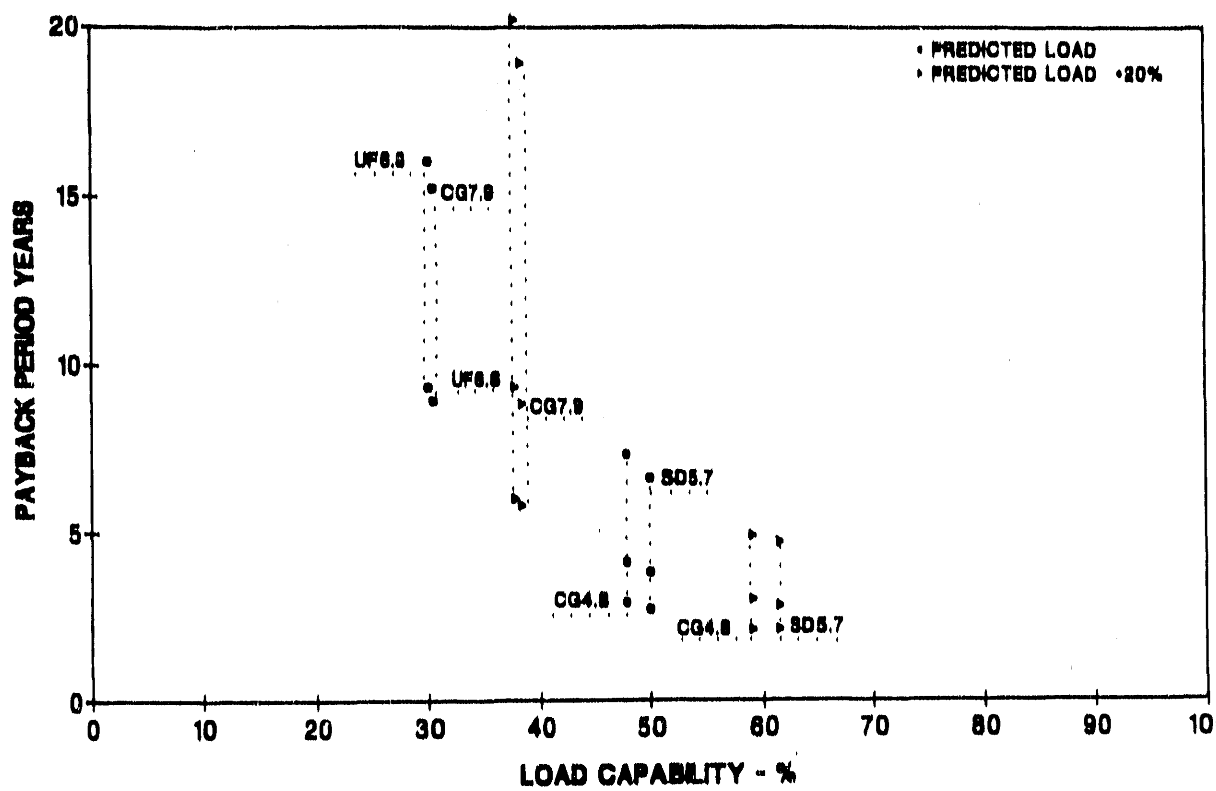


FIGURE 8-9
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT B

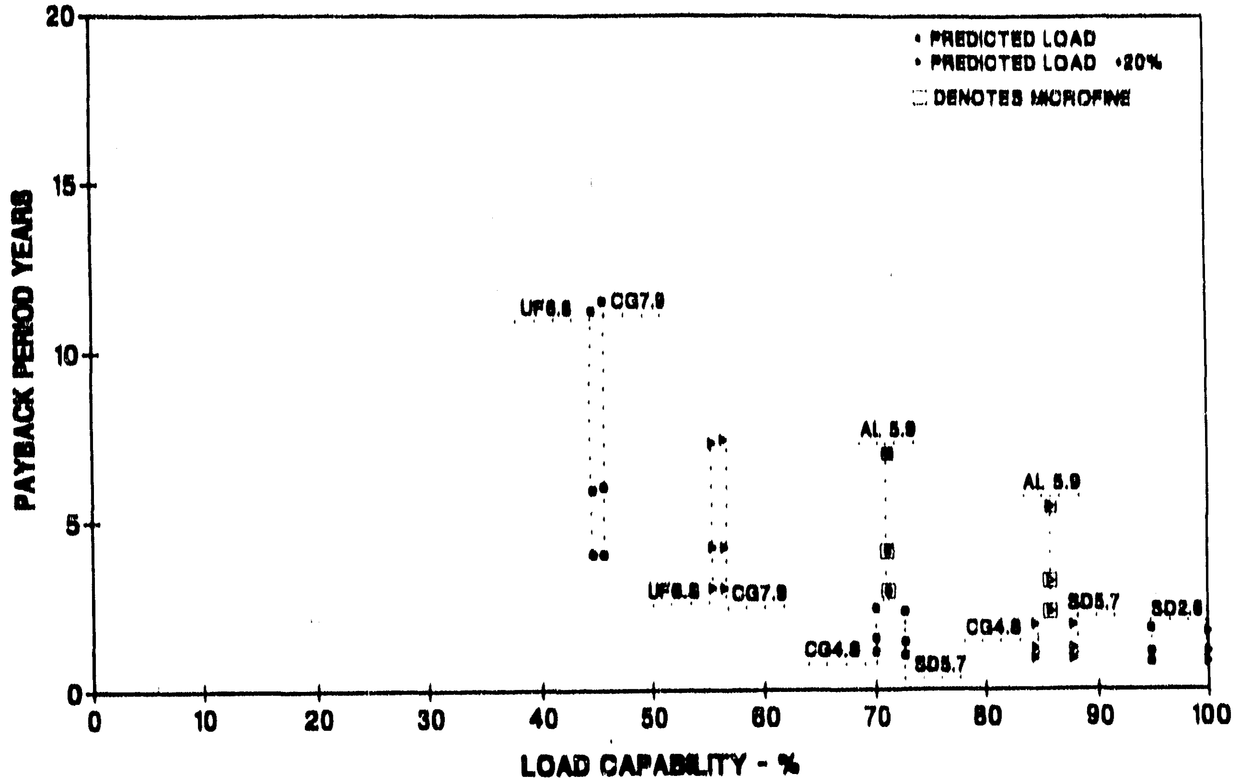


FIGURE 8-10
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT C

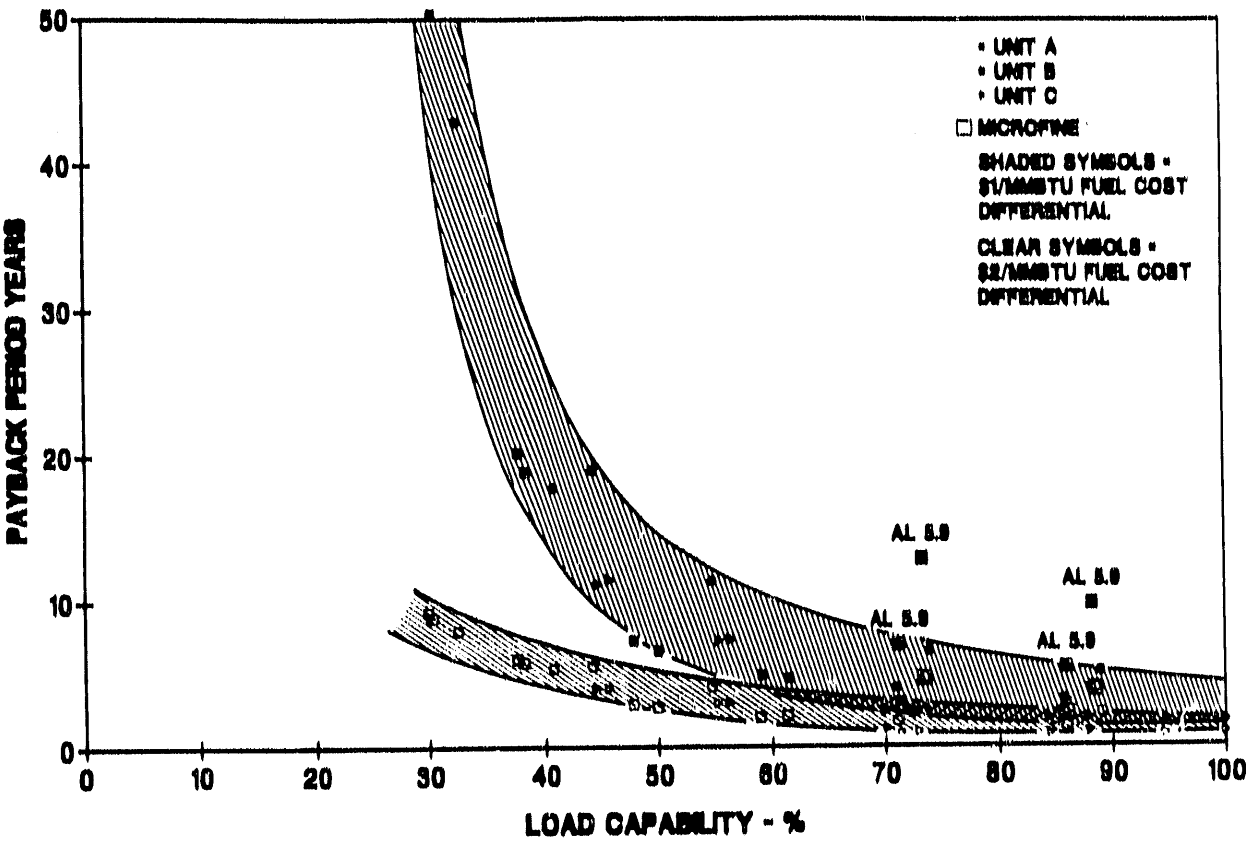


FIGURE 8-11
ECONOMIC EVALUATION RESULTS UTILITY UNITS

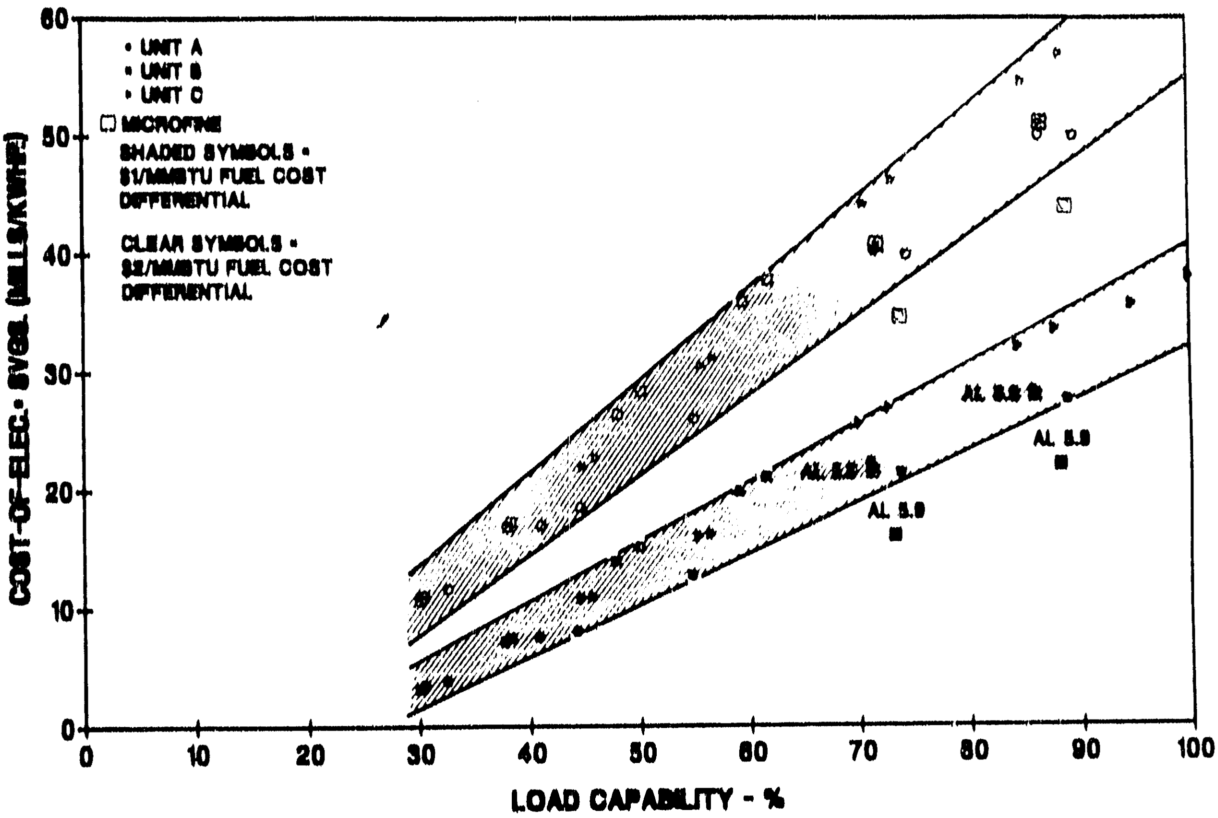


FIGURE 8-12
ECONOMIC EVALUATION RESULTS
UTILITY UNITS

dividing the levelized incremental annual operating and maintenance cost savings by the total annual power generation. The total annual power generation is the sum of the power generated by CWF, oil switching, and replacement power (i.e.: the original Base Case power generation). The primary variable influencing this economic feasibility indicator are load capability and DFC with load capability appearing to be the more sensitive variable for the range of expected values. The LICOES for the AL5.9 is slightly lower than the bands established for the other fuels because of the additional environmental control equipment requirem.ts discussed above.

Similarly, Figures 8-13 to 8-16 show payback period plots for the industrial Unit D as a function of DFC and derated load capability for the study fuels. Two additional operating modes are considered as described previously. Figures 8-17 to 8-20 show the same group of payback period plots for industrial unit E. The results for AL5.9 microfine lie very close to those for CG7.9. Figure 8-21 and 8-22 generalize these limited results for the two industrial units. For Case I with DFC's of $1.00 and $2.00 per million Btu, payback periods are between about 5 to 8 years and 2 to 4 years, respectively, for loads greater than 50% MCR. For loads less than 50% MCR, payback periods are between about 8 to 20 years and 4 to 8 years, respectively. In contrast, for Case II with DFC's of $1.00 and $2.00 per million Btu, payback periods run between about 10 to 20 years and 4 to 8 years respectively, for loads greater than 50%. For loads less than 50% MCR, the situation is worse with payback periods as high as 22 to over 50 years, and 8 to 22 years, respectively.

All payback periods for the various process heater design combinations (single and twin) and fuel cost differentials shown in Figures 8-23 and 8-24, are longer than two years - the pay back period considered economically attractive in the hydrocarbon processing industry for modifications of existing equipment. The payback period range is from 3.4 years for twin horizontal cabin heaters with the largest ($\$2.0/10^6$ Btu) fuel cost differential to 17.6 years for a single vertical cylindrical

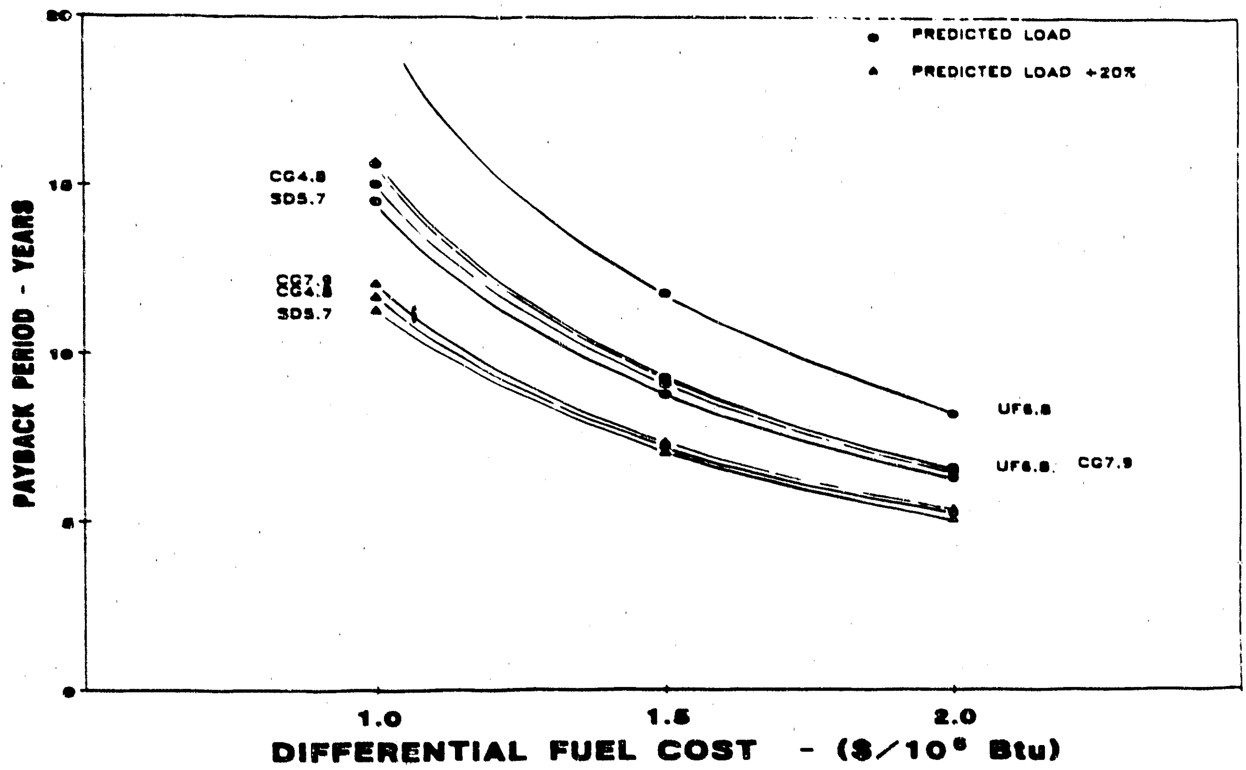


FIGURE 8-13
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT D
CASE I OPERATING MODE

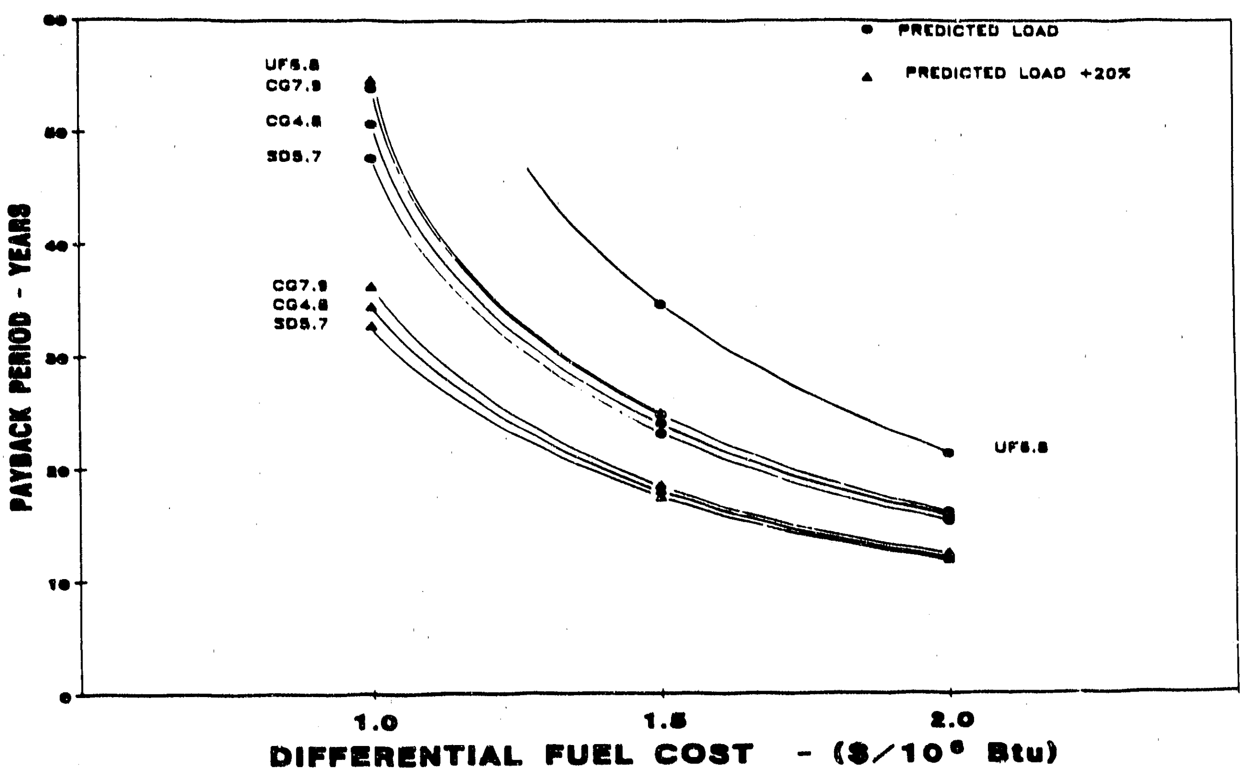


FIGURE 8-14
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT D
CASE II OPERATING MODE

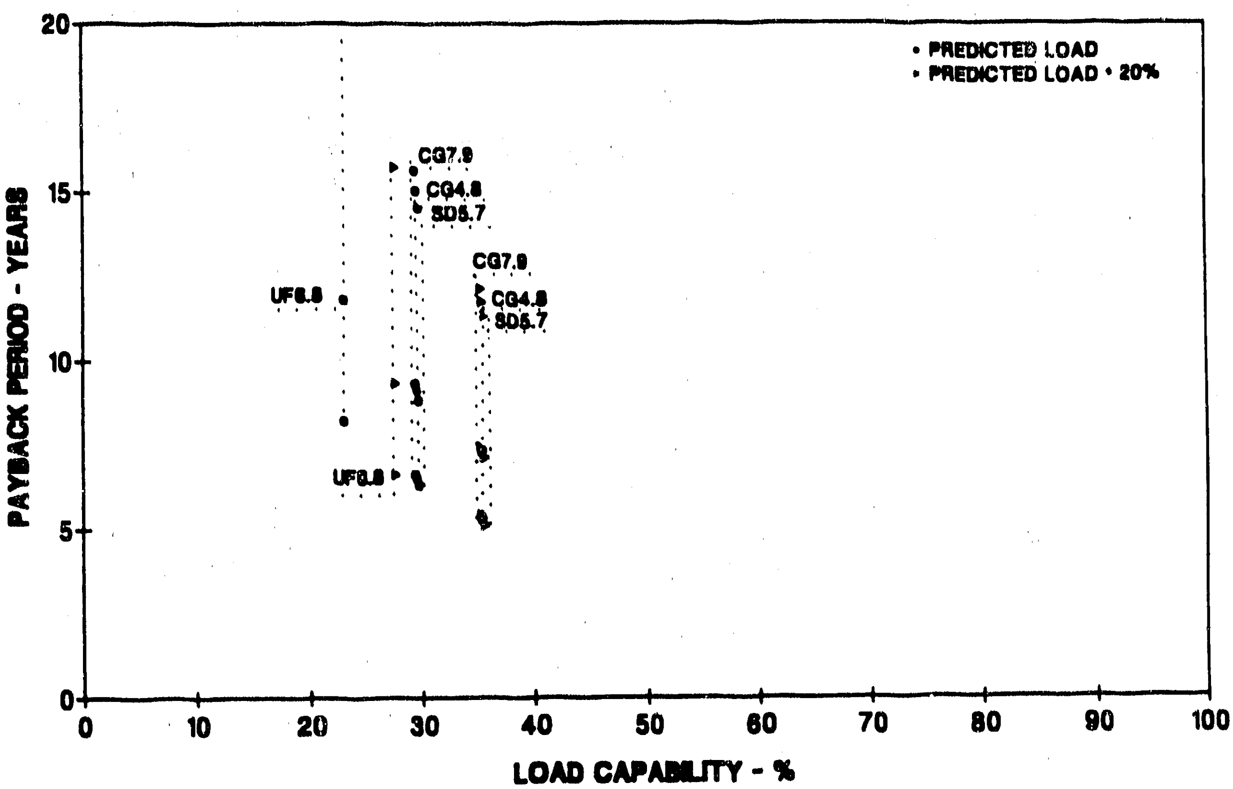


FIGURE 8-15
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT D
CASE I OPERATING MODE

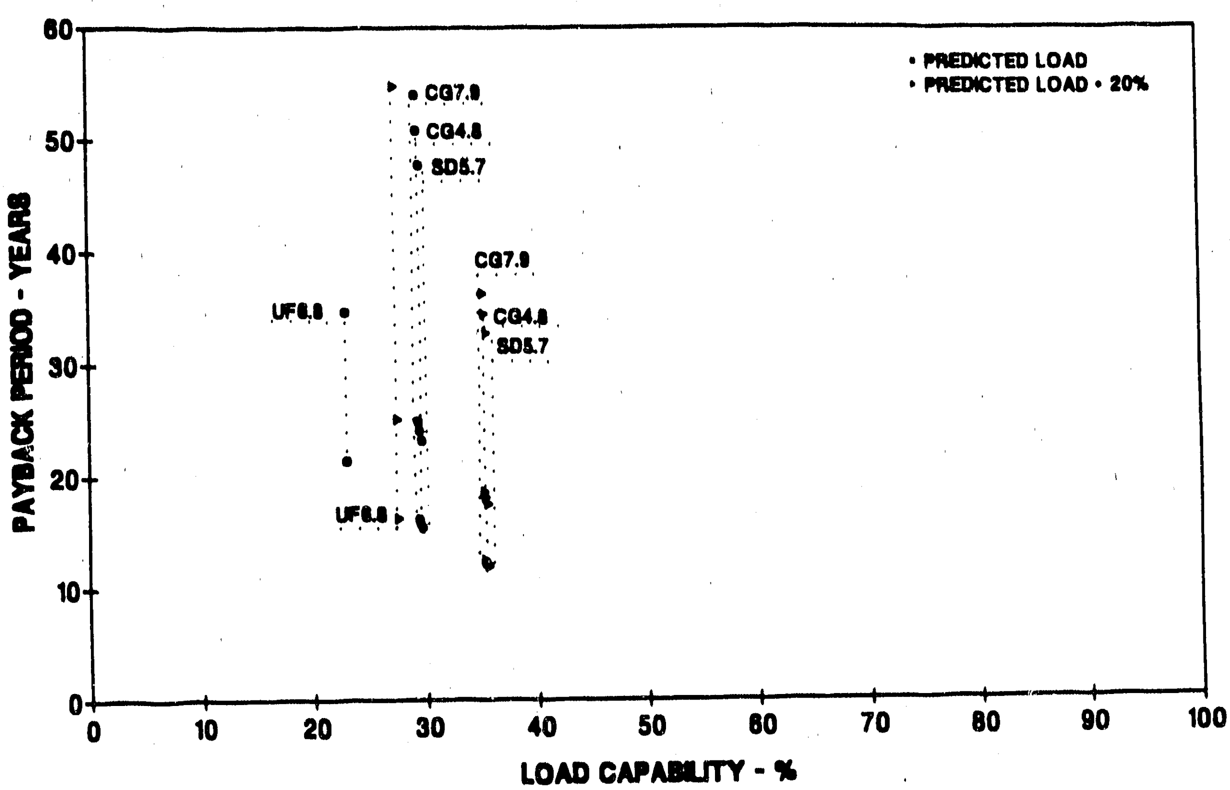


FIGURE 8-16
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT D
CASE II OPERATING MODE

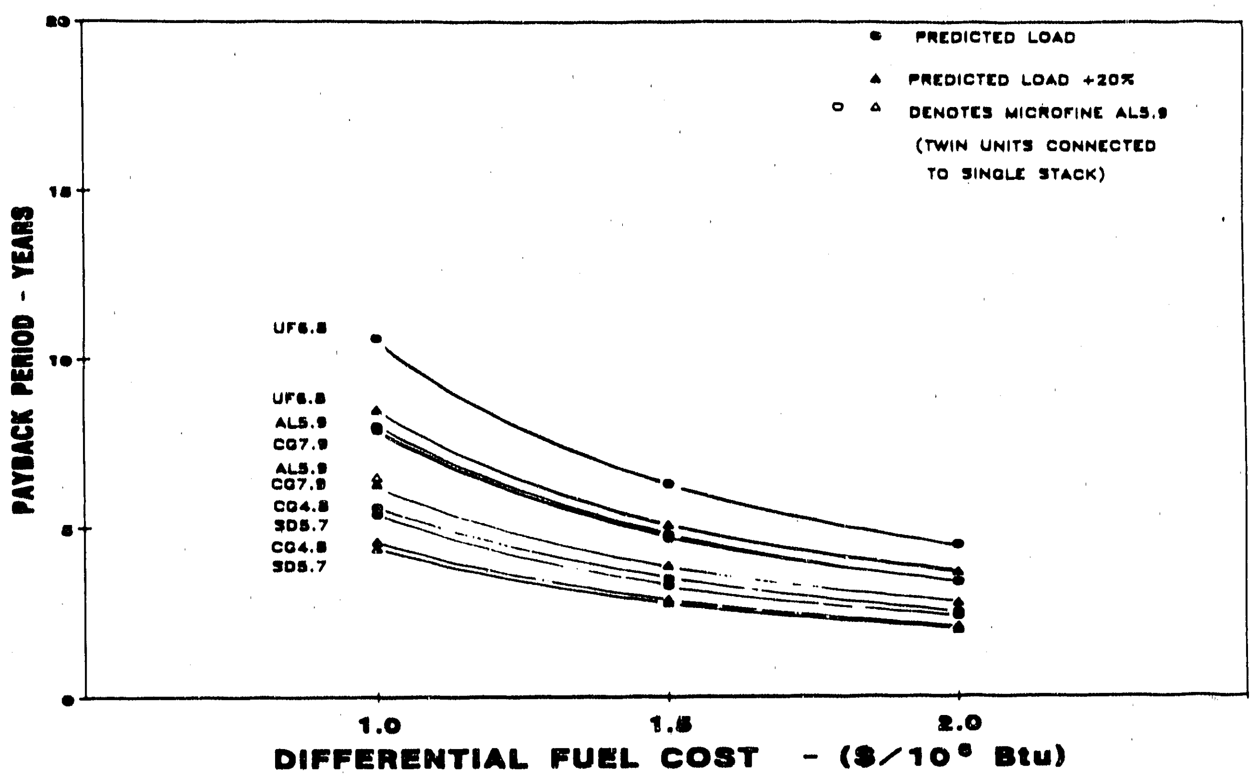


FIGURE 8-17
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT E
CASE I OPERATING MODE

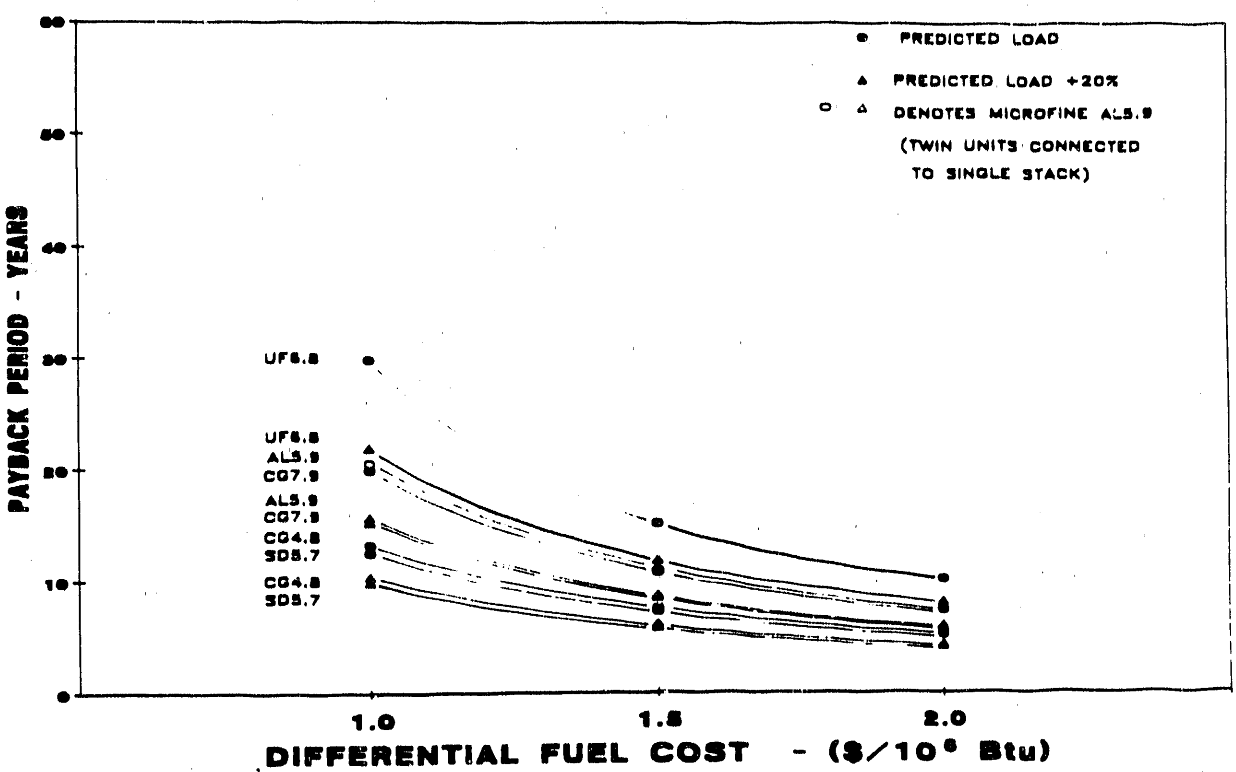


FIGURE 8-18
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT E
CASE II OPERATING MODE

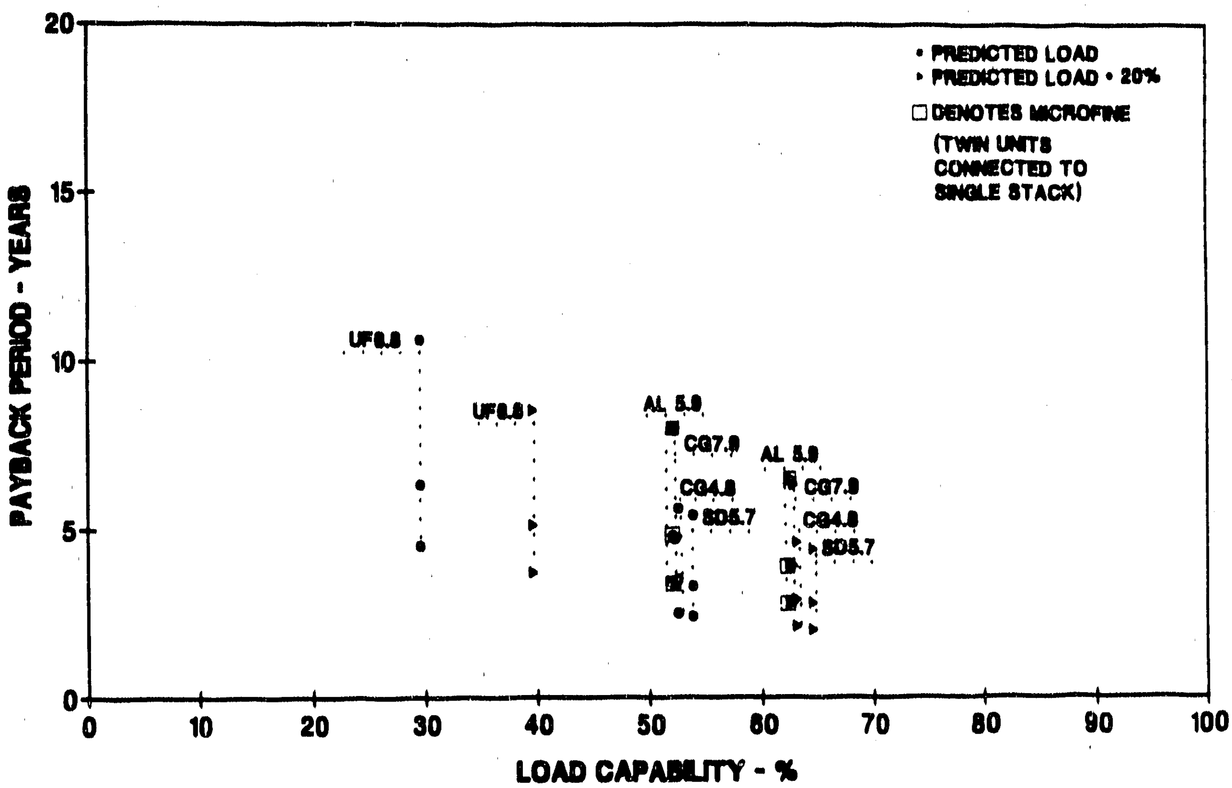


FIGURE 8-19
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT E
CASE I OPERATING MODE

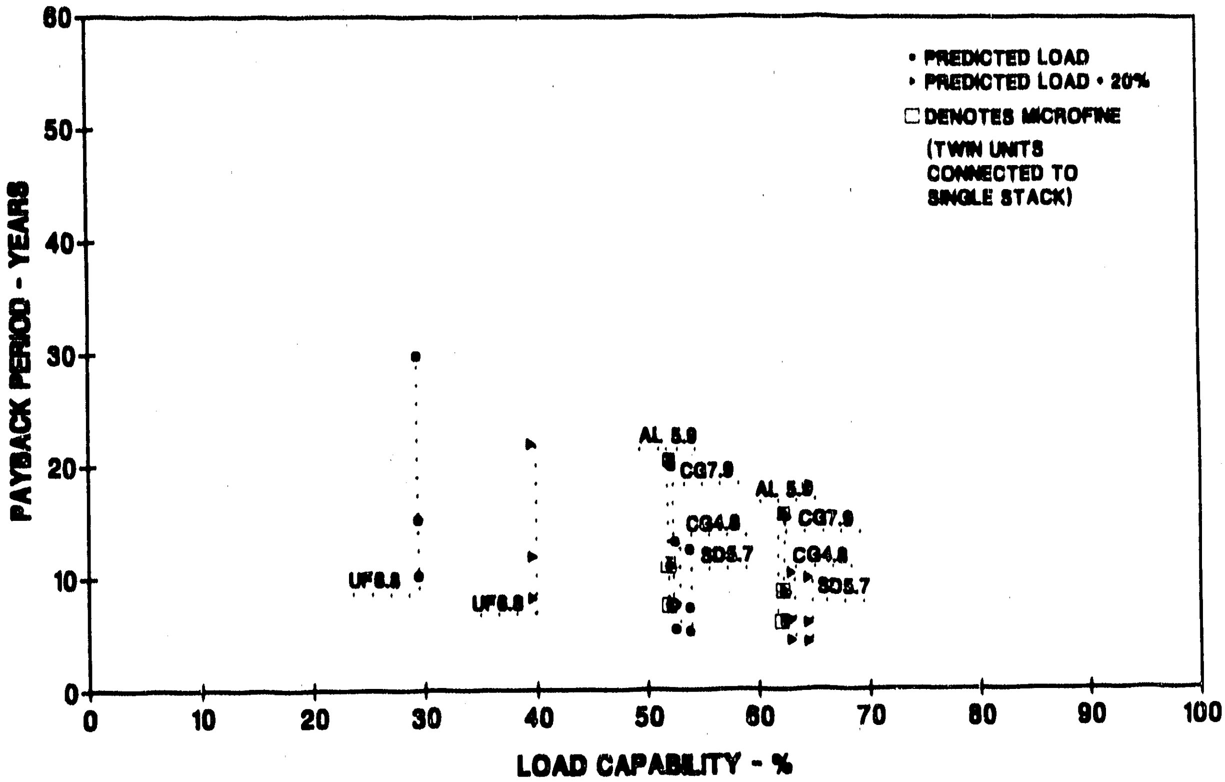


FIGURE 8-20
PAYBACK PERIOD VS. LOAD CAPABILITY
UNIT E
CASE II OPERATING MODE

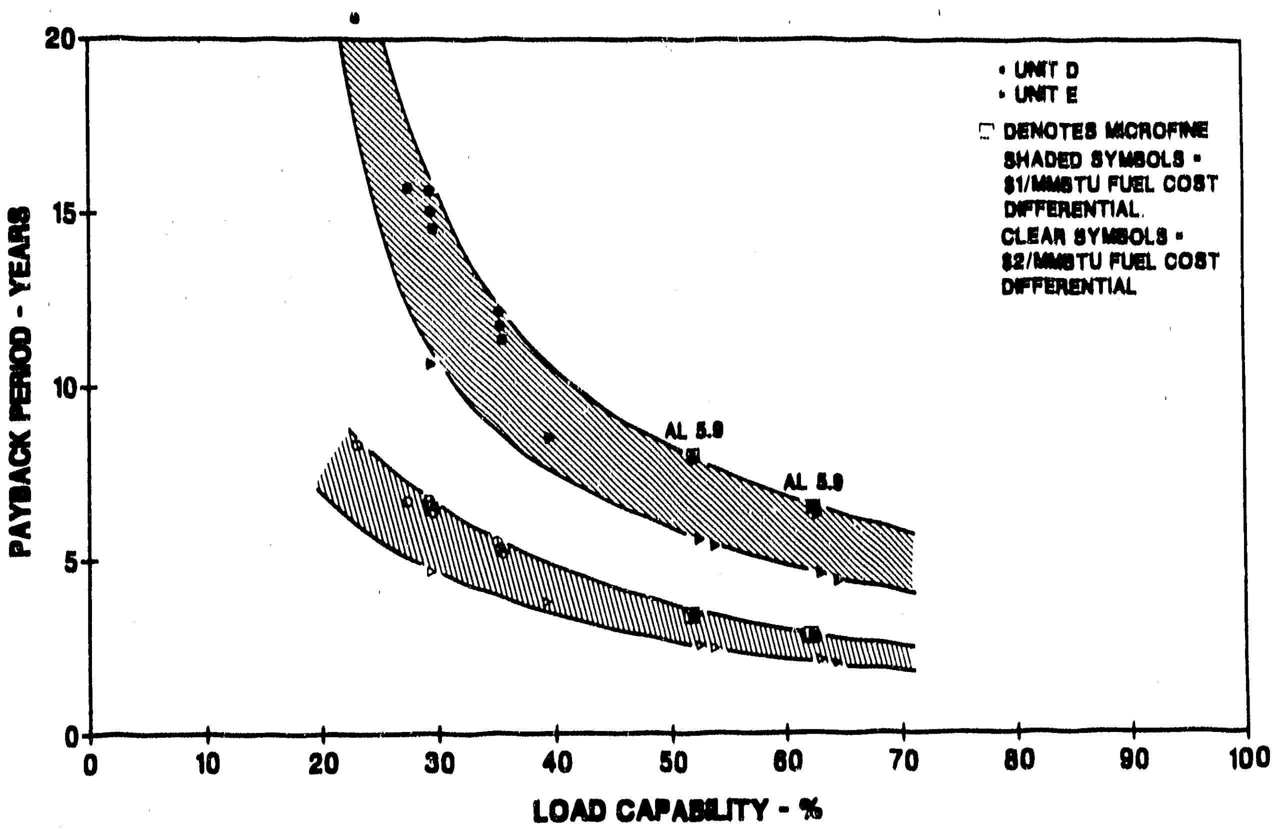


FIGURE 8-21
ECONOMIC EVALUATION RESULTS INDUSTRIAL UNITS
CASE I OPERATING MODE

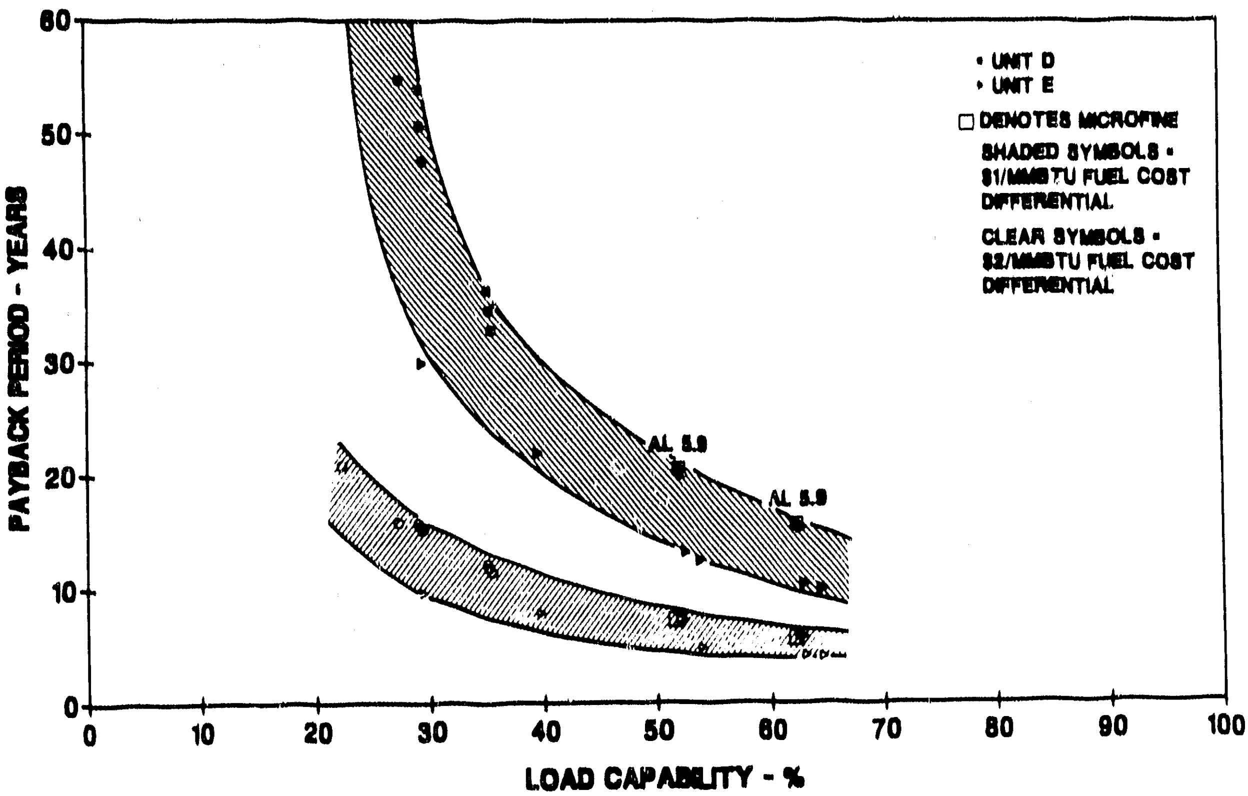


FIGURE 8-22
ECONOMIC EVALUATION RESULTS INDUSTRIAL UNITS
CASE II OPERATING MODE

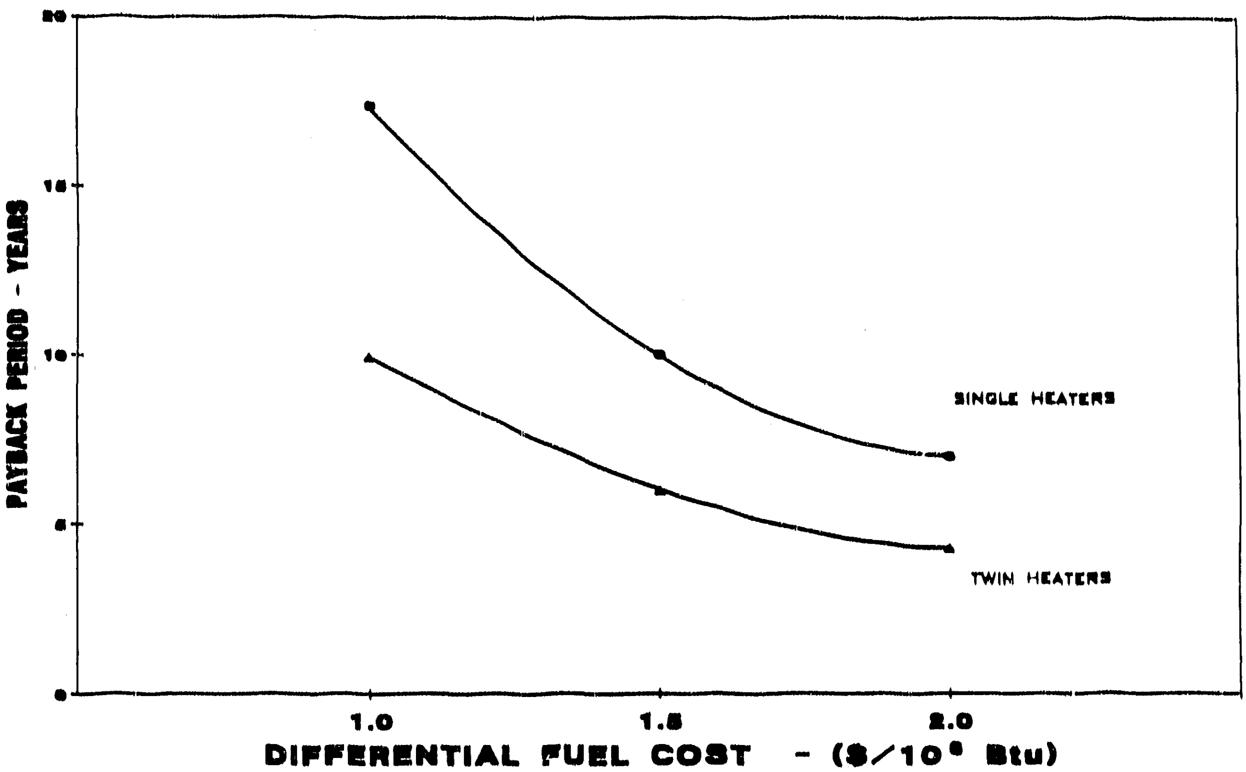


FIGURE 8-23
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT F
VERTICAL CYLINDRICAL

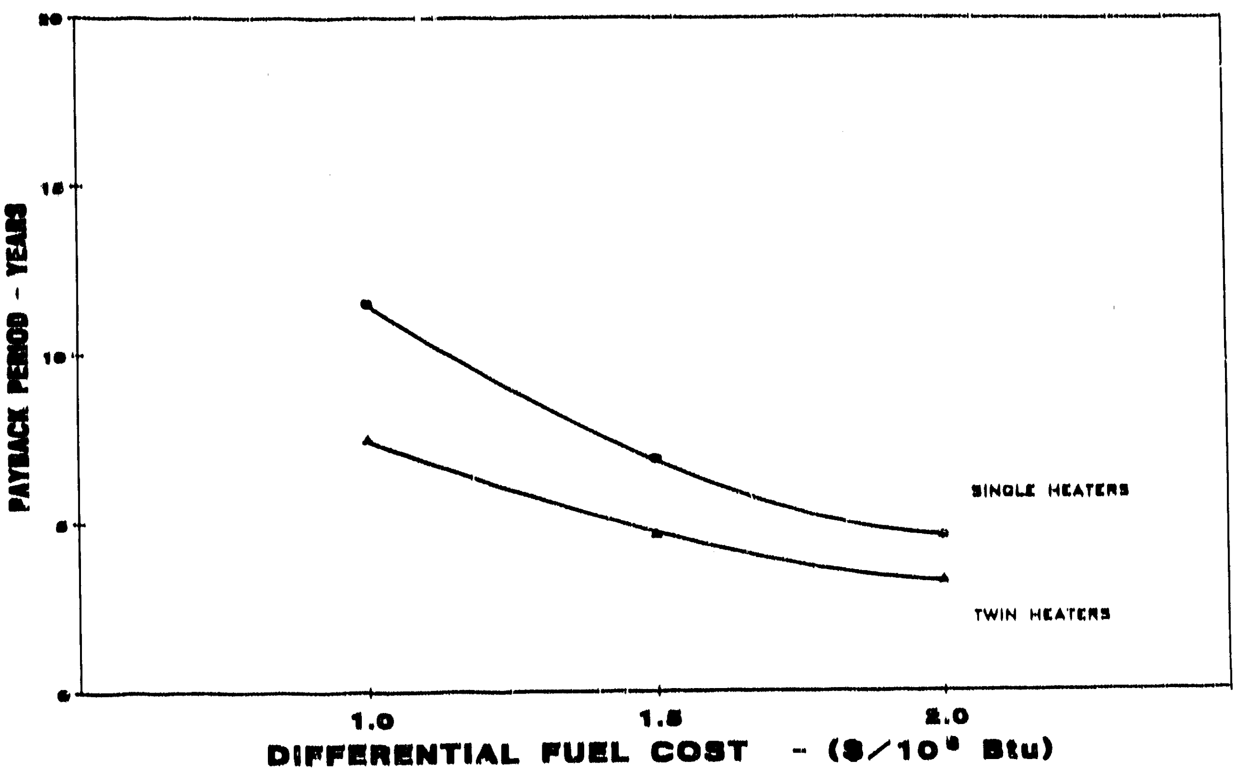


FIGURE 8-24
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT G
CABIN TYPE

heater with the smallest ($1.0/10^6 Btu) fuel cost differential. As the cost difference between CWF and fuel oil is presently closer to $1.0/10^6 Btu than $2.0/10^6 Btu the pay back period range is more likely from 7.6 to 17.6 years.

Four additional graphs, Figures 8-25 to 8-28, show the effects of the degree of heater availability with regard to fuel use. In these cases, it was assumed that the total availability of the heaters is still 95% (as used earlier), however, the availability to fire CWF and fuel oil with their corresponding fuel consumption is varied from 90% to 85% and to 80%. The payback periods for the heaters using these alternate availability factors are longer (between 10 and 45%) than the payback period for the heaters using the availability factor that was established as the basis of the study.

The other economic consideration in evaluating the modification of the selected heaters for CWF firing is unit downtime to make the modifications. The required modifications are extensive. For the horizontal cabin heater, the modification work to the heater that requires the heater to be out of service includes:

- Removal and replacement of all heater surface, tube supports and refractories in the radiant chamber.

- Replacement of the convection section.

- Installation of hearth ash hopper.

- Addition of radiant soot blowers.

- Relocation of heater burners and fuel system.

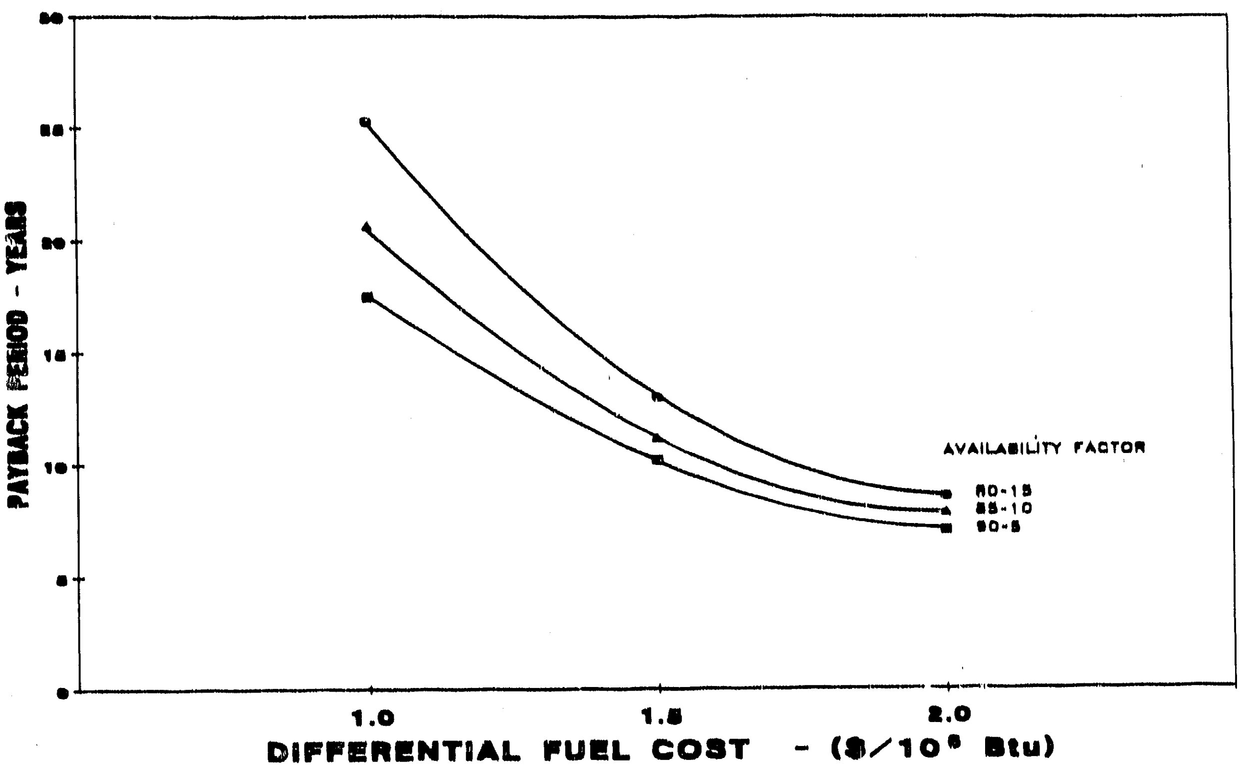


FIGURE 8-25
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT F
SINGLE HEATER VERTICAL CYLINDRICAL

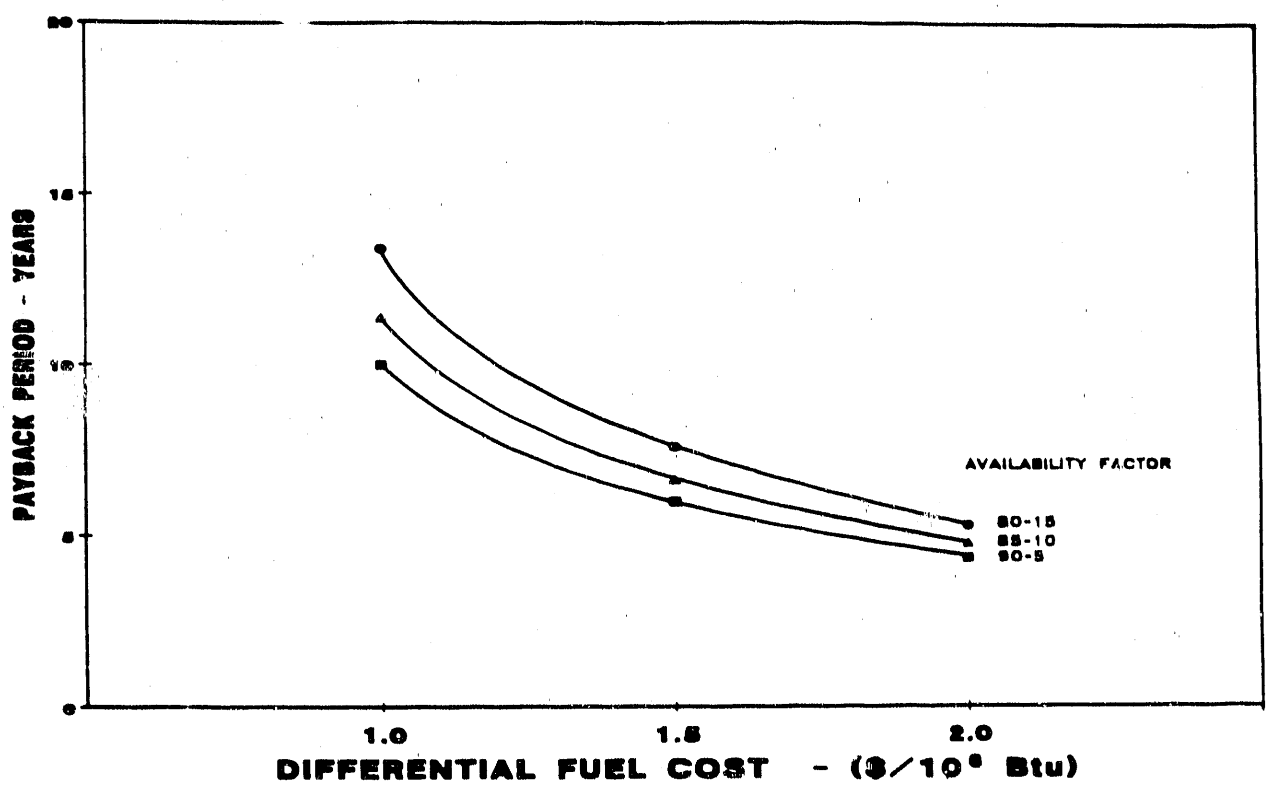


FIGURE 8-26
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT F

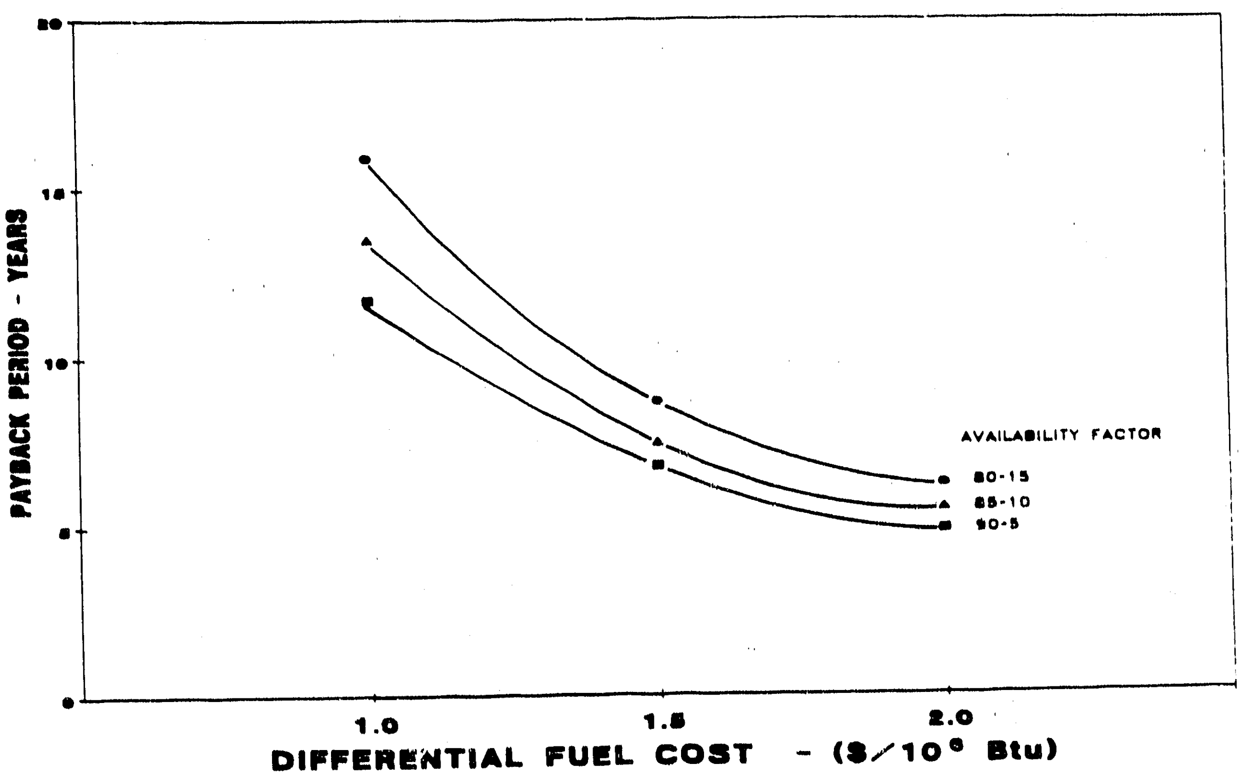


FIGURE 8-27
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT G
SINGLE HEATER CABIN TYPE

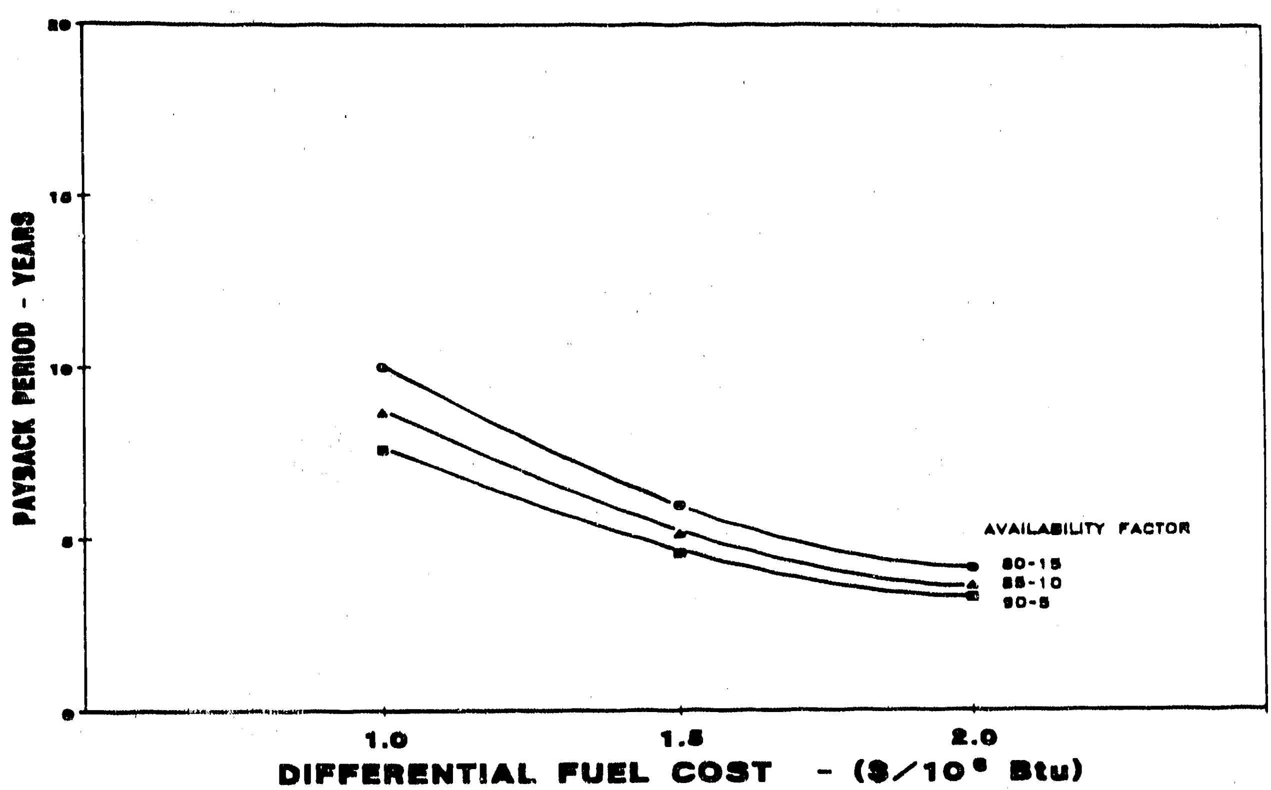


FIGURE 8-28
PAYBACK PERIOD VS. DIFFERENTIAL FUEL COST
UNIT G

These modifications would require at least two months of unit shutdown - more than a month longer than would be normally scheduled for a plant after a year or two of operation. In this particular case, this would result in the loss of production of over 1,140,000 barrels of product per heater that is converted. Using a typical $1/BBL average product to feedstock price differential, this would result in over a million dollars of lost profit for the plant per heater that is converted while ignoring any additional unit downtime costs. Although these potential profits are not included in the pay back period projections for each heater, they are, in these cases, significant and cannot be ignored in the overall evaluation for converting the heaters to CWF firing.

9. CONCLUSIONS

UNIT SELECTION

The seven units selected for this study represent generic designs widely found in public electric utility, industrial steam generator, or process unit applications. Their configurations and sizes represent a significant portion of possible CWF conversion candidates. They also meet the general selection criteria used to choose study units: (a) were originally designed for oil and/or gas firing (no "future coal" provision), (b) currently fire oil or other low ash fuel, and (c) have at least 20 years of plant life remaining.

PERFORMANCE ON CWF

Based on the laboratory test results obtained in the Task 1 through Task 5 studies, the firing of coal-water fuels in furnaces can be accomplished with currently available technology. The Task 6 performance calculations confirm the general technical feasibility of CWF operation (aside from economic feasibility). The Task 6 analysis also shows, however, that significant load reductions are often necessary if severe operating problems, such as erosion, fouling, slagging, and excessive carbon loss are to be avoided. In some cases load reduction was neither required, nor economically feasible, but questions as to reliability and availability are raised.

It is possible to predict performance in a consistent way, using the Guidelines developed as discussed in Section 4. The Performance Guidelines are based on laboratory results, and predicted load capabilities are intentionally somewhat conservative. Actual field operating experience with fouling, slagging, erosion behavior, and excess carbon loss, may permit relaxing some of the Guideline Limits and increasing the firing rate at a specific operating site. Thus the principal results given in Table 9-1 show (a) maximum load permitted by the Performance Guidelines, and (b) maximum load if the firing rate is permitted to increase by 20%.

TABLE 9-1 PERFORMANCE RESULTS ON CWF

UTILITY UNITS

Unit	Configuration	% Load to Grid (a) Max. CWF Load (%) (b) Max. CWF Load + 20% increase in firing rate	Comments
A	Close-coupled Screen	(a) 33 - 74 (b) 41 - 89	% - load-to-grid limits are very unit specific. Load loss picked up by other units
B	Box	(a) 30 - 50 (b) 38 - 62	
C	Close-coupled Arch	(a) 45 - 73 95 (extra clean coal) (b) 55 - 88 100 (extra clean coal)	
Average for all Utilities:		(a) 36 - 66 (b) 45 - 80	

INDUSTRIAL UNITS

Unit	Configuration	% Load to Grid (a) Max. CWF Load (%) (b) Max. CWF Load + 20% increase in firing rate	Comments
D	Type-A Shippable	(a) 23 - 30 (b) 28 - 36	Compact design of most industrial units results in low CWF loads. Load loss picked up by other units.
E	VU-60 Modular	(a) 33 - 54 (b) 40 - 65	
Average for both Industrials:		(a) 28 - 42 (b) 34 - 51	

PROCESS UNITS

Unit	Configuration	% Load	Comments
F	Vertical Cylindrical	100	Close to 100% availability is a prime requirement for most process heaters. No spare capacity.
G	Horizontal Cabin	100	

The performance calculations show that the cleaner coals permit higher loads due, for example, to higher Velocity Limits, higher Clear Space Temperature Limits, and improved ability to meet the SHO to RHO Temperature Differential Limits. On shop-assembled industrial units, furnace volume can limit load regardless of cleanliness of the CWF. For extra clean CWF's (e.g., SD2.6) it appears reasonable to increase the NHI/PA and Burner Zone Release Rate Guideline Limits and take advantage of higher Gas Velocity Limits permitted by the fuel.

The load limits determined for each of the utility units generally reflect specific details of each design, such as clear spaces or free gas areas at certain banks in the convection pass. These design details are unit-specific and do not necessarily represent the general characteristics of the three unit types studied. That is to say, for example, that is should not be assumed that all close-coupled arch units will be able to operate at higher CWF loads than box units. Likewise, it should not be assumed that all shippable industrial units will have lower CWF load limits than modular units.

The following conclusions, however, do appear justified:

- Utility units are more likely to have higher CWF load limits than industrial units.

- The principal load limiters for utility units are often clear space and gas velocity limits.

- The principal load limiters for industrial units are often furnace liberation or clear space limits.

- Process units are likely to be able to operate at their required 100% MCR ratings.

RETROFIT REQUIREMENTS

As a preliminary checklist of possible CWF conversion items, the following questionnaire may be useful:

- o Does existing economizer require replacement?
- o Does the design CWF require a new (or modified) particulate collection device?
- o Does the design CWF require a scrubber?
- o Does the existing furnace bottom require a slope change?
- o Do burner revisions require extensive windbox or pressure part work?
- o Are new fans required?
- o Is available site space limited?
- o Do higher than design steam temperatures occur when firing CWF which would result in above-design metal temperatures in a particular heat transfer section? If so, does the incremental improvement in load justify replacing the section with higher grade material?
- o If the Gas Velocity Limit, or Clear Space Temperature Limit in a particular heat transfer section affects derated load, is it (a) physically possible, and (b) economically justifiable, to open the tube transverse spacing perpendicular to the gas flow with a replacement section?

In general, the more of these questions that can be answered "No", the lower the scope of the CWF conversion work. This type of list should only be used as a preliminary screen, however, as design details can play a large role in determining the actual scope of work and resulting costs.

The scope of work involved in conversion of the units to CWF firing varies considerably from unit to unit and from fuel to fuel. Some utility boilers appear to be designed for a high ash oil and therefore have some aspects of a "future coal" design. This is the case with Unit C. The scope of work for the "boiler island" portion of Unit C is significantly less than for Units A or B, since it has a fairly steep furnace hopper slope, ash hoppers below the furnace, and an economizer which is suitable for CWF operation.

The presence of an existing particulate collection device (for example, the ESP's installed at the three utility plants) can significantly reduce the conversion work if the chosen CWF has such characteristics that the existing collection device can meet the local emission limits at the maximum CWF load. Likewise, if the sulfur content of the CWF produces SO_2 emission levels which are below local limits, no SO_2 scrubber would be required. For small industrial units or process units, installation of a wet scrubber can be considerably less costly than an ESP for particulate removal, even when the SO_2 removal feature is not required.

In retrofit work, the cleaner CWF's represent a potential cost saving in conversion site work. For example, there can be reduced or zero need for additions to existing ESP's. For low sulfur coal based CWF's, it is possible that environmental requirements can be met without adding SO_2 scrubber equipment. The cleaner fuels demand less extensive soot blower installation changes, and can reduce the need for possible heat transfer section configuration changes to allow higher gas velocities or clear space temperatures. The reduced list of conversion items means less scheduled downtime for a potential customer making a CWF conversion.

ECONOMIC EVALUATION

Of the three types of units studied, utility vs. industrial vs. process heaters, the economy-of-scale characteristic of utility units offers the best capital cost retrofit option for substantially reducing the amount of oil presently being fired. For the size ranges typical of industrial steam generators and hydrocarbon processing heaters, the retrofit capital costs appear to be quite high for the amount of oil potentially saved.

The variables which most strongly influence the economic feasibility of CWF conversion are load capability, retrofit capital costs, and DFC. Load capability is influenced by cleanliness of the CWF.

For the mid-1985 study period, the DFC between CWF and fuel oil is closer to the smallest value in the study than the highest ($1.00 and $2.00 per million Btu fired, respectively).

At the smaller DFC's, payback periods are more sensitive to load capability. For utilities able to operate at derated loads greater than 60% MCR, payback periods are usually under 10 years. At 80% or more MCR; paybacks period usually range from 1 to 5 years for the case studied. For industrial units, payback periods are extremely sensitive to the operating mode. In general, the Case II (CWF used for 50% - oil at MCR used other 50% of time) operating mode payback periods are 2 to 3 times longer than for Case I (CWF used for 100% of operating time). The shorter Case I payback periods range from about 2 to 20 years depending on the DFC and derated load capability.

An industrial unit conversion is about 1.5 to 2 times more costly than a utility unit conversion when comparing capital costs on an equivalent basis ($ per million Btu/hr fired, for example). Thus the large utility units have a significant economy of scale.

The specific capital required to convert utility units ranges from about $60 to $420 per kilowatt of derated capacity, or between about $60 to $140 per kilowatt of nameplate capacity. For industrial units, specific capital requirements for conversions range from about $40 to $125 per lb/hr steam derated output, or from $25 to $32 per lb/hr steam of nameplate capacity.

There is little economic incentive for converting modern industrial process heaters to CWF firing. The required changes to modify existing process heaters to CWF firing are costly, and the amount of oil saved for the amount of investment is small compared to large utility boilers.

The payback period for the most favorable modification case (modification to the larger selected heater in the study with the largest DFC) is almost double the payback period considered acceptable (1.5 to 2 years) in the hydrocarbon processing industry. The payback period for the least favorable modifications case (modifications of the smaller heater in the study with the smallest DFC) is almost nine times the acceptable payback period.

The levelized analysis for the utility units firing CWFs indicates significant savings in levelized cost of electricity. Changes in load capability and DFC affect this evaluation parameter. For example, at $1.00 per million Btu DFC, every 10 percentage point increase in load capability provides about a 5 mill per kilowatt hour additional cost-of-electricity savings. At 50% MCR load capability, levelized cost-of-electricity savings of about 10 to 15 mills per kilowatt hour are predicted. In contrast, at $2.00 per million Btu DFC, and 50% MCR load capability, levelized cost-of-electricity savings range from about 21 to 29 mills per kilowatt hour, and every 10 percentage point load increase adds about 7.5 mills per kilowatt hour to the savings.

In general, on Units A, B, C, and Case I Unit E, the two cleanest fuels, SD5.7 and CG4.8 (and SD2.6 for Unit C), become economically attractive at $1.50 DFC or higher, at which point the payback periods fall to about four years or less. At $2.00 DFC, all the fuels are attractive for Unit C, but for Units A and B, the UF6.8 CWF can only become marginally attractive if the firing rate can be increased by 20%.

The CG7.9 fuel is only marginally attractive on Unit A, and could at best become only marginally attractive on Unit B if the firing rate could increase 20%. The microfine AL5.9 fuel results for Units A, C, and E generally lie between those of the cleaner fuels, SD5.7 and CG4.8, and the dirtier fuels, UF6.8 and CG7.9.

The overall analysis clearly shows that conversion to CWF's generally becomes uneconomic under almost any circumstances when the DFC approaches and goes below $1.00 per million Btu. An exception to this statement is illustrated in the case of Unit C in which the four cleanest fuels were capable of attaining greater than 70% MCR. Three of these fuels had payback periods of 2-1/2 years or less at a DFC of $1.00 per million BTU. The extra clean fuel, SD2.6, had a payback period of 1.8 years at the DFC of $1.00 per million Btu, illustrating the potential benefits of its special preparation prior to burning. These results were obtained without the provisional 20% firing rate increase. An analysis of fuel processing costs indicated the costs of cleaning either the Cedar Grove or Splash Dam coals to low ash levels were more than justified by more economical operation of utility units.

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APPENDIX

SUMMARY OF
COAL-WATER FUEL COST ESTIMATES
FOR COMMERCIAL CASES

INTRODUCTION

This report covers the work conducted as Subtask No. 6.5.4, in support of the Combustion Engineering/Gulf Research & Development Company research project under DOE Contract No. DE-AC22-82 PC50271. The overall objective of this project is to provide sufficient data on coal-water fuel (CWF) properties in order to assess the potential for commercial firing of this fuel in furnaces designed for oil. The objective of Subtask 6.5.4 is to develop orientation economics for CWF production, based on coals identified in the test program as being technically suitable.

In order to evaluate the commercial feasibility of using CWF's in utility boilers and other applications, assuming technical feasibility, it is necessary to develop estimates of the probable cost of commercially producing these fuels. Costs are estimated in terms of dollars per million Btu's delivered to the ultimate user. Raw coal cost and transportation are based on the assumption that the CWF plant is located close to the coal source and to a market for the by-product steam coal. Two cases are considered for each coal, a low ash case (approximately 2% ash) and a high ash case (approximately 7% ash). The marketing of by-product coal to a nearby steam plant appears to be an essential part of the overall economics of manufacturing low ash CWF via the cleaning circuit used in this evaluation.

SELECTION OF COALS FOR COMMERCIAL CASES

Table I shows the guidelines developed under Tasks 1 and 3 for coal selection from environmental, combustion, ash fouling and boiler life considerations(1). Based on CWF preparation experience with a larger number of coals under Task 3 of this project, the following coals were

TABLE I

CWF Feed Coal Properties (Beneficiated)(1)

Sulfur	1.2 lb SO_2/mm Btu 0.8% sulfur @ 13.300 Btu/lb
Ash	2%
Volatile Matter	>29%
Moisture	7%
Heating Value	13,500 Btu/lb
Fuel Ratio (FC/VM)	<2.2
TGA	7 minutes for 99% burnout
Flammability Index	1000°F
Ash Properties:	
Softening Temperature	2300°F (reducing atmosphere)
Fluid Temperature	2500°F (reducing atmosphere)
Free Quartz (% of ash)	25% Maximum
Sodium Content (% of ash)	2% Maximum
Slurrability	Vendor approval

selected as suitable for commercially manufacturing CWF that meets the required slurrability, storage, handling and combustion criteria(2):

- Cedar Grove
- Splash Dam
- Upper Freeport

The run-of-mine characteristics of these coals are shown in Table II. Washability characteristics indicate that the coals can be cleaned by conventional beneficiation processes down to nominal 2% ash levels(3). For this project actual ash levels varied from 2.17% to 3.77%. Coarse cleaning of the coals at 1-1/2 inches x 0 size and about 1.6 specific gravity (to approximately 7% ash) removes enough ash to produce a steam quality coal product, as well as a coal suitable for the high ash CWF cases (Table III). After crushing and screening the coals to 3/8 inch x 28 mesh size, they can be cleaned at about 1.3 specific gravity to the range of 2% ash, acceptable for low ash CWF manufacturing (Table IV).

CWF MANUFACTURING PLANT DESIGN BASIS

Previous studies have shown that the minimum capacity for economic production of CWF is 20,000 bbl/day of the product(4). Based on the results of vendor experience with CWF preparation under Task 3 of this project, a solids concentration of 68 wt% in the product is used as the basis for estimating cleaned coal requirements.

Table V shows the material balance for the three coals during cleaning to the high ash and low ash levels for CWF manufacture. In order to minimize the overall cost of CWF production, all coals are first coarse cleaned by the less expensive heavy media vessel cleaning method. The product of coarse cleaning is then further cleaned in a heavy media cyclone to produce the feed for the low ash CWF preparation. The reject from this second cleaning step has a high heating value (>14,000 Btu/lb on a dry basis) and an ash content from 8% to 11 wt% and is, therefore, suitable for sale as steam coal to coal burning boilers. The fines resulting from grinding (approximately 8% of the feed coal) are cleaned separately and added to the steam coal.

TABLE II

Characteristics of Run-of-Mine Coals
(Dry Basis)

COAL SEAM	ASH, Wt %	VM, Wt %	SULFUR Wt %	HEATING VALUE, Btu/lb
Cedar Grove	14.86	36.00	0.86	12,879
Splash Dam	18.41	27.15	0.57	12,563
Upper Freeport	19.90	32.34	1.18	12,697

TABLE III

Estimated Heavy Media Vessel Cleaning Recoveries

Specific Gravity of Separation: 1.6

1-1/2 inch x 0 Size, Dry Basis

COAL TYPE	RECOVERY, Wt %	ASH, Wt %	HEATING VALUE, Btu/lb
Cedar Grove	89	6.7	14,244
Splash Dam	84	7.1	14,548
Upper Freeport	68	7.1	14,429

TABLE IV

Estimated Heavy Media Cyclone Cleaning Recoveries

Specific Gravity: 1.3

3/8 inch x 28 Mesh, Dry Basis

COAL TYPE	RECOVERY, Wt %	ASH, Wt %	HEATING VALUE, Btu/lb
Cedar Grove	52	3.0	14,860
Splash Dam	35	2.2	15,407
Upper Freeport	30	3.8	14,927

TABLE V

Material Balance

COAL TYPE	RUN-OF-MINE	TO HEAVY MEDIA VESSEL CLEANING	TO HEAVY MEDIA CYCLONE CLEANING	TO STEAM COAL MARKET	REFUSE	TO CWF PLANT
Cedar Grove						
(Low)	386	355	317	162	41	183
(High)	223	205	-	16	24	183
Splash Dam						
(Low)	565	520	440	296	86	183
(High)	235	216	-	16	36	183
Upper Freeport						
(Low)	672	618	423	277	212	183
(High)	291	268	-	16	92	183

PROCESS DESCRIPTION

Figure 1 shows a flow diagram of the low ash CWF manufacturing process, including coal cleaning. For the high ash CWF option, the heavy media cyclone cleaning and centrifugal drying steps are omitted. The cleaning equipment for each type of coal is sized according to the coal's washability characteristics in order to provide a cleaned coal feed rate of 183 tons/hr to the CWF preparation section. This rate provides for the production of 20,000 bbl/day of CWF containing 68 wt% coal. In accordance with commercial coal preparation industrial practice, the CWF manufacturing plant is assumed to operate 2 shifts/day for 250 days/year.

The cleaning plant is assumed to be located near the mine site, with trucks used to deliver run-of-mine (ROM) coal. The ROM coal is emptied from the trucks into a hopper from which it is transferred to a belt conveyor via feeders. The design of the unloading facility is based on the tonnage requirements, the bulk properties of the coal, and the use of trucks(5). The design of the receiving hoppers calls for a minimum slope angle of 50 degrees from the horizontal. However, as the moisture content or the percentage of fines in the coal increases, the slope should be increased to 60 degrees or more. Hoppers are lined with an abrasive-resistant material, such as stainless steel, to minimize wear and maintenance. Coal from the hoppers is conveyed to a set of crushers for reducing the size to 1-1/2 inches top size. Figure 2 shows a mechanical flow diagram of a typical double roll crusher system used for such applications.

The ROM coal is received on a raw coal conveyor which discharges onto a fixed grizzly to remove the 1-1/2 inch x 0 material. A tramp iron magnet protects the downstream crushing equipment. Plus 1-1/2 inches oversize material from the grizzly is reduced to minus 1-1/2 inches in two-stage double-roll crushers and combined with the natural 1-1/2 inch x 0 material on a crushed coal conveyor. The crushed coal is stored in a conical ground storage facility.

Approximately 8% of the raw coal crushed to 1-1/2 inches top size is finer than 28 mesh in size and is difficult to clean in a heavy media circuit. The fine coal is, therefore, separated from the coarse coal in a wet

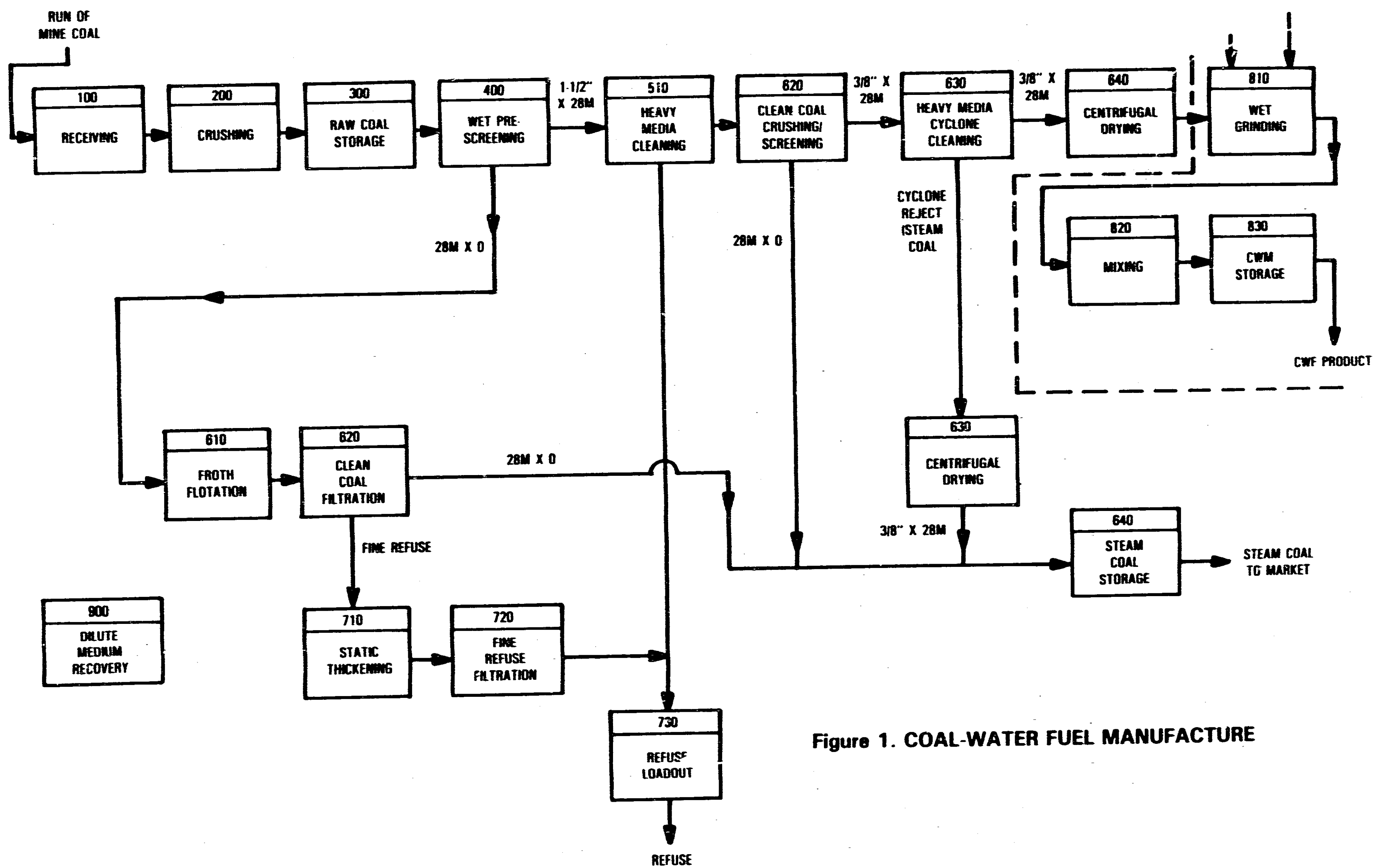

Figure 1. COAL-WATER FUEL MANUFACTURE

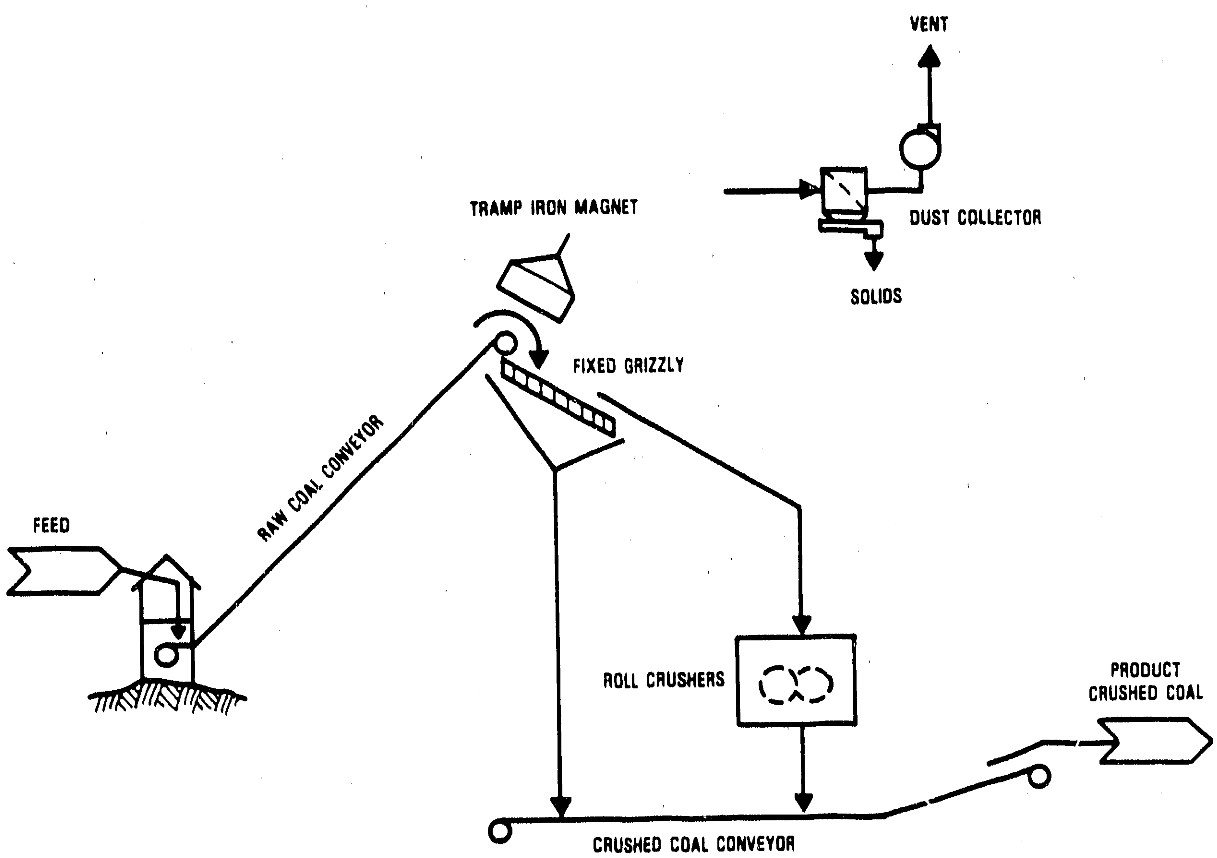

Figure 2. A TYPICAL RAW COAL CRUSHING CIRCUIT[8]

screening circuit and sent to a froth flotation unit for cleaning. Feed slurry to the flotation cells contains between 3% to 15% solids, depending on the particle size distribution and the raw coal characteristics. Flotation capacities range from 2.2 to 2.4 gpm per cubic foot of cell volume with about three minutes retention time in the cells. Clean coal, with about three minutes retention time in the cells. Clean coal, consisting of 28 mesh by 0 size, is mechanically skimmed off as an aerated froth, usually at 20% to 30% solids. The commonly used reagents are methylisobutyl carbinol (MIBC) as a frother at 0.1 to 0.5 lb per ton of solids and, depending on the type of coal, kerosene or fuel oil as a collector at 0.5 to 2 lb per ton of solids.

The 1-1/2 inch x 28 mesh coal from the wet screening circuit is sent to heavy media vessels for coarse cleaning to about 7% ash. As the presized and prewetted feed enters the cleaning circuit, particles lighter than the specific gravity of the media rise to the surface and overflow the weir with a small amount of dense media. Particles heavier than the specific gravity of the media sink to the bottom of the bath, where they are removed continuously by a slow moving flight conveyor. The trough-type units typically operate at feed rates of 20 to 25 tph per foot of overflow weir width. Recommended recirculating media rates range from 200 to 260 gal/min per foot of width. Figure 3 shows a typical heavy media separation circuit.

The cleaned coal from the coarse cleaning circuit is crushed to 3/8 inch top size, either for further cleaning in a heavy media cyclone circuit if it is desired to produce a low ash. CWF, or for feeding to wet grinding if high ash CWF is desired. For fine-size, difficult-to-clean coals with near gravity material about 10%, the heavy media cyclone has proven to be one of the most efficient cleaning tools(5). Heavy media cyclones are extensively used for coal within the 1-3/4 inch to 28 mesh size range. Recently, these cyclones have been used for cleaning without removing the minus 28 mesh coal. Figure 4 shows a mechanical flow diagram of a heavy media cyclone system.

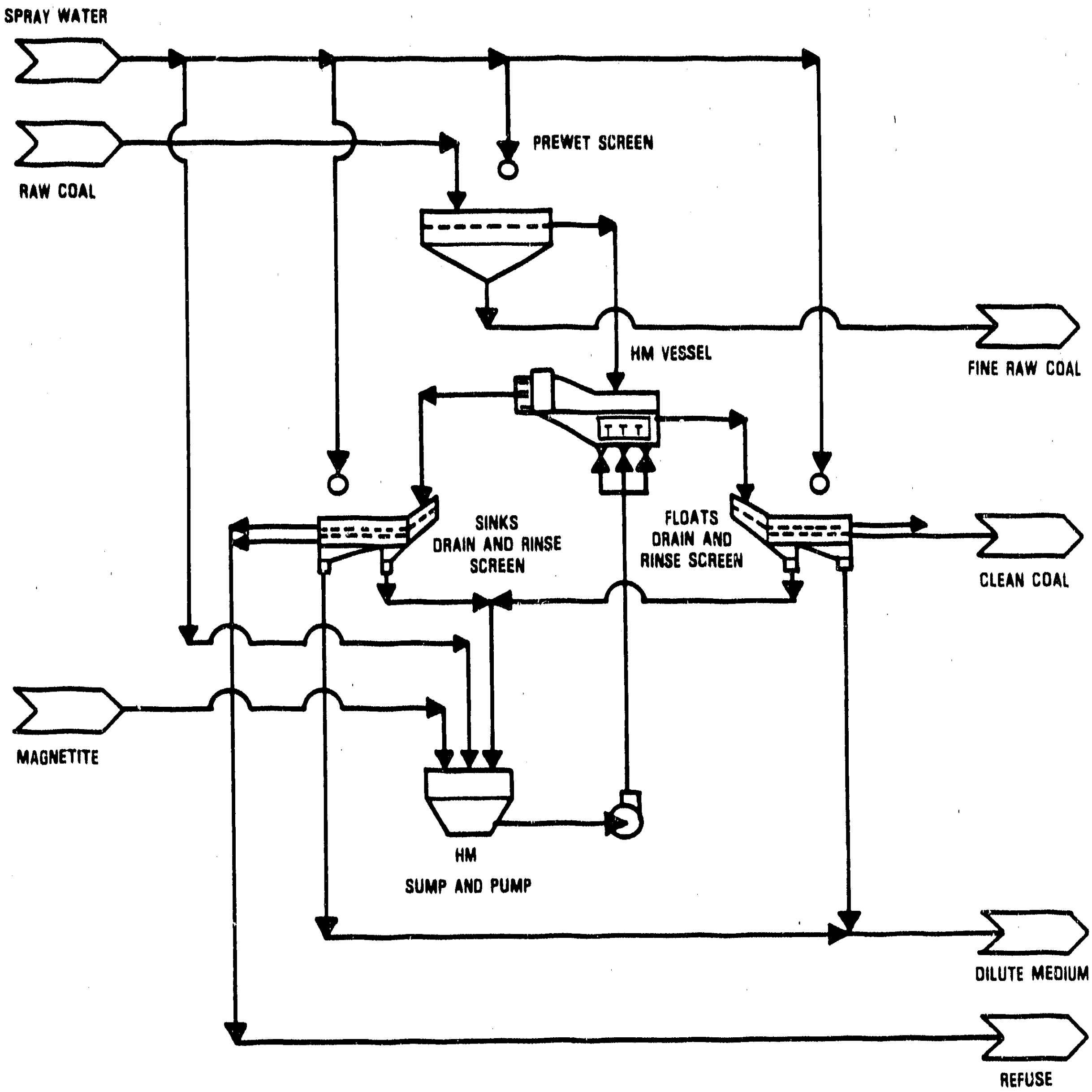

Figure 3. A TYPICAL HEAVY MEDIUM VESSEL SYSTEM[a]

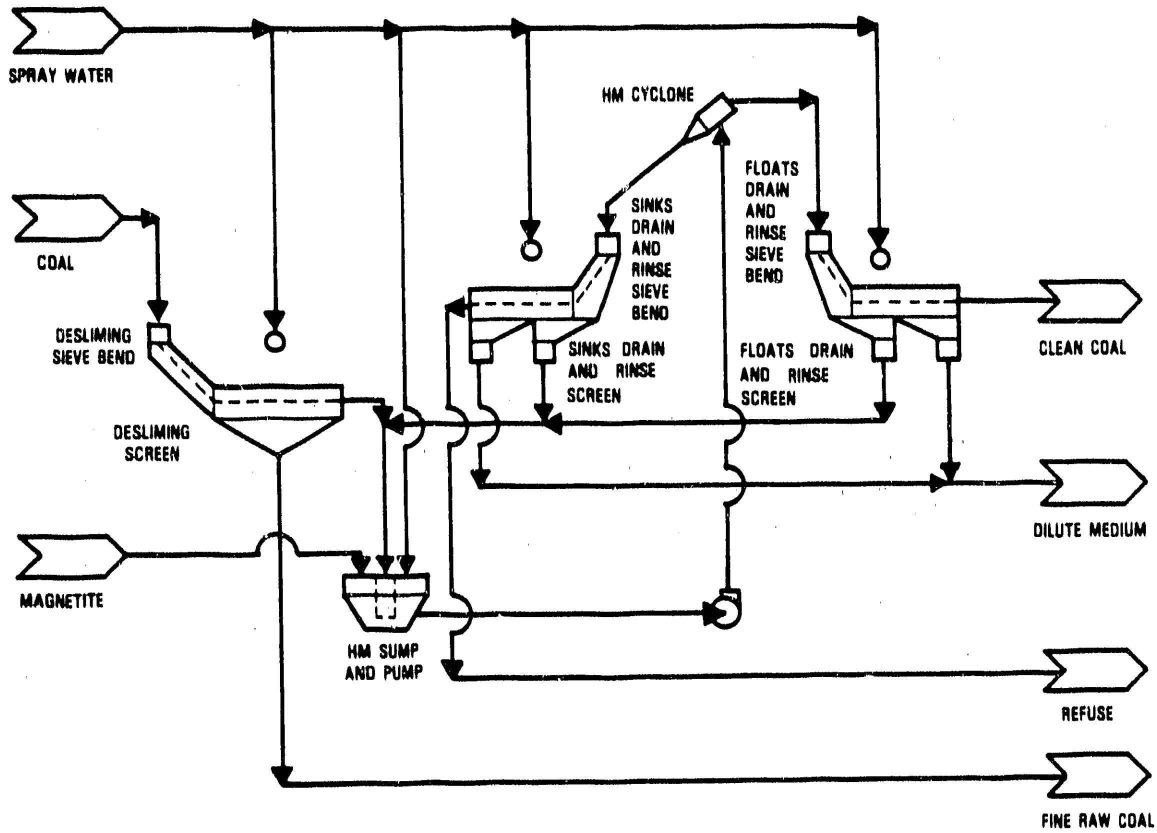

Figure 4. HEAVY MEDIUM CYCLONE-MECHANICAL FLOW DIAGRAM[8]

The feed to the cyclone generally consists of 5 parts of magnetite by weight for each part coal. About 75% of the media fed to the cyclone reports with the overflow and 25% with underflow. The solid split between the underflow and overflow for the chosen specific gravity of separation is calculated using washability data. The cleaned coal product from the heavy media cyclones is dewatered by centrifuges before grinding to 200 to 325 μm size for CWF preparation. The reject stream from the heavy media cyclones is dewatered and mixed with the cleaned coal produced by froth flotation and sold as steam coal to a nearby customer.

CWF Preparation

Cleaned and dewatered coal from the heavy media cyclone circuit can be transported by truck, barge or train to the user's site for CWF preparation or processed to CWF at the cleaning plant location. Economics (see Table X) are presented for both of these cases assuming the user is 500 miles from the coal mine.

In the CWF Preparation section, the clean coal is first ground to the particle size distribution specified in Table I (90% minus 200 mesh and up to 30% less than 10 microns). Closed circuit wet grinding is used, because it consumes 30% less energy than dry grinding(6). In this process, the oversized particles produced by wet grinding in the ball mill are separated from the fine particles and recycled through the grinder. A hydraulic classifier is used for the size separation.

The product from the grinding circuit is conveyed to mixing tanks into which CWF additives and makeup water are added. The final CWF product is stored in holding tanks before it is loaded into tank cars for shipment to consumers.

COST ESTIMATES

Basis of Estimates

Capital investment and operating costs for the process units are estimated from published data(5,6). Based on experience with costs in the coal preparation industry, an exponential scale factor of 0.85 is used for converting published capital investments to the required capacities.

The total constructed capital investment estimate consists of direct plant cost, construction related indirect cost, engineering services, contingencies and interest on capital during construction. The direct cost comprises equipment, piping, instrumentation, electrical and civil structures. The indirect costs include field labor, temporary construction facilities, construction equipment and supplies, and miscellaneous construction services.

Annual maintenance labor and materials costs are calculated at 4% of total capital investment. General administration, insurance, and property taxes are calculated at 3% of capital investment. Labor, materials and utilities are estimated based on the process design, and supervision was calculated at 37% of operating labor.

Results and Discussion

Table VI shows a breakdown of constructed capital cost for cleaning the three coals to two different ash levels. A major part of the capital investment is for the heavy media circuit that is necessary to reduce ash levels to about 7% to 8%. The total cleaning plant cost depends on the washability characteristics of the coal selected and, consequently, on the material balance shown in Table V. The highest capital cost is for Upper Freeport coal, at $45.8 Million for the low ash case and $22.7 Million for the high ash case. Cedar Grove requires the least capital at $30.8 Million for the low ash case and $14.8 Million for the high ash case.

The capital costs for processing 183 tph of the cleaned coal to CWF are shown in Table VII. The total constructed capital cost is $26.3 Million and represents 35% to 65% of the total cost of the combined plant, including cleaning for the three coals.

Table VIII shows the operating and maintenance (O&M) costs for coal cleaning and CWF manufacturing. The cost of raw coal accounts for about

TABLE VI

COAL CLEANING PLANT CAPITAL COSTS
(Mid-1985, $1000's)

DIRECT COSTS:	CEDAR GROVE Low	CEDAR GROVE High	SPLASH DAM Low	SPLASH DAM High	UPPER FREEPORT Low	UPPER FREEPORT High
Raw Coal Receiving	1,223	844	1,674	1,155	1,901	1,311
Raw Coal Crushing	1,274	879	1,744	1,203	1,980	1,366
Raw Coal Storage	1,834	1,265	2,511	1,732	2,851	1,967
Wet Prescreening	735	507	1,006	694	1,142	788
H. M. Vessel Cleaning	1,519	1,048	2,079	1,434	2,361	1,629
Clean Coal Crushing	99	68	133	92	125	86
H. M. Cyclone Cleaning	3,409		4,578		4,321	
Centrifugal Drying-Clean Coal	131		131		131	
Refuse Loadout	107	67	164	78	361	177
Dilute Medium Recovery	786	286	1,056	297	997	314
Centrifugal Drying-Steam Coal	98		176		159	
Steam Coal Storage	814	113	1,409	118	1,317	116
Static Thickener	519	358	710	490	806	556
Froth Flotation	339	234	465	321	528	364
Clean Coal Filtration	849	586	1,171	808	1,321	911
Refuse Filtration	170	117	218	150	263	181
Belt Conveying	1,351	932	1,850	1,276	2,100	1,448
Total Direct Costs	15,257	7,303	21,075	9,846	22,664	11,215
Indirect Costs	3,891	1,862	5,374	2,511	5,789	2,860
Total Field Construction Cost	19,148	9,166	26,449	12,357	28,443	14,074
Engineering Services	2,872	1,375	3,967	1,854	4,266	2,111
Contingency	5,505	2,635	7,604	3,553	8,177	4,046
Interest During Construction Owner's Costs	3,303	1,581	4,562	2,132	4,906	2,428
Total Constructed Capital Cost	30,828	14,757	43,583	19,895	45,795	22,660

TABLE VII

Capital Costs for CWF Manufacturing Process
(Mid-1985, $1000's)

Direct Costs:	
Wet Grinding and Mixing	8,771
CWF Storage	4,241
Total Direct Costs	13,012
Indirect Costs	3,318
Total Field Construction Costs	16,330
Engineering Services	2,450
Contingency	4,695
Interest During Construction	2,817
Total Constructed Capital Costs	26,291

TABLE VIII

Operating and Maintenance Costs

(Mid-1985, $\$10^6$/Year)

	COAL CLEANING COSTS						
	CEDAR GROVE		SPLASH DAM		UPPER FREEPORT		CWF PREPARATION COST
ASH LEVEL:	Low	High	Low	High	Low	High	
Raw Material							
Coal at $1.65/Million Btu	65.66	37.87	93.71	38.94	112.62	48.74	--
Preparation							
Electricity @ 5c/kwh	0.66	0.38	0.96	0.40	1.12	0.48	0.15
Number of Operators/Shift	(10)	(9)	(10)	(9)	(10)	(9)	(7)
Fixed O&M Cost							
Operating Labor Cost	0.54	0.49	0.54	0.49	0.54	0.49	0.38
Maintenance Labor, Materials	1.23	0.59	1.70	0.80	1.83	0.91	1.05
General Adm. Cost, Insurance, Property Tax	0.92	0.44	1.28	0.60	1.37	0.68	0.79
Supervision	0.20	0.18	0.20	0.18	0.20	0.18	0.14
Variable O&M Cost							
Magnetite @ 0.5 lb/T Feed to H. M. Vessel	0.04	0.02	0.05	0.02	0.06	0.03	--
H. M. Cyclone @ 1.5 lb/T Feed	0.10	--	0.13	--	0.13	--	--
Flotation Reagents	0.03	0.02	0.05	0.02	0.05	0.02	
Water	0.04	0.02	0.05	0.02	0.07	0.03	0.02
Dispersant & Stabilizer							10.20
pH Control							2.93
Grinding Plant Wear							0.15
Solid Waste Disposal	0.22	0.13	0.47	0.20	1.10	0.50	
Total O&M Costs	69.64	40.14	99.15	41.66	119.10	52.05	15.81

95% of the total O&M costs for coal cleaning. Upper Freeport has the highest O&M cost of $119.1 Million per year, because of the low yield of cleaned product. The O&M costs for the CWF preparation section are $15.8 Million per year and account for 10% to 30% of the total O&M costs. Dispersants and stabilizers cost $10.2 Million/yr and account for the major part of the CWF manufacturing costs.

The overall cost of CWF manufacturing, including coal cleaning, is summarized in Table IX. Total capital costs for the three coals range from $41 to $72 Million. Operating and maintenance costs range from $56 to $135 Million per year. By selling the refuse from coarse cleaning as steam coal, a by-product credit of $3 to $55 Million per year may be realized. The highest credit is received for Splash Dam coal. The capital charge of 18.60% represents a construction period of 3 to 5 years, 12% return on investment at 100% equity financing, accelerated tax-based depreciation, an investment tax credit of 10%, a plant operating life of 20 years and an income tax rate of 50%.

The cost of manufactured CWF ranges from $2.91 to $4.43 per Million Btu. Of the coals used in this study, the Cedar Grove coal is the most economically attractive for CWF manufacture.

<u>Delivered Costs</u>

Transportation of cleaned coal by unit train or barge is more economical than transportation of manufactured CWF in tank trucks. In this study it is assumed that either cleaned coal or CWF is transported 500 miles from Appalachian coal fields to the user's site in New England or Florida. Table X shows a comparison of the effect of the two transportation options on delivered CWF cost. Transportation of manufactured CWF may be the only option available when a manufacturer supplies CWF to a number of users from a central plant. The cost of delivered CWF in such cases ranges from $4 to $6 per million Btu.

If the CWF is manufactured on site, the cost is reduced to $3.50 to $5 per million Btu, after transportation of cleaned coal by train or barge.

TABLE IX

Coal Cleaning Plant Capital Costs
(Mid-1985, $1000's)

	COAL TYPE					
	CEDAR GROVE		SPLASH DAM		UPPER FREEPORT	
ASH LEVEL:	Low	High	Low	High	Low	High
Total Capital Cost, Coal Cleaning	30.83	14.76	42.58	19.89	45.79	22.66
CWF Plant (183 T/hr. coal)	26.29	26.29	26.29	26.29	26.29	26.29
Total	57.12	41.05	68.87	46.19	72.09	48.95
	$ MILLION/YR.					
Annual Costs, Coal Cleaning						
- O&M, including Coal Cost	69.64	40.14	99.15	41.66	119.10	52.05
- CWF Plant (20,000 bbl/day)	15.81	15.81	15.81	15.81	15.81	15.81
Total O&M	85.45	55.94	114.96	57.47	134.91	67.86
By-Product Credit (Steam Coal)	(29.24)	(2.99)	(55.15)	(3.06)	(51.90)	(3.03)
Capital Charge at 18.60%	10.62	7.63	12.81	8.59	13.41	9.10
Total Costs	66.84	60.59	72.62	63.00	96.42	73.93
CWF Cost, $/10^6 Btu	3.06	2.91	3.24	2.99	4.43	3.56

TABLE X

Delivered Cost of CWF
($ per Million Btu)

TYPE OF COAL	MANUFACT. CWF COST	CLEANED COAL TRANSPORTATION[1] TRAIN TRANSP. COST[1]	CLEANED COAL TRANSPORTATION[1] CWF COST F.O.B. PLANT	CLEANED COAL TRANSPORTATION[2] BARGE TRANSP. COST[2]	CLEANED COAL TRANSPORTATION[2] CWF COST F.O.B. PLANT	CWF TRANSPORTATION TRANSP. COST[3]	CWF TRANSPORTATION DELIVERED CWF COST	BOTH COAL AND CWF TRANSP.[1,3]	BOTH COAL AND CWF TRANSP.[2,3]
Cedar Grove:									
- Low Ash	3.06	0.59	3.65	0.30	3.36	1.29	4.35	4.94	4.65
- High Ash	2.91	0.61	.3.52	0.31	3.22	1.34	4.25	4.86	4.56
Splash Dam:									
- Low Ash	3.24	0.57	3.81	0.29	3.53	1.24	4.48	5.05	4.77
- High Ash	2.99	0.60	3.59	0.31	3.30	1.31	4.30	4.90	4.61
Upper Freeport:									
- Low Ash	4.43	0.59	5.02	0.30	4.73	1.28	5.71	6.30	6.01
- High Ash	3.56	0.61	4.17	0.31	3.87	1.32	4.89	5.49	5.19

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[1] 500 miles by train at $0.035/ton-mile of dry coal.

[2] 500 miles by barge at $0.0179/ton-mile of dry coal.

[3] 500 miles at $26.00/ton of CWF.

CONCLUSION

Cost estimates for the manufacture and delivery of coal-water fuels in commercial cases have been developed in this study. Three coals at two ash levels are considered. Cost estimates are presented for transportation of coal and CWF. Of course, transportation distance of both the coal and the CWF must be minimized in the interest of economy.

The marketing of by-product coal to a steam plant is essential to the overall economics of selling low ash CWF. Capital costs for manufacturing CWF range from $41 to $72 Million, depending on the source coal. Annual operating and maintenance costs range from $56 to $135 Million. This results in a range of costs for CWF from $2.91 to $4.43 per million Btu, excluding the costs of transportation.

Among the transportation options considered, barge transportation of cleaned coal is the least expensive. The lowest cost case is that of CWF from Cedar Grove high ash coal ($3.22 per million Btu, delivered).

In situations where a CWF manufacturer has to transport cleaned coal to a central location and then transport CWF by tank-trucks to a number of industrial customers, the total delivered cost of CWF may range as high as $5.00 to $6.30 per million Btu.

The highest cost of delivered CWF is represented by the Upper Freeport low ash case ($6.30 per million Btu, when both coal and CWF are transported).

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