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COAL BASED ELECTRIC GENERATION COMPARATIVE TECHNOLOGIES REPORT

October 26, 1989

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By
Stone & Webster Management Consultants, Inc.
Houston, Texas

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For

Ohio Clean Fuels, Inc.
(DOE CLEAN COAL TECHNOLOGY I PROJECT)

Department of Energy
Cooperative Agreement
No. DE-FC22-88PC79797

Stone & Webster Management Consultants, Inc.
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October 26, 1989

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EXECUTIVE SUMMARY

Ohio Clean Fuels, Inc. (OCF) has licensed technology that involves Co-Processing (Co-Pro) poor grade (high sulfur) coal and residual oil feedstocks to produce clean liquid fuels on a commercial scale. These liquid fuels can be used in many applications, including electric power generation. Stone & Webster is requested to perform a comparative technologies report for grassroot plants utilizing coal as a base fuel and assume all the technologies considered are mature technologies. In the case of Co-Processing technology the plant considered is the nth plant in a series of applications. This report presents the results of an economic comparison of this technology with other power generation technologies that use coal.

The technologies evaluated were:

- Co-Processing integrated with simple cycle combustion turbine generators, (CSC)
- Co-Processing integrated with combined cycle combustion turbine generators, (CCC)
- Pulverized coal-fired boiler with flue gas desulfurization and steam turbine generator, (PC)
- Circulating fluidized bed boiler and steam turbine generator, (CFB)

Conceptual designs for each technology were developed. For comparative purposes, the designs were based on approximately equivalent net electrical outputs for each technology. A base case of 310 MWe net for each technology was established. Sensitivity analyses at other net electrical output sizes varying from 220 MWe's to 1770 MWe's were also performed.

For the base case, the CSC uses 83,607 pounds per hour of distillate utility fuel and 28,610 pounds per hour of naphtha and is composed of a Co-Processing unit with fuel storage facilities, and two 160 MWe combustion turbine generator sets. The CCC utilizes the same size Co-Processing unit and one 160 MWe combustion turbine generator set, one heat recovery steam generator, and a 171 MWe steam turbine. The PC consists of a pulverized coal-fired boiler, 351 MWe single reheat steam turbine, a wet limestone flue gas desulfurization system, an electrostatic precipitator, and ash and sludge handling and disposal facilities. The CFB includes three 125 MWe circulating fluidized bed boilers, a 349 MWe single reheat steam turbine, a fabric filter particulate removal system, and ash and limestone handling and disposal facilities. All technologies studied included coal handling facilities for Ohio No. 5 and No. 6 coals. In addition, the Co-Processing plant requires pipeline tie-in connections for Cold Lake blend crude oil and natural gas.

Estimates of capital, operating and maintenance costs were developed for each technology in accordance with EPRI Technical Assessment Guidelines (EPRI-TAG). The Co-Processing capital cost estimates were based on costs developed in the Prototype Commercial Coal/Oil Co-Processing Project sponsored by DOE and the Ohio Coal Development Office. Projection of fuel costs, feedstock costs and escalation factors were based on DOE's mid escalation scenario.

An economic comparison was performed based on the busbar energy cost (Mills per kilowatt-hour). The results of the comparison for the base case at two specific dispatch factors (DF)* are as follows:

BASE CASE BUSBAR COST (MILLS/Kwh)

	FIRST YEAR (1990)		LEVELIZED (20 YRS)	
	61% DF	96% DF	61% DF	96% DF
CCC	81	63	101	88
PC	96	70	113	85
CFB	84	63	100	77

*DF- Dispatch Factor - the percentage of time annually that the unit would be dispatched if it were available 100 percent of the time. The capacity factor is equal to the dispatch factor times the availability factor for each facility.

At 61% DF, the CCC consumes all the distillate produced and allows all the naphtha to be sold. The CCC consumes all the naphtha and distillate at 96% DF. The simple cycle is not analyzed at these higher dispatch factors because CSC technology is only appropriate for DF's corresponding to peaking power generation. These results show that all the technologies are competitive from an economic standpoint. However, it also shows that the Co-Processing alternatives become more competitive at lower dispatch factors. The reason for the sensitivity to dispatch factor is that the Co-Processing technology produces clean liquid fuels that can be easily sold or stored until peak electric power is needed, and can be burned in less expensive combustion turbine generators. This allows the capital intensive Co-Processing facility to be base loaded independently of the power generating equipment. The Co-Processing facility can continue to produce fuel whether the combustion turbine (CT) is dispatched or not. At high dispatch factors, the naphtha and utility fuel produced can be blended for use in the CT. At medium dispatch factors, the naphtha not utilized can be sold on the market. At low dispatch factor, the extra utility fuel not utilized can also be sold as a #2 fuel oil equivalent. These sales provide credits against the cost of the electricity production. The other coal based technologies do not have the storage and peaking capability inherent in the Co-Processing technology. With PC and CFB technologies the complete investment must sit idle during periods when power is not being generated.

Cases were also analyzed at various dispatch factors using an approach where the megawatt rating of the CCC increased as the dispatch factor decreased, so that the fuel consumption for the Co-Processing Combined Cycle remained the same, utilizing all the produced distillate. The megawatt rating of a simple cycle unit (CSC), PC unit and the CFB unit were also increased as the generation dispatch factor decreased so that all power generation technologies had the same net rating at a given dispatch factor. Changes in dispatch factor thus resulted in changes in capital cost, operating and maintenance costs, and fuel consumption of the PC and CFB technologies. The feedstock consumption of Co-Processing technology was unchanged since at all dispatch factors the unit operated at full capacity. The electric output varied between 1770 MWe's at 10 percent DF to 223 MWe's at 75 percent DF. The results are as follows:

LEVELIZED BUSBAR COST (MILLS/Kwh)

DF	CCC	CSC	PC	CFB
10%	276.5	186.2	394.8	292.9
35%	123.5	137.3	148.0	134.7

This analysis showed the Co-Processing technologies to be cheaper at lower dispatch factors than the other alternatives. The report also shows that if the power generating equipment is used to provide peak power, and consequently has a low dispatch factor, the cost of the electrical energy of the Co-Processing technologies is much below that of the other coal based fuel technologies studied. At 20 percent dispatch factor the Co-Processor electrical energy will cost 78 percent of PC and 91.6 percent of CFB. While at an 80 percent dispatch factor, the Co-Processor electrical energy will cost 1.7 percent less than PC. However, CCC will cost approximately 8.8 percent more than CFB as marketable Co-Processing products are consumed for power generation.

The approximate break even dispatch factor for CCC vs. CFB is 60 percent. At a 60 percent dispatch factor the approximate busbar cost of electricity produced by the CCC and CFB is 101 Mills/kwh. While the busbar cost for PC is 113 Mills/kwh.

The calculated emission of Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x) and Carbon Monoxide (CO) of these four technologies were also assessed. The results of this assessment show that the Co-Processing based technologies produced 50 - 65 percent less Sulfur Dioxide (SO_2) than PC or CFB and 50 percent less NO_x than the PC technology. These values are shown below:

AIR EMISSIONS

(LB/MBTU)

LB/MBTU	CSC*	CCC*	PC	CFB
SO_2	0.3	0.3	0.7	0.7
NO_x	0.2	0.2	0.6	0.2
CO	0.03	0.03	0.03	0.03

* Values are for power producing facilities and do not include Co-Processor unit emmissions which are not significant for these elements.

All electric utilities have a mix of base and peak load generating capabilities. This report shows that the coal/oil Co-Processing technologies is economically competitive with pulverized coal generation but is marginally competitive for base case at dispatch factors greater than 60 percent with circulating fluidized bed technology. However, Co-Processing based technologies are far more competitive than any other coal based fuel technology studied in meeting peak demand requirements.

TABLE OF CONTENTS

1.0 INTRODUCTION

Ohio Clean Fuels, Inc. (OCF), in co-sponsorship with the United States Department of Energy (DOE) and the State of Ohio, proposes to construct a prototype Coal/Oil Co-Processing plant in the state of Ohio. This project is being conducted as part of the DOE's Clean Coal Technology I program. The primary objective of the OCF project is to demonstrate the technology of simultaneously processing (co-processing) poor-grade coal (high in sulfur and nitrogen) and crude oil residuum feedstocks to produce clean liquid fuel products on a commercial scale.

Preliminary analyses conducted by OCF and their consultants indicated that Co-Pro fuel may be economically utilized at a number of electric utility plants in Ohio to reduce air pollutant emissions. Stone & Webster Management Consultants, Inc. (MCI) and Stone & Webster Engineering Corporation (SWEC) were retained by OCF to perform a five phase study to identify investor owned electric utilities and power plants in the state of Ohio for which the use of Co-Processed fuel would offer an economically attractive means of reducing SO_2 and NO_x emissions. This study is being conducted in cooperation with major Ohio utilities and is presently in Phase 3, Detailed Analysis of Selected Units. The total study is scheduled for completion around the end of 1989 and will be the subject of a separate report.

In parallel with the above, Stone & Webster was also requested to perform a comparative technologies report for "grassroot plants" assuming mature Co-Processing technology. The purpose of this report was to evaluate four power generation technologies which use coal as primary fuel and/or feed stock. The following technologies are considered in the evaluation:

- Co-Processor Simple Cycle (CSC)
- Co-Processor Combined Cycle (CCC)
- Pulverized Coal with Flue Gas Desulfurization (PC)
- Circulating Fluidized Bed (CFB)

The report developed comparable designs for each technology and estimated the required capital and operating cost data bases. Stone & Webster relied on its experience from previous projects to develop the design basis of the PC and CFB technologies. Costs and operating data are consistent with EPRI Technical Assessment Guidelines (EPRI-TAG) values. The Co-Processing plant design is based on the work done for the DOE Clean Coal I technology project "Prototype Commercial Coal/Oil Co-Processing Plant". DOE price projections for fuel, feed and byproducts were also utilized in the evaluation. This information along with supporting technical and economic data constituted the basis of the economic model. Economic comparison of the technologies is in terms of the total busbar cost of electricity produced (Mills/Kwh). An assessment of the air pollutant stack emissions was also conducted. A comparison of emissions for each of the technologies is described in Section 5. No quantitative economic value is assigned for differences of air pollutants produced by each technology; however, these differences are significant in light of increasingly stringent environmental legislation.

This report presents the results of the comparative technologies studied. Section 2 describes the technologies evaluated. Appendix A provides detailed plant descriptions. The economic model is described in Section 3 and the results are described in Section 4. Assessment of stack air pollutant emissions are discussed in Section 5. Sample economic model printouts are included in Appendix B.

2.0 DESCRIPTION OF TECHNOLOGIES

2.1 Design Basis

To be compatible, the design of each comparative technology assumed the same net electric output, site conditions, fuel characteristics and other attributes, where applicable. Some of the common design characteristics are discussed below.

2.1.1 Unit Capacity

The nominal 310 MWe net output rating was chosen for each alternative for two reasons. First, this rating is easily produced by multiple units of commercially available CFB modular units. Second, the design basis distillate ("utility fuel") product output from the Co-Processor plant can support this rating at a 61 percent dispatch factor with a single combustion turbine and a supplementary fired (HRSG) Heat Recovery Steam Generator. Supplementary firing temperatures were held below 1400°F for technical reasons. The 61 percent dispatch factor is a reasonable and typical value for utility operations. EPRI defines in their Technical Assessment Guide (EPRI-TAG) 70 percent as base loaded power plant dispatch factor. 300MWe is a "small size" for the EPRI intermediate central station unit, based on current trends in the industry and falls in EPRI guidelines standards at the high end of the intermediate loaded unit.

The gross capacity for each plant is different and reflects the inherent auxiliary power requirements for each technology. Economic comparisons of technologies are performed on busbar costs bases. This analysis considers the differences in availability of each technology based on the latest EPRI-TAG.

2.1.2 Site Conditions

For study purposes, a typical plant location in the Northern Ohio area was chosen. The site is assumed to be clear and level with no special attributes or problems. The site is in Seismic Zone I, with an elevation of 600 feet above mean sea level. A river for raw water supply is assumed to be within six miles of the plant site. Pile-type foundations are assumed for capital cost estimates. The following ambient conditions are used for cycle performance calculations. These are taken from the EPRI-TAG for this region of the country, assuming a baseload facility.

Dry-bulb temperature	60 F
Wet-bulb temperature	52°F
Atmospheric pressure	14.4 psia

Cooling water system requirements are based on the maximum temperature conditions shown below. Mechanical-draft cooling towers are used for each technology. For freeze protection and winterization considerations, the Design Minimum Temperature is -20°F.

Maximum dry-bulb temperature	95°F
Wet-bulb temperature	75°F
Atmospheric pressure	14.4 psia

2.1.3 Fuel/Feed Characteristics

For this report, it is assumed that the Co-Processing plant and its related power generation equipment (either simple or combined cycle) will be located on the same site.

One advantage of Co-Processing technology is that the fuel producing Co-Processing plant can be located remote from the power generation equipment since the fuel can be stored. The fuel could be transported by truck, rail or pipeline from this plant to multiple utilities, plants and locations. This would permit selecting the optimum site for each facility separately. The clean coal power generation equipment, which is not land intensive, could be located in or near urban areas or other electric load centers. No credit in the economic model was assigned for this advantage of the Co-Processing technologies.

The design basis coal for the PC, and the CFB is a blend of unwashed Ohio No. 5 and No. 6 coal (Table 2-1). The Co-Processor utilizes a mixture of washed Ohio No. 5 and No. 6 coal blend (Table 2-1A) and Cold Lake Crude Blend (Table 2-2) as the design basis feed for the Coal/Oil Co-Processor. Properties for the coal blend and the Cold Lake Crude Blend feeds are given in Tables 2-1, 2-1A, and 2-2, respectively.

TABLE 2-1

OHIO NO. 5 AND NO. 6 COAL BLEND

UNWASHED COAL ANALYSIS - AS FIRED

FOR PC AND CFB PLANTS

Constituent	% By Weight
Carbon	61.023
Moisture	9.9
Hydrogen	4.325
Nitrogen	1.442
Ash	10.69
Sulfur	3.93
Oxygen	8.69

Higher Heating Value = 10812 Btu/lb

TABLE 2-1A

OHIO NO. 5 AND NO. 6 COAL BLEND

WASHED AND DRY BASIS FOR CO-PROCESSING PLANTS

Constituent	% by Weight
Carbon	73.05
Hydrogen	4.82
Nitrogen	1.49
Ash	8.53
Sulfur	2.86
Oxygen	9.125
Chlorine	0.125

Higher Heating Value = 13,226 BTU/lb

TABLE 2-2

COLD LAKE BLEND CRUDE

FUEL PROPERTIES

API Gravity	23.6	
Sulfur Wt.%	3.29	
Mercaptan Sulfur WPPM	300	
Neutralization Number, mg/g	0.84	
Pour Point	-65	Deg F
Viscosity @ 100 Deg F	41.4	CS
Viscosity @ 80 Deg F	70.1	CS
Viscosity @ 60 Deg F	130.2	CS
Nitrogen, Wt.%	0.28	
Reid Vapor Pressure	5.9	psia
Maximum Salt Content, ptb	20 (actual measured value 2.4)	

2.1.4 Common Attributes

Though the technologies differ appreciably in their method of fuel conversion and power generation, the basic design of all four plants is based on assumed commonalities for equivalent basis of comparison. These are:

- The ultimate heat sink for the Rankine Cycle power generation equipment is mechanical draft cooling towers.
- Coal and limestone delivery is by rail. Coal as received, is 2" x 0", as mined for the circulating fluidized bed and pulverized coal technologies and is washed for the Co-Processing technologies.
- Fuel/feed storage capacity is for 60 days at 100 percent base load operation. In the case of CCC and CSC, this is accomplished by storing the utility fuel produced by the process portion of the plant.
- Two 100 percent motor driven boiler feed pumps and at least two 50 percent pumps, fans, etc. are utilized for critical services.
- Onsite waste disposal facilities, except for the Co-Process technology where vacuum bottoms material is sold.

- Complete water treatment facilities including pretreatment and mixed bed demineralizers.

2.2 Technology Descriptions

2.2.1 Coal/Oil Co-Processor Power Plants

The plant configurations used for this study are based on a combination of the Ohio Clean Fuel's Prototype Coal/Oil Co-Processing Plant and either a simple cycle combustion turbine power plant or a combustion turbine combined cycle power plant.

The Co-Processing Plant is described in the Preliminary Process Description report developed by SWEC as part of the DOE Clean Coal Technology project as referenced before. A block diagram depicting the process is included as Figure 2-1.

No attempt has been made at this time to optimize the fuel production and power production process interface. Table 2-3 presents the stream flow rates and qualities for the prototype coal/oil co-processing plant. Table 2-4 summarizes the co-processing plant fuel outputs and converts the units into the format used for the power production calculations.

FIGURE 2-1
OHIO PROTOTYPE CO-PROCESSING PLANT
OVERALL BLOCK FLOW DIAGRAM
COLD LAKE BLEND CRUDE

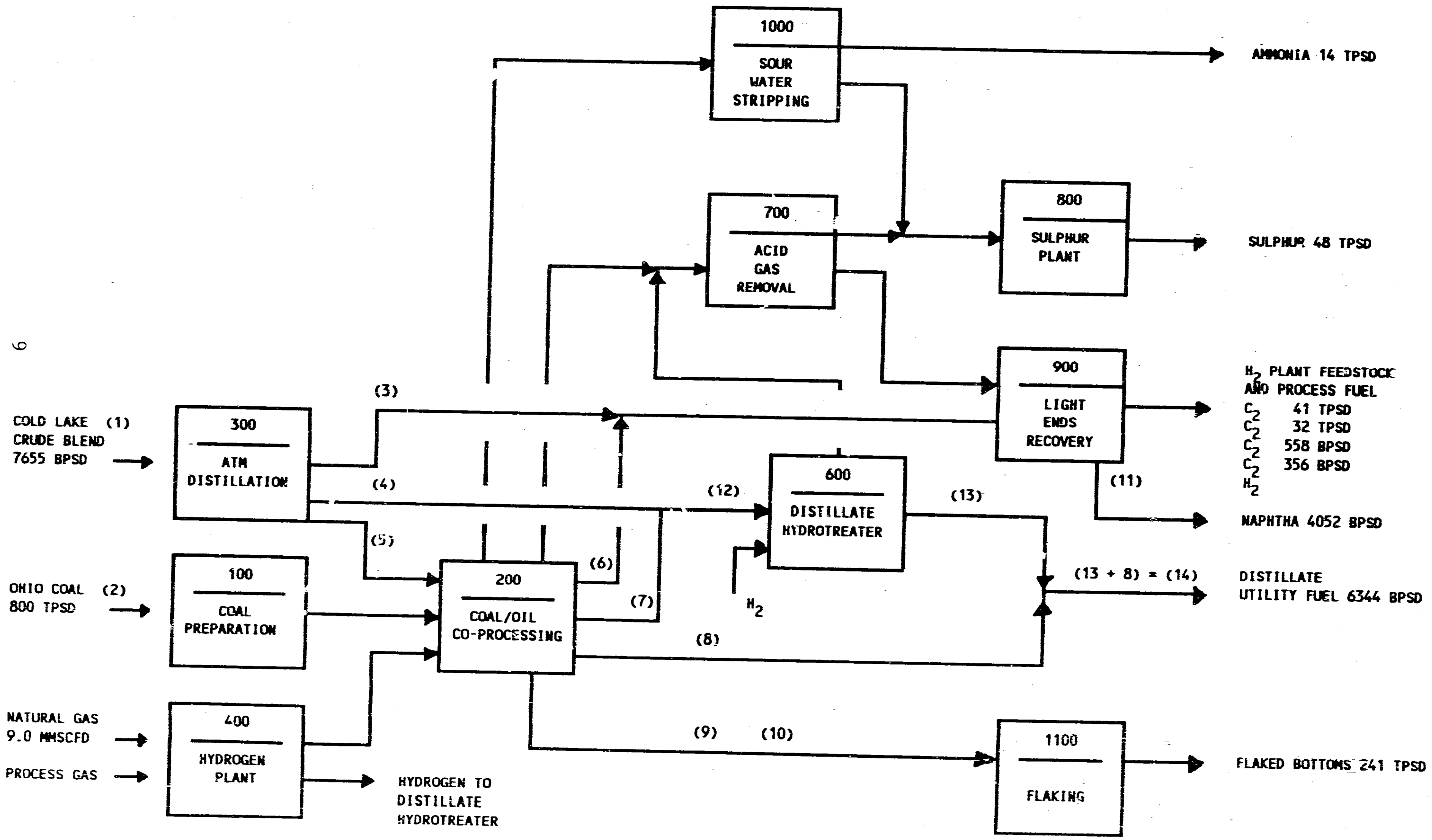


TABLE 2-3

PROTOTYPE COAL/OIL CO-PROCESSING PLANT
COLD LAKE BLEND, NORMAL RECYCLE
STREAM FLOWRATES AND QUALITIES

Stream No.	Description	Flowrate BPSD	Flowrate TPSD	API Gravity	Sulfur Content (WT%)	Nitrogen Content (WT%)
1	Cold Lake Crude/ Condensate Blend	7,655		23.6	3.29	0.28
2	Ohio No. 5/6 Coal (Washed and Dried basis)		765		2.86	1.49
3	Straight Run Naphtha (1)	2,114		71.7	0.10	1 Wppm
4	Straight Run Distillate	1,203		28.4	1.57	60 Wppm
5	Co-Processor Oil Feed	4,282	765	7.1	4.75	0.49
6	Co-Processed Naphtha (1)	1,938		58.4	0.14	0.04
7	Co-Processed Distillate	3,551		29.4	0.31	0.13
8	Co-Processed Vacuum Gas Oil VGO	1,590		14.0	0.42	0.27
9	Co-Processor Vacuum Bottoms -Excl. Solids		138	-7.6	1.05	1.13
10	Co-Processor Vacuum Bottoms -Incl. Solids (2)		241		4.73	0.84

TABLE 2-3 (cont'd)

PROTOTYPE COAL/OIL CO-PROCESSING PLANT
COLD LAKE BLEND, NORMAL RECYCLE
STREAM FLOWRATES AND QUALITIES

Stream No.	Description	Flowrate BPSD	Flowrate TPSD	API Gravity	Sulfur Content (WT%)	Nitrogen Content (WT%)
11	Total Naphtha (Streams 3 & 6)	4,052		65.1	0.12	0.02
12	Total Distillate (Streams 4& 7)	4,754		29.1	0.63	0.10
13	Total Distillate After HTU	4,754		29.1	0.30	0.07
14	Utility Fuel Product (Streams 8 & 11 & 13)	10,396		38.6	0.26	0.09

NOTES

(1) Naphtha Streams shown net of C1-C4 components

(2) Co-Processor Vacuum Bottoms Stream including Solids has:

Ash Content = 27.1 wt%

Unconverted Coal = 15.7 wt%

Total Solids = 42.8 wt%

BASIS

- Analysis based upon true boiling point (TBP) method
- Cold Lake Blend Distillation based on Imperial Oil Limited assay of February 1987
- Co-Processing yields/qualities based on Imperial Oil Limited memorandum dated July 6, 1988
- Crude Distillation unit heavy oil cut point of 650 deg. F
- Carry-under of VGO to vacuum bottoms based on stream 108 of HRI computer simulation output

TABLE 2-4

PROTOTYPE COAL/OIL CO-PROCESSING PLANT

COLD LAKE BLEND, NORMAL RECYCLE

STREAM FLOWRATES AND QUALITIES FOR POWER PRODUCTION USE

Stream No.	Description	Yield BPSD	API Gravity	Specific Gravity	Flow LB/HR	HHV[1] BTU/LB	LHV[1] BTU/LB	%S(2)	%N(2)
13	HTU Discharge	4754	29.1	0.881	61,055	-	-	0.30	0.07
8	Co-Processed Vacuum Gas Oil	1590	14.0	0.973	22,552	-	-	0.42	0.27
13+8	Total Distillate	6344	25.0	0.904	83,607	19,140	18,010	0.33	0.12
11	Naphtha	4052	65.1	0.720	42,529	20,310	18,940	0.12	0.02
14	Total Blend	10,396	38.5	0.832	126,141	19,534	18,323	0.26	0.09

Note (1) Heating values obtained per API Technical Data Book, October 1964, Figure 14A1.1 as a function of API Gravity. In the case of the Distillate and Naphtha blend the heating values are calculated as a weighted averages.

Note (2) Per attachment for streams 8, 11, 13. Values for blends are based on calculated flowrates of the constituents.

2.2.1.1 Coal/Oil Co-Processing Plant

Coal/Oil Co-Processing technology was developed by Hydrocarbon Research, Inc. (HRI) and employs an ebullated-bed reactor to produce a range of hydrocarbon products from coal, petroleum residuum, and hydrogen produced from natural gas. This technology produces a clean (≤0.33 percent S and ≤0.12 percent N) distillate grade utility fuel, naphtha, propane and butane, as well as sulfur and ammonia byproducts. When coupled with a combustion turbine based power plant, the result is an efficient conversion of coal to electric energy with minimum or no pollution control technology equipment requirements.

The basic components of Co-Processing power plants are:

- Cold Lake Crude Blend Storage
- Coal Handling and Preparation Facilities
- Coal/Oil Co-Processing Unit
- Atmospheric Distillation Unit
- Steam Reformer (Hydrogen Plant)
- Distillate Hydrotreater
- Acid Gas Removal Unit
- Sour Water Stripper
- Sulfur Plant
- Light Ends Recovery Unit
- Combustion Turbine - Generators
- Heat Recovery Steam Generators (HRSGs) - for combined cycle only
- Steam Turbine - Generator Plant for combined cycle only
- Water and Waste Treatment Plant

2.2.1.2 Coal/Oil Co-Processor Thermal Cycles

For the combined cycle case, the steam cycle has been designed to effectively capture combustion turbine waste heat and maximize steam production and resulting power generation. This is done through the use of single drum, supplementary fired HRSG. The HRSG has an internal reheater and an external deaerator. The supplemental fuel for the HRSG's is the Co-Processor produced distillate and/or distillate/naphtha blend. Cycle performance data is summarized in Table 2-5.

The combustion turbine-generators performance and costs are based on a GE MS-7001 F ("FRAME 7F"). The steam turbine-generator has inlet conditions of 1800 psig, 1000°F/1000°F. The combined cycle is sized such that when a Frame 7F combustion turbine is operating at base load conditions, the remaining distillate produced by the co-processing unit is fired in the HRSG without exceeding 1400°F gas temperature.

See Appendix A for a more detailed description of the plant and equipment.

2.2.2 Pulverized Coal

The Pulverized Coal (PC) plant incorporating Flue Gas Desulfurization (FGD) is the most conventional of the technologies studied. Pulverized coal plants are the most technically mature and the most commonly employed technology using coal. FGD technology and associated equipment is a developing technology which has been commercialized however, it has not reached the level of maturity of PC plant components. The FGD system effectively reduces sulfur emissions; however, it imposes additional auxiliary power and steam demand which reduces the net capacity of the unit and increases the heat rate. Cycle performance data is contained in Table 2-5.

The PC Plant selected for the study is an adaptation of an existing SWEC designed unit reconfigured to fit the Northern Ohio site. The basic components of Pulverized Coal plant includes the following:

- Coal, Limestone and Scrubber Sludge Storage and Handling
- Wet Limestone Flue Gas Desulfurization Equipment
- Electrostatic Precipitator for Particulate Removal
- Steam Turbine - Generator Plant
- Fly Ash and Bottom Ash Handling and Disposal Facilities
- Water and Waste Water Treatment Plant

Steam turbine has throttle conditions of 2400 psig, 1000°F/1000°F single reheat. The assumed steam turbine performance was based on a Westinghouse TC2F-31 Steam Turbine.

See Appendix A for a more detailed description of plant and equipment.

2.2.3 Circulating Fluidized Bed (CFB)

Circulating Fluidized Bed (CFB) represents the latest in commercially implemented boiler technology. Fluidized bed technology in general offers advantages over conventional PC boilers in the areas of fuel flexibility, in-situ SO_2 removal, and boiler efficiency. Though several different fluid bed design alternatives have been proposed and implemented to various degrees in the industry, the Circulating Fluidized Bed (CFB) was chosen for the study. This is based on SWEC's extensive experience with this design in addition to the utility industry's current level of interest in CFBs. The majority of utility sized power projects currently underway in the U.S. employ CFBs.

The CFB Plant conceptual design for the study was created from the PC Plant, by removing the boiler, coal pulverizers, fans, ash handling system, precipitator, and limestone scrubber. In their place were added three nominally rated 125MWe Circulating Fluidized Bed combustors, each with a FD, ID, and primary air fan and a bag house. The three nominal 125MWe CFB combustors were used rather than a larger combustor to be consistent with the current state of development of CFB technology. The steam turbine-generator, feedwater cycle and condenser/cooling systems are the same as the PC Plant.

The basic components of Circulating Fluidized Bed power plant include the following:

- Coal and Limestone Storage and Handling
- Circulating Fluidized Bed Boiler
- Fabric Filter Particulate Removal (Part of CFB Boiler)

- Steam Turbine - Generator Plant
- Ash Handling and Disposal Facilities
- Water and Waste Water Treatment Plant

The steam turbine has throttle conditions of 2400 psig, 1000°F/1000°F single reheat. The analysis program modeled a Westinghouse TC2F-31 Steam Turbine. Cycle performance data for the CFB power plant is contained in Table 2-5.

See Appendix A for a more detailed description of plant and equipment.

TABLE 2-5

CYCLE PERFORMANCE SUMMARY

	CCC	CSC	PC	CFB
<u>Fuel</u>	Co-Pro Distillate	Co-PrO Distillate/ Naphtha Blend	Ohio No. 6 & No. 5 Coal	Ohio No. 6 & No. 5 Coal
Feedrate, lb/hr	133,084	177,883	304,095	296,808
Heating Value(LHV),Btu/lb	18,010	18,323	10,812	10,812
Wt% Sulfur (as received)	0.33	0.26	3.93	3.93
Wt% Nitrogen (as received)	0.12	0.09	1.442	1.442
<u>Combustion Turbine</u>				
Quantity & Type	GE MS7001F	GE MS7001F	--	--
Firing Temp., °F	2084	2084	--	--
Steam/Water Inj. - lb/hr	97,102(s)	123,066(w)	--	--
Exhaust Temp, °F	1084.59	1080.37	--	--
Gross Power Generated - kW (1)	159,888	304,248	--	--
<u>HRSGs & Steam Turbine</u>				
Steam Cond psia/°F/°F	1815/1000/1000	---	2400/1000/1000	2400/1000/1000
Cond. Pres, in Hg abs	3.56	---	3.56	3.56
Stack Temp, °F	287	---	300	295
Gross Power Generated kW	170,992	---	351,254	348,791
<u>Overall System</u>				
Gross Power, kW	330,880	304,248	351,254	348,791
Aux Power, kW	20,690	4,564	41,033	38,600
Net System Power, kW	310,191	299,684	310,191	310,191
Capacity Factor, %	56.8	56.8	49	50
Equivalent Availability,%	92.6	92.6	79.3	81.3
Net Heat Rate, - Btu/kW-hr LHV	7,727	10,876	9,979	9,723
Net Heat Rate Btu/kW-hr-HHV	8,212	11,558	10,602	10,348

NOTE 1. The values are based on standard temperature and pressure.

3.0 DESCRIPTION OF ECONOMIC MODEL AND PARAMETERS

This section discusses the development of the parameters used in the economic model for comparing the various technologies. A model was developed which allows sensitivity and trend analysis by varying specific inputs. The key parameters considered include:

- Capital Costs
- Operating and maintenance costs, including fuel/feeds and consumables.
- Revenues from product and byproduct sales.
- Escalation
- Capacity factor

Much of the model was set up along the lines of the methods used in the EPRI-TAG. Data on specific technologies taken from EPRI-TAG are referenced where appropriate. To establish a common basis, all technologies were assumed operational in January, 1990, with the payment on the debt service paid in December of each operating year. Basic cost data is provided in current (1989) dollars.

To avoid speculation on specific electrical energy rates, the economic analysis is performed in terms of busbar cost (Mills/kwh, 1990 dollars) over the life of the project, 20 years. The only revenue streams considered in the analysis are those derived from the sale of Co-Processing products and byproducts, where applicable. The busbar costs are levelized over the 20 years at an 11 percent discount rate.

Busbar costs in the model are divided into 5 basic components. These are:

- Carrying charges
- Fuel/feed costs
- Variable O&M costs (includes consumables)
- Fixed O&M costs
- Product and byproduct revenues (credit)

A 20 year cash flow stream is developed for each of these components. All streams are then normalized through division by the product of net capacity, capacity factor and period hours (8,760 hours/year). The resulting busbar cost (converted to Mills/Kwh) of each commodity is then levelized by calculating the net present value of the stream and dividing by the sum of the present worth factors for each year. Summation of these values yields the levelized total busbar cost, a common denominator for comparing the different technologies in terms of cost of electrical service. The results of this analysis are discussed in Section 4. Printouts of the base case with and without naphtha sales are included in Appendix B. A description of these printouts is also contained in Appendix B. The remainder of this section discusses the key parameters.

3.1 Capital Costs

Stone & Webster developed estimates for direct capital costs, indirect and distributables, contingency, for the four technologies described in detail in Appendix A. This information was based on a combination of vendor quotes as well as data and experience from past projects. Data from past projects was escalated to 1989 dollars. The Co-Processing plant cost is for the nth plant and assumes a mature technology. Capital costs for the base cases are summarized in Table 3-1.

For the sensitivity analysis of power plant unit capacity, material and labor costs are adjusted by the ratio of the base unit size to the sensitivity unit size raised to the 0.8 power. The assumption ignores any economics of scale and consequently may bias the study against pulverized coal (PC) technology. PC Technology is more sensitive to economies of scale than the fluidized bed or combustion turbine technology, both of which are at their maximum practical size in the base case. The bias does not significantly affect the conclusions of the study.

Portions of the estimates for the fluidized bed boilers and boiler associated equipment are adjusted based on a multiple 125 MWe unit. (125 MWe is the maximum standard commercially available unit size for the circulating fluidized bed technology.) The combustion turbine and HRSG portion of the combined cycle plant estimate is adjusted based on the ratio of combustion turbine prices for the frame

7EA turbine to the Frame 7F combustion turbine. The additional boiler equipment prices in the combined cycle estimate were adjusted based on the HRSG price ratio for the different frame sizes. The combined cycle steam turbine price was adjusted based on the steam turbine capacity ratio to the 0.8 power. All other prices for the combined cycle plant were adjusted by the entire plant capacity ratio to the 0.8 power.

3.2 Operating and Maintenance Costs

Operating and maintenance costs include the cost of fuel, feedstock, consumables, waste disposal, operating and maintenance labor, materials and overhead. These are discussed further below.

3.2.1 Fuel/Feed and Consumables

Unit prices for coal, Cold Lake Crude Blend and natural gas are given on Table 3.2 from the annual energy outlook (DOC/EIA-0383(89)). The coal for the Co-Processing plant had an additional $5 per ton for washing at the mine mouth. Coal, Cold Lake Crude Blend and natural gas usages are derived and provided by the project team. Limestone usage, ash, slag and FGD sludge generation rates are estimated for each technology based on as fired Ohio No. 5 and No. 6 blend coal. Disposal of waste is assumed to be onsite. A disposal cost of $15/ton is assessed for FGD sludge disposal and $10/ton assessed for disposal of all other wastes. Flaked bottoms produced by Co-Processor are assumed to be sold at 85 percent of the value (commodity price) of the coal price. Annual costs for these items were calculated based on the unit price, usage rate and unit capacity factor.

The fuel and feedstock prices are calculated based on the source value (i.e., minemouth) plus transportation to the site. Each component is the escalated at the appropriate rate(see Section B.2, Escalation and Prices).

Make-up water, demineralized water, plant catalysts and chemicals, condensate polishing recharge, and wastewater treatment costs are estimated as annual allowances based on capacity factor, plant usage and estimates from previous similar projects.

3.2.2 Products and Byproducts

The unit price estimates for sulfur, ammonia, distillate and naphtha were developed by Stone & Webster based on a market analysis. These prices are shown in Table 3-2. Production rates are based on calculation and/or data from previous SWEC studies.

3.2.3 Operation Labor

The operating labor force required for each technology is estimated based on previous Stone & Webster experience with operating plants. All operating labor is based on a 2000 manhour work year. The average salary for all plant operators is assumed to be $25/hr including burden.

The following numbers of operating personnel are used:

Technology	Number of Operating Personnel
• CSC	110
• CCC	122
• PC	102
• CFB	81

3.2.4 Maintenance Labor and Materials

Total maintenance costs are estimated per EPRI-TAG at 2.5 percent of the total direct cost for each technology. 40 percent of the cost is allocated for maintenance labor and 60 percent for materials. This factoring was validated by estimating the required maintenance labor force and applying an average annual salary.

3.2.5 Owner's Overhead During Operation

Owner's overhead during operation was estimated to be 30 percent of the sum of the operation and maintenance labor for the various technologies.

3.2.6 Fixed and Variable O&M Components

In accordance with EPRI-TAG, O&M costs are divided into fixed and variable components. Fixed O&M is calculated as total O&M cost times Capacity Factor. Variable O&M is then determined as the difference of total and fixed O & M cost.

3.3 Fuel and Consumables Escalations

The latest DOE fuel cost escalations are used in the economic analyses. Consumables are escalated at compatible values.

3.4 Capacity Factor

Capacity factor is the ratio of the total amount of electricity produced during a period divided by the product of unit capacity and total period hours. Capacity Factor is the product of two separate factors: Equivalent Availability Factor and Dispatch Factor.

Capacity Factor = (Equivalent Availability Factor) x (Dispatch Factor)

The values of Base Capacity Factor used in this study are given in Table 3-3.

3.4.1 Equivalent Availability Factor

The Equivalent Availability Factor is defined as the number of available hours, less equivalent derated hours (planned and unplanned), divided by the period hours. Mathematically this is expressed (for one year) as:

EAF = (AH - (EUDH+EPDH))/8760.

AH is available hours. EUDH is equivalent unplanned derated hours and EPDH is equivalent planned derated hours. Derated hours = derated capacity/unit capacity times the number of hours at derated capacity. The EAF used for each technology is given in Table 3-3.

3.4.2 Dispatch Factor

The Dispatch Factor is the percent of total time that a unit would be called on to operate if it were available 100 percent of the time. (Capacity factor is equal to the dispatch factors times the unit availability.) Units that burn cheap fuel and that are efficient will have high dispatch factors. Units that burn more expensive fuel or that are inefficient will have low dispatch factors. This is because normally the cheapest energy producer will be put on line, and the more expensive units are only called upon as a last resort. The study evaluated effects of dispatch factors ranging from 10 percent to 96 percent. The dispatch factor of 61.34 percent was selected for the base case analysis.

At this dispatch factor the combined cycle consumes all the distillate produced by the Co-Processing Plant. The naphtha is sold on the open market. The simple cycle unit, at the same dispatch factor will burn all of the distillate and most of the naphtha to generate the same kilowatts. The remainder of the naphtha is sold in the market.

Once a base dispatch factor was selected it was held constant for all power generation technologies. However, the Co-Processing plant is assumed to operate continuously other than for scheduled and unscheduled outages. This resulted in a 90.14 capacity factor (330 days per year) for the Co-Processing plant. The combustion turbines of the Co-Processing/CCC and Co-Processing/CSC operate at the specified dispatch factor and availability based on EPRI-TAG values. During periods of non-operation by the combustion turbine, fuel produced by the Co-Processing plant is stored. Its product can be stored until needed and/or sold at market value. By comparison power generating units must operate only as dispatched because their product (electricity) is not easily stored.

Feed inputs and fuel consumption were calculated for each alternative at different dispatch factors. Each technology is assumed to have a constant heat rate, equal to the full load heat rate throughout it's load range This assumption implies that units are operated only at maximum output. In the range of conditions considered in this study, this assumption may cause a bias in favor of the pulverized coal and fluidized bed units. At low capacity factors these units will cycle frequently and use more fuel at low load operation due to higher heat rates at low loads and extended time required for startup. The combustion turbines start much more rapidly, with much less excess startup fuel consumption. This bias does not significantly affect the conclusions of the study.

TABLE 3-1

CAPITAL COST SUMMARY
(1989 Dollars)

	CCC	PC	CFB	CSC
Co-Processing Plant	208,964,374	--	--	208,964,374
Power Generation Equipment	187,376,179	412,688,884	361,509,845	109,331,450
Total Direct Cost	396,340,553	412,688,884	361,509,845	312,295,824
Indirect Costs & Distributables	60,426,146	52,374,044	45,595,707	49,935,928
AFI @ 10%	39,684,055	41,268,888	36,150,985	31,829,582
Total Estimated Cost	496,400,754	506,331,867	443,256,537	400,061,335
Installed Cost/kW (net)	1,600	1,632	1,429	1,290

TABLE 3-2

MATERIAL PRICES (1989 Dollars)

FUEL/FEED AND CONSUMABLES

ITEM	DELIVERED COST
Coal (unwashed)	$36.72/ton (fob, plt)
Crude (cold lake blend)	$13.87/bbl
Natural Gas	$2.50/MCF
Limestone	$15/ton
Demineralized Water	$0.9/1000 gal
Makeup Water	$2.0/1000 gal
FGD Disposal	$15/ton
Ash, Slag, Disposal	$10/ton

PRODUCTS AND BYPRODUCTS

ITEM	NETBACK PRICE
Naphtha	$20.76/bbl
Sulfur	$81/ton
Ammonia	$133.86/ton
Flaked Bottoms	$18.26/ton

TABLE 3-3

AVAILABILITY, DISPATCH, AND CAPACITY FACTORS

Technology	EAF	Source	Base Dispatch Factor	Base Capacity Factor
	%		%	%
CSC				
Co-Processor	90	OCF	--	90 (1)
Simple Cycle	92.6	EPRI TAG	61.34	56.3
CCC				
Co-Processor	90	OCF	--	90 (1)
Combined Cycle	92.6	EPRI TAG	61.34	56.3
PC	79.3	EPRI TAG	61.34	49
CFB	81.3	EPRI TAG	61.34	50

NOTE: (1) Based on 330 stream days operation per year and is not affected by the generation dispatch factor.

4.0 DISCUSSION OF RESULTS

The economic model discussed in Section 3.0 was used to compare the technologies developed in Section 2.0. In all cases, the Co-Processing unit is operated 330 days per year. If there is naphtha and distillate produced that is not required for electric generation it is sold to offset costs. An analysis was performed that verified it is more economical to continue to operate the Co-Processing plant at full capacity (330 days per year) rather than matching its operation to that of the combustion turbine.

4.1 Base Case Results

The base case is at 61.34 percent dispatch factor and is presented in Appendix B1. At this level, all naphtha produced is sold. The following table summarizes the results:

	CCC	PC	CFB
Capital Cost $	496,400,754	506,331,866	443,256,537
Capital Cost $/Kwh	1600	1632	1429
Equivalent Availability %	92.6	79.3	81.3
Capacity Factor %	57	49	50
Net Generation Kwh	310,191	310,191	310,191
Annual Generation Mwh	1,479,271	1,321,753	1,355,088
1990 Busbar Cost Mills/Kwh	80.857	95.59	84.468
Levelized Busbar Cost Mills/Kwh	101.016	112.679	100.277

This case shows that the three alternatives are comparable within the accuracy of the study. In the first year of operation, the Co-Processing plant combined cycle generation is the most cost effective approach. However, over time with the escalation assumptions utilized, the Circulating Fluidized Bed generation alternative is more competitive.

The annual busbar costs are plotted in Figure 4.1. Starting in 1994, the fourth year of operation, the cost of the CCC is higher than CFB. The PC is always higher than the other two. This is due to the PC having the highest capital cost and the lowest equivalent availability. The following table provides a more detailed description of the levelized busbar costs in Mills/Kwh:

	CCC	PC	CFB
Capital Cost	47.196	54.532	46.565
Effective Fuel Cost	29.194	27.468	26.749
Consumables	5.931	10.438	10.207
Fixed O&M	10.620	9.846	8.331
Variable O&M	8.077	10.396	8.375
	--------	--------	--------
Total	101.016	112.679	100.277

Refer to Appendix B for the development of the effective fuel cost. The effective fuel cost takes into account Co-Processor by-product sales. The effective fuel cost of 29.194 Mills/Kwh for CCC is approximately 2.445 Mills/Kwh above the CFB. The Pulverized Coal with Flue Gas Desulfurization has the highest capital and O&M cost.

4.2 SENSITIVITY ANALYSIS

Various sensitivity studies were performed to analyze potential variations to the base case. Each case takes the base case and makes one modification. The following cases were studied:

Case 1: Dispatch factor sensitivity

Case 2: Capital cost sensitivity

Case 3: Coal escalation rate sensitivity

Case 4: Oil escalation rate sensitivity

Case 1: Dispatch Factor Sensitivity:

Figure 4.2 shows the levelized busbar cost when the dispatch factor is adjusted from 10 percent to 96.5 percent. At 96.5 percent dispatch factor, all distillate and naphtha produced by the Co-Processing plant is used to fire the combined cycle plant. The case is presented in Appendix B2. The chart shows that CCC is most competitive in the 20 to 55 percent dispatch factor range. This result shows the economic advantage of selling the naphtha and reinforces the conclusion regarding the inherent advantage of the Co-Processing technologies because they can be decoupled from the fuel production process.

Case 2: Capital Cost Sensitivity:

The next sensitivity performed varied the capital cost estimates. The Stone & Webster capital cost estimates have an inherent accuracy of +/- 25 percent. The following table shows the levelized busbar cost in Mills/Kwh varying the capital cost by +/- 25 percent:

CAPITAL COST ESCALATION

	CCC	PC	CFB
Capital -25%	91.596	101.568	90.783
Base Capital	101.016	112.679	100.277
Capital +25%	110.437	123.791	109.771

The background for this study was to assume that this is the nth plant and that the the Co-Processing technology was mature. The plant design and cost for the Co-Processing plant is from the Stone & Webster preliminary design for the first commercial plant. The PC and CFB technologies are mature and the costs are known. The mature CCC plant cost will vary based on what is learned from the first plant's construction and operation.

Case 3 and Case 4: Coal and Oil Escalation Sensitivity:

The next two sensitivity analyses were on coal and oil escalation rates. The escalation rate for each fuel was adjusted independently by 20 percent in each year. The levelized busbar costs in Mills/Kwh are shown in the following tables:

COAL PRICE ESCALATION

	CCC	PC	CFB
Coal -20%	100.946	112.415	100.019
Base	101.016	112.679	100.277
Coal +20%	101.090	112.955	100.546

OIL PRICE ESCALATION

	CCC	PC	CFB
Oil -20%	99.922	112.679	100.277
Base	101.016	112.679	100.277
Oil +20%	102.358	112.679	100.277

The CCC cost is not as sensitive to change with coal price as the others since that is only part of it's feedstock. The PC and CFB each vary slightly over 0.5 Mills/Kwh while CCC varies less than 0.2 Mill/Kwh for the varying coal cost. Oil is only used by the CCC alternative and the change to busbar cost is 2.436 Mills/Kwh.

4.3 Generation Capacity Sensitivity:

A sensitivity study was performed varying the amount of installed generation along with the dispatch factor. The capacity of the installed generation for CCC was calculated to use all distillate produced by the Co-Processing plant at the dispatch factor under consideration. A combination Co-Processor with simple cycle combustion turbine (CSC) alternative was added to the analysis. The megawatt rating of the CCC was increased as the dispatch factor decreased, so that the fuel consumption for the CCC remained the same as in the sell all naphtha case. The megawatt rating of the CSC, PC and the CFB unit were also increased as the dispatch factor decreased so that all power generation technologies had the same rating. Changes in dispatch factor thus resulted in changes in capital cost, operating and maintenance costs, and fuel and feedstock consumption. The methods used for adjusting these values in the model were described in Section 3.4.2. At higher dispatch factors, in order to keep the CSC net generation equal to that of the CCC, various amounts of naphtha were burned to match the requirements of the available sizes. The net installed capacity ranges from 1,769,712 Kwh for a 10 percent dispatch factor to 223,032 Kwh for a dispatch factor of 75 percent. The results are shown in Figure 4.3 and the following tables:

CAPITAL COSTS (In 1989 Dollars)

	10% Dispatch Factor	35% Dispatch Factor
CCC	1,727,862,301	632,669,201
CSC	838,355,601	475,284,101
PC	2,411,484,900	737,792,100
CFB	1,754,247,300	688,044,700

LEVELIZED BUSBAR COST (MILLS/Kwh)

	10% Dispatch Factor	35% Dispatch Factor
CCC	276.469	123.472
CSC	186.230	137.321
PC	394.798	147.950
CFB	292.877	134.661

At the lower dispatch factors, the Co-Processor with a simple cycle combustion turbine is the most competitive. We realize that this magnitude of generation would not be built for such a low dispatch factor. However, this does indicate that for peaking generation using a coal based technology that a Co-Processed based plant is more competitive than either the pulverized coal or circulating fluidized bed generation alternatives.

FIG. 4.1 — ANNUAL BUSBAR COST

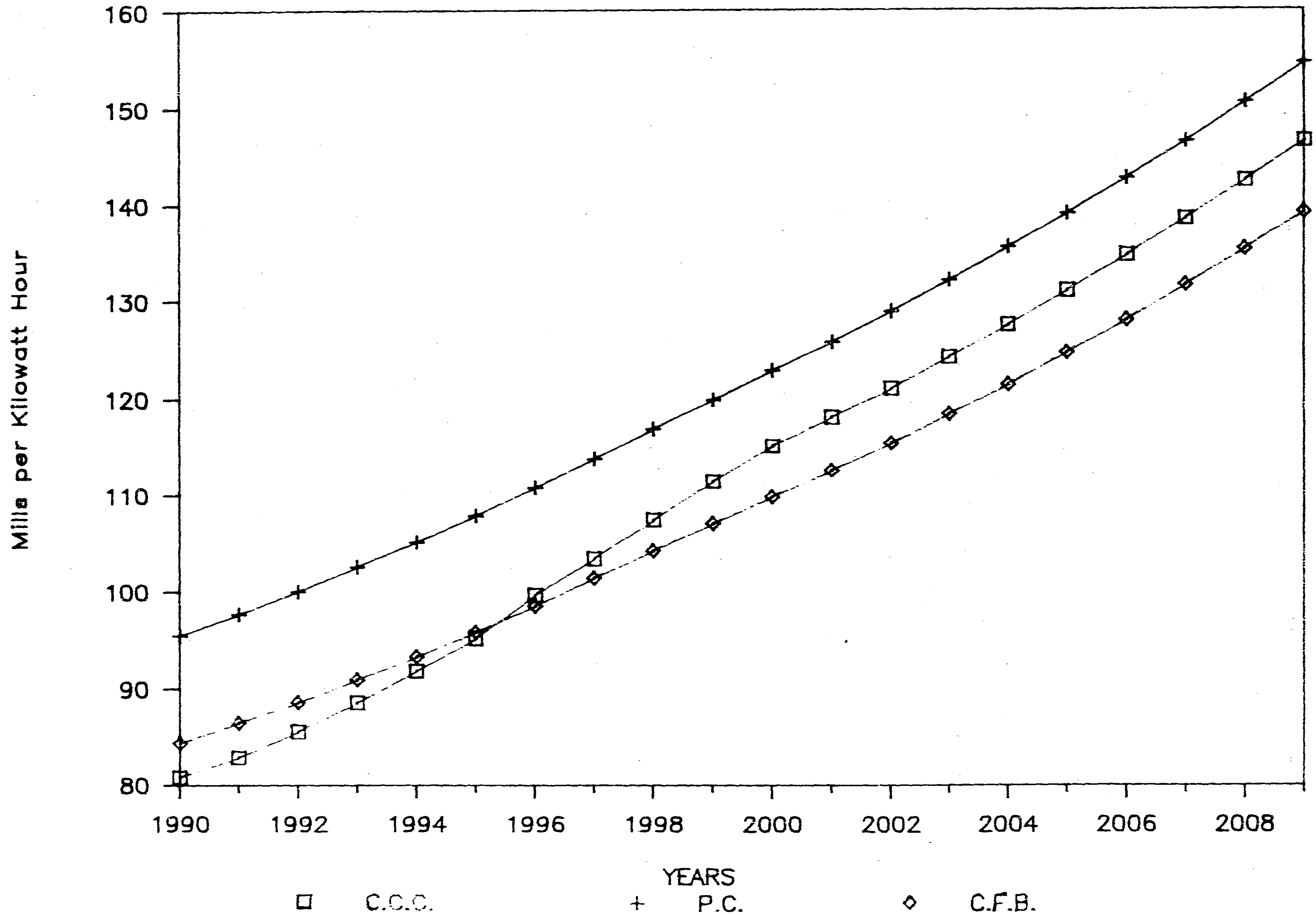


FIG. 4.2 – LEVELIZED TOTAL BUSBAR COST

Base Case

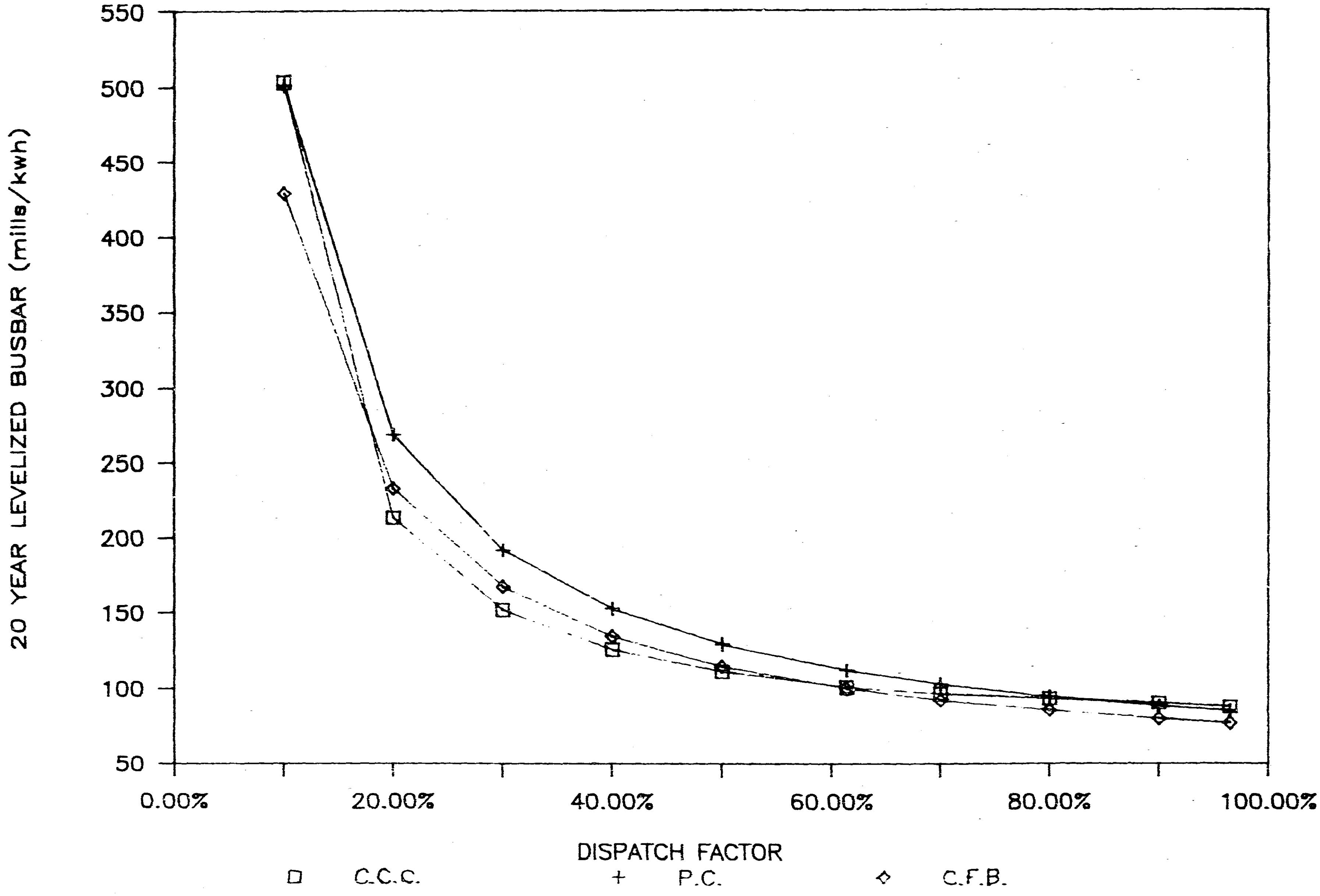
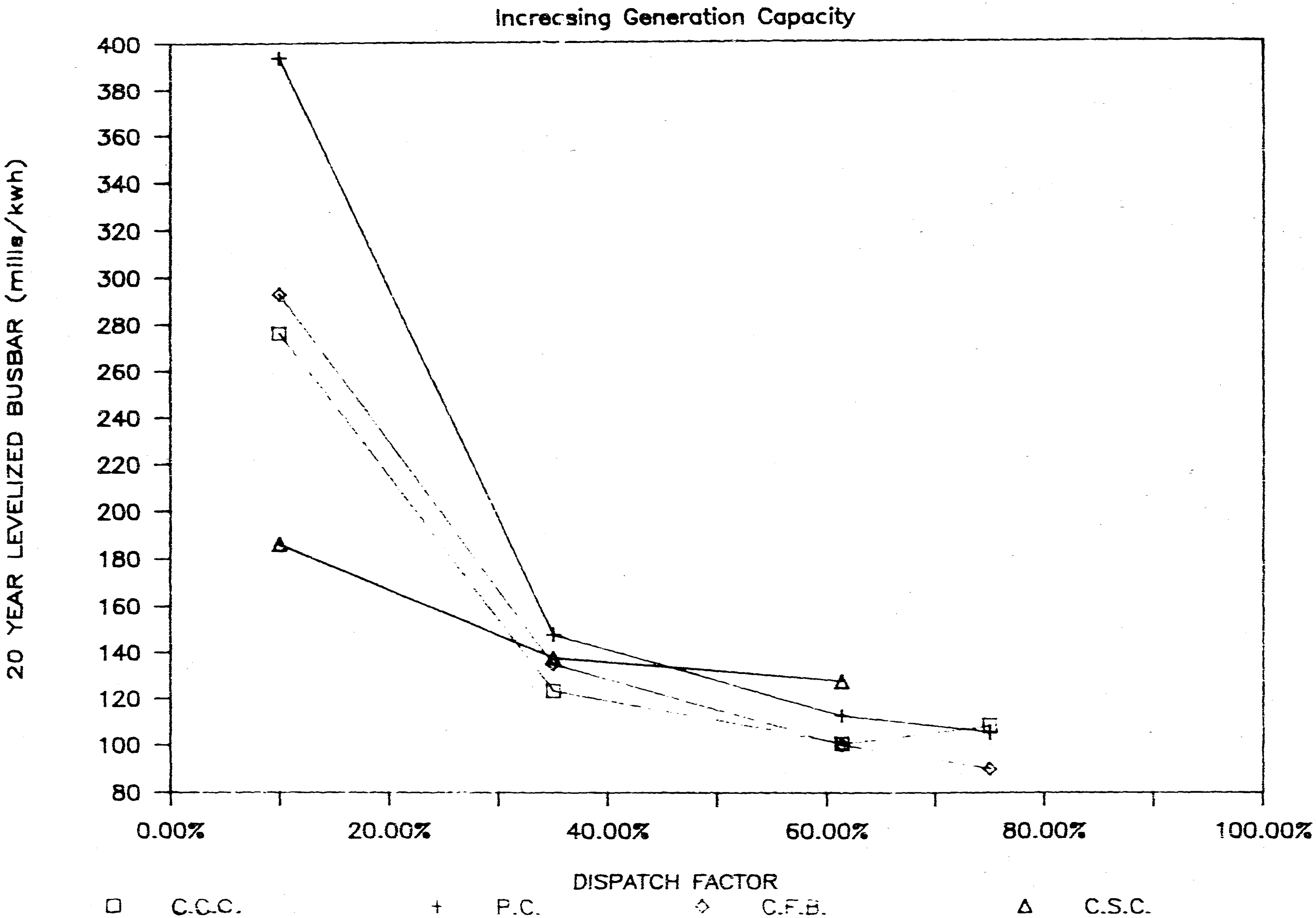


FIG. 4.3 – LEVELIZED TOTAL BUSBAR COST



5.0 AIR POLLUTANTS EMISSION ASSESSMENT

From an environmental permitting viewpoint of the utility end-users of the Co-Processed fuels, with the exception of solid waste production and air emissions, there is no major distinction between these comparative technologies selected for this study. Since solid waste production and their disposal costs have been included in the overall cost comparison for these technologies, only air emissions will be discussed in this section.

This section describes and compares expected emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx) and carbon monoxide (CO) from each of the four alternate power generation technologies (conventional pulverized coal boiler with flue gas desulfurization, circulating fluidized bed boiler, Co-Processing/Simple Cycle, and Co-Processing/Combined Cycle). For easier comparison, Table 5.1 lists these emissions in lbs/million Btu heat input, and in parts per million (ppm) by volume for pollutant concentrations.

It should be noted that air emissions described herein cover only those from the end-user of the Co-Processed fuels, and do not include those from the Co-Processing plant itself. Any environmental issues concerning the Co-Processing plant will be dealt separately by the owner of the Co-Processing plant, and should not affect the Co-Processed fuel end-users.

5.1 Sulfur Dioxide Emissions

Sulfur dioxide emissions from power generation depend on the sulfur content in the combustion fuel and the sulfur dioxide removal efficiency incorporated in the combustion process and/or subsequent flue gas treatment.

Based on a higher heating value (HHV) of 10,812 Btu/lb and 3.93 percent of sulfur by weight in the unwashed bituminous coal used in this study, uncontrolled sulfur dioxide emissions would be approximately 7.27 lbs/million Btu heat input of coal. For both conventional PC boiler and circulating fluidized bed (CFB) boiler, a sulfur dioxide removal efficiency of at least 90 percent will be required to meet the sulfur dioxide new source performance standards (NSPS). This will result in controlled sulfur dioxide emissions of approximately 0.727 lb/million Btu heat input. However, it should be noted that sulfur dioxide emissions of less than 0.727 lb/million Btu might be required on a case-by-case basis to satisfy the requirements of the PSD (prevention of significant deterioration) review.

For CFB boilers, sulfur dioxide removal of 90 percent or higher will be accomplished by feeding limestone as required into the CFB furnace. For conventional PC boilers, sulfur dioxide removal is accomplished by treating the flue gas with wet limestone scrubbers. The 0.727 lb/million Btu emissions are equivalent to sulfur dioxide emissions of approximately 375 ppmvd (ppm by volume, on a dry basis), at the 3 percent excess oxygen level typically for utility boiler operating conditions. For the same amount (in terms of pounds per hour or pounds per million Btu.) of sulfur dioxide emissions, at lower excess oxygen levels (3%) generally means lower excess air for dilution and, therefore, higher sulfur dioxide concentrations in emissions as compared to higher (15%) excess oxygen levels typically for the combustion turbine.

For the Co-Processing/Simple Cycle (CSC) application, Co-Processed fuel blend (a blend of all distillate and naphtha products) will be fired in the combustion turbine. Based on a HHV of 19,534 Btu/lb and 0.26 percent of sulfur by weight in the Co-Processed fuel blend and assuming no additional sulfur dioxide removal requirements, sulfur dioxide emissions from the CSC application burning Co-Processed fuel blend will be approximately 0.266 lb/million Btu heat input of the Co-Processed fuel blend, which is approximately 65 percent less than sulfur dioxide emission rates for PC or CFB base cases. These sulfur dioxide emissions are equivalent to approximately 150 ppmvd if adjusted to the 3 percent oxygen level, or 50 ppmvd if adjusted to the 15 percent oxygen level typically for combustion turbines. The 0.26 weight percent of sulfur in the Co-Processed fuel blend is well below the NSPS limit of 0.8 percent by weight for combustion turbine fuels. The 50 ppmvd sulfur dioxide emissions at 15 percent oxygen are also well below the NSPS of 150 ppmvd for combustion turbines.

For the Co-Processing/Combined Cycle (CCC), Co-Processed fuels will be used in the combustion turbine as well as the duct burner to supplement heat input to the waste heat recovery boiler. Only distillate will be used in the CCC, when CCC dispatch factors are approximately 10 to 61.3 percent (see Section 3.4.2 for discussion of dispatch factor). Some naphtha has to be used in addition to 100 percent distillate in the CCC, when CCC dispatch factors are between 61.3 percent and 96 percent. Naphtha usage increases with increasing dispatch factors. At a dispatch factor of approximately 96 percent, all Co-Processed distillate and naphtha will be consumed in the CCC.

Based on a HHV of 19,140 Btu/lb and 0.33 percent of sulfur by weight in the Co-Processed distillate and assuming no additional sulfur dioxide removal requirements, sulfur dioxide emissions from either the combustion turbine or the duct burner of the CCC burning only Co-Processed distillate will be approximately 0.345 lb/million Btu heat input of the Co-Processed distillate, which is approximately 50 percent less than sulfur dioxide emission rates for PC or CFB base cases. These sulfur dioxide emissions from either the turbine or the duct burner are equivalent to approximately 195 ppmvd at 3 percent oxygen, or 65 ppmvd at 15 percent oxygen. Both the fuel sulfur content and the sulfur dioxide emission concentration meet the NSPS as required for the combustion turbine portion of the CCC application.

When naphtha in addition to distillate are burned simultaneously in the CCC, sulfur dioxide emissions will be less than when only Co-Processed distillate is burned. This is due to naphtha's lower sulfur content and higher HHV than distillate's. When all Co-Processed distillate and naphtha products are blended, the total blend has a HHV of 19,534 Btu/lb and a sulfur content of 0.266 percent by weight. Burning the total blend in the CCC (either combustion turbines or duct burners) will result in sulfur dioxide emissions of approximately 0.266 lb/million Btu, which are approximately 150 ppmvd at 3 percent oxygen or 50 ppmvd at 15 percent oxygen as described above for the CSC application.

When heat input to duct burners is greater than 250 million Btu/hr, 40 CFR 60 Subpart Da, which contains emission limits and percent reduction requirements, will apply. Since the Co-Processed fuel is produced from Co-Processing Cold Lake crude plus condensate and 40/60 blend Ohio No. 5/6 bituminous coal, burning Co-Processed fuel is equivalent to burning crude oil and coal simultaneously. Based on 7,853 barrels/day of Cold Lake crude plus condensate (at API gravity of 23.6) and 800 tons/day of washed coal (at a HHV of 12,628 Btu/lb on a received basis), the crude oil and coal heat input fractions to the commercial Co-Processing plant are approximately 0.705 and 0.295, respectively. Based on these heat input fractions and sulfur dioxide emissions of less than 0.6 lb/million Btu from burning Co-Processed fuels, a sulfur dioxide removal efficiency of at least 84.1 percent, per 40 CFR 60.43 a(h)(2) is required to meet NSPS for duct burners. Since the Co-Processing plant will remove more than 84.1 percent of its sulfur input from the crude oil and coal feed, burning Co-Processed fuel (distillate or naphtha) meets also this NSPS of 84.1 percent sulfur dioxide removal for duct burners.

In the case that heat input to duct burners is 250 million Btu/hr or less, but greater than 100 million Btu/hr, and is 30 percent or less heat input to the steam generating unit, the NSPS sulfur dioxide emission limit is 0.56 lb/million Btu for duct burners (with no percent removal requirements). Co-Processed distillate's 0.345 or total blend's 0.266 lb/million Btu sulfur dioxide emissions meet also this NSPS.

In short, based on current preliminary process design, Co-Processed fuel (distillate or naphtha) with a sulfur content of 0.33 weight percent or less emits approximately 50-65 percent less sulfur dioxide than PC or CFB base cases, and appears to meet the NSPS for the CSC or the CCC application. However, a case-by case evaluation will be required to determine whether more stringent sulfur dioxide emission limits might be imposed to satisfy the requirements of the new source review for a specific site, regardless of technology utilized.

5.2 Nitrogen Oxides Emissions

Nitrogen oxides (NOx) formed in combustion processes are usually due either to thermal fixation of atmospheric nitrogen in the combustion air (thermal NOx) or to the conversion of chemically bound nitrogen in the fuel (fuel NOx). The formation of thermal NOx depends strongly on peak temperature, excess oxygen level, and time of exposure. Fuel NOx emissions increase with increasing fuel nitrogen content (although not proportional) and fuel/air mixing. In contrast to thermal NOx, fuel NOx production is relatively insensitive to small changes in combustion zone temperatures.

For natural gas and light distillate oil (less than 0.01 percent nitrogen by weight) firing, nearly all NOx emissions are thermal NOx. With Co-Processed distillate (0.12 percent nitrogen by weight) and residual oil (0.1-0.5 percent nitrogen by weight), fuel NOx can account for a significant portion of total NOx production. With coal (0.5-2.0 percent nitrogen by weight), fuel NOx can account for even higher percentages of total NO_x production than residual oil.

For conventional PC boilers, the uncontrolled NOx emissions will be in the range of 1.0 to 2.0 lbs/million Btu heat input. By applying low-NOx burners and other combustion modification techniques, a PC boiler firing bituminous coal will be capable of meeting the NSPS of 0.60 lb/million Btu heat input. Assuming that no additional NOx emission reduction is required to satisfy requirements of the PSD review, this 0.6 lb/million NOx is equivalent to NOx emissions of approximately 430 ppmvd at 3 percent excess oxygen for the unwashed coal.

For CFB boilers which typically have much lower combustion temperatures (1,550-1,600 F) than PC boilers, NOx emissions will be in the range of 0.10 to 0.30 lb/million Btu with staged secondary air techniques. Assuming that no additional NOx emission reduction is required to satisfy the PSD review, the emissions of 0.10 to 0.30 lb/million are equivalent to approximately 70 to 220 ppmvd NOx at 3 percent oxygen for the unwashed coal.

For Co-Processing/Simple Cycle applications, the uncontrolled NOx emissions from the combustion turbine burning either distillate or distillate/naphtha blend are expected to be approximately 140 to 210 ppmvd at 15 percent oxygen. By water injection (or steam injection if desirable) into the combustion chamber at appropriate water/fuel ratios to lower the peak temperature, NOx emissions from the combustion turbine will be reduced from the 140-210 ppmvd range to approximately 42 ppmvd. Assuming that no additional NOx reduction is required to satisfy the PSD review, the NOx emissions of 42 ppmvd at the 15 percent oxygen level are equivalent to approximately 0.162 lb/million Btu Co-Processed fuel heat input to the combustion turbine.

For Co-Processing/Combined Cycle applications burning either distillate or distillate/naphtha blend, by similar steam injection (or water injection if desirable), NOx emissions from the CCC combustion turbine alone will be approximately 42 ppmvd. Similarly, the NOx emissions of 42 ppmvd at the 15 percent oxygen level are equivalent to approximately 0.162 lb/million Btu Co-Processed fuel heat input to the combustion turbine of the CCC application.

Per EPA definitions, Co-Processed distillate or distillate/naphtha blend with a 0.09-0.12 weight percent nitrogen is classified as "residual oil" (greater than 0.05 weight percent nitrogen), not as "distillate oil" (0.05 weight percent nitrogen or less). As a result, NOx emissions from Co-Processed fuel-fired duct burners for the CCC service will be designed to meet the NSPS of 0.4 lb/million Btu as required for duct burners firing "residual oil." The 0.4 lb/million Btu emissions are equivalent to approximately 310 ppmvd NOx at 3 percent oxygen typically for utility boilers.

Flue gas inlet to the CCC waste heat recovery boiler will consist of combustion turbine exhaust gas and duct burner flue gas. Assuming that no additional NOx reduction is required to satisfy the PSD review requirement, NOx emissions from the waste heat recovery boiler will depend on the relative fuel flow ratio to the turbine and duct burner. For the assumed case of approximately 2:1 fuel flows to the combustion turbine and duct burner, NOx emissions will be approximately 0.241 lb/million Btu Co-Processed fuel heat input to the CCC application. For the sake of comparison, these combined NOx emissions from the CCC application will be approximately 190 ppmvd if adjusted to 3 percent excess oxygen or approximately 62 ppmvd if adjusted to 15 percent excess oxygen.

5.3 Carbon Monoxide Emissions

Carbon monoxide (CO) emissions are due to unburnt combustibles, which generally are in quite small amounts except during start-ups, temporary upsets or other conditions preventing complete combustion. Measures used for NOx control such as water/steam injection or combustion modifications (low temperature or low excess air) can increase CO emissions. Therefore, such measures are generally applied only to the point where CO emissions will not be excessive.

For PC boilers firing bituminous coal, CO emissions are expected to be approximately 0.02-0.04 lb/million Btu heat input. This is equivalent to approximately 25-50 ppmvd at 3 percent excess oxygen based on the unwashed coal.

For CFB boilers, CO emissions are expected to be higher than PC boilers due to lower combustion temperatures. CO emissions from CFB boilers are expected to be approximately 0.05-0.15 lb/million Btu heat input or 60-180 ppmvd at 3 percent oxygen based on the unwashed coal.

For the Co-Processing/Simple Cycle application, CO emissions will be approximately 21-65 ppmvd at 15 percent oxygen or 0.05-0.15 lb/million Btu heat input for firing either Co-Processed distillate alone or distillate/naphtha blend .

For the CCC application, CO emissions from the combustion turbine alone will be approximately 21-65 ppmvd at 15 percent oxygen or 0.05-0.15 lb/million Btu heat input as in the above CSC application. CO emissions from Co-Processed fuel-fired duct burners will be approximately 0.03-0.06 lb/million Btu heat input or 40-80 ppmvd at 3 percent oxygen. These CO emissions will be relatively independent of the Co-Processed fuel used (distillate or distillate/naphtha blend). However, the combined CO emissions from both the combustion turbine and the duct burner will depend on the relative fuel flow ratio to them. For the assumed case of a ratio of approximately 2:1 between combustion turbine and duct burner fuel flows, CO emissions will be approximately 0.043-0.12 lb/million Btu heat input. These CO emissions are equivalent to approximately 18-50 ppmvd if adjusted to 15 percent oxygen, or 55-155 ppmvd if adjusted to 3 percent oxygen.

TABLE 5.1

COMPARISON OF AIR EMISSIONS
FOR FOUR POWER GENERATION ALTERNATIVES

Air Emissions	PC Boiler With Scrubber (PC)	Fluidized Bed Boiler (CFB)	Co-Processor Simple Cycle (CSC)	Co-Processor Combined Cycle (CCC)
In Lb/Million Btu[1]				
Sulfur Dioxide(SO_2)	≤ 0.727	≤ 0.727	0.266	0.345[3]
Nitrogen Oxides(NO_x)	≤ 0.6	0.10-0.30	0.162	0.241[2]
Carbon Monoxide(CO)	0.02-0.04	0.05-0.15	0.05-0.15	0.043-0.12[2]
In PPM By Volume, Dry @ 3% Oxygen				
Sulfur Dioxide	≤ 375	≤ 375	150	195[3]
Nitrogen Oxides	≤ 430	70-220	127	190[2]
Carbon Monoxide	25-50	60-180	65-190	55-155[2]
In PPM By Volume, Dry @ 15% Oxygen				
Sulfur Dioxide	--	--	50	65[3]
Nitrogen Oxides	--	--	42	62[2]
Carbon Monoxide	--	--	21-65	18-50[2]

NOTES:

(1) Based on heating values of Co-Processed fuel and coal used for power generation, respectively.

(2) Assuming that Co-Processed fuel feeds to combustion turbines and duct burners in the CCC are approximately 2 to 1.

(3) Based on Co-Processed distillate only (HHV= 19,140 Btu/lb and sulfur of 0.33 percent by weight). These values will decrease with increasing naphtha usage. When all naphtha is blended with all distillate, sulfur dioxide emissions will be 0.266 lb/million Btu or 150 ppmvd at 3 percent oxygen.

6.0 CONCLUSIONS

These results show that all of the technologies are competitive from an economic standpoint. It also shows that the Co-Processing Technology becomes particularly most competitive at lower dispatch factors. The reason for the sensitivity to dispatch factor is that the Co-Processor Process produces clean liquid fuels that can be easily sold or stored, until peak power is needed, when they can be burned in less expensive combustion turbine generators. This allows the capital intensive Co-Processing facility to be base loaded independently of the power generating equipment. The Co-Processing facility can continue to produce fuel whether the combustion turbine (CT) is dispatched or not. The other coal based technologies studied do not have the storage and peaking capability inherent in the Co-Processing plant. With these technologies the complete investment must sit idle during periods when power is not being generated.

The naphtha and utility fuel produced can be blended for use in the CT at high dispatch factors. At medium dispatch factors, the naphtha not needed can be sold on the market. At low dispatch factors, the extra utility fuel not utilized can also be sold as a #2 fuel oil equivalent. These sales provide credits against the cost of power production.

The results of the generation sensitivity study also show that the Co-Processing simple cycle power plant is the best economical choice for peaking purposes, at dispatch factors of less than 20 percent, when compared to other coal based fuel generation within the specific parameters of the study. The approximate break even dispatch factor for CCC vs. CFB is 60 percent dispatch factor the approximate busbar cost of electricity produced by the CCC and CFB is 102 Mills/Kwh. While the busbar cost for PC is 114 Mills/Kwh. The following table shows the levelized busbar cost for varying dispatch factors for the base case:

LEVELIZED BUSBAR COSTS (MILLS/Kwh)

	10% DF	35% DF	61% DF	96% DF
CCC	276.5	123.5	101.0	87.6
CSC	186.2	137.3	127.2	N/A
CFB	292.9	134.7	100.3	76.9
PC	394.8	148.0	112.7	85.1

The air pollutant emissions, in the form of SO_2, from the Co-Processing Combined Cycle Power Plant are approximately 50 to 65 percent less than a Pulverized Coal Power Plant with a wet scrubber and/or a Circulating Fluidized Bed Power Plant. The CCC and CFB carbon monoxide and NO_x emissions are approximately equal.

All utilities have a mix of both base and peak load demands. The flexibility of the Co-Processing combined cycle to easily uncouple the combustion turbine to operate in the simple cycle mode and quickly respond to peak generation demands and at higher dispatch factors competitively produce intermediate load generation makes this clean coal based fuel technology more attractive, within the study guidelines, when compared to the other technologies studied.

Thus it appears that Co-Processing technology (CCC/CSC) is very competitive compared to PC and CFB based on the following:

1. It processes poor grade coal (high sulfur) and heavy oil which are in abundant supply in North America.

2. It is more competitive at dispatch factor at or below 60 percent.

3. It is far more competitive in meeting peak demands for any coal based technology studied.

4. Clean liquid fuel which is produced can be utilized in less expensive combustion turbine generators.

5. It meets stringent environmental criteria of clean air and reduces acid rain without producing waste in the form of ash, scrubber sludge and slag.

6. Fuel can be stored and/or sold and the plant can continue full production independent of the electric generation plant does not have to stand idle.

APPENDIX A

DETAILED PLANT DESCRIPTIONS

APPENDIX A
DETAILED PLANT DESCRIPTIONS

A.1 Co-Processor/Combined Cycle (CCC)

A.1.1 General

The design basis for the 310 MW net Co-Processor Combined Cycle (CCC) Generating Unit is derived from two sources. The Coal/Oil Co-Processing design basis given in the SWEC Preliminary Process Description (PPD), and the Combined Cycle Plant is composed of a conventional combustion turbine, a supplementary fired heat recovery steam generator (HRSG), and a steam turbine with auxiliaries. The central portion of the process plant is based on the technology developed by Hydrocarbon Research Incorporated (HRI) and produces Distillate fuel to supply the General Electric MS 7001F (Frame 7F) combustion turbine generators and the supplementary fired Heat Recovery Steam Generators (HRSG's).

The coal feed is a 40/60 blend of Ohio No. 5 and No. 6 coal described in Table 2-1A. Coal is received (2 in x 0 in), pulverized to minus 30 mesh, and slurried with petroleum derived residual oil before being fed to the Co-Processor. Crude oil feed (see Table 2-3) is separated by atmospheric distillation into naphtha and distillate products, and an atmospheric bottoms stream. These atmospheric bottoms, with properties of API gravity of 6.6, 5.17 percent sulfur, and 0.52 percent nitrogen, are used in the coal/oil feed slurry.

A.1.1.1 Land and Land Rights

Land requirement is 110 acres which includes 75 acres for the Co-Processor facility and 5 acres for the combined cycle power plant, and the balance for additional fuel and vacuum bottoms storage.

A.1.1.2 Yardwork

The area to be built upon and the coal storage area will be cleared and graded. Landscaping is not included. An 8 foot high chain link security fence is provided around the main plant area. Roadways around the plant will be paved. A paved main access road is provided around the main plant area.

The Co-Processor facility and the power plant each have their own service water and boiler feedwater storage. The Co-Processor Plant has a 500,000 gal. storage tank for service water, a 450,000 gal. tank for firewater, a 40,000 gal. tank for demineralized water, and a 15,000 gal. tank for potable water. The Combined Cycle Plant has two 600,000 gal. tanks for combined raw water, service water, and fire water storage, a 500,000 gal. tank for demineralized water storage, and a 500,000 gal condensate storage tank.

Onsite feed storage consists of a 15-day supply of coal, a 15-day supply of crude oil, and a 60-day supply of turbine fuel (either No. 2 Fuel Oil or Co-Processor distillate product) for backup in case of an interruption in Co-processor Plant operation.

A.1.1.3 Main Buildings

The Administration Building covers 6,000 ft^2 and includes offices as well as a Satellite Control Room. The Control Building covers 6,000 ft^2 and houses, in addition to the Main Control Room, a Locker Area and Lunch Area. Both of these buildings are constructed of insulated metal siding and are equipped with HVAC. The Maintenance/Warehouse Building covers 5,750 ft^2 and includes maintenance shops, a chemical laboratory, and warehouse space for spare parts etc.

A.1.1.4 Miscellaneous Buildings

Miscellaneous buildings include:

a) Wastewater Treatment Building
b) Analyzers Shelters (5)
c) Fire Station
d) Satellite Control Buildings (3)
e) Demineralizer Building and Fire Pumphouse
f) Switchgear Buildings (3)

A.1.1.5 Makeup Intake Structure

The makeup water system for the plant is installed to supply 1,350 gpm of raw water makeup to the cooling tower and water treatment system. Two 50 percent makeup water pumps are located in a screenwell at the river. The screenwell is a concrete structure containing the pumps, two stationary intake screens, and a chlorination equipment room.

A.1.1.6 Water Treatment

Raw water will be pumped from the raw water storage tanks to the solids contact clarifier. Hydrated lime, and alum (coagulant aide) will be injected in the primary zone of the clarifier to the incoming raw water. Floc formation and mixing action in the clarifier will coagulate particles where solids separation will take place and the softened clarifier water will then be filtered in a 3 bay gravity filter. Filtrate will be collected in the wetwell immediately below the gravity filter. Clarified, softened and filtered water will then be transferred from the wetwell by pumps to the level controlled tank.

Service water pumps will transfer water from the service water storage tank and pressurize the service water header. A side stream from the service header will be diverted and chlorinated as make up for potable water to the potable water storage tank.

Demineralizer make-up water will also be drawn from the service water storage tank and pumped to a two train demineralizer system. Each demineralizer train will consist of strong acidification, strong base anion and mix bed. Each train will be of full capacity and will produce neutral waste through a waste neutralization tank. The demineralizer system will also include acid/caustic regeneration skids complete with day tanks, metering pumps, dilution tees, etc. Acid and caustic bulk storage tanks will be used for chemical supply. Demineralized product water will be stored in a rubber lined steel tank. Demineralized water will be pumped to consuming units.

A.1.1.7 Wastewater Treatment System

The wastewater treatment system consists of an equalization basin, dissolved air flotation (DAF) system, primary and secondary clarifiers, physical/chemical precipitation and settling facilities, gravity filter, post-aeration basin and contaminated and non-contaminated run-off holding ponds.

The streams that terminate in the equalization basin include non-segregated waste streams from the sour water stripper, segregated desalter stream, contaminated rain run-off (and non-contaminated run-off when it becomes contaminated) from the holding pond. The waste is transferred to the dissolved air flotation unit by screw pumps.

The effluent waste from the equalization basin is mixed with a dissolved air/water mixture in the DAF unit. The air/water mixture includes pressurized dissolved air and recycled effluent. The oil and grease skimmed from the top of the DAF unit are sent to a recovered oil tank and then pumped to the slop tank/crude storage tanks. The sludge collected from the DAF unit is pumped to Unit 1100 (Bottoms Processing). The effluent wastewater from the DAF is transferred to the primary clarifier and then onto the physical/chemical precipitation and settling tanks by gravity flow.

The effluent from the primary clarifier is mixed with a chemical feed stream before it reaches the physical/chemical precipitation and settling tanks. The sludge collected from the settling tanks is pumped to Unit 1100 (Bottoms Processing). The effluent wastewater is transferred to the aeration basin by gravity flow.

Before the effluent from the physical/chemical precipitation and settling tanks reaches the aeration basin, it is mixed with recycled effluent from the post aeration basin and recycled sludge from the secondary clarifier. The air to the aeration basin is supplied by air blowers and is diffused and mixed in the water by mechanical agitators. The effluent wastewater is transferred to the secondary clarifier by gravity flow.

Sludge collected from the secondary clarifier is recycled to the aeration basin. The excess sludge is sent to the dewatering unit. The effluent wastewater is transferred to the filter by gravity.

Before the effluent from the secondary clarifier reaches the gravity filter, it is mixed with a chlorine stream for disinfection. The filter backwash water is returned to the aeration basin. Filtrate is collected in the wet well immediately below the filter. The filtrate is pumped from the filter wet well to the post aeration basin.

The wastewater in the post aeration basin is mixed with air supplied by air blowers and is diffused and mixed with the water by a mechanical agitator. The effluent may be recycled to the aeration basin (to reduce excessive BOD shock loading) and/or discharged to the outfall.

The contaminated rain from the process area will be held in the contaminated rain run-off holding pond. The effluent from this pond will be transferred at a controlled rate to the waste water treatment plant equalization basin. Water in the non-contaminated basin will be tested to determine whether or not the water is contaminated. If the water is contaminated, it will be transferred to the equalization basin. If it is not contaminated, it will be discharged to the outfall.

The sanitary waste treatment system includes a pre-aeration basin and an extended aeration package wastewater plant. All plant sanitary waste streams and drains will terminate in the pre-aeration basin. The waste in the pre-aeration basin is mixed with air supplied by air blowers. The waste from the pre-aeration basin is pumped to the extended aeration package wastewater plant where it is mixed with air supplied by air blowers. The sludge collected from the package plant clarifier is sent to the dewatering unit. The effluent is discharged to the outfall after chlorination.

A.1.1.8 Accessory Electrical Equipment

Electrical power is delivered to the plant via two independent 138 KV circuits from the utility company or the combined cycle plant via overhead transmission lines which dead-end in the high voltage switchyard. From there the power is transmitted through two 138 KV SF_6 circuit breakers into the primary terminals of two 20 MVA transformers which transform the voltage down to 13.8 KV. The secondary side of two 20 MVA transformers are cable connected to the incomer breakers of the 13.8 KV double ended switchgear. Double ended switchgear is characterized by two incomer breakers and a tie breaker, which are interlocked so that only two of the three breakers can be closed at the same time. This arrangement allows for redundancy, and all equipment is sized so that one circuit can handle the entire plant load in the event of one circuit outage.

From the 13.8 KV double ended bus, power is transmitted through two feeder breakers to the primary side of two 15 MVA transformers which transform the voltage down to 4.16 KV. The secondary side of the 15 MVA transformers flows through two incomer breakers of the 4.16 KV double ended switchgear. From the 4.16 KV double ended bus, power is transmitted through two fused switches to the primary side of two 2 MVA transformers which transform the voltage down to 480V. From the secondary side of the 2 MVA transformers, power is transmitted through two incomer breakers to the 480 volt double ended switchgear. Two other double feeder combinations feed two 1.5 MVA transformers and 1 MVA transformers from the 4.16 KV bus respectively to form 480 volt double-ended substations No. 1 and No. 2, which are similar to the 480 volt switchgear described previously. From the 480 volt switchgear, power is fed through feeder breakers to 480 volt Motor Control Centers (MCC) from which the plant 480 volt motors are supplied.

To provide for critical loads, a 1500 KVA emergency diesel generator feeds power to a 4.16 KV switchgear lineup through an incomer breaker.

Motors larger than 4500 horsepower are fed through circuit breakers from the 13.8 KV switchgear. Motors larger than 200 horsepower and smaller than 4500 horsepower are fed through fused contractors from the 4.16 KV bus. Motors 200 horsepower and smaller are fed through motor starters in the 480 volt motor control centers.

A.1.1.9 Instruments and Controls

A computer-based distributed control system (DCS) is provided.

A.1.1.10 Balance of Plant Equipment

A service air system is provided for general plant air use, including two oil-free reciprocating service air compressors with aftercoolers and receivers, each capable of delivering 125 psig, 1,000 scfm.

An instrument air system is provided, including an oil-free reciprocating instrument air compressor capable of delivering 125 psig, 350 scfm for instrument and control air. A heatless desiccant air drying system is included.

One auxiliary boiler rated at 50,000 lb/hr is supplied. The boiler will use either Co-Processor distillate product and condensate for makeup from the condensate storage tank. Also included is an auxiliary deaerator, two auxiliary boiler feed pumps, an auxiliary condensate pump, and a blowdown tank. The auxiliary boiler is located in the Administration and Service Building.

A.1.2 COMBINED CYCLE POWER PLANT

A.1.2.1 Main Powerhouse

The main powerhouse consists of three sections - the combustion turbine section, the steam turbine section, and the control building, which includes the control room on one floor and electrical switchgear equipment on the second floor. The combustion turbine and the steam turbine sections are equipped with ventilation only. The Control Building requires HVAC. Each of the sections is equipped with fire protection. The building is insulated and covered with metal siding.

A.1.2.2 Combustion Turbine and Steam Generating Equipment

One General Electric Company MS 7001F (Frame 7F) combustion turbine generators will fire the distillate fuel produced in the Co-Processor Plant. The combustion turbine-generators will also be capable of firing No. 2 oil for backup operation. The combustion turbine-generators include fuel skids, inlet and exhaust silencing, inlet air filtering, turning gear and motor, fire protection, NO_x steam injection system, motor control center, hydrogen supply and carbon dioxide purge systems, excitation compartment, switchgear compartment, and auxiliary transformer.

The combustion turbine heat recovery system consists of one Heat Recovery Steam Generator (HRSG), supplementary fired to 1400°F, with HP steam drum producing 1,124,615 lb/hr of 1800 psig 1005°F superheated steam, and a reheater section producing 955,900 lb/hr of 480 psig 1005°F superheated steam. The HRSG also includes an economizer, as well as HP superheater and reheater sections. Included with each steam generator is ductwork from the gas turbine exhaust flanges, a gunite-lined metal bypass duct, bypass damper, inlet damper, ductwork from the steam generator to the exhaust stack, exhaust damper, and a single gunite-lined metal exhaust stack (19 ft dia, 300 ft high).

The balance of the steam generating equipment includes:

(a) An HRSG sampling system.

(b) An HRSG vents, drain, and blowdown system.

(c) Closed component cooling water exchangers and pumps.

(d) A chemical treatment system for feeding oxygen scavenger, inhibitor and dispersant to the boiler feed system.

(e) HRSG Supplementary Firing burners and Fuel System.

A.1.2.3 Fuel Oil Equipment

In the event of an extended Co-Processor plant outage (greater than 60 days) No. 2 oil is used for fueling the gas turbines and for supplying fuel to the HRSG supplementary firing burners. The system consists of a 350,000 gal tank and two 150 gpm pumps with a discharge pressure of 300 psig.

A.1.2.4 Turbine Generator

The steam turbine generator is a General Electric 3,600 rpm tandem compound single reheat machine with a single flow 26 in. last-stage bucket. At steam conditions of 1,800 psig, 1000°F/1000°F, the unit is rated at 173,000kW at 2.5 in. Hg absolute. The turbine generator includes a protective valve system, steam bypass valves, lube oil system, steam seal system, controlled turbine exhaust water spray system, motor-operated turning gear, protective devices, thermocouples, supervisory instrumentation, operating instruments, and electrohydraulic control system. Feedwater cycle includes a 60 psia deaerator and a low pressure feedwater heater. The deaerator discharges into two 50 percent motor driven feed pumps, rated 1200 GPM each at 2300 psig discharge pressure, that supply feedwater to the HRSG economizer section.

A.1.2.5 Condenser System

The condenser system includes the main steam condenser with a duty of 831 MM Btu/hr. The condenser is a 1 pass 90/10 Cu/Ni, 36 ft long containing 15,765 tubes 5/8 in. diameter BWG 18 (heat transfer surface = 151,542 ft^2). Also included are two 50 percent capacity condensate pumps rated 1100 gpm each at 75 psig discharge pressure.

Cooling water is supplied to the main condenser by two circulating water pumps located in a pumphouse at the cooling tower. These pumps are 22,000 gpm each at TDH = 120 ft.

A.1.2.6 Cooling Tower

The cooling tower is a six-cell mechanical draft tower. The cooling tower is sized to meet the VWO condenser duty at the maximum ambient temperature design conditions.

A.1.2.7 Main Transformers

A 180 MVA transformer and two 100 MVA transformers will service the combustion turbine and single steam turbine.

A.1.3 COAL/OIL Co-Processor Plant

The Co-Processor Plant is divided into the following units:

Unit 000	Feed Storage and Handling
Unit 100	Coal Preparation
Unit 200	Co-Processor

Unit 300	Atmospheric Distillation
Unit 400	Steam Reforming
Unit 500	Intentionally Left Blank
Unit 600	Distillate Hydrotreating
Unit 700	Acid Gas Removal
Unit 800	Sulfur Plant
Unit 900	Light Ends Recovery
Unit 1000	Sour Water Stripping
Unit 1100	Bottoms Processing
Unit 1200	Utilities
Unit 1300	General Offsites

The daily plant feedstocks requirements are approximately as follows:

Feedstock	Requirement
Coal	800 tons
Crude Oil	7655 barrels
Natural Gas	9.0×10^6 SCF
Raw Water	1.4×10^6 gallons
Electricity	15,650 kW

The daily yield of products and byproducts from the plant are approximately as follows:

Product	Amount
Naphtha	4052 barrels/SD
Distillate Fuel	6344 barrels/SD
Bottoms Product	241 tons/SD
Sulfur	48 tons/SD
Ammonia	14 tons/SD

The following is detailed description of each process unit.

A.1.3.1 Unit 000 Feed Storage and Handling

The two primary feed stocks to the plant are Cold Lake Crude Blend and a 40/60 blend of Ohio No. 5 and No. 6 Coal. Cold Lake Crude Blend is received from a pipeline and stored in two 113,000 barrel floating roof tanks. From the storage tanks it is charged directly to the Atmospheric Distillation Unit. Coal is received either by truck or rail, metered, sampled and stored on-site before being conveyed to the Coal Preparation Unit.

A.1.3.2 Unit 100 Coal Preparation

In the Coal Preparation Unit, the coal blend is first classified, with the coal over 1/2 inch being sent to a hammer mill crusher. The crushed coal is recombined with the smaller (1/2 in. x 0) coal from the classifier, then the total coal stream is sent to be pulverized in an air swept bowl mill to the minus 30 mesh size required by the Co-Processor. The pulverized coal is pneumatically conveyed to surge bins located above the slurry mix tank in the Co-Processing Unit.

A.1.3.3 Unit 200 Co-Processor

Atmospheric bottoms from the Atmospheric Distillation Unit and coal from the Coal Preparation Unit are combined, then mixed with hydrogen, heated and fed to the Co-Processor section. In the two stage ebullated bed reaction system, most of the coal and atmospheric bottoms are converted to lighter products. Much of the sulfur is converted to easily removable hydrogen sulfide and most of the nitrogen combines with hydrogen to form ammonia.

Hydrogen from the reaction section is separated and purified, then recycled to the reactors. The liquid product from the reactor is separated and fractionated to produce naphtha, distillate and vacuum bottoms. Off gas is sent to the Acid Gas Removal Unit for H_2S removal, then goes to the Light Ends Recovery Unit where butane and propane are separated from the fuel gas. The naphtha product from the Co-Processor is blended with straight run naphtha from the Atmospheric Distillation Unit as it enters the Light Ends Recovery Unit where it is stabilized and serves as a lean oil for recovery of butane and propane. The distillate products are blended into the distillate fuel blend without further treatment. Vacuum bottoms product, which contains heavy oil, unconverted coal and ash, is sent to hot storage before flowing to the Bottoms Processing Unit where it is solidified. The solid bottoms product is temporarily stored on-site, then shipped by truck or rail as a low grade fuel (11,280 BTU/lb HHV).

A.1.3.4 Unit 300 Atmospheric Distillation

Cold Lake Crude from storage is separated into naphtha, distillate and atmospheric bottoms products in the Atmospheric Distillation Unit. The crude is desalted, preheated by exchanging heat with products and a column pumparound, then fractionated in a trayed distillation column. The naphtha product (straight run naphtha) is blended with Co-Processor naphtha, then stabilized in the Light Ends Recovery Unit. Distillate product is hydrotreated in the Distillate Hydrotreating Unit to reduce the sulfur level, then joins the Co-Processor distillate products to make up the blended distillate fuel oil. Atmospheric bottoms from the distillation unit is the oil portion of the feed to the Co-Processor Unit.

A.1.3.5 Unit 400 Steam Reforming

Hydrogen for the Co-Processor and the hydrotreaters is produced from natural gas in the Steam Reforming Unit. Natural gas is compressed, preheated and blended with steam, then passes through the reformer furnace where it is converted to hydrogen and carbon monoxide. The reformer effluent is then passed through a high temperature shift converter where most of the CO reacts with steam to produce additional H_2 and CO_2. The effluent is purified using a multi-bed pressure swing adsorption unit to produce 98.5 mol percent hydrogen product.

A.1.3.6 Unit 600 Distillate Hydrotreating

Straight run and Co-Processor distillate boiling in the range of 350-650 deg F is treated in the Distillate Hydrotreater to reduce the sulfur level to approximately 0.05 weight percent to meet diesel fuel specification. Other distillate products from the Atmospheric Distillate Unit and the Co-Processing Unit are sent directly to storage without hydrotreating.

The distillate feed is mixed with recycle and makeup hydrogen, preheated and reacted to convert practically all of the sulfur and nitrogen to H_2S and NH_3, respectively. Effluent from the reactor is cooled and separated in two stages into recycle hydrogen and stripper feed. The liquid portion of the effluent is steam stripped to remove H_2S, NH_3 and light ends, then goes to distillate fuel storage. Off gas from the stripper, along with intermittent purge from the effluent separator, goes to the Acid Gas Removal Unit for removal of H_2S and NH_3, then to the Light Ends Recovery Unit for separation of fuel gas from propane and butane products.

A.1.3.7 Unit 700 Acid Gas Removal Unit

Off gas streams from the Co-Processor and the Distillate Hydrotreater flow to the Acid Gas Removal Unit for removal of H_2S which is then sent to the Sulfur Plant for production of sulfur product. The treated combined gas stream goes to the Light Ends Recovery Unit where butane and propane products are recovered from the fuel gas.

The combined gas streams are compressed to 50 psia, then contacted with a solution of di-glycol amine (DGA), which absorbs H_2S from the gas down to a level of less than 100 ppm. Treated off gas flows directly from the amine contactor to the Light Ends Recovery Unit. Amine from the contactor, with the absorbed H_2S, flows to a reboiled amine stripper where the H_2S is stripped from the amine. H_2S acid gas flows from the stripper to the Sulfur Plant while lean amine from the bottom of the stripper is recycled to the contactor.

A.1.3.8 Unit 800 Sulfur Plant

H_2S acid gas from the Acid Gas Removal Unit and the Sour Water Stripping Unit flow to the Sulfur Plant where the H_2S is converted to elemental sulfur. The sulfur plant consists of two parallel Claus Sulfur trains followed by a Shell Claus Offgas Treater (SCOT) tail gas cleanup system.

Acid gas is partially combusted to SO_2 in a reaction furnace, then the uncombusted H_2S and the SO_2 react to form elemental sulfur and water. The sulfur product is condensed and stored as a liquid prior to shipment.

In the SCOT Unit, effluent from the Claus plant passes through a reducing gas furnace to convert SO_2 back to H_2S, then is treated in an amine contactor to absorb the H_2S. Treated off gas is incinerated for final conversion of remaining H_2S to SO_2. Amine from the contactor is stripped to remove the absorbed H_2S, then recycled to the contactor. The H_2S stripped from the amine is recycled to the Claus Plant.

A.1.3.9 Unit 900 Light Ends Recovery

The Light Ends Recovery Unit recovers propane and heavier hydrocarbons from the fuel gas and stabilizes the naphtha which is subsequently fed to the naphtha hydrotreater. The off gas from the unit supplies the majority of the fuel gas for the refinery.

Treated off gas from the Acid Gas Removal Unit is compressed, cooled and mixed with blended naphtha from the Co-Processor and the Atmospheric Distillation Unit. The resulting vapor is mixed with off gas from the deethanizer and the stabilizer, then passes through the LPG absorber where propane and heavier components are absorbed.

The liquid from the feed flash joins absorber bottoms to be stabilized. Part of the stabilized naphtha is recycled to the absorber as lean oil while the remainder goes to storage, to be later fed to the naphtha hydrotreater. Off gas from the stabilizer goes to the absorber while the LPG distillate product flows to the deethanizer. Deethanizer off gas is recycled to the LPG absorber, while mixed propane and butane from the bottom of the deethanizer is cooled and treated in the Mercaptan Removal System to ensure that the final products will meet corrosion specifications. After mercaptan removal, the propane and butane products are separated in the depropanizer. Propane is dried in a desiccant dryer, and both products are sent to pressurized storage.

A.1.3.10 Unit 1000 Sour Water Stripping

Sour water from several plant process units is treated in the Sour Water Stripping Unit to recover H_2S and NH_3 prior to being sent to waste treatment. The unit is based on the ARISTECH PHOSAM-W process licensed by USX Engineers and Consultants, Inc. The unit produces H_2S acid gas for sulfur production, anhydrous ammonia product and stripped sour water.

The combined sour water stream is stripped in a reboiled stripper, with the bottoms being cooled and sent to waste treatment. Overhead from the stripper flows through an absorber where ammonia is removed from the acid gas. Acid gas flows to the Sulfur Plant, and ammonia rich solution from the absorber is stripped in the Phosam stripper. Bottoms from the stripper is recycled to the absorber, and overhead consisting of ammonia and water is fractionated to produce the anhydrous ammonia product. Water from the ammonia fractionation is recycled to the sour water stripper.

A.1.3.11 Unit 1100 Bottoms Processing

Vacuum bottoms from the Co-Processing Unit, consisting of heavy oil, ash and unconverted coal, is solidified and shipped offsite as a solid fuel product. Vacuum bottoms is cooled by generating steam, then is introduced into a water bath solidification system, which produces cylindrical shaped solid product. The product is further cooled in the water bath, drained, then conveyed to a storage building.

From the storage building, the product is conveyed to a loading system for loading into rail cars or trucks.

An agitated storage tank with a hot oil heating system is provided for emergency storage of the bottoms product if the solidification system is inoperable. Provisions for diluting the bottoms with cutter stock are also available for extended storage requirements.

A.1.3.12 Unit 1200 Utilities

On-site utility systems include potable, service and demineralized water systems(described in Section A.1.1.6), a multi-level steam system, circulating cooling water system, plant and instrument air system, firewater system, fuel system and flare system.

A.1.3.13 Unit 1300 General Offsites

The General Offsites include the waste water treatment system (described in Section A.1.1.7), product and in-process tankage, and buildings (described in Section A.1.1.4) and site improvements.

Storage tanks, transfer and loading pumps are provided for all products as required. In addition, in-process storage is provided for critical intermediate streams to preclude the need for overall shutdowns due to temporary failures in individual units.

A.2 Pulverized Coal/Flue Gas Desulfurization (PC)

A.2.1 General

The plant consists of a 310 MW net unit, with a boiler, turbine generator and auxiliary equipment. The turbine generator is a tandem compound, two flow exhaust, condensing, reheat type, rated at 369,000 kW when operating at 2,400 psig, 1,000°F at the throttle, reheating to 1,000 °F, 2.5 inch Hg abs at the exhaust, 0.0 percent makeup with all seven stages of feedwater heating inservices. Steam for the turbine generator will be provided by a boiler having a maximum continuous rating (MCR) of

2,659,067 lb/hr at 2,600 psig and 1,005°F using pulverized Ohio No. 5 and No. 6 bituminous coal as fuel.

A.2.2 Site

The plant is located in the State of Ohio. The site is at an elevation of 600 feet above mean sea level and is clear and level. The site is served by the railroad. Railroad track will be provided for handling unit trains with rotary-dump hopper cars. Engines and cars for the coal unit trains are not included in the capital cost estimate. A river for raw water supply is 3 miles from the site.

A.2.3 Station Arrangement

The site is designed to accommodate two units of equal size. The boiler room and turbine room are enclosed.

A precipitator is provided for the collection of fly ash and located between the boiler air preheater and the induced draft fans.

A wet limestone flue gas desulfurization system is located between the induced draft fans and the stack.

Two 50 percent capacity motor driven boiler feed pumps are located on the operating floor along with the two high pressure feedwater heaters and the low pressure feedwater heaters.

The condenser is a single pass design with tubes perpendicular to the turbine centerline. Two 50 percent capacity condensate pumps are located adjacent to the condenser on the ground floor. The sixth and seventh point heaters are located in the condenser neck. A mechanical draft cooling tower is provided.

An auxiliary boiler for start-up and station heating is located on the ground floor in the Administration and Service Building.

Five coal pulverizers with their respective silos and feeders are located along the front of the boiler next to the turbine room auxiliary bay.

Adequate aisles, withdrawal spaces, and clearances for equipment maintenance, including turbine generator laydown space, are provided.

A.2.4 Description of plant and equipment

A.2.4.1 Land and Land Rights

Adequate land for the plant site and land rights for the makeup water pipeline are required. These costs are included in the capital cost estimate.

A.2.4.2 Yardwork

The area to be built upon and the coal storage area will be cleared and graded. Landscaping is not included. A paved main access road is provided from the existing highway, about 2,000 feet long. The roadways around the plant will be paved. An 8 foot high chain link security fence is provided around the main plant area.

An 18 inch buried pipeline provides plant makeup water from the river, approximately 3 miles away. A pump well is provided at the river with two full size makeup water pumps. Two 600,000 gallon tanks are provided for combined raw and firewater storage. Plant service water is also pumped from these tanks. Water for boiler feedwater makeup and condensate system makeup is stored in the 180,000 gallon demineralized water storage tank and condensate storage tank, respectively.

Provisions for a 60 day capacity coal pile is included. A system is installed for collecting rainwater runoff from the pile and pumping it to the wastewater treatment system. Provisions for a 60 day capacity limestone storage area is included. Cooling tower blowdown water is used for coal dust suppression, bottom ash removal, wash down and miscellaneous uses. It is stored in a 100,000 gallon storage tank.

Other yardwork consists of a storm sewer system, fire protection system, rail trackwork and lighting.

A.2.4.3 Main Powerhouse

The major plant components and buildings are supported on 75 ton piles, 50 feet long. Other buildings are supported on spread footings. The main powerhouse consists of a steel frame turbine building, auxiliary bay, control building, and boiler house, enclosed with metal siding. The control room and computer room are enclosed with concrete masonry and air conditioned. The buildings are provided with ventilation and fire protection. An elevator is installed to provide service to the boiler platform levels.

A.2.4.4 Administration Building

A two-level administration building is provided, supported on piles. It contains laboratories and rest rooms on the first level and with offices on the second level.

A.2.4.5 Miscellaneous Buildings

The miscellaneous yard buildings provide preengineered metal buildings for equipment and activities throughout the site. The buildings can be grouped into the following categories:

Gate house.

Fire pumphouse.

Chlorination building.

Auxiliary boiler and feedwater treatment building.

Warehouse.

Bottom ash pump building.

Hydrogen storage.

Ignition oil and equipment backwash building.

A.2.4.6 Boiler Plant

The steam generating unit is a natural circulation, balanced draft furnace type, with a drum, producing 2,659,667 lb/hr of steam at 2,600 psig/1,005°F, with a single reheat at 610 psig/1,005°F. The unit is coal-fired with No. 2 fuel oil provided for ignition. Feedwater is supplied at 475°F.

Five pressurized mills supply pulverized coal to the furnace. Two primary air fans are provided. Coal discharged from each coal silo hopper is fed to a gravimetric type coal feeder through chutes with shutoff gates. Each of the five feeders discharge through chutes to a pulverizer.

Thirty pulverized coal burners and No. 2 oil steam atomized ignitors are provided with the boiler package.

On regenerative type Ljungstrom air preheater is included.

Two 50 percent capacity forced draft fans are provided, each rated at 1,650,000 lb per hour, 17 inch H_2O, and driven by 2,400 hp electric motors located on ground level. the fan inlets are provided with acoustical silencers. The fans are controlled with inlet vanes.

Two 50 percent capacity induced draft fans are provided, each rated at 1,765,000 lb per hour, 31 inch H_2O, at 300°F and driven by a 4,500 hp electric motor. The fans are located at ground level and are equipped with inlet vane controls and inlet silencers. Glycol air heaters are installed in the fan inlet ducts for air preheater average cold end temperature control.

A.2.4.7 Feedwater Equipment

There are seven stages of extraction feedwater heating. They are divided into two high pressure closed feedwater heaters, a deaerator, and four low pressure closed feedwater heaters. All heaters are horizontal with Type 304 stainless steel tubes. The heaters are numbered in succession from the economizer inlet to the condenser. The sixth and seventh point heaters are located in the condenser neck. The first, second, fourth, and fifth point heaters are located on the operating floor of the turbine building. The deaerator is located at an elevation above the turbine building operating floor in the auxiliary bay.

Two 50 percent, 2,500 gpm, 3,000 psig centrifugal boiler feed pumps are provided. The pumps take suction from the deaerator and discharges to the second point heater. One 680 gpm, 1,400 psi startup boiler feed pump will be provided, driven by a 700 hp, 4,160 V electric motor.

A full flow condensate polishing system is provided consisting of 3 x 50 percent capacity filter-demineralizers and the necessary pretreatment and solids removal equipment.

A chemical treatment system is provided for feeding hydrazine and ammonia to the condensate and boiler feed system.

A.2.4.8 Ash Handling Systems

A bottom ash wet sluicing system, having a capacity of 30 tons per hour is provided, including a two compartment flooded type ash hopper, clinker grinders, jet pulsion type pumping equipment, conveying piping, and two 210 ton capacity dewatering bins. The ash is sluiced to the dewatering bins where it can be removed by truck for offsite disposal. The sluice water drains by gravity to two setting/surge tanks where the ash sluice pumps take suction.

A wet disposal system for pyrites, having a capacity of 10 tons per hour from the transfer bin, is provided, including tramp iron hoppers, jet pulsion type pumping equipment, and transfer tank. The ash is sluiced to the dewatering bins.

A dry fly ash handling system, having a capacity of 35 tons per hour from precipitator and economizer hoppers, is provided, including feeders, blowers, a 1,150 ton capacity silo with dustless unloaders. The ash is conveyed to the silo where it can be removed by truck for offsite disposal.

A.2.4.9 Coal Handling System

A complete coal handling system is provided for receiving, stockpiling, reclaiming, and coaling of inplant silos.

Unit trains are unloaded by a rotary car dumper at a rate of 2,500 tons per hour. Coal is then transported to the storage area for stock-out by a traveling stacker-reclaimer. If, during stock-out, coal is required at inplant silos, 600 or 1,200 tons per hour can be diverted to the boiler house. An electrically heated thaw shed will be provided. Normal reclaim from storage is by traveling stacker-reclaimer and can be at either 600 or 1,200 tons per hour. Emergency reclaim is by bulldozing or truck to an underground reclaim hopper. As with normal reclaim, rates can be either 600 or 1,200 tons per hour.

Both normal and emergency reclaimed coal are conveyed to a crusher house for crushing to a minus 1¼ inch product before transportation to the inplant silos. From the crusher house to the plant, dual conveyor paths are furnished, providing reliability in the coal handling system. Each path handles 600 tons per hour, permitting the maximum 1,200 tons per hour reclaim rate.

The system also includes all necessary dust suppression, dust collection, fire protection, weighing, tramp metal detection and removal, sampling, sump pumps and area drainage equipment.

A.2.4.10 Limestone Handling System

The limestone handling system is a complete system provided to contain receiving, storage and preparation equipment, including conveyors, hoppers, weigh scales, reclaimer, tunnels, pits, electrical controls, dust collection, and foundations for the buildings, conveyor supports, tunnels, pits, and sumps.

A.2.4.11 Fuel Oil Equipment

A light fuel oil system is provided for supplying ignition and warmup oil to the boiler. The system consists of a 150,000 gallon light oil storage tank, two 40 gpm, 300 psi oil pumps and piping and controls.

A.2.4.12 Stack

A 450 feet high reinforced concrete stack structure is provided to serve the unit. The concrete stack has a 17 foot diameter circular steel liner with a corrosion resistant fiberglass lining.

A.2.4.13 Precipitator

A cold side electrostatic precipitator is provided between the boiler air preheater outlet and the induced draft fans. The precipitator will remove the dust entrained in the flue gas leaving the air preheater such that emissions do not exceed 0.03 lb/MBtu.

The precipitator includes dampers, discharge electrodes, collecting plates, transformers-rectifier sets, and a rapping system. Flue gas ductwork is provided from the air preheater to the precipitator and from the precipitator to the induced draft fans. The precipitator will have a redundant electrical field.

A.2.4.14 Flue Gas Desulfurization (FGD) System

An FGD system to remove sulfur dioxide (SO_2) from flue gas is installed downstream of the precipitator and induced draft fans. The FGD system uses a limestone slurry for scrubbing the gas and uses fly ash to stabilize the sludge.

Flue gas from the induced draft fans enters three 50 percent absorber modules. These modules are of the spray tower type, with recycle tanks and pumps; SO_2 removal efficiency will be 90 percent. Each tower has inlet and outlet isolation dampers (zero leakage) and mist eliminators (for removing entrained droplets).

To prevent condensation in the cooled gases downstream of the absorber modules, a flue gas reheat system is provided, consisting of two fans supplying ambient air through a steam coil heat exchanger, using steam from the turbine crossover. The heated air mixes with the gases raising the temperature.

In addition to flue gas handling and SO_2 removal, there are systems for reagent storage/handling/preparation and waste storage/handling/treatment. Besides mechanical equipment, the FGD system has all necessary ductwork from the induced draft fans to the stack, piping, electrical work, instruments, buildings (with HVAC), and enclosures.

A.2.4.15 Turbine Generator

The turbine generator is a 3,600 rpm tandem compound, single reheat unit with a double flow low pressure element. Guaranteed output is 369,000 kW when operating at 2,400 psi/1,000°F at the throttle, reheating to 1,000°F, 2.5 inch Hg abs at the exhaust, 0.0 percent makeups, and with all seven stages of feedwater heating inservice.

The generator is a 3 phase, 60 Hz, 18,000 V, 3,600 rpm hydrogen cooled unit that is rated at 407,000 kVA, 0.90 OF, 0.55 SCR, with 45 psig hydrogen pressure. The exciter is a static type.

The generator is a hydrogen inner-cooler unit with water-gas heat exchangers mounted within the generator housing. Hydrogen cooling within the generator is achieved by means of inner cooled conductors within both the stator and the rotor. Circulation of the hydrogen is performed by a single multistage axial-flow compressor-type blower mounted on the turbine end of the rotor.

The exciter is totally enclosed and self-ventilated. Two air coolers are mounted within the enclosure to remove heat. They are water-air heat exchangers. The lube oil system will have two full size coolers. The seal oil system has a hydrogen side seal oil cooler and an air side seal oil cooler. Each of these coolers are gas-water heat exchangers.

Isolated phase bus ducts are provided to carry the generator output to the main transformer.

A.2.4.16 Makeup Intake Structure

The makeup water system is installed to supply 4,300 gpm of raw water makeup to the cooling tower, FGD, and other requirements. Two 50 percent makeup water pumps are included and located in a screenwell at the river. The screenwell is a concrete structure, containing the pumps, two stationary intake screens, and a chlorination equipment room.

A.2.4.17 Condenser Equipment

The LP element exhausts into a single pass, 210,000 square foot heat transfer surface area condenser with 38 foot long tubes oriented perpendicular to the turbine shaft. Condenser tubes are 90-10 Cu-Ni material, except those in the air cooling section which are 70-30 Cu-Ni. The condenser is floor supported, with expansion joints between the turbine exhaust and the condenser neck. Two 100 percent capacity two-stage condenser exhauster pumps are supplied. Two 50 percent capacity motor-driven vertical circulating water pumps are located at the cooling tower in a pumphouse. Each pump is rated at 50,000 gpm at 60 feet TDH with a 1200 hp motor. Two 50 percent capacity motor-driven condensate pumps are supplied, each driven by a 800 hp motor supplies 2,060 gpm at 1,125 feet. The vertical nine stage pumps take suction from the condenser hotwell.

A.2.4.18 Cooling Tower Equipment

The cooling tower is a six cell, counterflow, mechanical draft system constructed of wood (Douglas Fir), treated with acid copper chromate pressure preservative. Underground piping will connect the condenser to the cooling tower, this pipe will be steel encased in concrete inside the turbine building and concrete elsewhere.

A.2.4.19 Water Treatment System

The water treatment equipment is installed in the auxiliary boiler and feedwater treatment building. River water for makeup is processed through two 50 percent capacity clarified-filter units. This water is then pumped to the makeup water storage tank, located in the yard. Water for boiler makeup is pretreated and processed through a demineralized water treatment system. The pretreatment consists of lime softening, filters, and two each of anion, cation, and mixed bed exchange units. The water is pumped to the demineralized water storage tank in the yard.

A.2.4.20 Wastewater Treatment System

Wastewater from collection system will be treated by neutralization followed by treatment in two 50 percent clarifiers. Clarifier overflow is pumped to the FGD system for makeup and blowdown is pumped to the FGD thickener.

The sanitary waste treatment system includes a pre-aeration basin and an extended aeration package wastewater plant. All plant sanitary waste streams and drains will terminate in the pre-aeration basin. The waste in the pre-aeration basin is mixed with air supplied by air blowers. The waste from the pre-aeration basin is pumped to the extended aeration package wastewater plant where it is mixed with air supplied by air blowers. The sludge collected from the package plant clarifier is sent to the dewatering unit. The effluent is discharged to the outfall after chlorination.

A.2.4.21 Accessory Electrical Equipment

One normal station service transformer is included, with single primary and split secondary windings. It is rated at 40 MVA, 65°C, 17,700-4,160 V/4,160 delta-wye-wye conducted. Two half-size reserve station service transformers are included. The 4,160 V station service system consists of two 3,000 amp buses and 5 kV class indoor metal clad switchgear. Six 480 V double-ended load center substations and twenty-three 480 V motor control centers are provided. A 125 V dc battery system and a 400 kW, 480 V ac diesel generator are provided. The switchyard and transmission lines are outside the plant cost boundary.

A.2.4.22 Instruments and Controls

A computer-based distributed control system (DCS) is provided.

A.2.4.23 Miscellaneous Power Plant Equipment

A service air system is provided for general plant air use, including two oil-free reciprocating service air compressors with aftercoolers, intercoolers and receivers, each capable of delivering 125 psig, 1,000 scfm.

An instrument air system is provided, including an oil-free reciprocating instrument air compressor capable of delivering 125 psig, 350 scfm instrument, and control air. A heatless desiccant air drying system is included.

One auxiliary boiler rated at 90,000 lb per hour is supplied. The boiler will use No. 2 fuel oil and condensate for makeup from the condensate storage tank. Also included is an auxiliary deaerator, two auxiliary boiler feed pumps, an auxiliary condensate pump, and a blowdown tank. The auxiliary boiler is located in the administration and service building.

A.2.4.24 Main Transformer

One main transformer is included, rated at 407 kVA, 3 phase, 60 Hz 21,250 V delta primary and 345,000 V grounded wye secondary.

A.3 Circulating Fluidized Bed (CFB)

A.3.1 General

The 310 MW net plant consists of a single unit, with three boiler modules, a turbine generator and auxiliary equipment.

The turbine generator is a tandem compound, two flow exhaust, condensing, reheat type, rated at 369,000 kW when operating at 2,400 psig, 1,000°F at the throttle, reheating of 1,000°F, 2.5 inch Hg abs at the exhaust, 0.0 percent makeup with all seven stages of feedwater heating in service. Steam for the turbine generator will be provided by boilers having a maximum continuous rating (MCR) of 2,555,298 lb/hr at 2600 psi gauge and 1,005°F using Ohio No. 5 and No. 6 blend bituminous coal as fuel.

A.3.2 Site

The plant is located in the Ohio area. The site is at an elevation of 600 feet. above mean sea level and is clear and level. The site is served by the railroad. Railroad track will be provided for handling unit trains with rotary-dump hopper cars. Engines and cars for the coal unit trains are not included in the capital cost estimate. A river for raw water supply is three miles from the site.

A.3.3 Station Arrangement

The site is designed to accommodate a single unit. The boiler room and turbine room are enclosed.

The unit consists of three 125 MW boiler modules. Each module is comprised of a steam generation unit with baghouse and is independent, from primary and secondary air fans through and including induced draft fans. A single stack is utilized for each unit.

Two 50 percent capacity motor driven boiler feed pumps are located on the operating floor along with the two high pressure feedwater heaters and four low pressure feedwater heaters.

The condenser is a single pass design with tubes perpendicular to the turbine centerline. Two 50 percent capacity condensate pumps are located adjacent to the condenser on the ground floor. The sixth and seventh point heaters are located in the condenser neck. A mechanical draft cooling tower is provided.

An auxiliary boiler for startup and station heating is located on the ground floor in the Administration and Service Building.

Adequate aisles, withdrawal spaces and clearances for equipment maintenance including turbine generator laydown space are provided.

A.3.4 Description of plant and equipment

A.3.4.1 Land and Land Rights

Adequate land for the plant site and land rights for the makeup water pipeline are required. These costs are included in the capital cost estimate.

A.3.4.2 Yard Work

The area to be built upon and the coal and limestone storage areas will be cleared and graded. Landscaping is not included. A paved main access road is provided from the existing highway, about 2,000 feet long. The roadways around the plant will be paved. An 8 foot high chain link security fence is provided around the main plant area.

An 18 inch buried pipeline provides plant makeup water from the river, approximately 3 miles away. A pump well is provided at the river with two full size makeup water pumps. Two 600,000 gallon tanks are provided for combined raw and firewater storage. Plant service water is also pumped from these tanks. Water for boiler feedwater makeup and condensate system makeup is stored in the 180,000 gallon demineralized water storage tank and condensate storage tank, respectively.

Provision for a 60 day capacity coal pile is included. A system is installed for collecting rain water runoff from the pile and pumping it to the Wastewater Treatment System. Cooling tower blowdown water is used for coal dust suppression, wash down and miscellaneous uses. It is stored in a 100,000 gallon storage tank.

Other yard work consists of a storm sewer system, fire protection system, rail trackwork and lighting.

A.3.4.3 Main Power House

The major plant components and buildings are supported on 75 ton piles, 50 feet long. Other buildings are supported on spread footings. The main power house consists of a steel frame turbine building, auxiliary bay, control building, and boiler house, enclosed with metal siding. The control room and computer room are enclosed with concrete masonry and air conditioned. The buildings are provided with ventilation and fire protection. An elevator is installed to provide service to the boiler platform levels.

A.3.4.4 Administration Building

A two-level administration building is provided, supported on piles. It contains laboratories and rest rooms on the first level and with offices on the second level.

A.3.4.5 Miscellaneous Buildings

The miscellaneous yard buildings provide preengineered metal buildings for equipment and activities throughout the site. The buildings can be grouped into the following categories:

Gate house.

Fire pumphouse.

Chlorination building.

Auxiliary boiler and feedwater treatment building.

Warehouse.

Hydrogen storage.

Ignition oil and equipment backwash building.

A.3.4.6 Boiler Plant

The steam generating unit is a circulating fluid bed boiler comprised of three modules with a combined output of 2,555,298 lb/hr of superheat steam at 2,600 psig and 1,005°F and 2,059,126 lb/hr reheat steam at 563 psig and 1,005°F. The unit is designed for Ohio No. 5 and No. 6 blend bituminous coal, limestone with 90 percent $CACO_3$ content and No. 2 fuel oil for ignition. Feedwater is supplied at 470°F.

Each boiler module, capable of 40 percent total output, consists of a CFB combustor with a refractory lined lower section and a water wall lined upper section, two recycle cyclones located at the outlet of the CFB to collect approximately 99 percent of the entrained solids for circulation back to the circulating bed, and a single boiler backpass with two storage superheater. A single tubular air heater designed with gas over the tubes and air through the tubes is also supplied.

Six 300 ton coal bins sized for 12 hours capacity deliver fuel to three gravimetric feeders for gravity feed to the combustor. A single 650 ton 24 hour limestone storage bin located adjacent to the limestone crusher building provides for direct feed into the combustor via pneumatic transport. Two primary air fans, one secondary air fan, and two induced draft fans are also provided for each module.

A.3.4.7 Feedwater Equipment

There are seven stages of extraction feedwater heating. They are divided into two high pressure closed feedwater heaters, a deaerator, and four low pressure closed feedwater heaters. All heaters are horizontal with Type 304 stainless steel tubes. The heaters are numbered in succession from the economizer inlet to the condenser. The sixth and seventh point heaters are located in the condenser neck. The first, second, fourth, and fifth point heaters are located on the operating floor of the turbine building. The deaerator is located at an elevation above the turbine building operating floor in the auxiliary bay.

Two 50 percent, 2,500 gpm, 3,000 psig centrifugal boiler feed pump is provided. The pump takes suction from the deaerator and discharges to the second point heater. One 680 gpm 1,400 psig startup boiler feed pump will be provided, driven by a 700 hp 4160 V electric motor.

A full flow condensate polishing system is provided consisting of 3 x 50 percent capacity filter-demineralizers and the necessary pretreatment and solids removal equipment.

A chemical treatment system is provided for feeding hydrazine and ammonia to the condensate and boiler feed system.

A.3.4.8 Ash Handling Systems

A bottom ash system for this type of boiler is not required. A fly ash removal system is provided with ash pickup at the CFB bed drain, multiclone and baghouse hoppers and pneumatic transport to the ash storage silo. A complete ash removal system is provided for each module except for the storage silo for which only one is supplied per unit. The 2,000 ton silo is sized for 64 hour capacity to allow for a complete fillup during a weekend operation without emptying. Dry, dustless unloading is provided for.

A.3.4.9 Coal Handling System

A complete coal handling system is provided for receiving, stockpiling, reclaiming and coaling of inplant silos.

Unit trains are unloaded by a rotary car bumper beyond a thaw shed at a rate of 2,500 tons per hour. Coal is then transported to the storage area for stock-out by a travelling stacker-reclaimer. If, during stock-out, coal is required at inplant silos, 600 or 1,200 tons per hour can be diverted to the boiler house. An electrically heated thaw shed will be provided. Normal reclaim from storage is by travelling stacker-reclaimer and can be at either 600 or 1,200 tons per hour. Emergency reclaim is by bulldozing or truck to an underground reclaim hopper. As with normal reclaim, rates can be either 600 or 1,200 tons per hour.

Both normal and emergency reclaimed coal are conveyed to a crusher house for crushing to a minus 1/4 inch product before transportation to the inplant silos. From the crusher house to the plant, dual conveyor paths are furnished, providing reliability in the coal handling system. Each path handles 600 tons per hour, permitting the maximum 1,200 tons per hour reclaim rate.

The system also includes all necessary dust suppression, dust collection, fire protection, weighing, tramp metal detection and removal, sampling, sump pumps and area drainage equipment.

A.3.4.10 Limestone Handling System

The limestone handling system is a complete system provided to contain receiving, storage, and preparation equipment including conveyors, hoppers, weigh scales, reclaimer, tunnels, pits, electrical, controls, dust collection, and foundations for the buildings, conveyor supports, tunnels, pits, and sumps. A covered limestone pile with 30 days storage is provided. A belt conveyor transports limestone to the crusher building where it is dry crushed to a mean particle size of 300-500 microns. From here it is pneumatically transported to the four limestone storage bins.

A.3.4.11 Fuel Oil Equipment

A light fuel oil system is provided for supplying ignition and warmup oil to the boiler. The system consists of a 150,000 gallon light oil storage tank, two 40 gpm, 300 psi oil pumps and piping and controls.

A.3.4.12 Stack

A 450 foot high reinforced concrete stack structure is provided to serve the unit. The concrete stack has 17 foot diameter circular steel liner with a corrosion resistant fiberglass lining.

A.3.4.13 Baghouse

A pulse jet baghouse per module is provided between the air preheater outlet and the induced draft fans. The unit is complete with fiberglass bags, carbon steel shell, required hopper accessories, (hopper heating, level detecting, and vibrators) and is designed at an air to cloth ratio 3.75 to 1 with one compartment out for cleaning and one out for maintenance.

A.3.4.14 Turbine Generator

The turbine generator is a 3,600 rpm tandem compound, single reheat unit with a double flow low pressure element. Guaranteed output is 369,000 kW when operating at 2,400 psi/1,000°F at the throttle, reheating to 1,000°F, 2.5 inches Hg abs at the exhaust, 0.0 percent makeups, and with all seven stages of feedwater heating inservice.

The generator is a 3 phase, 60 Hz, 18000 V, 3,600 rpm hydrogen cooled unit that is rated at 407,000 kVA, 0.90 PF, 0.55 SCR, with 45 psig hydrogen pressure. The exciter is a static type.

The generator is a hydrogen inner-cooler unit with water-gas heat exchangers mounted within the generator housing. Hydrogen cooling within the generator is achieved by means of inner cooled conductors within both the stator and the rotor. Circulation of the hydrogen is performed by a single multistage axial-flow compressor-type blower mounted on the turbine end of the rotor.

The exciter is totally enclosed and self-ventilated. Two air coolers are mounted within the enclosure to remove heat. They are water-air heat exchangers. The lube oil system will have two full size coolers. The seal oil system has a hydrogen side seal oil cooler and an air side seal oil cooler. Each of these coolers are gas-water heat exchangers.

Isolated phase bus ducts are provided to carry the generator output to the main transformer.

A.3.4.15 Makeup Intake Structure

The makeup water system is installed to supply 4,300 gpm of raw water makeup to the cooling tower and other requirements. Two 50 percent makeup water pumps are included and located in a screenwell at the river. The screenwell is a concrete structure, containing the pumps, two stationary intake screens and a chlorination equipment room.

A.3.4.16 Condenser Equipment

The LP element exhausts into a single pass 210,000 square foot heat transfer surface area condenser with 38 foot long tubes oriented perpendicular to the turbine shaft. Condenser tubes are 90-10 Cu-Ni except those in the air cooling section which are 70-30 Cu-Ni. The condenser is floor supported, with expansion joints between the turbine exhaust and the condenser neck. Two 100 percent capacity two-stage condenser exhauster pumps are supplied. Two 50 percent capacity motor-driven vertical circulating water pumps are located at the cooling tower in a pumphouse. Each pump is rated at 50,000 gpm at 60 feet TDH with a 1,200 hp motor. Two 50 percent capacity motor-driven condensate pumps are supplied, each driven by a 800 hp motor supplies 2,060 gpm at 1,125 feet. The vertical 9 stage pumps take suction from the condenser hotwell.

A.3.4.17 Cooling Tower Equipment

The cooling tower is a six cell, counterflow, mechanical draft system constructed of wood (Douglas Fir), treated with acid copper chromate pressure preservative. Underground piping will connect the condenser to the cooling tower, this pipe will be steel encased in concrete inside the turbine building and concrete elsewhere.

A.3.4.18 Water Treatment System

The water treatment equipment is installed in the auxiliary boiler and feedwater treatment building. River water for makeup is process through two 50 percent capacity clarified-filter units. This water is then pumped to the makeup water storage tank, located in the yard. Water for boiler makeup is pretreated and processed through a demineralized water treatment system. The pretreatment consists of lime softening, filters, and two each of anion, cation and mixed bed exchange units. The water is pumped to the demineralized water storage tank in the yard.

A.3.4.19 Wastewater Treatment System

Wastewater from collection system will be treated by neutralization followed by treatment in two 50 percent clarifiers.

A.3.4.20 Accessory Electrical Equipment

One normal station service transformer is included, with single primary and split secondary windings. It is rated at 40 MVA, 60°C, 17,700-4,160 V/4,160 delta-wye-wye connected. Two half-size reserve station service transformers are included. The 4,160 V station service system consists of two 3,000 amp buses and 5 kV class indoor metal cald switchgear. Six 480 V double-ended load center substations and twenty-three 480 V motor control centers are provided. A 125 V dc battery system and a 400 kW, 480 V ac diesel generator are provided. The switchyard and transmission lines are outside the plant cost boundary.

A.3.4.21 Instruments and Controls

A computer based distributed control system (DCS) is provided.

A.3.4.22 Miscellaneous Power Plant Equipment

A service air system is provided for general plant air use, including two oil-free reciprocating service air compressors with aftercoolers, intercoolers and receivers, each capable of delivering 125 psig, 1,000 scfm.

An instrument air system is provided, including an oil-free reciprocating instrument air compressor capable of delivering 125 psig, 350 scfm for instrument and control air. A heatless desiccant air drying system is included.

One auxiliary boiler rated at 90,000 lb per hr is supplied. The boiler will use No. 2 fuel oil and condensate for makeup from the condensate storage tank. Also included is an auxiliary deaerator, two auxiliary boiler feed pumps, an auxiliary condensate pump and a blowdown tank. The auxiliary boiler is located in the Administration and Service Building.

A.3.4.23 Main Transformer

One main transformer is included, rated at 407 kVA, 3 phase, 60 Hz, 21,250 V delta primary and 345,000 volt grounded wye secondary.

A.4 Co-Processor/Simple Cycle Combustion Turbines (CSC)

A.4.1 General

The design basis for the 310 MW net Co-Processor Simple Cycle (CSC) Generating Unit is derived from the Coal\Oil Co-Processor design basis given in the SWEC Preliminary Process Description (PPD). The central portion of the process plant is based on the technology developed by Hydrocarbon Research Incorporated (HRI) and produces Distillate fuel to supply the General Electric MS 7001F (Frame 7F) combustion turbine generators.

The coal feed is a 40/60 blend of Ohio No. 5 and No. 6 coal described in Table 2-1A. Coal is received (2 in x 0 in), pulverized to minus 30 mesh, and slurried with petroleum derived residual oil before being fed to the Co-Processor. Crude oil feed (see Table 2.3) is separated by atmospheric distillation into naphtha and distillate products, and an atmospheric bottoms stream. These atmospheric bottoms, with properties of API gravity of 6.6, 5.17 percent sulfur, and 0.52 percent nitrogen, are used in the coal/oil feed slurry.

A.4.1.1 Land and Land Rights

Land requirement is 110 acres which includes 75 acres for the Co-Processor facility and 5 acres for the simple cycle power plant, and the balance for additional fuel and vacuum bottoms storage.

A.4.1.2 Yardwork

The area to be built upon and the coal storage area will be cleared and graded. Landscaping is not included. An 8 foot high chain link security fence is provided around the main plant area. Roadways around the plant will be paved. A paved main access road is provided around the main plant area.

The Co-Processor facility and the power plant each have their own service water, fire water and demineralized water storage. The Co-Processor Plant has a 500,000 gal. storage tank for service water, a 450,000 gal. tank for firewater, a 40,000 gal. tank for demineralized water, and a 15,000 gal. tank for potable water. The Simple Cycle Plant has two 600,000 gal. tanks for combined raw water, service water, and fire water storage and a 400,000 gal. tank for demineralized water storage.

Onsite feed storage consists of a 15-day supply of coal, a 15-day supply of crude, and a 60-day supply of turbine fuel (either No. 2 Fuel Oil or Co-Processor distillate product) for backup in case of an interruption in Co-Processor Plant operation.

A.4.1.3 Main Buildings

The Administration Building covers 6,000 ft^2 and includes offices as well as a Satellite Control Room. The Control Building covers 6,000 ft^2 and houses, in addition to the Main Control Room, a Locker Area and Lunch Area. Both of these buildings are constructed of insulated metal siding and are equipped with HVAC. The Maintenance/Warehouse Building covers 5,750 ft^2 and includes maintenance shops, a chemical laboratory, and warehouse space for spare parts etc.

A.4.1.4 Miscellaneous Buildings

Miscellaneous buildings include:

a) Wastewater Treatment Building
b) Analyzers Shelters (5)
c) Fire Station
d) Satellite Control Buildings (3)
e) Demineralizer Building and Fire Pumphouse
f) Switchgear Buildings (3)

A.4.1.5 Makeup Intake Structure

The makeup water system for the plant is installed to supply 1,350 gpm of raw water makeup to the water treatment system. Two 50 percent size makeup water pumps are located in a screenwell at the river. The screenwell is a concrete structure containing the pumps, two stationary intake screens, and a chlorination equipment room.

A.4.1.6 Water Treatment

Raw water will be pumped from the raw water storage tank to the solids contact clarifier. Hydrated lime, and alum (coagulant aide) will be injected in the primary zone of the clarifier to the incoming raw water. Floc formation and mixing action in the clarifier will coagulate particles where solids separation will take place and the softened clarifier water will then be filtered in a 3 bay gravity filter. Filtrate will be collected in the wetwell immediately below the gravity filter. Clarified, softened and filtered water will then be transferred from the wetwell by pumps to the level controlled tank.

Service water pumps will transfer water from the service water storage tanks and pressurize the service water header. A side stream from the service header will be diverted and chlorinated as make up for potable water to the potable water storage tank.

Demineralizer make-up water will also be drawn from the raw water storage tanks and pumped to a two train demineralizer system. Each demineralizer train will consist of strong acidification, strong base anion and mix bed. Each train will be of full capacity and will produce neutral waste through a waste neutralization tank. The demineralizer system will also include acid/caustic regeneration skids complete with day tanks, metering pumps, dilution tees, etc. Acid and caustic bulk storage tanks will be used for chemical supply. Demineralized product water will be stored in a rubber lined steel tank. Demineralized water will be pumped to the consuming units.

A.4.1.7 Wastewater Treatment System

The wastewater treatment system consists of an equalization basin, dissolved air flotation (DAF) system, primary and secondary clarifiers, physical/chemical precipitation and settling facilities, gravity filter, post-aeration basin and contaminated and non-contaminated run-off holding ponds.

The streams that terminate in the equalization basin include non-segregated waste streams from the sour water stripper, segregated desalter stream, contaminated rain run-off (and non-contaminated run-off when it becomes contaminated) from the holding pond. The waste is transferred to the dissolved air flotation unit by screw pumps.

The effluent waste from the equalization basin is mixed with a dissolved air/water mixture in the DAF unit. The air/water mixture includes pressurized dissolved air and recycled effluent. The oil and grease skimmed from the top of the DAF unit are sent to a recovered oil tank and then pumped to the slop tank/crude storage tanks. The sludge collected from the DAF unit is pumped to Unit 1100 (Bottoms Processing). The effluent wastewater from the DAF is transferred to the primary clarifier and then onto the physical/chemical precipitation and settling tanks by gravity flow.

The effluent from the primary clarifier is mixed with a chemical feed stream before it reaches the physical/chemical precipitation and settling tanks. The sludge collected from the settling tanks is pumped to Unit 1100 (Bottoms Processing). The effluent wastewater is transferred to the aeration basin by gravity flow.

Before the effluent from the physical/chemical precipitation and settling tanks reaches the aeration basin, it is mixed with recycled effluent from the post aeration basin and recycled sludge from the secondary clarifier. The air to the aeration basin is supplied by air blowers and is diffused and mixed in the water by mechanical agitators. The effluent wastewater is transferred to the secondary clarifier by gravity flow.

Sludge collected from the secondary clarifier is recycled to the aeration basin. The excess sludge is sent to the dewatering unit. The effluent wastewater is transferred to the filter by gravity.

Before the effluent from the secondary clarifier reaches the gravity filter, it is mixed with a chlorine stream for disinfection. The filter backwash water is returned to the aeration basin. Filtrate is collected in the wet well immediately below the filter. The filtrate is pumped from the filter wet well to the post aeration basin.

The wastewater in the post aeration basin is mixed with air supplied by air blowers and is diffused and mixed with the water by a mechanical agitator. The effluent may be recycled to the aeration basin (to reduce excessive BOD shock loading) and/or discharged to the outfall.

The contaminated rain from the process area will be held in the contaminated rain run-off holding pond. The effluent from this pond will be transferred at a controlled rate to the waste water treatment plant equalization basin. Water in the non-contaminated basin will be tested to determine whether or not the water is contaminated. If the water is contaminated, it will be transferred to the equalization basin. If it is not contaminated, it will be discharged to the outfall.

The sanitary waste treatment system includes a pre-aeration basin and an extended aeration package wastewater plant. All plant sanitary waste streams and drains will terminate in the pre-aeration basin. The waste in the pre-aeration basin is mixed with air supplied by air blowers. The waste from the pre-aeration basin is pumped to the extended aeration package wastewater plant where it is mixed with air supplied by air blowers. The sludge collected from the package plant clarifier is sent to the dewatering unit. The effluent is discharged to the outfall after chlorination.

A.4.1.8 Accessory Electrical Equipment

Electrical power is delivered to the plant via two independent 138 KV circuits from the utility company or the simple cycle plant via overhead transmission lines which dead-end in the high voltage switchyard. From there the power is transmitted through two 138 KV SF_6 circuit breakers into the primary terminals of two 20 MVA transformers which transform the voltage down to 13.8 KV. The secondary side of two 20 MVA transformers are cable connected to the incomer breakers of the 13.8 KV double ended switchgear. Double ended switchgear is characterized by two incomer breakers and a tie breaker, which are interlocked so that only two of the three breakers can be closed at the same time. This arrangement allows for redundancy, and all equipment is sized so that one circuit can handle the entire plant load in the event of one circuit outage.

From the 13.8 KV double ended bus, power is transmitted through two feeder breakers to the primary side of two 15 MVA transformers which transform the voltage down to 4.16 KV. The secondary side of the 15 MVA transformers flows through two incomer breakers of the 4.16 KV double ended switchgear. From the 4.16 KV double ended bus, power is transmitted through two current limiting fused switches to the primary side of two 2 MVA transformers which transform the voltage down to 480V. From the secondary side of the 2 MVA transformers, power is transmitted through two incomer breakers to the 480 volt double ended switchgear. Two other double feeder combinations feed two 1.5 MVA transformers and 1 MVA transformers from the 4.16 KV bus respectively to form 480 volt doublended substations No. 1 and No. 2, which are similar to the 480 volt switchgear previously described. From the 480 volt switchgear, power is fed through feeder breakers to 480 volt Motor Control Centers (MCC) from which the plant 480 volt motors are supplied.

To provide for critical loads, a 1500 KVA emergency diesel generator feeds power to a 4.16 KV switchgear lineup through an incomer breaker.

Motors larger than 4500 horsepower are fed through circuit breakers from the 13.8 KV switchgear. Motors larger than 200 horsepower and smaller than 4500 horsepower are fed through fused contractors from the 4.16 KV bus. Motors 200 horsepower and smaller are fed through motor starters in the 480 volt motor control centers.

A.4.1.9 Instruments and Controls

A computer-based distributed control system (DCS) is provided.

A.4.1.10 Balance of Plant Equipment

A service air system is provided for general plant air use, including two oil-free reciprocating service air compressors with aftercoolers, intercoolers and receivers, each capable of delivering 125 psig, 1,000 scfm.

An instrument air system is provided, including an oil-free reciprocating instrument air compressor capable of delivering 125 psig, 350 scfm for instrument and control air. A heatless desiccant air drying system is included.

A.4.2 SIMPLE CYCLE POWER PLANT

A.4.2.1 Main Powerhouse

The main powerhouse consists of two sections - the combustion turbine section and the control building, which includes the control room on one floor and electrical switchgear equipment on the second floor. The combustion turbine section is equipped with ventilation only. The Control Building requires HVAC. Each of the sections is equipped with fire protection. The building is insulated and covered with metal siding.

A.4.2.2 Combustion Turbine

Two General Electric Company MS 7001F (Frame 7F) combustion turbine generators will fire the distillate fuel produced in the Co-Processor Plant. The combustion turbine-generators will also be capable of firing No. 2 oil for backup operation. The combustion turbine-generators include fuel skids, inlet and exhaust silencing, inlet air filtering and evaporative cooling, turning gear and motor, fire protection, NO_x water injection system, motor control center, hydrogen supply and carbon dioxide purge systems, excitation compartment, switchgear compartment, and auxiliary transformer.

A.4.2.3 Fuel Oil Equipment

In the event of an extended Co-Processor plant outage (greater than 60 days) No. 2 oil is used for fueling the combustion turbines. The system consists of a 350,000 gal. tank and two 150 gpm pumps with a discharge pressure of 300 psig.

A.4.2.4 Main Transformers

A 180 MVA transformer and a 100 MVA transformer will service each combustion turbine.

A.4.3 COAL/OIL Co-Processor Plant

The Co-Processor Plant is divided into the following units:

Unit 000	Feed Storage and Handling
Unit 100	Coal Preparation
Unit 200	Co-Processor
Unit 300	Atmospheric Distillation

Unit 400	Steam Reforming
Unit 500	Intentionally Left Blank
Unit 600	Distillate Hydrotreating
Unit 700	Acid Gas Removal
Unit 800	Sulfur Plant
Unit 900	Light Ends Recovery
Unit 1000	Sour Water Stripping
Unit 1100	Bottoms Processing
Unit 1200	Utilities
Unit 1300	General Offsites

A destailed discussion of the individual Co-Pro units are included in subsections A.1.3.1 through A.1.3.13.

APPENDIX B

DESCRIPTION OF THE ECONOMIC MODEL

APPENDIX B

DESCRIPTION OF THE ECONOMIC MODEL

B.0 DESCRIPTION OF THE ECONOMIC MODEL PRINTOUTS (B1 & B2)

- CCC Ohio Clean Fuels Co-Processed Fuel with a Combined Cycle Generator
- CSC Ohio Clean Fuels Co-Processed Fuel with a Simple Cycle Generator
- PC Pulverized Coal with Flue Gas Desulfurization
- CFB Circulating Fluidized Bed

A printout of the model is contained in Appendix B for the base comparison of the CCC, PC and CFB technologies. Appendix B1 contains the case where all naphtha from the Co-Processor is sold and B2 contains the case where all naphtha is blended with the distillate and fired in the combined cycle generator. The printout is structured so that the first two pages summarize unique input data and results for the three technologies. The third and fourth pages contain common escalation factors and prices. Next, follows two pages for each technology showing the analysis for years 1990 - 2009.

This is a cost comparison of the technologies. It is assumed that 100 percent debt financing will be used and paid back over 20 years for all technologies. An attempt has been made to determine all unique comparative technology costs, such as the difference in land requirements. Costs such as permitting and legal fees have not been included and are assumed equal for these facilities. The Co-Processor byproducts of flaked bottoms, sulfur and ammonia are sold and appear as a negative cost in the analysis. Naphtha is sold in cases where it is not required for electric generation.

B.1 Inputs and Results

At the top of the first page of the printout, under the heading CAPITAL, are the capital cost of the alternatives and the electric operating parameters of the facilities. They are all 310,191 Kw net electric generation plants. The capacity factor is calculated as the product of the equivalent availability obtained from the EPRI Technical Assistant Guide and the Dispatch Factor. Dispatch factor is the percentage of time annually that the unit would be dispatched if it were available 100 percent of the time. The dispatch factor is the same for all technologies in each case and is printed at the bottom of the second page. The capacity factor for the Co-Processing unit is 330 days per year or 90.41 percent. For the case where all naphtha produced is sold, the following capacity factors are calculated for the electric generating units:

	CCC	PC	CFB
Dispatch Factor	61.34%	61.34%	61.34%
Availability	92.6%	79.3%	81.3%
Capacity Factor	57%	49%	50%

The capital costs of the facilities has been estimated by Stone & Webster and are split into direct and indirect costs. Allowance For Indeterminants (AFI) of 10 percent of direct costs has been added to each estimate. This is considered reasonable since the study assumes mature technology in all cases.

The next three sections of page 1 of the printout list the fuel (feedstock), consumable and byproducts for each technology. Most of these values are entered as hourly quantities which are multiplied by the hours of plant operation based on the plant capacity factor. In the CCC calculation, the different capacity factors for the Co-Processor unit and the combined cycle generation are taken into account when calculating annual quantity requirements. The byproduct section indicates the amount of utility fuel blend consumed by the combined cycle unit and the amount of naphtha sold. The two cases in appendix B show the following amounts:

	Sell Naphtha	No Naphtha Sales
Blend (Bbl/Hr)	264.33	433.16
Naphtha (Bbl/Hr)	168.83	0.0

The operation and maintenance costs are calculated along EPRI-TAG guidelines as follows:

- Operation is based on the number of operators indicated at 2,000 hours per year at $25. per hour.
- Total maintenance is calculated at 2.5 percent of direct capital cost. It is estimated that 40 percent of this is labor and 60 percent material.
- Owner's overhead is 30 percent of the total labor. This includes the cost of benefits to workers as well as the cost of management of the facilities.

After calculating the total O&M, it is split into Fixed O&M as the total O&M times Capacity Factor. The Variable O&M is the remainder.

The bottom of the first page of the printouts shows the resulting levelized busbar cost of electricity in mills/Kwh for the different technologies. This is calculated by taking the Net Present Value of the annual busbar cost at 11 percent and divided by the sum of the present worth factors. The busbar cost was calculated in each year by dividing the total cost by the number of kilowatts generated in that year. In this study the annual generation is constant within each technology for each year, therefore the initial prices and escalation parameters can heavily impact the results. In 1990, CCC is 3 mills/Kwh lower than the CFB; However, the twenty year levelized cost shows that the CCC is 1 mills/Kwh higher than the CFB.

BUSBAR COST IN MILLS/KWH

	1990	Levelized
CCC	81	101
PC	96	113
CFB	84	100

Page 2 of the printout shows the 1989 price of fuel (feedstock) and consumable. The fuel prices were derived from the Annual Energy Outlook prepared by the DOE. These prices as well as the escalations are described in section B.2 below. The transportation and consumable prices were estimated by Stone & Webster based on data from projects we are familiar with.

Page 2 also shows the Co-Processor capacity factor which is 90 percent (330 days per year). The combined cycle generator has been sized to utilize all of the blended distillate and naphtha produced by the Co-Processor unit. Adequate fuel storage has been included in the capital cost to cover for operating the combined cycle unit during outages of the Co-Processor. The overall annual net Kwh generated by the combined cycle unit has been adjusted for Co-Processor operation while the generator is out-of-service.

B.2 Escalation and Prices

Pages 3 and 4 of the printout show the 1989 prices and escalation parameters used in the analysis. These cases were derived from the Annual Energy Outlook dated Dec. 1988 (DOE/EIA-0383(89)) Base Forecast, Appendix A and a required DOE analysis of high sulfur coal in Ohio. These reports forecast in 1988 prices. For this study, escalation factors have been calculated from the DOE reports to facilitate calculations. The GNP (Gross National Product) Deflator is used for price categories not addressed in the report.

The delivered price of coal, crude, natural gas and the netback price of ammonia and flaked bottoms have been split into commodity and transportation for escalation purposes. The commodity escalation is based on the DOE report where possible. The transportation costs are adjusted by the GNP Deflator.

The DOE estimate of oil price is the imported cost for U.S. refiners (refiners acquisition cost - RAC). A regression analysis was performed comparing the price of WTI (West Texas Intermediate) to RAC in order to determine a basis for Cold Lake Blend, a feedstock of the Co-Processor unit. This analysis showed that the price of WTI averages $1.64 plus 97.8 percent imported crude. This is a differential of $1.32 per barrel in 1989 for the World Oil price of $14.93. This constant differential was used in all years to calculate WTI based on the DOE World Oil price. The Cold Lake Blend commodity percent price is estimated at 75 percent of WTI.

The coal, crude and natural gas prices are from the above mentioned DOE reports. Stone & Webster estimated the prices of sulfur, ammonia and naphtha Transportation prices were estimated using current rates and estimated distances. Flaked bottoms, a by-product of the Co-Processor, is priced at 65 percent of coal.

B.3 Annual Results

The remaining pages of the printout show the annual results for each technology as follows:

pages 5-6	- Co-Processor and Combined cycle
pages 7-8	- Pulverized coal with flue gas desulfurization
pages 9-10	- Circulating Fluidized Bed

Each of these show the above mentioned costs on an annual basis escalated at the appropriate rates. Since this is a cost analysis, revenue from by-products is shown as a negative cost added to the other costs. After the annual costs are calculated, they are divided by the annual net kilowatts generated by the facility to calculate the busbar cost in mills/Kwh. These annual busbar costs are then levelized and reported in the front summary page.

APPENDIX B1

BASE CASE - SELL ALL NAPHTHA

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
OCF CASE A - SELL ALL NAPHTHA
BASIC DATA

REV. 3.2 PAGE 1
DATE: 16 August 1989

			CO-PROCESSOR COMBINED CYCLE	PULVERIZED COAL	FLUIDIZED BED
			****** TECHNOLOGY INPUT BASE YEAR 1989 **********		
CAPITAL:	NET CAPACITY, KW		310,191	310,191	310,191
	CAPACITY FACTOR, %		57%	49%	50%
	FUEL REQUIREMENT (MMBTU/HR)		-	-	-
	DIRECT CAPITAL COST, $		$396,340,553	$412,688,884	$361,509,845
	INDIRECTS & DISTRIB'S, $		$60,426,146	$52,374,094	$45,595,707
	AFI @ 10%		$39,634,055	$41,268,888	$36,150,985
	TOTAL ESTIMATED COST,$		$496,400,754	$506,331,866	$443,256,537
	EQUIVALENT AVAILABILITY, %		92.6%	79.3%	81.3%
FUEL:	COAL USAGE	(TONS/HR)	33.3	152	148
	OIL USAGE	(BBL/HR)	319.0	0	0
	NATURAL GAS	(MMBTU/HR)	377.0	0	0
CONSUMABLES:	LIMESTONE,	(TONS/HR)	0	25.4	54.2
	DEMINERALIZED WATER	(GPM)	635	26	26.0
	MAKE-UP WATER	(GPM)	2632	4278	3180
	CHEMICALS	($/YR)	$4,192,680	$527,100	$527,100
	CONDENSATE POLISHING RECHRG,	(GPM)	$0	4,332	4,332
	WASTEWATER TREATMENT,	($/YR)	$0	$320,000	$320,000
	ASH DISPOSAL	(TONS/HR)	0	15.2	75.9
	FGD SLUDGE	(TONS/HR)	0	63.4	0
BY-PRODUCTS:	DISTILLATE/NAPHTHA BLEND	(BBL/HR)	264.33	0	0
	NAPHTHA SALES	(BBL/HR)	168.83	0	0
	FLAKED BOTTOMS	(TONS/HR)	10.00	0	0
	SULFUR	(TONS/HR)	2.10	0	0
	AMMONIA	(TONS/HR)	0.60	0	0
O & M:	LABOR FORCE - OPERATION	(MEN)	122	102	81
	OPERATION LABOR SALARY	($/YR)	$6,100,000	$5,100,000	$4,050,000
	MAINTENANCE (LABOR & MATERIAL $/YR)		$9,908,514	$10,317,222	$9,037,746
	OWNER'S OVERHEAD (@30% TOTAL LABOR)		$3,019,022	$2,768,067	$2,299,530
	TOTAL O & M COST		$19,027,535	$18,185,289	$15,387,276
	FIXED PART (TOTAL * CAP.FACTOR)		$10,807,800	$8,845,801	$7,673,545
	VARIABLE O & M, (TOTAL - FIXED)		$8,219,735	$9,339,488	$7,713,731

EFFECTIVE FUEL COST CALCULATION:		CCC	PC	CFB
FEEDSTOCK COST	(mills/kwh)	72.732	27.468	26.799
BYPRODUCT SALES	(mills/kwh)	-43.538	0.000	0.000
EFFECTIVE LEVELIZED FUEL COST	(mills/kwh)	29.194	27.468	26.799

20 YEAR LEVELIZED BUSBAR COSTS:				
CAPITAL COST	(mills/kwh)	47.196	54.532	46.565
EFFECTIVE FUEL COST	(mills/kwh)	29.194	27.468	26.799
CONSUMABLES COST	(mills/kwh)	5.931	10.438	10.207
FIXED O & M COST	(mills/kwh)	10.620	9.846	8.331
VARIABLE O & M COST	(mills/kwh)	8.077	10.396	8.375
TOTAL LEVELIZED BUSBAR COST	(mills/kwh)	101.016	112.679	100.277

COMMODITY UNIT PRICES AND VARIOUS FINANCIAL FACTORS BASE YEAR 1989

			PRICE	UNITS
FUEL	HIGH-SULFUR COAL	(COMMODITY)	$29.72	($/TON)
	HIGH-SULFUR COAL	(TRANSPORTATION)	$7.00	($/TON)
	NATURAL GAS	(COMMODITY)	$1.80	($/MMBTU)
	NATURAL GAS	(TRANSPORTATION)	$0.70	($/MMBTU)
	HEAVY CRUDE	(COMMODITY)	$12.19	($/BBL)
	HEAVY CRUDE	(TRANSPORTATION)	$1.68	($/BBL)
CONSUMABLES	LIMESTONE	(DELIVERED)	$15.00	($/TON)
	DEMIN WATER	(DELIVERED)	$0.90	($/1000 GAL)
	MAKEUP WATER	(DELIVERED)	$2.00	($/1000 GAL)
	ASH DISPOSAL	(DELIVERED)	$10.00	($/TON)
	FGD SLUDGE DISPOSAL	(DELIVERED)	$15.00	($/TON)
	SLAG DISPOSAL	(DELIVERED)	$10.00	($/TON)
	CONDENSATE POLISH RECH.	(DELIVERED)	$0.012	($/1000 GAL)
MISC. FACTORS & DATA	COPRO CAPACITY FACTOR (330 days/year)		90.41%	
	INTEREST RATE		13.00%	
	YEARS OF LOAN		20	(YRS)
	DISCOUNT RATE FOR NPV		11.00%	
	SUM OF PRESENT WORTH FACTORS FOR LEVELIZING		7.963	
	DISPATCH FACTOR		61.34%	

ITEM		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DOE MIDDLE FORECAST DATA												
GNP DEFLATOR			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
CHEMICALS & ALLIED PRODUCTS (GNP)			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
HIGH SULFUR COAL - COMMODITY (DOE)			6.76%	5.72%	5.93%	5.84%	5.55%	5.50%	5.65%	5.74%	5.29%	5.12%
HIGH SULFUR COAL - TRANS. (GNP)			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
NATURAL GAS - COMMODITY (DOE)			12.05%	11.75%	21.01%	18.06%	14.40%	12.91%	21.21%	9.75%	10.91%	10.94%
NATURAL GAS - TRANSPORTATION (GNP)			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
WORLD OIL - COMMODITY (DOE)			9.38%	8.65%	7.89%	13.21%	16.27%	14.72%	15.12%	13.59%	12.32%	9.17%
COLD LAKE BLEND - TRANS. (GNP)			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
SULFUR (GNP)			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
AMMONIA (GNP)			5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
PRICES												
COAL COMMODITY ($/TON)		$29.72	$31.73	$33.54	$35.53	$37.61	$39.70	$41.88	$44.24	$46.78	$49.26	$51.78
TRANSPORTATION		$7.00	$7.35	$7.73	$8.13	$8.56	$9.00	$9.47	$9.99	$10.50	$11.03	$11.55
	NET FOR PC & CFB	$36.72	$39.08	$41.27	$43.66	$46.16	$48.70	$51.35	$54.23	$57.29	$60.29	$63.33
COAL WASHING ($/TON)		$5.00	$5.25	$5.52	$5.81	$6.11	$6.43	$6.77	$7.13	$7.50	$7.88	$8.25
	NET FOR CCC	$41.72	$44.33	$46.79	$49.47	$52.28	$55.13	$58.12	$61.36	$64.79	$68.16	$71.58
WORLD OIL ($/BARREL)		$14.93	$16.33	$17.74	$19.14	$21.67	$25.20	$28.91	$33.28	$37.80	$42.46	$46.35
WTI ($/BARREL)		$16.25	$17.65	$19.06	$20.46	$22.99	$26.52	$30.23	$34.60	$39.12	$43.78	$47.67
COLD LAKE CRUDE COMMODITY ($/BARREL)		$12.19	$13.24	$14.30	$15.35	$17.24	$19.89	$22.67	$25.95	$29.34	$32.83	$35.75
TRANSPORTATION		$1.68	$1.76	$1.85	$1.95	$2.05	$2.16	$2.27	$2.40	$2.52	$2.65	$2.77
	NET	$13.87	$15.00	$16.15	$17.30	$19.30	$22.05	$24.94	$28.34	$31.86	$35.48	$38.52
NATURAL GAS COMMODITY ($/MCF)		$1.80	$2.02	$2.25	$2.73	$3.22	$3.68	$4.16	$5.04	$5.53	$6.14	$6.81
TRANSPORTATION		$0.70	$0.74	$0.77	$0.81	$0.86	$0.90	$0.95	$1.00	$1.05	$1.10	$1.15
	NET	$2.50	$2.75	$3.03	$3.54	$4.08	$4.58	$5.11	$6.04	$6.58	$7.24	$7.96
PRODUCT PRICES												
NAPHTHA COMMODITY ($/BBL)		$19.50	$21.18	$22.88	$24.56	$27.59	$31.82	$36.27	$41.52	$46.94	$52.53	$57.20
TRANSPORTATION		$1.26	$1.32	$1.39	$1.46	$1.54	$1.62	$1.71	$1.80	$1.89	$1.98	$2.08
	TOTAL	$20.76	$22.50	$24.27	$26.02	$29.13	$33.44	$37.98	$43.31	$48.83	$54.52	$59.28
AMMONIA COMMODITY ($/TON)		$129.86	$136.35	$143.36	$150.79	$158.73	$166.99	$175.76	$185.25	$194.84	$204.54	$214.24
TRANSPORTATION		$4.00	$4.20	$4.42	$4.64	$4.89	$5.14	$5.41	$5.71	$6.00	$6.30	$6.60
	NETBACK TOTAL	$133.86	$140.55	$147.78	$155.43	$163.62	$172.13	$181.17	$190.95	$200.84	$210.85	$220.84
SULFUR ($/TON)	NETBACK PRICE	$81.00	$85.05	$89.42	$94.05	$99.01	$104.16	$109.63	$115.55	$121.53	$127.58	$133.63
FLAKED BOTTOMS COMMODITY ($/TON)		$25.26	$26.97	$28.51	$30.20	$31.97	$33.74	$35.60	$37.61	$39.77	$41.87	$44.01
TRANSPORTATION		$7.00	$7.35	$7.73	$8.13	$8.56	$9.00	$9.47	$9.99	$10.50	$11.03	$11.55
	NETBACK TOTAL	$18.26	$19.62	$20.78	$22.08	$23.41	$24.74	$26.12	$27.62	$29.26	$30.84	$32.47

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DOE MIDDLE FORECAST DATA										
GNP DEFLATOR	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
CHEMICALS & ALLIED PRODUCTS (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
HIGH SULFUR COAL - COMMODITY (DOE)	4.88%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
HIGH SULFUR COAL - TRANS. (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
NATURAL GAS - COMMODITY (DOE)	8.50%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
NATURAL GAS - TRANSPORTATION (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
WORLD OIL - COMMODITY (DOE)	7.80%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
COLD LAKE BLEND - TRANS. (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
SULFUR (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
AMMONIA (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
PRICES										
COAL COMMODITY ($/TON)	$54.31	$56.66	$59.11	$61.67	$64.34	$67.13	$70.04	$73.07	$76.23	$79.53
TRANSPORTATION	$12.05	$12.57	$13.11	$13.68	$14.28	$14.89	$15.54	$16.21	$16.91	$17.65
NET FOR PC & CFB	$66.36	$69.23	$72.23	$75.36	$78.62	$82.02	$85.57	$89.28	$93.15	$97.18
COAL WASHING ($/TON)	$8.61	$8.98	$9.37	$9.77	$10.20	$10.64	$11.10	$11.58	$12.08	$12.60
NET FOR CCC	$74.96	$78.[illegible]	$81.60	$85.13	$88.82	$92.66	$96.67	$100.86	$105.23	$109.78
WORLD OIL ($/BARREL)	$49.97	$52.13	$54.39	$56.74	$59.20	$61.76	$64.44	$67.23	$70.14	$73.17
WTI ($/BARREL)	$51.29	$53.45	$55.71	$58.06	$60.52	$63.08	$65.76	$68.55	$71.46	$74.49
COLD LAKE CRUDE COMMODITY ($/BARREL)	$38.46	$40.09	$41.78	$43.55	$45.39	$47.31	$49.32	$51.41	$53.59	$55.87
TRANSPORTATION	$2.89	$3.02	$3.15	$3.28	$3.43	$3.57	$3.73	$3.89	$4.06	$4.23
NET	$41.36	$43.10	$44.93	$46.83	$48.81	$50.89	$53.05	$55.30	$57.65	$60.10
NATURAL GAS COMMODITY ($/MCF)	$7.39	$7.71	$8.04	$8.39	$8.75	$9.13	$9.53	$9.94	$10.37	$10.82
TRANSPORTATION	$1.20	$1.26	$1.31	$1.37	$1.43	$1.49	$1.55	$1.62	$1.69	$1.76
NET	$8.59	$8.96	$9.35	$9.76	$10.18	$10.62	$11.08	$11.56	$12.06	$12.58
PRODUCT PRICES										
NAPHTHA COMMODITY ($/BBL)	$61.54	$64.14	$66.85	$69.67	$72.62	$75.70	$78.91	$82.25	$85.75	$89.39
TRANSPORTATION	$2.17	$2.26	$2.36	$2.46	$2.57	$2.68	$2.80	$2.92	$3.04	$3.18
TOTAL	$63.71	$66.40	$69.21	$72.14	$75.19	$78.38	$81.70	$85.17	$88.79	$92.57
AMMONIA COMMODITY ($/TON)	$223.52	$233.20	$243.30	$253.83	$264.83	$276.29	$288.26	$300.74	$313.76	$327.35
TRANSPORTATION	$6.89	$7.18	$7.49	$7.82	$8.16	$8.51	$8.88	$9.26	$9.66	$10.08
NETBACK TOTAL	$230.41	$240.39	$250.79	$261.65	$272.98	$284.80	$297.13	$310.00	$323.42	$337.43
SULFUR ($/TON) NETBACK PRICE	$139.42	$145.46	$151.76	$158.33	$165.18	$172.34	$179.80	$187.58	$195.71	$204.18
FLAKED BOTTOMS COMMODITY ($/TON)	$46.16	$48.16	$50.25	$52.42	$54.69	$57.06	$59.53	$62.11	$64.80	$67.60
TRANSPORTATION	$12.05	$12.57	$13.11	$13.68	$14.28	$14.89	$15.54	$16.21	$16.91	$17.65
NETBACK TOTAL	$34.11	$35.59	$37.13	$38.74	$40.42	$42.17	$43.99	$45.90	$47.88	$49.96

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
CO-PROCESSOR/COMBINE CYCLE TECHNOLOGY

OCF CASE A - SELL ALL NAPHTHA
(Thousands of Dollars)

REV. 3.2 PAGE 5
DATE: 16 August 1989

ITEM	BASIC ANNUAL COST DATA (1989 DOLLARS)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
INSTALLED CAPITAL COST	$496,401										
ANNUAL DEBT SERVICE		$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665
BUSBAR CARRYING CHARGE (mills/kwh)		47.196	47.196	47.196	47.196	47.196	47.196	47.196	47.196	47.196	47.196
FUEL											
COAL	$11,003	$11,691	$12,341	$13,046	$13,787	$14,539	$15,328	$16,184	$17,087	$17,976	$18,878
OIL USAGE	$35,037	$37,902	$40,808	$43,703	$48,754	$55,705	$63,020	$71,612	$80,495	$89,637	$97,331
NATURAL GAS	$7,465	$8,217	$9,037	$10,571	$12,169	$13,687	$15,248	$18,034	$19,656	$21,615	$23,776
TOTAL FUEL COST		$57,810	$62,185	$67,320	$74,711	$83,931	$93,596	$105,830	$117,239	$129,228	$139,984
BUSBAR FUEL COST (mills/kwh)		38.610	41.532	44.962	49.898	56.056	62.511	70.682	78.302	86.309	93.493
CONSUMABLES											
LIMESTONE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMINERALIZED WATER	$272	$285	$300	$315	$332	$349	$368	$387	$407	$428	$448
MAKE-UP WATER	$1,572	$1,650	$1,735	$1,825	$1,921	$2,021	$2,127	$2,242	$2,358	$2,475	$2,593
CHEMICALS	$4,193	$4,402	$4,629	$4,868	$5,125	$5,391	$5,674	$5,981	$6,291	$6,604	$6,917
CONDENSATE POLISHING RECHRG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ASH DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST		$6,338	$6,663	$7,009	$7,378	$7,761	$8,169	$8,610	$9,056	$9,507	$9,958
BUSBAR CONSUMABLES (mills/kwh)		4.233	4.450	4.681	4.928	5.184	5.456	5.751	6.048	6.350	6.651
PRODUCT & BYPRODUCT											
NAPHTHA		($30,090)	($32,448)	($34,790)	($38,951)	($44,716)	($50,781)	($57,917)	($65,298)	($72,896)	($79,269)
FLAKED BOTTOMS	($1,446)	($1,554)	($1,646)	($1,748)	($1,854)	($1,959)	($2,069)	($2,188)	($2,318)	($2,443)	($2,571)
SULFUR	($1,347)	($1,415)	($1,487)	($1,564)	($1,647)	($1,732)	($1,823)	($1,922)	($2,021)	($2,122)	($2,223)
AMMONIA	($636)	($668)	($702)	($739)	($778)	($818)	($861)	($907)	($954)	($1,002)	($1,049)
TOTAL PRODUCT & BY-PRODUCT SALES		($33,727)	($36,283)	($38,842)	($43,229)	($49,225)	($55,534)	($62,934)	($70,592)	($78,463)	($85,113)
PRODUCT & BYPROD. SALES (mills/kwh)		(22.525)	(24.233)	(25.942)	(28.872)	(32.877)	(37.090)	(42.033)	(47.147)	(52.404)	(56.845)
O & M											
OPERATION LABOR SALARY	$6,100	$6,405	$6,734	$7,083	$7,456	$7,844	$8,256	$8,702	$9,152	$9,608	$10,064
MAINTENANCE	$9,909	$10,404	$10,939	$11,505	$12,112	$12,741	$13,410	$14,135	$14,867	$15,607	$16,347
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$3,019	$3,170	$3,333	$3,506	$3,690	$3,882	$4,086	$4,307	$4,530	$4,755	$4,981
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TOTAL O & M COST	$19,028	$19,979	$21,006	$22,094	$23,258	$24,468	$25,752	$27,143	$28,549	$29,971	$31,391
FIXED O & M		$11,348	$11,931	$12,550	$13,211	$13,898	$14,628	$15,417	$16,216	$17,024	$17,830
VARIABLE O & M		$8,631	$9,074	$9,544	$10,047	$10,570	$11,125	$11,725	$12,333	$12,947	$13,561
BUSBAR FIXED O & M (mills/kwh)		7.579	7.969	8.382	8.823	9.282	9.769	10.297	10.830	11.370	11.909
BUSBAR VARIABLE O & M (mills/kwh)		5.764	6.061	6.375	6.710	7.059	7.430	7.831	8.237	8.647	9.057
TOTALS											
ANNUAL NET MWH GENERATED		1497271	1497271	1497271	1497271	1497271	1497271	1497271	1497271	1497271	1497271
TOTAL ANNUAL COST		$121,064	$124,236	$128,245	$132,782	$137,599	$142,648	$149,314	$154,917	$160,907	$166,885
TOTAL BUSBAR COST (mills/kwh)		80.857	82.975	85.653	88.683	91.900	95.272	99.724	103.466	107.467	111.460

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
CO-PROCESSOR/COMBINE CYCLE TECHNOLOGY

OCF CASE A - SELL ALL NAPHTHA
(Thousands of Dollars)

REV. 3.2 PAGE 6
DATE: 16 August 1989

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INSTALLED CAPITAL COST										
ANNUAL DEBT SERVICE	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665
BUSBAR CARRYING CHARGE (mills/kwh)	47.196	47.196	47.196	47.196	47.196	47.196	47.196	47.196	47.196	47.196
FUEL										
COAL	$19,771	$20,627	$21,520	$22,452	$23,424	$24,438	$25,496	$26,600	$27,752	$28,954
OIL USAGE	$104,485	$108,901	$113,508	$118,314	$123,329	$128,561	$134,019	$139,714	$145,655	$151,854
NATURAL GAS	$25,653	$26,764	$27,923	$29,132	$30,393	$31,709	$33,082	$34,514	$36,009	$37,568
TOTAL FUEL COST	$149,908	$156,291	$162,950	$169,897	$177,146	$184,708	$192,597	$200,829	$209,416	$218,376
BUSBAR FUEL COST (mills/kwh)	100.121	104.384	108.831	113.471	118.312	123.363	128.632	134.130	139.865	145.849
CONSUMABLES										
LIMESTONE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMINERALIZED WATER	$467	$488	$509	$531	$554	$578	$603	$629	$656	$685
MAKE-UP WATER	$2,705	$2,822	$2,944	$3,072	$3,205	$3,344	$3,488	$3,639	$3,797	$3,961
CHEMICALS	$7,217	$7,529	$7,855	$8,195	$8,550	$8,920	$9,307	$9,710	$10,130	$10,569
CONDENSATE POLISHING RECHRG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ASH DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST	$10,389	$10,839	$11,308	$11,798	$12,309	$12,842	$13,398	$13,978	$14,583	$15,215
BUSBAR CONSUMABLES (mills/kwh)	6.939	7.239	7.553	7.880	8.221	8.577	8.948	9.336	9.740	10.162
PRODUCT & BYPRODUCT										
NAPHTHA	($85,191)	($88,788)	($92,540)	($96,456)	($100,541)	($104,802)	($109,249)	($113,887)	($118,727)	($123,776)
FLAKED BOTTOMS	($2,702)	($2,819)	($2,941)	($3,068)	($3,201)	($3,340)	($3,484)	($3,635)	($3,792)	($3,957)
SULFUR	($2,319)	($2,419)	($2,524)	($2,633)	($2,747)	($2,866)	($2,990)	($3,120)	($3,255)	($3,396)
AMMONIA	($1,095)	($1,142)	($1,192)	($1,243)	($1,297)	($1,353)	($1,412)	($1,473)	($1,537)	($1,603)
TOTAL PRODUCT & BY-PRODUCT SALES	($91,306)	($95,168)	($99,197)	($103,401)	($107,786)	($112,362)	($117,135)	($122,115)	($127,311)	($132,732)
PRODUCT & BYPROD. SALES (mills/kwh)	(60.982)	(63.561)	(66.252)	(69.059)	(71.988)	(75.044)	(78.232)	(81.559)	(85.029)	(88.649)
O & M										
OPERATION LABOR SALARY	$10,500	$10,954	$11,429	$11,924	$12,440	$12,978	$13,540	$14,127	$14,738	$15,377
MAINTENANCE	$17,055	$17,794	$18,564	$19,368	$20,207	$21,082	$21,994	$22,947	$23,940	$24,977
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$5,197	$5,422	$5,656	$5,901	$6,157	$6,423	$6,701	$6,992	$7,294	$7,610
TOTAL O & M COST	$32,751	$34,170	$35,649	$37,193	$38,803	$40,483	$42,236	$44,065	$45,973	$47,964
FIXED O & M	$18,603	$19,409	$20,249	$21,126	$22,041	$22,995	$23,991	$25,029	$26,113	$27,244
VARIABLE O & M	$14,148	$14,761	$15,400	$16,067	$16,763	$17,488	$18,246	$19,036	$19,860	$20,720
BUSBAR FIXED O & M (mills/kwh)	12.425	12.963	13.524	14.110	14.720	15.358	16.023	16.717	17.440	18.196
BUSBAR VARIABLE O & M (mills/kwh)	9.449	9.859	10.285	10.731	11.195	11.680	12.186	12.714	13.264	13.838
TOTALS										
ANNUAL NET MWH GENERATED	1497271	1497271	1497271	1497271	1497271	1497271	1497271	1497271	1497271	1497271
TOTAL ANNUAL COST	$172,407	$176,796	$181,375	$186,152	$191,136	$196,336	$201,761	$207,421	$213,326	$219,486
TOTAL BUSBAR COST (mills/kwh)	115.148	118.079	121.137	124.328	127.656	131.129	134.752	138.533	142.476	146.591

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
PULVERIZED COAL TECHNOLOGY

OCF CASE A - SELL ALL NAPHTHA
(Thousands of Dollars)

ITEM	BASIC ANNUAL COST DATA (1989 DOLLARS)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
INSTALLED CAPITAL COST	$506,332										
ANNUAL DEBT SERVICE		$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078
BUSBAR CARRYING CHARGE (mills/kwh)		54.532	54.532	54.532	54.532	54.532	54.532	54.532	54.532	54.532	54.532
FUEL											
COAL	$23,799	$25,328	$26,749	$28,297	$29,920	$31,561	$33,282	$35,147	$37,129	$39,072	$41,045
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST		$25,328	$26,749	$28,297	$29,920	$31,561	$33,282	$35,147	$37,129	$39,072	$41,045
BUSBAR FUEL COST (mills/kwh)		19.162	20.237	21.409	22.637	23.878	25.180	26.592	28.090	29.560	31.053
CONSUMABLES											
LIMESTONE	$1,623	$1,705	$1,792	$1,885	$1,984	$2,088	$2,197	$2,316	$2,436	$2,557	$2,678
DEMINERALIZED WATER	$6	$6	$7	$7	$7	$8	$8	$9	$9	$9	$10
MAKE-UP WATER	$2,187	$2,297	$2,415	$2,540	$2,674	$2,813	$2,961	$3,120	$3,282	$3,446	$3,609
CHEMICALS	$527	$553	$582	$612	$644	$678	$713	$752	$791	$830	$870
CONDENSATE POLISHING RECHRG	$13	$14	$15	$15	$16	$17	$18	$19	$20	$21	$22
WASTEWATER TREATMENT	$320	$336	$353	$372	$391	$411	$433	$456	$480	$504	$528
ASH DISPOSAL	$648	$680	$715	$752	$792	$833	$877	$924	$972	$1,020	$1,069
FGD SLUDGE	$4,052	$4,255	$4,474	$4,705	$4,953	$5,211	$5,484	$5,781	$6,080	$6,383	$6,685
BOTTOMS/SLAG DISPOSAL	$0.000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST		$9,846	$10,352	$10,889	$11,462	$12,058	$12,691	$13,377	$14,070	$14,770	$15,470
BUSBAR CONSUMABLES (mills/kwh)		7.449	7.832	8.238	8.672	9.123	9.602	10.120	10.645	11.175	11.7[illegible]5
PRODUCT & BYPRODUCT											
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M											
OPERATION LABOR SALARY	$5,100	$5,355	$5,630	$5,922	$6,234	$6,558	$6,902	$7,275	$7,652	$8,033	$8,414
MAINTENANCE	$10,317	$10,833	$11,390	$11,980	$12,611	$13,267	$13,964	$14,718	$15,480	$16,251	$17,021
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$2,768	$2,906	$3,056	$3,214	$3,384	$3,559	$3,746	$3,949	$4,153	$4,360	$4,567
TOTAL O & M COST	$18,185	$19,095	$20,076	$21,116	$22,229	$23,385	$24,612	$25,941	$27,285	$28,644	$30,002
FIXED O & M		$9,288	$9,765	$10,271	$10,813	$11,375	$11,972	$12,619	$13,272	$13,933	$14,594
VARIABLE O & M		$9,806	$10,311	$10,845	$11,416	$12,010	$12,640	$13,323	$14,013	$14,711	$15,408
BUSBAR FIXED O & M (mills/kwh)		7.027	7.388	7.771	8.181	8.606	9.058	9.547	10.041	10.54[illegible]	11.041
BUSBAR VARIABLE O & M (mills/kwh)		7.419	7.801	8.205	8.637	9.086	9.563	10.080	10.602	11.13[illegible]	11.657
TOTALS											
TOTAL ANNUAL COST		$126,347	$129,255	$132,380	$135,689	$139,082	$142,664	$146,544	$150,562	$154,564	$158,595
TOTAL BUSBAR COST (mills/kwh)		95.590	97.791	100.155	102.659	105.226	107.936	110.871	113.911	116.939	119.989

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
PULVERIZED COAL TECHNOLOGY

OCF CASE A - SELL ALL NAPHTHA
(Thousands of Dollars)

REV. 3.2 PAGE 8
DATE: 16 August 1989

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INSTALLED CAPITAL COST										
ANNUAL DEBT SERVICE	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078
BUSBAR CARRYING CHARGE (mills/kwh)	54.532	54.532	54.532	54.532	54.532	54.532	54.532	54.532	54.532	54.532
FUEL										
COAL	$43,007	$44,869	$46,812	$48,839	$50,954	$53,160	$55,462	$57,863	$60,369	$62,983
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$43,007	$44,869	$46,812	$48,839	$50,954	$53,160	$55,462	$57,863	$60,369	$62,983
BUSBAR FUEL COST (mills/kwh)	32.538	33.947	35.417	36.950	38.550	40.219	41.961	43.778	45.673	47.651
CONSUMABLES										
LIMESTONE	$2,794	$2,915	$3,042	$3,173	$3,311	$3,454	$3,604	$3,760	$3,923	$4,092
DEMINERALIZED WATER	$10	$11	$11	$12	$12	$13	$13	$14	$14	$15
MAKE-UP WATER	$3,765	$3,928	$4,098	$4,276	$4,461	$4,654	$4,856	$5,066	$5,285	$5,514
CHEMICALS	$907	$947	$988	$1,030	$1,075	$1,121	$1,170	$1,221	$1,274	$1,329
CONDENSATE POLISHING RECHRG	$23	$24	$25	$26	$27	$28	$30	$31	$32	$34
WASTEWATER TREATMENT	$551	$575	$600	$625	$653	$681	$710	$741	$773	$807
ASH DISPOSAL	$1,115	$1,163	$1,213	$1,266	$1,321	$1,378	$1,438	$1,500	$1,565	$1,633
FGD SLUDGE	$6,975	$7,277	$7,592	$7,921	$8,264	$8,622	$8,995	$9,385	$9,791	$10,215
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST	$16,141	$16,840	$17,569	$18,330	$19,123	$19,951	$20,815	$21,717	$22,657	$23,638
BUSBAR CONSUMABLES (mills/kwh)	12.212	12.740	13.292	13.868	14.468	15.095	15.748	16.430	17.142	17.884
PRODUCT & BYPRODUCT										
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M										
OPERATION LABOR SALARY	$8,778	$9,159	$9,555	$9,969	$10,401	$10,851	$11,321	$11,811	$12,322	$12,856
MAINTENANCE	$17,759	$18,528	$19,330	$20,167	$21,040	$21,951	$22,902	$23,893	$24,928	$26,007
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$4,765	$4,971	$5,186	$5,411	$5,645	$5,889	$6,144	$6,410	$6,688	$6,978
TOTAL O & M COST	$31,302	$32,657	$34,071	$35,546	$37,086	$38,691	$40,367	$42,115	$43,938	$45,841
FIXED O & M	$15,226	$15,885	$16,573	$17,291	$18,039	$18,820	$19,635	$20,486	$21,373	$22,298
VARIABLE O & M	$16,076	$16,772	$17,498	$18,256	$19,046	$19,871	$20,731	$21,629	$22,565	$23,543
BUSBAR FIXED O & M (mills/kwh)	11.520	12.018	12.539	13.082	13.648	14.239	14.856	15.499	16.170	16.870
BUSBAR VARIABLE O & M (mills/kwh)	12.162	12.689	13.238	13.812	14.410	15.034	15.685	16.364	17.072	17.812
TOTALS										
TOTAL ANNUAL COST	$162,528	$166,444	$170,530	$174,793	$179,241	$183,881	$188,722	$193,773	$199,042	$204,540
TOTAL BUSBAR COST (mills/kwh)	122.964	125.927	129.018	132.244	135.608	139.119	142.782	146.603	150.589	154.749

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
FLUIDIZED BED TECHNOLOGY

OCF CASE A - SELL ALL NAPHTHA
(Thousands of Dollars)

REV. 3.2 PAGE 9
DATE: 16 August 1989

ITEM	BASIC ANNUAL COST DATA (1989 DOLLARS)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
INSTALLED CAPITAL COST	$443,257										
ANNUAL DEBT SERVICE		$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099
BUSBAR CARRYING CHARGE (mills/kwh)		46.565	46.565	46.565	46.565	46.565	46.565	46.565	46.565	46.565	46.565
FUEL											
COAL	$23,805	$25,335	$26,756	$28,305	$29,928	$31,570	$33,292	$35,157	$37,139	$39,083	$41,057
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST		$25,335	$26,756	$28,305	$29,928	$31,570	$33,292	$35,157	$37,139	$39,083	$41,057
BUSBAR FUEL COST (mills/kwh)		18.696	19.745	20.888	22.086	23.297	24.568	25.945	27.407	28.841	30.298
CONSUMABLES											
LIMESTONE	$3,552	$3,729	$3,921	$4,124	$4,341	$4,567	$4,807	$5,066	$5,329	$5,594	$5,859
DEMINERALIZED WATER	$6	$6	$7	$7	$7	$8	$8	$9	$9	$10	$10
MAKE-UP WATER	$1,667	$1,750	$1,840	$1,936	$2,038	$2,144	$2,256	$2,378	$2,501	$2,626	$2,750
CHEMICALS	$527	$553	$582	$612	$644	$678	$713	$752	$791	$830	$870
CONDENSATE POLISHING RECHRG	$14	$14	$15	$16	$17	$18	$18	$19	$20	$21	$22
WASTEWATER TREATMENT	$320	$336	$353	$372	$391	$411	$433	$456	$480	$504	$528
ASH DISPOSAL	$3,316	$3,482	$3,660	$3,850	$4,053	$4,264	$4,488	$4,730	$4,975	$5,223	$5,470
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST		$9,871	$10,379	$10,916	$11,492	$12,089	$12,724	$13,411	$14,106	$14,808	$15,510
BUSBAR CONSUMABLES (mills/kwh)		7.285	7.659	8.056	8.480	8.921	9.390	9.897	10.409	10.928	11.446
PRODUCT & BYPRODUCT											
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M											
OPERATION LABOR SALARY	$4,050	$4,253	$4,471	$4,703	$4,951	$5,208	$5,481	$5,777	$6,077	$6,379	$6,682
MAINTENANCE	$9,038	$9,490	$9,977	$10,494	$11,047	$11,622	$12,232	$12,892	$13,560	$14,236	$14,910
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$2,300	$2,415	$2,539	$2,670	$2,811	$2,957	$3,112	$3,280	$3,450	$3,622	$3,794
TOTAL O & M COST	$15,387	$16,157	$16,987	$17,867	$18,809	$19,787	$20,825	$21,950	$23,087	$24,237	$25,386
FIXED O & M		$8,057	$8,471	$8,910	$9,380	$9,367	$10,386	$10,946	$11,513	$12,087	$12,660
VARIABLE O & M		$8,099	$8,516	$8,957	$9,429	$9,919	$10,440	$11,004	$11,574	$12,150	$12,726
BUSBAR FIXED O & M (mills/kwh)		5.946	6.252	6.575	6.922	7.282	7.664	8.078	8.496	8.920	9.342
BUSBAR VARIABLE O & M (mills/kwh)		5.977	6.284	6.610	6.958	7.320	7.704	8.120	8.541	8.966	9.391
TOTALS											
TOTAL ANNUAL COST		$114,462	$117,221	$120,188	$123,328	$126,545	$129,940	$133,618	$137,431	$141,227	$145,051
TOTAL BUSBAR COST (mills/kwh)		84.468	86.505	88.694	91.011	93.385	95.891	98.604	101.419	104.220	107.042

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
FLUIDIZED BED TECHNOLOGY

CCF CASE A - SELL ALL NAPHTHA
(Thousands of Dollars)

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INSTALLED CAPITAL COST										
ANNUAL DEBT SERVICE	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099
BUSBAR CARRYING CHARGE (mills/kwh)	46.565	46.565	46.565	46.565	46.565	46.565	46.565	46.565	46.565	46.565
FUEL										
COAL	$43,019	$44,882	$46,825	$48,853	$50,968	$53,175	$55,477	$57,880	$60,386	$63,001
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$43,019	$44,882	$46,825	$48,853	$50,968	$53,175	$55,477	$57,880	$60,386	$63,001
BUSBAR FUEL COST (mills/kwh)	31.746	33.121	34.555	36.051	37.612	39.241	40.940	42.713	44.562	46.492
CONSUMABLES										
LIMESTONE	$6,113	$6,378	$6,654	$6,942	$7,243	$7,557	$7,884	$8,225	$8,581	$8,953
DEMINERALIZED WATER	$11	$11	$11	$12	$13	$13	$14	$14	$15	$15
MAKE-UP WATER	$2,869	$2,994	$3,123	$3,259	$3,400	$3,547	$3,700	$3,861	$4,028	$4,202
CHEMICALS	$907	$947	$988	$1,030	$1,075	$1,121	$1,170	$1,221	$1,274	$1,329
CONDENSATE POLISHING RECHRG	$23	$24	$26	$27	$28	$29	$30	$32	$33	$34
WASTEWATER TREATMENT	$551	$575	$600	$625	$653	$681	$710	$741	$773	$807
ASH DISPOSAL	$5,707	$5,954	$6,212	$6,481	$6,762	$7,055	$7,360	$7,679	$8,011	$8,358
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST	$16,182	$16,883	$17,614	$18,376	$19,172	$20,002	$20,868	$21,772	$22,715	$23,698
BUSBAR CONSUMABLES (mills/kwh)	11.942	12.459	12.998	13.561	14.148	14.761	15.400	16.067	16.763	17.488
PRODUCT & BYPRODUCT										
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M										
OPERATION LABOR SALARY	$6,971	$7,273	$7,588	$7,916	$8,259	$8,617	$8,990	$9,379	$9,785	$10,209
MAINTENANCE	$15,556	$16,230	$16,933	$17,666	$18,431	$19,229	$20,061	$20,930	$21,836	$22,782
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$3,958	$4,129	$4,308	$4,495	$4,689	$4,893	$5,104	$5,325	$5,556	$5,797
TOTAL O & M COST	$26,486	$27,632	$28,829	$30,077	$31,380	$32,738	$34,156	$35,635	$37,178	$38,788
FIXED O & M	$13,208	$13,780	$14,377	$14,999	$15,649	$16,326	$17,033	$17,771	$18,540	$19,343
VARIABLE O & M	$13,277	$13,852	$14,452	$15,078	$15,731	$16,412	$17,123	$17,864	$18,637	$19,444
BUSBAR FIXED O & M (mills/kwh)	9.747	10.169	10.609	11.069	11.548	12.048	12.570	13.114	13.682	14.274
BUSBAR VARIABLE O & M (mills/kwh)	9.798	10.222	10.665	11.127	11.609	12.111	12.636	13.183	13.754	14.349
TOTALS										
TOTAL ANNUAL COST	$148,786	$152,496	$156,367	$160,406	$164,619	$169,015	$173,601	$178,386	$183,378	$188,586
TOTAL BUSBAR COST (mills/kwh)	109.798	112.536	115.393	118.373	121.482	124.726	128.110	131.641	135.325	139.169

APPENDIX B2

ALL NAPHTHA BLENDED WITH DISTILLATE

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
OCF CASE A - NO NAPHTHA SALES

REV. 3.2 PAGE 1
DATE: 16 August 1989

	BASIC DATA		CO-PROCESSOR COMBINED CYCLE	PULVERIZED COAL	FLUIDIZED BED
			****** TECHNOLOGY INPUT BASE YEAR 1989 **********		
CAPITAL:	NET CAPACITY, KW		310,191	310,191	310,191
	CAPACITY FACTOR, %		89%	77%	78%
	FUEL REQUIREMENT (MMBTU/HR)		-	-	-
	DIRECT CAPITAL COST, $		$396,340,553	$412,688,884	$361,509,845
	INDIRECTS & DISTRIB'S, $		$60,426,146	$52,374,094	$45,595,707
	AFI @ 10%		$39,634,055	$41,268,8[illegible]8	$36,150,985
	TOTAL ESTIMATED COST,$		$496,400,754	$506,331,8[illegible]6	$443,256,537
	EQUIVALENT AVAILABILITY, %		92.6%	7[illegible].3%	81.3%
FUEL:	COAL USAGE	(TONS/HR)	33.3	152	148
	OIL USAGE	(BBL/HR)	319.0	0	0
	NATURAL GAS	(MMBTU/HR)	377.0	0	0
CONSUMABLES:	LIMESTONE,	(TONS/HR)	0	25.4	54.2
	DEMINERALIZED WATER	(GPM)	635	26	26.0
	MAKE-UP WATER	(GPM)	2632	4278	3180
	CHEMICALS	($/YR)	$4,192,680	$527,100	$527,100
	CONDENSATE POLISHING RECHRG,	(GPM)	$0	4,332	4,332
	WASTEWATER TREATMENT,	($/YR)	$0	$320,000	$320,000
	ASH DISPOSAL	(TONS/HR)	0	15.2	75.9
	FGD SLUDGE	(TONS/HR)	0	63.4	0
BY-PRODUCTS:	DISTILLATE/NAPHTHA BLEND	(BBL/HR)	433.16	0	0
	NAPHTHA SALES	(BBL/HR)	0.00	0	0
	FLAKED BOTTOMS	(TONS/HR)	10.00	0	0
	SULFUR	(TONS/HR)	2.10	0	0
	AMMONIA	(TONS/HR)	0.60	0	0
O & M:	LABOR FORCE - OPERATION	(MEN)	122	102	81
	OPERATION LABOR SALARY	($/YR)	$6,100,000	$5,100,000	$4,050,000
	MAINTENANCE (LABOR & MATERIAL $/YR)		$9,908,514	$10,317,222	$9,037,746
	OWNER'S OVERHEAD (@30% TOTAL LABOR)		$3,019,022	$2,768,067	$2,299,530
	TOTAL O & M COST		$19,027,535	$18,185,289	$15,387,276
	FIXED PART (TOTAL * CAP.FACTOR)		$17,002,815	$13,916,201	$12,072,010
	VARIABLE O & M, (TOTAL - FIXED)		$2,024,720	$4,269,087	$3,315,265

EFFECTIVE FUEL COST CALCULATION:		CCC	PC	CFB
FEEDSTOCK COST	(mills/kwh)	44.876	27.468	26.799
BYPRODUCT SALES	(mills/kwh)	-2.135	0.000	0.000
EFFECTIVE LEVELIZED FUEL COST	(mills/kwh)	42.741	27.468	26.799
20 YEAR LEVELIZED BUSBAR COSTS:				
CAPITAL COST	(mills/kwh)	29.120	34.663	29.599
EFFECTIVE FUEL COST	(mills/kwh)	42.741	27.468	26.799
CONSUMABLES COST	(mills/kwh)	4.205	10.094	9.872
FIXED O & M COST	(mills/kwh)	10.308	9.846	8.331
VARIABLE O & M COST	(mills/kwh)	1.228	3.021	2.288
TOTAL LEVELIZED BUSBAR COST	(mills/kwh)	87.602	85.092	76.889

COMMODITY UNIT PRICES AND VARIOUS FINANCIAL FACTORS BASE YEAR 1989

			PRICE	UNITS
FUEL	HIGH-SULFUR COAL	(COMMODITY)	$29.72	($/TON)
	HIGH-SULFUR COAL	(TRANSPORTATION)	$7.00	($/TON)
	NATURAL GAS	(COMMODITY)	$1.80	($/MMBTU)
	NATURAL GAS	(TRANSPORTATION)	$0.70	($/MMBTU)
	HEAVY CRUDE	(COMMODITY)	$12.19	($/BBL)
	HEAVY CRUDE	(TRANSPORTATION)	$1.68	($/BBL)
CONSUMABLES	LIMESTONE	(DELIVERED)	$15.00	($/TON)
	DEMIN WATER	(DELIVERED)	$0.90	($/1000 GAL)
	MAKEUP WATER	(DELIVERED)	$2.00	($/1000 GAL)
	ASH DISPOSAL	(DELIVERED)	$10.00	($/TON)
	FGD SLUDGE DISPOSAL	(DELIVERED)	$15.00	($/TON)
	SLAG DISPOSAL	(DELIVERED)	$10.00	($/TON)
	CONDENSATE POLISH RECH.	(DELIVERED)	$0.012	($/1000 GAL)
MISC. FACTORS & DATA	COPRO CAPACITY FACTOR (330 days/year)		90.41%	
	INTEREST RATE		13.00%	
	YEARS OF LOAN		20	(YRS)
	DISCOUNT RATE FOR NPV		11.00%	
	SUM OF PRESENT WORTH FACTORS FOR LEVELIZING		7.963	
	DISPATCH FACTOR		96.50%	

STONE & WEBSTER COMPARITIVE TECHNOLOGY REPORT ITEM	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
OCF CASE A - NO NAPHTHA SALES									REV. 3.2	DATE: 16 August 1989	PAGE 3
DOE MIDDLE FORECAST DATA											
GNP DEFLATOR		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
CHEMICALS & ALLIED PRODUCTS (GNP)		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
HIGH SULFUR COAL - COMMODITY (DOE)		6.76%	5.72%	5.93%	5.84%	5.55%	5.50%	5.65%	5.74%	5.29%	5.12%
HIGH SULFUR COAL - TRANS. (GNP)		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
NATURAL GAS - COMMODITY (DOE)		12.05%	11.75%	21.01%	18.06%	14.40%	12.91%	21.21%	9.75%	10.91%	10.94%
NATURAL GAS - TRANSPORTATION (GNP)		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
WORLD OIL - COMMODITY (DOE)		9.38%	8.65%	7.89%	13.21%	16.27%	14.72%	15.12%	13.59%	12.32%	9.17%
COLD LAKE BLEND - TRANS. (GNP)		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
SULFUR (GNP)		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
AMMONIA (GNP)		5.00%	5.14%	5.18%	5.27%	5.20%	5.25%	5.40%	5.18%	4.98%	4.74%
PRICES											
COAL COMMODITY ($/TON)	$29.72	$31.73	$33.54	$35.53	$37.61	$39.70	$41.88	$44.24	$46.78	$49.26	$51.78
TRANSPORTATION	$7.00	$7.35	$7.73	$8.13	$8.56	$9.00	$9.47	$9.99	$10.50	$11.03	$11.55
NET FOR PC & CFB	$36.72	$39.08	$41.27	$43.66	$46.16	$48.70	$51.35	$54.23	$57.29	$60.29	$63.33
COAL WASHING ($/TON)	$5.00	$5.25	$5.52	$5.81	$6.11	$6.43	$6.77	$7.13	$7.50	$7.88	$8.25
NET FOR CCC	$41.72	$44.33	$46.79	$49.47	$52.28	$55.13	$58.12	$61.36	$64.79	$68.16	$71.58
WORLD OIL ($/BARREL)	$14.93	$16.33	$17.74	$19.14	$21.67	$25.20	$28.91	$33.28	$37.80	$42.46	$46.35
WTI ($/BARREL)	$16.25	$17.65	$19.06	$20.46	$22.99	$26.52	$30.23	$34.60	$39.12	$43.78	$47.67
COLD LAKE CRUDE COMMODITY ($/BARREL)	$12.19	$13.24	$14.30	$15.35	$17.24	$19.89	$22.67	$25.95	$29.34	$32.83	$35.75
TRANSPORTATION	$1.68	$1.76	$1.85	$1.95	$2.05	$2.16	$2.27	$2.40	$2.52	$2.65	$2.77
NET	$13.87	$15.00	$16.15	$17.30	$19.30	$22.05	$24.94	$28.34	$31.86	$35.48	$38.52
NATURAL GAS COMMODITY ($/MCF)	$1.80	$2.02	$2.25	$2.73	$3.22	$3.68	$4.16	$5.04	$5.53	$6.14	$6.81
TRANSPORTATION	$0.70	$0.74	$0.77	$0.81	$0.86	$0.90	$0.95	$1.00	$1.05	$1.10	$1.15
NET	$2.50	$2.75	$3.03	$3.54	$4.08	$4.58	$5.11	$6.04	$6.58	$7.24	$7.96
PRODUCT PRICES											
NAPHTHA COMMODITY ($/BBL)	$19.50	$21.18	$22.88	$24.56	$27.59	$31.82	$36.27	$41.52	$46.94	$52.53	$57.20
TRANSPORTATION	$1.26	$1.32	$1.39	$1.46	$1.54	$1.62	$1.71	$1.80	$1.89	$1.98	$2.08
TOTAL	$20.76	$22.50	$24.27	$26.02	$29.13	$33.44	$37.98	$43.31	$48.83	$54.52	$59.28
AMMONIA COMMODITY ($/TON)	$129.86	$136.35	$143.36	$150.79	$158.73	$166.99	$175.76	$185.25	$194.84	$204.54	$214.24
TRANSPORTATION	$4.00	$4.20	$4.42	$4.64	$4.89	$5.14	$5.41	$5.71	$6.00	$6.30	$6.60
NETBACK TOTAL	$133.86	$140.55	$147.78	$155.43	$163.62	$172.13	$181.17	$190.95	$200.84	$210.85	$220.84
SULFUR ($/TON) NETBACK PRICE	$81.00	$85.05	$89.42	$94.05	$99.01	$104.16	$109.63	$115.55	$121.53	$127.58	$133.63
FLAKED BOTTOMS COMMODITY ($/TON)	$25.26	$26.97	$28.51	$30.20	$31.97	$33.74	$35.60	$37.61	$39.77	$41.87	$44.01
TRANSPORTATION	$7.00	$7.35	$7.73	$8.13	$8.56	$9.00	$9.47	$9.99	$10.50	$11.03	$11.55
NETBACK TOTAL	$18.26	$19.62	$20.78	$22.08	$23.41	$24.74	$26.12	$27.62	$29.26	$30.84	$32.47

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DOE MIDDLE FORECAST DATA										
GNP DEFLATOR	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
CHEMICALS & ALLIED PRODUCTS (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
HIGH SULFUR COAL - COMMODITY (DOE)	4.88%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
HIGH SULFUR COAL - TRANS. (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
NATURAL GAS - COMMODITY (DOE)	8.50%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
NATURAL GAS - TRANSPORTATION (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
WORLD OIL - COMMODITY (DOE)	7.80%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
COLD LAKE BLEND - TRANS. (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
SULFUR (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
AMMONIA (GNP)	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%
PRICES										
COAL COMMODITY ($/TON)	$54.31	$56.66	$59.11	$61.67	$64.34	$67.13	$70.04	$73.07	$76.23	$79.53
TRANSPORTATION	$12.05	$12.57	$13.11	$13.68	$14.28	$14.89	$15.54	$16.21	$16.91	$17.65
NET FOR PC & CFB	$66.36	$69.23	$72.23	$75.36	$78.62	$82.02	$85.57	$89.28	$93.15	$97.18
COAL WASHING ($/TON)	$8.61	$8.98	$9.37	$9.77	$10.20	$10.64	$11.10	$11.58	$12.08	$12.60
NET FOR CCC	$74.96	$78.21	$81.60	$85.13	$88.82	$92.66	$96.67	$100.86	$105.23	$109.78
WORLD OIL ($/BARREL)	$49.97	$52.13	$54.39	$56.74	$59.20	$61.76	$64.44	$67.23	$70.14	$73.17
WTI ($/BARREL)	$51.29	$53.45	$55.71	$58.06	$60.52	$63.08	$65.76	$68.55	$71.46	$74.49
COLD LAKE CRUDE COMMODITY ($/BARREL)	$38.46	$40.09	$41.78	$43.55	$45.39	$47.31	$49.32	$51.41	$53.59	$55.87
TRANSPORTATION	$2.89	$3.02	$3.15	$3.28	$3.43	$3.57	$3.73	$3.89	$4.06	$4.23
NET	$41.36	$43.10	$44.93	$46.83	$48.81	$50.89	$53.05	$55.30	$57.65	$60.10
NATURAL GAS COMMODITY ($/MCF)	$7.39	$7.71	$8.04	$8.39	$8.75	$9.13	$9.53	$9.94	$10.37	$10.82
TRANSPORTATION	$1.20	$1.26	$1.31	$1.37	$1.43	$1.49	$1.55	$1.62	$1.69	$1.76
NET	$8.59	$8.96	$9.35	$9.76	$10.18	$10.62	$11.08	$11.56	$12.06	$12.58
PRODUCT PRICES										
NAPHTHA COMMODITY ($/BBL)	$61.54	$64.14	$66.85	$69.67	$72.62	$75.70	$78.91	$82.25	$85.75	$89.39
TRANSPORTATION	$2.17	$2.26	$2.36	$2.46	$2.57	$2.68	$2.80	$2.92	$3.04	$3.18
TOTAL	$63.71	$66.40	$69.21	$72.14	$75.19	$78.38	$81.70	$85.17	$88.79	$92.57
AMMONIA COMMODITY ($/TON)	$223.52	$233.20	$243.30	$253.83	$264.83	$276.29	$288.26	$300.74	$313.76	$327.35
TRANSPORTATION	$6.89	$7.18	$7.49	$7.82	$8.16	$8.51	$8.88	$9.26	$9.66	$10.08
NETBACK TOTAL	$230.41	$240.39	$250.79	$261.65	$272.98	$284.80	$297.13	$310.00	$323.42	$337.43
SULFUR ($/TON) NETBACK PRICE	$139.42	$145.46	$151.76	$158.33	$165.18	$172.34	$179.80	$187.58	$195.71	$204.18
FLAKED BOTTOMS COMMODITY ($/TON)	$46.16	$48.16	$50.25	$52.42	$54.69	$57.06	$59.53	$62.11	$64.80	$67.60
TRANSPORTATION	$12.05	$12.57	$13.11	$13.68	$14.28	$14.89	$15.54	$16.21	$16.91	$17.65
NETBACK TOTAL	$34.11	$35.59	$37.13	$38.74	$40.42	$42.17	$43.99	$45.90	$47.88	$49.96

STONE & WEBSTER COMPARITIVE TECHNOLOGY REPORT CO-PROCESSOR/COMBINE CYCLE TECHNOLOGY ITEM	BASIC ANNUAL COST DATA (1989 DOLLARS)	OCF CASE A - NO NAPHTHA SALES (Thousands of Dollars) 1990	1991	1992	1993	1994	1995	1996	1997	1998	REV. 3.2 PAGE 5 DATE: 16 August 1989 1999
INSTALLED CAPITAL COST	$496,401										
ANNUAL DEBT SERVICE		$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665
BUSBAR CARRYING CHARGE (mills/kwh)		29.120	29.120	29.120	29.120	29.120	29.120	29.120	29.120	29.120	29.120
FUEL											
COAL	$11,003	$11,691	$12,341	$13,046	$13,787	$14,539	$15,328	$16,184	$17,087	$17,976	$18,878
OIL USAGE	$35,037	$37,902	$40,808	$43,703	$48,754	$55,705	$63,020	$71,612	$80,495	$89,637	$97,331
NATURAL GAS	$7,465	$8,217	$9,037	$10,571	$12,169	$13,687	$15,248	$18,034	$19,656	$21,615	$23,776
TOTAL FUEL COST		$57,810	$62,185	$67,320	$74,711	$83,931	$93,596	$105,830	$117,239	$129,228	$139,984
BUSBAR FUEL COST (mills/kwh)		23.823	25.626	27.741	30.787	34.587	38.570	43.611	48.312	53.253	57.685
CONSUMABLES											
LIMESTONE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMINERALIZED WATER	$272	$285	$300	$315	$332	$349	$368	$387	$407	$428	$448
MAKE-UP WATER	$2,472	$2,596	$2,729	$2,871	$3,022	$3,179	$3,346	$3,527	$3,710	$3,894	$4,079
CHEMICALS	$4,193	$4,402	$4,629	$4,868	$5,125	$5,391	$5,674	$5,981	$6,291	$6,604	$6,917
CONDENSATE POLISHING RECHRG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ASH DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST		$7,283	$7,658	$8,054	$8,479	$8,920	$9,388	$9,895	$10,408	$10,926	$11,444
BUSBAR CONSUMABLES (mills/kwh)		3.001	3.156	3.319	3.494	3.676	3.869	4.078	4.289	4.502	4.716
PRODUCT & BYPRODUCT											
NAPHTHA		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FLAKED BOTTOMS	($1,446)	($1,554)	($1,646)	($1,748)	($1,854)	($1,959)	($2,069)	($2,188)	($2,318)	($2,443)	($2,571)
SULFUR	($1,347)	($1,415)	($1,487)	($1,564)	($1,647)	($1,732)	($1,823)	($1,922)	($2,021)	($2,122)	($2,223)
AMMONIA	($636)	($668)	($702)	($739)	($778)	($818)	($861)	($907)	($954)	($1,002)	($1,049)
TOTAL PRODUCT & BY-PRODUCT SALES		($3,636)	($3,836)	($4,051)	($4,278)	($4,510)	($4,753)	($5,017)	($5,293)	($5,567)	($5,843)
PRODUCT & BYPROD. SALES (mills/kwh)		(1.498)	(1.581)	(1.669)	(1.763)	(1.858)	(1.959)	(2.067)	(2.181)	(2.294)	(2.408)
O & M											
OPERATION LABOR SALARY	$6,100	$6,405	$6,734	$7,083	$7,456	$7,844	$8,256	$8,702	$9,152	$9,608	$10,064
MAINTENANCE	$9,909	$10,404	$10,939	$11,505	$12,112	$12,741	$13,410	$14,135	$14,867	$15,607	$16,347
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$3,019	$3,170	$3,333	$3,506	$3,690	$3,882	$4,086	$4,307	$4,530	$4,755	$4,981
TOTAL O & M COST	$19,028	$19,979	$21,006	$22,094	$23,258	$24,468	$25,752	$27,143	$28,549	$29,971	$31,391
FIXED O & M		$17,853	$18,771	$19,743	$20,783	$21,864	$23,012	$24,255	$25,511	$26,781	$28,051
VARIABLE O & M		$2,126	$2,235	$2,351	$2,475	$2,604	$2,740	$2,888	$3,038	$3,189	$3,340
BUSBAR FIXED O & M (mills/kwh)		7.357	7.735	8.136	8.565	9.010	9.483	9.995	10.513	11.036	11.559
BUSBAR VARIABLE O & M (mills/kwh)		0.876	0.921	0.969	1.020	1.073	1.129	1.190	1.252	1.314	1.377
TOTALS											
ANNUAL NET MWH GENERATED		2426683	2426683	2426683	2426683	2426683	2426683	2426683	2426683	2426683	2426683
TOTAL ANNUAL COST		$152,100	$157,678	$164,081	$172,834	$183,473	$194,648	$208,516	$221,567	$235,222	$247,641
TOTAL BUSBAR COST (mills/kwh)		62.678	64.977	67.615	71.222	75.607	80.211	85.926	91.304	96.932	102.049

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
CO-PROCESSOR/COMBINE CYCLE TECHNOLOGY

OCF CASE A - NO NAPHTHA SALES
(Thousands of Dollars)

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INSTALLED CAPITAL COST										
ANNUAL DEBT SERVICE	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665	$70,665
BUSBAR CARRYING CHARGE (mills/kwh)	29.120	29.120	29.120	29.120	29.120	29.120	29.120	29.120	29.120	29.120
FUEL										
COAL	$19,771	$20,627	$21,520	$22,452	$23,424	$24,438	$25,496	$26,600	$27,752	$28,954
OIL USAGE	$104,485	$108,901	$113,508	$118,314	$123,329	$128,561	$134,019	$139,714	$145,655	$151,854
NATURAL GAS	$25,653	$26,764	$27,923	$29,132	$30,393	$31,709	$33,082	$34,514	$36,009	$37,568
TOTAL FUEL COST	$149,908	$156,291	$162,950	$169,897	$177,146	$184,708	$192,597	$200,829	$209,416	$218,376
BUSBAR FUEL COST (mills/kwh)	61.775	64.405	67.149	70.012	72.999	76.115	79.367	82.758	86.297	89.989
CONSUMABLES										
LIMESTONE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DEMINERALIZED WATER	$467	$488	$509	$531	$554	$578	$603	$629	$656	$685
MAKE-UP WATER	$4,256	$4,440	$4,632	$4,833	$5,042	$5,260	$5,488	$5,726	$5,974	$6,232
CHEMICALS	$7,217	$7,529	$7,855	$8,195	$8,550	$8,920	$9,307	$9,710	$10,130	$10,569
CONDENSATE POLISHING RECHRG	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
WASTEWATER TREATMENT	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ASH DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST	$11,940	$12,457	$12,996	$13,559	$14,146	$14,758	$15,397	$16,064	$16,760	$17,485
BUSBAR CONSUMABLES (mills/kwh)	4.920	5.133	5.355	5.587	5.829	6.082	6.345	6.620	6.906	7.206
PRODUCT & BYPRODUCT										
NAPHTHA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FLAKED BOTTOMS	($2,702)	($2,819)	($2,941)	($3,068)	($3,201)	($3,340)	($3,484)	($3,635)	($3,792)	($3,957)
SULFUR	($2,319)	($2,419)	($2,524)	($2,633)	($2,747)	($2,866)	($2,990)	($3,120)	($3,255)	($3,396)
AMMONIA	($1,095)	($1,142)	($1,192)	($1,243)	($1,297)	($1,353)	($1,412)	($1,473)	($1,537)	($1,603)
TOTAL PRODUCT & BY-PRODUCT SALES	($6,116)	($6,380)	($6,657)	($6,945)	($7,246)	($7,559)	($7,887)	($8,228)	($8,584)	($8,956)
PRODUCT & BYPROD. SALES (mills/kwh)	(2.520)	(2.629)	(2.743)	(2.862)	(2.986)	(3.115)	(3.250)	(3.391)	(3.537)	(3.691)
O & M										
OPERATION LABOR SALARY	$10,500	$10,954	$11,429	$11,924	$12,440	$12,978	$13,540	$14,127	$14,738	$15,377
MAINTENANCE	$17,055	$17,794	$18,564	$19,368	$20,207	$21,082	$21,994	$22,947	$23,940	$24,977
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$5,197	$5,422	$5,656	$5,901	$6,157	$6,423	$6,701	$6,992	$7,294	$7,610
TOTAL O & M COST	$32,751	$34,170	$35,649	$37,193	$38,803	$40,483	$42,236	$44,065	$45,973	$47,964
FIXED O & M	$29,266	$30,534	$31,856	$33,235	$34,674	$36,175	$37,742	$39,376	$41,081	$42,860
VARIABLE O & M	$3,485	$3,636	$3,793	$3,958	$4,129	$4,308	$4,494	$4,689	$4,892	$5,104
BUSBAR FIXED O & M (mills/kwh)	12.060	12.582	13.127	13.696	14.289	14.907	15.553	16.226	16.929	17.662
BUSBAR VARIABLE O & M (mills/kwh)	1.436	1.498	1.563	1.631	1.702	1.775	1.852	1.932	2.016	2.103
TOTALS										
ANNUAL NET MWH GENERATED	2426683	2426683	2426683	2426683	2426683	2426683	2426683	2426683	2426683	2426683
TOTAL ANNUAL COST	$259,148	$267,201	$275,603	$284,369	$293,514	$303,055	$313,009	$323,394	$334,229	$345,533
TOTAL BUSBAR COST (mills/kwh)	106.791	110.110	113.572	117.184	120.953	124.884	128.986	133.266	137.731	142.389

STONE & WEBSTER COMPARITIVE TECHNOLOGY REPORT PULVERIZED COAL TECHNOLOGY ITEM	BASIC ANNUAL COST DATA (1989 DOLLARS)	OCF CASE A - NO NAPHTHA SALES (Thousands of Dollars) 1990	1991	1992	1993	1994	1995	1996	REV. 3.2 PAGE 7 DATE: 16 August 1989 1997	1998	1999
INSTALLED CAPITAL COST	$506,332										
ANNUAL DEBT SERVICE		$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078
BUSBAR CARRYING CHARGE (mills/kwh)		34.663	34.663	34.663	34.663	34.663	34.663	34.663	34.663	34.663	34.663
FUEL											
COAL	$37,440	$39,845	$42,081	$44,517	$47,070	$49,652	$52,360	$55,294	$58,411	$61,467	$64,572
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST		$39,845	$42,081	$44,517	$47,070	$49,652	$52,360	$55,294	$58,411	$61,467	$64,572
BUSBAR FUEL COST (mills/kwh)		19.162	20.237	21.409	22.637	23.878	25.180	26.592	28.090	29.560	31.053
CONSUMABLES											
LIMESTONE	$2,554	$2,682	$2,820	$2,966	$3,122	$3,284	$3,457	$3,643	$3,832	$4,023	$4,214
DEMINERALIZED WATER	$9	$10	$10	$11	$12	$12	$13	$13	$14	$15	$16
MAKE-UP WATER	$3,441	$3,613	$3,799	$3,996	$4,207	$4,425	$4,658	$4,909	$5,163	$5,421	$5,677
CHEMICALS	$527	$553	$582	$612	$644	$678	$713	$752	$791	$830	$870
CONDENSATE POLISHING RECHRG	$21	$22	$23	$24	$26	$27	$28	$30	$31	$33	$34
WASTEWATER TREATMENT	$320	$336	$353	$372	$391	$411	$433	$456	$480	$504	$528
ASH DISPOSAL	$1,019	$1,070	$1,125	$1,183	$1,245	$1,310	$1,379	$1,454	$1,529	$1,605	$1,681
FGD SLUDGE	$6,375	$6,694	$7,038	$7,402	$7,793	$8,198	$8,628	$9,094	$9,565	$10,041	$10,517
BOTTOMS/SLAG DISPOSAL	$0.000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST		$14,980	$15,750	$16,566	$17,439	$18,346	$19,309	$20,352	$21,406	$22,472	$23,537
BUSBAR CONSUMABLES (mills/kwh)		7.204	7.574	7.967	8.387	8.823	9.286	9.787	10.294	10.807	11.319
PRODUCT & BYPRODUCT											
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M											
OPERATION LABOR SALARY	$5,100	$5,355	$5,630	$5,922	$6,234	$6,558	$6,902	$7,275	$7,652	$8,033	$8,414
MAINTENANCE	$10,317	$10,833	$11,390	$11,980	$12,611	$13,267	$13,964	$14,718	$15,480	$16,251	$17,021
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$2,768	$2,906	$3,056	$3,214	$3,384	$3,559	$3,746	$3,949	$4,153	$4,360	$4,567
TOTAL O & M COST	$18,185	$19,095	$20,076	$21,116	$22,229	$23,385	$24,612	$25,941	$27,285	$28,644	$30,002
FIXED O & M		$14,612	$15,363	$16,159	$17,010	$17,895	$18,834	$19,852	$20,880	$21,920	$22,959
VARIABLE O & M		$4,483	$4,713	$4,957	$5,218	$5,490	$5,778	$6,090	$6,405	$6,724	$7,043
BUSBAR FIXED O & M (mills/kwh)		7.027	7.388	7.771	8.181	8.606	9.058	9.547	10.041	10.541	11.041
BUSBAR VARIABLE O & M (mills/kwh)		2.156	2.267	2.384	2.510	2.640	2.779	2.929	3.080	3.234	3.387
TOTALS											
TOTAL ANNUAL COST		$145,998	$149,985	$154,278	$158,816	$163,461	$168,359	$173,665	$179,180	$184,662	$190,189
TOTAL BUSBAR COST (mills/kwh)		70.212	72.130	74.194	76.377	78.610	80.966	83.518	86.170	88.806	91.464

STONE & WEBSTER
COMPARITIVE TECHNOLOGY REPORT
PULVERIZED COAL TECHNOLOGY

OCF CASE A - NO NAPHTHA SALES
(Thousands of Dollars)

REV. 3.2 PAGE 8
DATE: 16 August 1989

ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INSTALLED CAPITAL COST										
ANNUAL DEBT SERVICE	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078	$72,078
BUSBAR CARRYING CHARGE (mills/kwh)	34.663	34.663	34.663	34.663	34.663	34.663	34.663	34.663	34.663	34.663
FUEL										
COAL	$67,659	$70,588	$73,645	$76,834	$80,160	$83,631	$87,253	$91,031	$94,972	$99,085
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$67,659	$70,588	$73,645	$76,834	$80,160	$83,631	$87,253	$91,031	$94,972	$99,085
BUSBAR FUEL COST (mills/kwh)	32.538	33.947	35.417	36.950	38.550	40.219	41.961	43.778	45.673	47.651
CONSUMABLES										
LIMESTONE	$4,395	$4,587	$4,785	$4,992	$5,209	$5,434	$5,669	$5,915	$6,171	$6,438
DEMINERALIZED WATER	$16	$17	$18	$18	$19	$20	$21	$22	$23	$24
MAKE-UP WATER	$5,923	$6,180	$6,448	$6,727	$7,018	$7,322	$7,639	$7,970	$8,315	$8,675
CHEMICALS	$907	$947	$988	$1,030	$1,075	$1,121	$1,170	$1,221	$1,274	$1,329
CONDENSATE POLISHING RECHRG	$36	$38	$39	$41	$43	$44	$46	$48	$51	$53
WASTEWATER TREATMENT	$551	$575	$600	$625	$653	$681	$710	$741	$773	$807
ASH DISPOSAL	$1,754	$1,830	$1,909	$1,992	$2,078	$2,168	$2,262	$2,360	$2,462	$2,568
FGD SLUDGE	$10,973	$11,448	$11,944	$12,461	$13,001	$13,564	$14,151	$14,764	$15,403	$16,070
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST	$24,557	$25,620	$26,730	$27,887	$29,095	$30,354	$31,669	$33,040	$34,471	$35,963
BUSBAR CONSUMABLES (mills/kwh)	11.810	12.321	12.855	13.411	13.992	14.598	15.230	15.889	16.577	17.295
PRODUCT & BYPRODUCT										
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M										
OPERATION LABOR SALARY	$8,778	$9,159	$9,555	$9,969	$10,401	$10,851	$11,321	$11,811	$12,322	$12,856
MAINTENANCE	$17,759	$18,528	$19,330	$20,167	$21,040	$21,951	$22,902	$23,893	$24,928	$26,007
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$4,765	$4,971	$5,186	$5,411	$5,645	$5,889	$6,144	$6,410	$6,688	$6,978
TOTAL O & M COST	$31,302	$32,657	$34,071	$35,546	$37,086	$38,691	$40,367	$42,115	$43,938	$45,841
FIXED O & M	$23,953	$24,991	$26,073	$27,202	$28,380	$29,608	$30,890	$32,228	$33,623	$35,079
VARIABLE O & M	$7,348	$7,666	$7,998	$8,345	$8,706	$9,083	$9,476	$9,887	$10,315	$10,761
BUSBAR FIXED O & M (mills/kwh)	11.520	12.018	12.539	13.082	13.648	14.239	14.856	15.499	16.170	16.870
BUSBAR VARIABLE O & M (mills/kwh)	3.534	3.687	3.847	4.013	4.187	4.368	4.557	4.755	4.960	5.175
TOTALS										
TOTAL ANNUAL COST	$195,596	$200,944	$206,524	$212,345	$218,419	$224,755	$231,366	$238,263	$245,459	$252,967
TOTAL BUSBAR COST (mills/kwh)	94.064	96.636	99.320	102.119	105.040	108.088	111.267	114.584	118.044	121.655

STONE & WEBSTER COMPARITIVE TECHNOLOGY REPORT FLUIDIZED BED TECHNOLOGY ITEM	BASIC ANNUAL COST DATA (1989 DOLLARS)	OCF CASE A - NO NAPHTHA SALES (Thousands of Dollars) 1990	1991	1992	1993	1994	1995	1996	REV. DATE: 16 August 1989 1997	3.2 1998	PAGE 9 1999
INSTALLED CAPITAL COST	$443,257										
ANNUAL DEBT SERVICE		$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099
BUSBAR CARRYING CHARGE (mills/kwh)		29.599	29.599	29.599	29.599	29.599	29.599	29.599	29.599	29.599	29.599
FUEL											
COAL	$37,451	$39,857	$42,093	$44,530	$47,083	$49,666	$52,374	$55,309	$58,427	$61,485	$64,590
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST		$39,857	$42,093	$44,530	$47,083	$49,666	$52,374	$55,309	$58,427	$61,485	$64,590
BUSBAR FUEL COST (mills/kwh)		18.696	19.745	20.888	22.086	23.297	24.568	25.945	27.407	28.841	30.298
CONSUMABLES											
LIMESTONE	$5,587	$5,867	$6,168	$6,488	$6,830	$7,185	$7,562	$7,971	$8,383	$8,801	$9,218
DEMINERALIZED WATER	$10	$10	$11	$11	$12	$12	$13	$14	$14	$15	$16
MAKE-UP WATER	$2,623	$2,754	$2,895	$3,045	$3,206	$3,372	$3,549	$3,741	$3,935	$4,131	$4,327
CHEMICALS	$527	$553	$582	$612	$644	$678	$713	$752	$791	$830	$870
CONDENSATE POLISHING RECHRG	$21	$23	$24	$25	$26	$28	$29	$31	$32	$34	$35
WASTEWATER TREATMENT	$320	$336	$353	$372	$391	$411	$433	$456	$480	$504	$528
ASH DISPOSAL	$5,216	$5,477	$5,759	$6,057	$6,376	$6,708	$7,060	$7,441	$7,827	$8,216	$8,606
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST		$15,020	$15,792	$16,610	$17,485	$18,394	$19,360	$20,405	$21,462	$22,531	$23,599
BUSBAR CONSUMABLES (mills/kwh)		7.045	7.408	7.791	8.202	8.628	9.081	9.572	10.068	10.569	11.070
PRODUCT & BYPRODUCT											
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M											
OPERATION LABOR SALARY	$4,050	$4,253	$4,471	$4,703	$4,951	$5,208	$5,481	$5,777	$6,077	$6,379	$6,682
MAINTENANCE	$9,038	$9,490	$9,977	$10,494	$11,047	$11,622	$12,232	$12,892	$13,560	$14,236	$14,910
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$2,300	$2,415	$2,539	$2,670	$2,811	$2,957	$3,112	$3,280	$3,450	$3,622	$3,794
TOTAL O & M COST	$15,387	$16,157	$16,987	$17,867	$18,809	$19,787	$20,825	$21,950	$23,087	$24,237	$25,386
FIXED O & M		$12,676	$13,327	$14,017	$14,756	$15,524	$16,339	$17,221	$18,113	$19,015	$19,916
VARIABLE O & M		$3,481	$3,660	$3,850	$4,052	$4,263	$4,487	$4,729	$4,974	$5,222	$5,469
BUSBAR FIXED O & M (mills/kwh)		5.946	6.252	6.575	6.922	7.282	7.664	8.078	8.496	8.920	9.342
BUSBAR VARIABLE O & M (mills/kwh)		1.633	1.717	1.806	1.901	2.000	2.105	2.218	2.333	2.450	2.566
TOTALS											
TOTAL ANNUAL COST		$134,132	$137,971	$142,106	$146,476	$150,946	$155,659	$160,764	$166,076	$171,352	$176,674
TOTAL BUSBAR COST (mills/kwh)		62.919	64.720	66.659	68.709	70.806	73.017	75.412	77.903	80.378	82.875

STONE & WEBSTER COMPARITIVE TECHNOLOGY REPORT FLUIDIZED BED TECHNOLOGY	OCF CASE A - NO NAPHTHA SALES (Thousands of Dollars)							REV. 3.2 PAGE 10 DATE: 16 August 1989		
ITEM	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
INSTALLED CAPITAL COST										
ANNUAL DEBT SERVICE	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099	$63,099
BUSBAR CARRYING CHARGE (mills/kwh)	29.599	29.599	29.599	29.599	29.599	29.599	29.599	29.599	29.599	29.599
FUEL										
COAL	$67,678	$70,608	$73,665	$76,855	$80,183	$83,655	$87,277	$91,056	$94,999	$99,112
OIL USAGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NATURAL GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FUEL COST	$67,678	$70,608	$73,665	$76,855	$80,183	$83,655	$87,277	$91,056	$94,999	$99,112
BUSBAR FUEL COST (mills/kwh)	31.746	33.121	34.555	36.051	37.612	39.241	40.940	42.713	44.562	46.492
CONSUMABLES										
LIMESTONE	$9,617	$10,034	$10,468	$10,922	$11,395	$11,888	$12,403	$12,940	$13,500	$14,085
DEMINERALIZED WATER	$17	$17	$18	$19	$20	$21	$21	$22	$23	$24
MAKE-UP WATER	$4,514	$4,710	$4,914	$5,126	$5,348	$5,580	$5,821	$6,0[illegible]4	$6,337	$6,611
CHEMICALS	$907	$947	$988	$1,030	$1,075	$1,121	$1,170	$1,221	$1,274	$1,329
CONDENSATE POLISHING RECHRG	$37	$38	$40	$42	$44	$46	$48	$50	$52	$54
WASTEWATER TREATMENT	$551	$575	$600	$625	$653	$681	$710	$741	$773	$807
ASH DISPOSAL	$8,979	$9,367	$9,773	$10,196	$10,638	$11,098	$11,579	$12,080	$12,603	$13,149
FGD SLUDGE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BOTTOMS/SLAG DISPOSAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
REPLACEMENT ENERGY COST	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL CONSUMABLES COST	$24,622	$25,688	$26,800	$27,961	$29,171	$30,435	$31,752	$33,127	$34,562	$36,058
BUSBAR CONSUMABLES (mills/kwh)	11.550	12.050	12.572	13.116	13.684	14.276	14.894	15.539	16.212	16.914
PRODUCT & BYPRODUCT										
FLAKED BOTTOMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SULFUR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
AMMONIA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PRODUCT & BY-PRODUCT SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PRODUCT & BYPROD. SALES (mills/kwh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O & M										
OPERATION LABOR SALARY	$6,971	$7,273	$7,588	$7,916	$8,259	$8,617	$8,990	$9,379	$9,785	$10,209
MAINTENANCE	$15,556	$16,230	$16,933	$17,666	$18,431	$19,229	$20,061	$20,930	$21,836	$22,782
OWNER'S OVERHEAD (@30% TOTAL LABOR)	$3,958	$4,129	$4,308	$4,495	$4,689	$4,893	$5,104	$5,325	$5,556	$5,797
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TOTAL O & M COST	$26,486	$27,632	$28,829	$30,077	$31,380	$32,738	$34,156	$35,635	$37,178	$38,788
FIXED O & M	$20,779	$21,679	$22,618	$23,597	$24,619	$25,685	$26,797	$27,957	$29,168	$30,431
VARIABLE O & M	$5,706	$5,954	$6,211	$6,480	$6,761	$7,054	$7,359	$7,678	$8,010	$8,357
BUSBAR FIXED O & M (mills/kwh)	9.747	10.169	10.609	11.069	11.548	12.048	12.570	13.11[illegible]	13.682	14.274
BUSBAR VARIABLE O & M (mills/kwh)	2.677	2.793	2.914	3.040	3.171	3.309	3.452	3.601	3.757	3.920
TOTALS										
TOTAL ANNUAL COST	$181,884	$187,028	$192,394	$197,992	$203,833	$209,927	$216,285	$222,917	$229,838	$237,057
TOTAL BUSBAR COST (mills/kwh)	85.319	87.731	90.248	92.875	95.614	98.473	101.455	104.567	107.813	111.199

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