FINAL REPORT

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Evaluation of Fossil Fuel Power Plants with CO_2 Recovery

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LIST OF ACRONYMS AND ABBREVIATIONS

A/E	architect/engineer
AFBC	circulating atmospheric fluidized-bed combined cycle
AGR	acid gas removal
ASU	air separation unit
CO_2	carbon dioxide
COE	cost of electricity
CRT	cathode ray tube
CT	combustion turbine
DCS	distributed control system
DLN	dry low NOx
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FD	forced draft
FGD	flue gas desulfurization
FRP	fiberglass-reinforced plastic
FWH	feedwater heater
gpm	gallons per minute
GSC	gland steam condenser
h	hour
HHV	higher heating value
HP	high pressure
HRSG	heat recovery steam generator
ID	induced draft
IGCC	integrated gasification combined cycle
INTREX	integrated recycle heat exchanger
IP	intermediate pressure
kW	kilowatt
lb	pound
LHV	lower heating value
LP	low pressure
MEA	monoethanolamine
MMBtu	million British thermal units
MT	metric ton

MW	megawatt
NGCC	natural gas combined cycle
NOx	oxides of nitrogen
O&M	operations and maintenance
OD	outside diameter
PC	pulverized coal
psia	pounds per square inch absolute
psig	pounds per square inch gauge
scf	standard cubic feet
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SPE	steam packing exhauster
SSR	steam seal regulator
TAG	Technical Assessment Guide (EPRI)
TCR	total capital requirement
TGTU	tail gas treating unit
TPC	total plant cost
tpd	tons per day
tph	tons per hour
VHP	very high pressure
wt%	weight percent

EXECUTIVE SUMMARY

INTRODUCTION

Over the past decade, a growing concern has developed about the potential impact of carbon dioxide (CO_2) emissions on the future global environment. Much of this concern has focused on the coal-fired power plants that now produce 56 percent of U.S. electricity. The main reason for the continued use of coal as the major power plant fuel in the United States is its significantly lower cost compared to other fossil fuels.

There have been recent indications that permissible levels of CO_2 emissions may be curbed in the future. The primary objective of this task is to evaluate the performance and economic impact of CO_2 removal on a conventional pulverized coal (PC) power plant, natural gas combined cycle (NGCC) power plant, integrated gasification combined cycle (IGCC) power plant, and circulating atmospheric fluidized-bed combustion (AFBC) power plant. The conceptual design, cost estimate, and performance and economic impact of a CO_2 removal system for each power plant will be compared at the same nominal 400 MWe capacity. All plants deliver concentrated CO_2 at a purity suitable for pipeline transport. The plant descriptions are:

- A conventional PC plant using wet flue gas desulfurization (FGD) for sulfur capture and MEA unit for CO_2 capture in the flue gas.
- An NGCC power plant using an MEA unit for CO_2 capture in the flue gas.
- An IGCC power plant with CO_2 recovery (shifting to hydrogen and a Selexol unit for CO_2 capture and H_2S removal).
- A 400 MWe AFBC power plant, including limestone injection for sulfur capture and an MEA unit for CO_2 capture in the flue gas.

APPROACH

Technical descriptions, performance results, and equipment lists are developed for each of the cases. Heat and material balances are developed using the commercial steady-state flowsheet simulator ASPEN™. Results from the heat and mass balances are then used to determine parasitic loads and overall system efficiency. They are also used to determine airborne emissions, size process equipment, and generate a major equipment list. This information is then used to generate plant costs. These results establish a "measuring stick" that can be used to estimate the impact of CO_2 recovery for the various technologies.

Capital cost estimates are developed based on a combination of adjusted vendor-furnished cost data and Parsons cost estimating database. At this conceptual level of estimating, the accuracy is projected to be better than ±40 percent. The capital cost at the Total Plant Cost (TPC) level includes equipment, materials, labor, indirect construction costs, engineering, and contingencies. Cost values for production, operation, and maintenance, including any fuel, are determined on a first-year basis to form a part of the economic analysis.

Design Basis, 400 MW Plants

The performance, environmental, and cost figures developed in this report are the result of maintaining a consistent design basis throughout. Common design inputs for site, ambient, and fuel characteristics were developed.

The plant site is assumed to a mid-United States location consisting of approximately 300 usable acres (not including ash disposal) within 15 miles of a medium-sized metropolitan area, with a well-established infrastructure capable of supporting the required construction work force. Feedstocks consist of Illinois No. 6 coal, natural gas, and Greer limestone. Ninety percent of the carbon in the fuel is recovered as CO_2, compressed to 1200 psia and dried for pipeline transport. More than 98 percent of the sulfur in the coal is removed

Conventional Coal-Fired PC plant

This greenfield power plant is a conventional PC plant using wet FGD for sulfur capture and an MEA unit for CO_2 capture in the flue gas. Table ES-1 illustrates the basis for the size and configuration. Figure ES-1 is the process block flow diagram for the PC plant.

Table ES-1
PC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Plant Configuration	Conventional PC supercritical with CO_2 removal
Steam Conditions	Double reheat; 3500 psig/1050°F/ 1050°F/1050°F
Particulate Removal	Electrostatic precipitator (ESP)
Sulfur Removal	Limestone wet FGD
NOx Control	Selective catalytic reduction (SCR)
CO_2 Removal	MEA absorption

Natural Gas Combined Cycle (NGCC) Power Plant

This greenfield power plant is an NGCC power plant using an MEA unit for CO_2 capture in the flue gas. Table ES-2 illustrates the basis for the size and configuration. Figure ES-2 is the process block flow diagram for the NGCC plant.

Table ES-2
NGCC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Plant Configuration	Advanced natural gas-fired combined cycle with MEA CO_2 removal
Turbine Configuration	GE MS7001FA
Steam Conditions	1800 psig/1050°F/1050°F

Figure ES-1
Process Block Flow Diagram – PC Plant

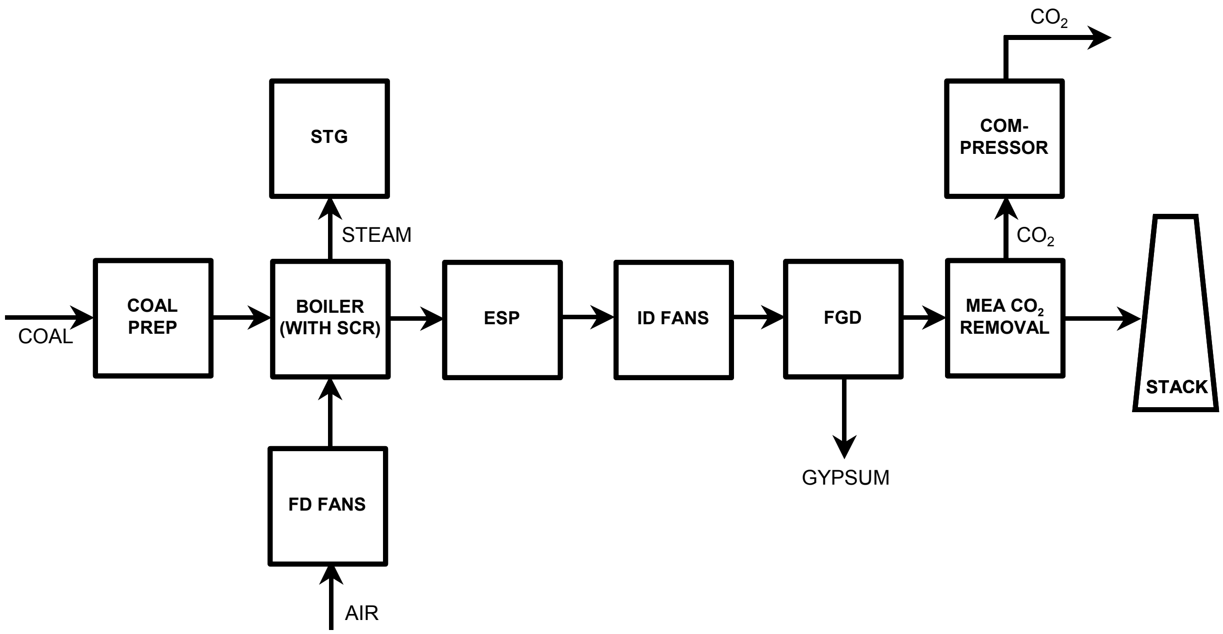
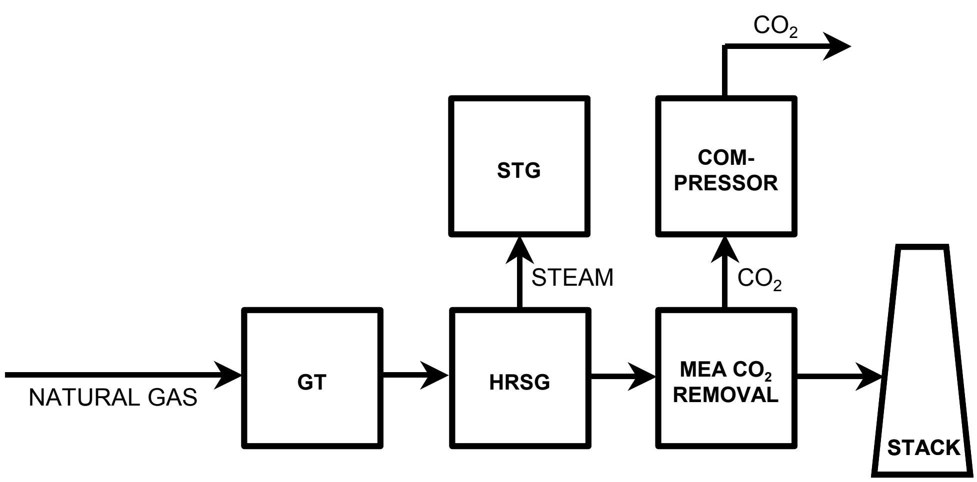


Figure ES-2
Process Block Flow Diagram – NGCC Plant



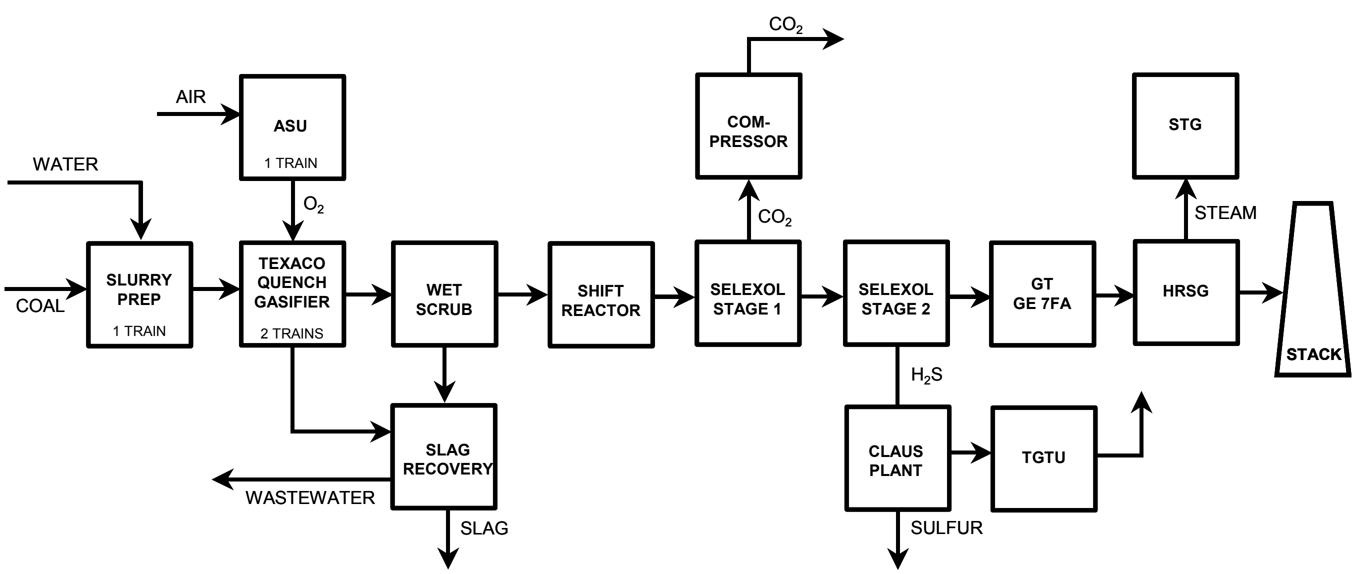
Integrated Gasification Combined Cycle (IGCC) Power Plant

This greenfield power plant is an IGCC power plant with CO_2 recovery (shifting to hydrogen and a Selexol unit for CO_2 capture and H_2S removal). Table ES-3 illustrates the basis for the size and configuration. Figure ES-3 is the process block flow diagram for the IGCC plant.

Table ES-3
IGCC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Fuel Gas Processing	Texaco quench gasifier Conventional pressure air separation unit (ASU) with high pressure feed Sour gas two-stage shift with COS hydrolysis Two-stage Selexol for H_2S and then CO_2 removal
Sulfur Recovery	Claus plant plus tail gas treating unit (TGTU)
Power Generation	Syngas expander GE 7FA combined cycle with steam injection for NOx control
Steam Conditions	Double reheat; 1800 psig/1000°F/1000°F
CO_2 Stream	Compressed to 1200 psia

Figure ES-3
Process Block Flow Diagram – IGCC Plant



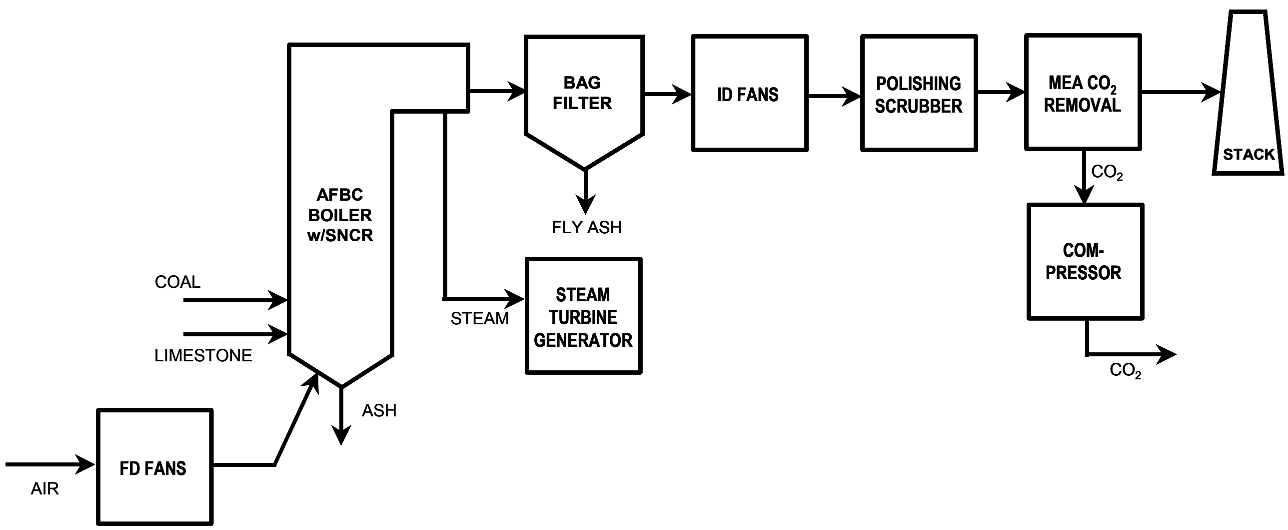
Atmospheric Fluidized-Bed Combustion (AFBC) Power Plant

This greenfield power plant is a 400 MWe AFBC power plant, including limestone injection for sulfur capture and an MEA unit for CO_2 capture in the flue gas. Table ES-4 illustrates the basis for the size and configuration. Figure ES-4 is the process block flow diagram for the AFBC plant.

Table ES-4
AFBC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Plant Configuration	Single train AFBC
Steam Conditions	Double reheat; 3500 psig/1050°F/ 1050°F/1050°F
Particulate Removal	Baghouse filter
Sulfur Removal	Limestone injection with coal/caustic polisher
NOx Control	Selective catalytic reduction (SCR)
CO_2 Removal	MEA absorption

Figure ES-4
Process Block Flow Diagram – AFBC Plant



A comparison of the plant performance is shown in Table ES-5. As expected, as a result of recovering and compressing 90 percent of the carbon as CO_2, each plant incurred a significant lowering in efficiency. The removal of CO_2 has a positive effect on the emissions from the plants. SO_2 for the fossil-fired plants with MEA processes for stack gas is reduced to essentially zero. This is due to the requirement for gas polishing before the MEA absorber. Table ES-6 shows the summary of plant emissions.

Also because of CO_2 recovery and compression, the plant capital requirement is increased, as are the operating costs. Table ES-7 is a summary comparison of the plant economics.

Table ES-5
Summary Plant Performance Comparisons

	PC Boiler	NGCC	IGCC	AFBC
Throttle Pressure (psig)	3500	1800	1800	3500
Throttle Temperature (°F)	1050	1050	1000	1050
First Reheat Outlet Temperature (°F)	1050	1050	1000	1050
Second Reheat Outlet Temperature (°F)	1050	--	--	1050
Gross Plant Power (MW_e)	489,990	446,867	573,870	489,990
Auxiliary Power (MW_e)	88,480	47,990	117,150	88,180
Net Plant Power (MW_e)	401,510	398,877	456,720	401,810
Net Plant Efficiency (HHV)	28.7%	39.2%	30.1%	28.2%
Net Plant Heat Rate (HHV)	11,897	8,701	11,344	12,102
As-Received Coal Feed (lb/h)	409,450	158,986	444,020	416,836
Thermal Input (kW_{th})	1,399,897	1,016,872	1,518,091	1,425,149
Sorbent Feed (lb/h)	42,052	--	--	85,071
CO_2 Recovered (lb/MWh)	2,172	952	2,018	2,245
CO_2 Avoided (lb/MWh)	1,469	704	1,601	1,470

Table ES-6
Summary Plant Air Emissions Comparisons

	PC Plant		NGCC		IGCC		AFBC	
	Lb/MMBtu	Lb/MWh	Lb/MMBtu	Lb/MWh	Lb/MMBtu	Lb/MWh	Lb/MMBtu	Lb/MWh
SO_2	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
NOx	0.126	1.50	0.033	0.28	0.028	0.25	0.127	1.50
Particulate	0.01	0.12	Nil	Nil	Nil	Nil	0.01	0..12
CO_2	20.0	238	11.4	99	22.5	255	20.2	237

Table ES-7
Summary Plant Economic Comparisons

	PC	NGCC	IGCC	AFBC
	\$1,000 (\$/kW)	**\$1,000 (\$/kW)**	**\$1,000 (\$/kW)**	**\$1,000 (\$/kW)**
Total Capital Cost	\$762,887 (\$1,900)	\$409,007 (\$1,025)	\$644,641 (\$1,412)	\$730,237 (\$1,817)
Total Capital Requirement	\$836,142 (\$2,083)	\$433,893 (\$1,088)	\$707,437 (\$1,549)	\$800,043 (\$1,991)
Annual Operating Costs	\$23,025	\$10,595	\$22,826	\$23,800
Cost of Electricity	**\$/MWh**	**\$/MWh**	**\$/MWh**	**\$/MWh**
Capital Charge	\$50.47	\$26.36	\$37.54	\$48.26
Fuel Cost	\$14.88	\$23.49	\$14.18	15.13
O&M Costs	\$10.07	\$4.66	\$8.78	\$10.40
Byproduct Credit	0	0	(\$0.60)	0
Net COE	\$75.42	\$54.51	\$59.90	\$73.79
Cost of Avoided CO_2	\$29.53/MT	\$52.31/MT	\$18.69/MT	\$27.50/MT

1. INTRODUCTION

1.1 BACKGROUND

Over the past decade, a growing concern has developed about the potential impact of carbon dioxide (CO_2) emissions on the future global environment. Much of this concern has focused on the coal-fired power plants that now produce 56 percent of U.S. electricity. The main reason for the continued use of coal as the major power plant fuel in the United States is its significantly lower cost compared to other fossil fuels.

There have been recent indications that permissible levels of CO_2 emissions may be curbed in the future. In conventional PC and circulating atmospheric fluidized bed combustion (AFBC) coal-fired units, CO_2 can be removed from the exhaust gas following heat recovery in an amine solvent based absorber/stripper system. Coal-based technologies that utilize integrated gasification combined cycle (IGCC), because they produce concentrated streams of CO_2 at high pressure, offer convenient opportunities that may be exploited for low-cost CO_2 removal.

The primary objective of this task is to evaluate the performance and economic impact of CO_2 removal on a conventional PC power plant, NGCC power plant, IGCC power plant, and AFBC power plant. The conceptual design, cost estimate, and the performance and economic impact of CO_2 removal system for each power plant will be compared at the same nominal 400 MWe capacity. All plants deliver concentrated CO_2 at a purity suitable for pipeline transport. The plant descriptions are:

- A conventional PC plant using wet FGD for sulfur capture and MEA unit for CO_2 capture in the flue gas.
- A NGCC power plant using an MEA unit for CO_2 capture in the flue gas.
- An IGCC power plant with CO_2 recovery (shifting to hydrogen and a Selexol unit for CO_2 capture and H_2S removal).
- A 400 MWe AFBC power plant, including limestone injection for sulfur capture and an MEA unit for CO_2 capture in the flue gas.

1.2 APPROACH

Technical descriptions, performance results, and equipment lists are developed for each of the cases. Heat and material balances are developed using the commercial steady-state flowsheet simulator ASPEN™. Results from the energy and mass balances are then used to determine parasitic loads and overall system efficiency. They are also used to determine airborne emissions, size process equipment, and generate a major equipment list. This information is then used to generate plant costs. These results establish a “measuring stick” that can be used to estimate the impact of CO_2 recovery for the various technologies.

Capital cost estimates are developed based on a combination of adjusted vendor-furnished cost data and Parsons cost estimating database. At this conceptual level of estimating, the accuracy is projected to be better than ±40 percent. The capital cost at the Total Plant Cost (TPC) level includes equipment, materials, labor, indirect construction costs, engineering, and contingencies.

Production, operation and maintenance, including any fuel, cost values are determined on a first-year basis to form a part of the economic analysis.

The following is prepared for each of the cases:

- Process descriptions.
- Process flow sheets (heat and material balances) including a simplified block flow diagram.
- Performance summary.
- Overall efficiency and net plant heat rate (HHV basis).
- Emissions summary.
- Major equipment list including design temperature, pressure, sparing, and operating capacity.
- Chemical and utility summary.
- Summary capital estimate including a detailed code of accounts.
- Capital cost in terms of \$/kW.
- Summary of production costs with details of the following sub-accounts: Fixed and Variable O&M, Consumables, Byproduct Credit, and Fuel.
- COE based on 65 percent capacity factor.

2. DESIGN BASIS, 400 MW PLANT

The performance, environmental, and cost figures developed in this report are the result of maintaining a consistent design basis throughout. Common design inputs for site, ambient, and fuel characteristics were developed and are defined in the following subsections.

2.1 PLANT SITE AND AMBIENT DESIGN CONDITIONS

The plant site is assumed to a mid-United States location consisting of approximately 300 usable acres (not including ash disposal) within 15 miles of a medium-sized metropolitan area, with a well-established infrastructure capable of supporting the required construction work force. The area immediately surrounding the site has a mixture of agricultural and light industrial uses. The site is served by a river of adequate quantity for use as makeup cooling water with minimal pretreatment and for the receipt of cooling system blowdown discharges.

A railroad line suitable for unit coal trains passes within 2-1/2 miles of the site boundary. A well-developed road network serves the site, capable of carrying multiple loads and with overhead restriction of not less than 16 feet (Interstate Standard).

The site is on relatively flat land with a maximum difference in elevation within the site of about 30 feet. The topography of the area surrounding the site is rolling hills, with elevations within 2,000 yards not more than 300 feet above the site elevation.

The site is within Seismic Zone 1, as defined by the Uniform Building Code. Table 2-1 lists the ambient characteristics of this site.

Table 2-1
Site Characteristics

Location	Mid USA
Topography	Level
Elevation	500 feet
Design Air Pressure	14.4 psia
Design Temperature, dry bulb	63°F
Design Temperature, max.	95°F
Design Temperature, min.	20°F
Relative Humidity	55%
Transportation	Rail access
Water	On site
Ash Disposal	Off site

<u>Feedstocks</u>

Illinois No. 6 coal — See Table 2-2

Natural gas — See Table 2-3

Greer limestone — See Table 2-4

Table 2-2
Base Coal Analysis – Illinois No. 6 Seam, Old Ben No. 26 Mine

Proximate Analysis	As-Received (wt%)	Dry Basis (wt%)
Moisture	11.12	
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
TOTAL	100.00	100.00
HHV (Btu/lb)	11,666	13,126
Ultimate Analysis	**As-Received (wt%)**	**Dry Basis (wt%)**
Moisture	11.12	-
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen (by difference)	6.88	7.75
TOTAL	100.00	100.00

Table 2-3
Natural Gas Analysis

	Volume, %
CH_4	90
C_2H_6	5
N_2	5
HHV, Btu/scf	1,002
HHV, Btu/lb	21,824

Table 2-4
Greer Limestone Analysis

	Dry Basis, %
Calcium Carbonate, $CaCO_3$	80.40
Magnesium Carbonate, $MgCO_3$	3.50
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

CO_2 Stream Properties

CO_2 delivery pressure 1200 psig

CO_2 specification -40° dew point
1.25% H_2 maximum
100 ppm SO_2 maximum
50 ppm H_2S maximum

Sulfur Removal >98%

NOx Emissions <0.02 lb/MMBtu

2.2 INDIVIDUAL CASE DESIGN BASES

2.2.1 Conventional Coal-Fired PC Plant

This greenfield power plant is a conventional PC plant using wet FGD for sulfur capture and MEA unit for CO_2 capture in the flue gas. Table 2-5 illustrates the basis for the size and configuration.

Table 2-5
PC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Plant Configuration	Conventional PC supercritical with CO_2 removal
Steam Conditions	Double reheat; 3500 psig/1050°F/ 1050°F/1050°F
Particulate Removal	Electrostatic precipitator (ESP)
Sulfur Removal	Limestone wet FGD
NOx Control	Selective catalytic reduction (SCR)
CO_2 Removal	MEA absorption

The major subsystems of the power plant are:

Coal Handling

To provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air Handling and Preheat – Air from the FD fans is heated in two vertical Ljungstrum regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the primary air fans, and is heated in the Ljungstrum type air preheaters for use as combustion air to the pulverizers.

- Coal Burners – Boiler will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation.
- Steam Generation and Reheat – Steam generator in this supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed for operation as a base-loaded unit for the majority of its life, with some weekly cycling the last few years.
- NOx Control – Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The second measure is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system will be designed to remove 63 percent of the incoming NOx. This, along with the low-NOx burners, will achieve the emission limit of 1.50 lb/MWh.
- Soot and Ash Removal – The soot-blowing system utilizes steam in an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Particulate removal is achieved with an ESP.
- Ash Handling System – The ash handling system scope is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). Fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo with pneumatic transport. Bottom ash from the boiler is fed into a clinker grinder prior discharge via a hydro-ejector to the ash pond.

Flue Gas Desulfurization

The flue gas desulfurization system comprises three subgroups:

- Limestone Handling and Reagent Preparation System – Function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. Limestone will be delivered to the plant by 25-ton trucks. Limestone is unloaded onto a storage pile located above vibrating feeders, fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder.
- Flue Gas Desulfurization System – Function of the FGD system is to scrub the boiler exhaust gases to remove 98 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet.
- Byproduct Dewatering – Function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack.

CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions, based on removing 90 percent of the CO_2 in the flue gas exiting the FGD system. An inhibited aqueous solution of MEA is used to remove the CO_2. CO_2 from the stripper is compressed to a pipeline pressure of 1200 psi by a multi-stage CO_2 compressor and dried.

Steam Turbine Generator

The turbine consists of a very-high-pressure (VHP) section, high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. sections. Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system.

Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

2.2.2 Natural Gas Combined Cycle (NGCC) Power Plant

This greenfield power plant is an NGCC power plant using an MEA unit for CO_2 capture in the flue gas. Table 2-6 illustrates the basis for the size and configuration.

Table 2-6
NGCC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Plant Configuration	Advanced natural gas-fired combined cycle with MEA CO_2 removal
Turbine Configuration	GE MS7001FA
Steam Conditions	1800 psig/1050°F/1050°F

The natural gas-fired combined cycle power plant comprises the following subsystems:

Gas Turbine Generator

The gas turbine generator selected for this application is based on the General Electric MS 7001FA model. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Two 7FAs, each equipped with an individual HRSG, are used to power a single steam turbine in a traditional 2 on 1 arrangement.

Heat Recovery Steam Generator

High-temperature flue gas at exiting the CT is conveyed through a HRSG (one for each turbine) to recover the large quantity of thermal energy that remains. The HRSG is configured with HP, IP, and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump.

CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions, based on removing 90 percent of the CO_2 in the HRSG flue gas. An inhibited aqueous solution of MEA is used to remove the CO_2. CO_2 from the stripper is compressed to a pipeline pressure of 1200 psig by a multi-stage CO_2 compressor and dried.

Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 1800 psig/1050°F/1050°F single reheat configuration. The steam turbine is a single machine consisting of tandem HP, IP, and double-flow LP turbine sections connected via a common shaft and driving a 3,600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing.

Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

2.2.3 Integrated Gasification Combined Cycle (IGCC) Power Plant

This greenfield power plant is an IGCC power plant with CO_2 recovery (shifting to hydrogen and a Selexol unit for CO_2 capture and H_2S removal). Table 2-7 illustrates the basis for the size and configuration.

Table 2-7
IGCC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Fuel Gas Processing	Texaco quench gasifier Conventional pressure air separation unit (ASU) with high pressure feed Sour gas two-stage shift with COS hydrolysis Two-stage Selexol for H_2S and then CO_2 removal
Sulfur Recovery	Claus plant plus tail gas treating unit (TGTU)
Power Generation	Syngas expander GE 7FA combined cycle with steam injection for NOx control
Steam Conditions	Double reheat; 1800 psig/1000°F/1000°F
CO_2 Stream	Compressed to 1200 psia

This greenfield power plant is a nominal 400 MW coal-fired IGCC power plant with H_2S and CO_2 removal. The major subsystems of the power plant are:

Coal Receiving and Handling

To provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Coal-Water Slurry Preparation and Feeding

The slurry preparation and feeding system mills crushed coal and generates a slurry for the gasifier. Three trains at 50 percent are required. The slurry storage tank is sized to hold 8 hours of slurry product.

Coal Gasification

The gasification technology for this study is that of Texaco Power and Gasification (Texaco). The design basis gasifier is the Texaco oxygen-blown slurry-feed entrained flow quench configuration. For the 400 MWe size, two commercial-scale gasifiers with each having a maximum coal throughput of 2,500 tpd dry will be required.

Air Separation Unit

One train at 100 percent will be used to produce nominally 3000 tpd of 95 percent oxygen product. Plant consists of a multi-staged air compressor, an air separation cold box, and an oxygen compression system. A liquid oxygen storage tank will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

Raw Gas Cooling

Hot raw gas from the quench gasifier exits the gasifier at about 1100 psia and 486°F. This gas stream is scrubbed and cooled to 400°F.

Water Gas Shift / Syngas Humidification

A set of high-temperature shift reactors is used to shift the bulk of the CO in the fuel gas to CO_2. A two-staged shift is utilized in order to maximize CO conversion while maintaining reasonable reactor volumes. The fuel gas stream is cooled in a series of low temperature economizers and then routed to the Selexol unit. Fuel gas condensate is recovered and routed to a sour drum.

Sulfur Removal and Recovery / Carbon Dioxide Removal and Compression

A unique feature of this power plant configuration is that H_2S and CO_2 are removed within the same process system, the Selexol process.

- Selexol Process – The purpose of the Selexol process is to preferentially remove H_2S as a product stream and then to preferentially remove CO_2 as a separate product stream. This is achieved in the double-stage Selexol process.

H_2S is removed in the first absorber. Sweet fuel gas flowing from the first absorber is cooled and routed to the second absorber unit. In this absorber, the fuel gas is contacted with "unloaded" lean solvent. The solvent removes approximately 97 percent of the CO_2 remaining in the fuel gas stream, for an overall 90 percent CO_2 recovery. Pressure of gas exiting the Selexol process is reduced through an expansion turbine.

- CO_2 Compression and Drying – CO_2 is flashed from the rich solution is compressed in a multiple-stage, intercooled compressor to supercritical conditions. During compression, the CO_2 stream is dehydrated with triethylene glycol. The virtually moisture-free dense phase CO_2 steam is then ready for pipeline transportation.
- Claus Unit – Acid gas from the first-stage absorber of the Selexol unit is routed to the Claus plant, representing an overall sulfur recovery efficiency of 99.7 percent. Acid gas from the Selexol unit and tail gas amine unit are preheated and sent to the Claus furnace where H_2S is catalytically oxidized to SO_2.

  Three preheaters and three sulfur converters are needed to obtain a per-pass H_2S conversion of approximately 97.8 percent. Tail gas from the Claus unit containing unreacted sulfur species such as H_2S, COS, and SO_2 is processed in an amine tail gas treating unit in order to recycle sulfur back to the Claus plant. Sweet gas from the amine absorber, which contains fuel gas species such as H_2 and CO, is compressed and recycled to the gasifier.

Combustion Turbine and Heat Recovery

The combustion turbine selected for this application is based on the General Electric Model 7FE. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Waste heat rejected by the gas turbine is recovered by the HRSG. The HRSG, along with raw gas coolers and the fire tube boiler located in the gasifier island, generate steam utilized in the steam turbine to generate electrical power.

Steam Turbine

The Rankine cycle used in this case is based on a state-of-the-art 1800 psig/1000°F/1000°F single reheat configuration. The steam turbine is assumed to consist of tandem HP, IP, and double-flow LP turbine sections connected via a common shaft (along with the combustion turbine) and driving a 3600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing

Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the gasifier island. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a series of low-temperature raw gas coolers located within the gasifier island.

2.2.4 Circulating Atmospheric Fluidized-Bed Combustion (AFBC) Power Plant

This greenfield power plant is a 400 MWe AFBC power plant, including limestone injection for sulfur capture and an MEA unit for CO_2 capture in the flue gas. Table 2-8 illustrates the basis for the size and configuration.

Table 2-8
AFBC Plant Design Basis

Plant Capacity	Nominal 400 MWe
Plant Configuration	Single train AFBC
Steam Conditions	Double reheat; 3500 psia/1050°F/ 1050°F/1050°F
Particulate Removal	Baghouse filter
Sulfur Removal	Limestone injection with coal/caustic polisher
NOx Control	Selective catalytic reduction (SCR)
CO_2 Removal	MEA absorption

The major subsystems of the power plant are:

Coal Handling

To provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Limestone Sorbent Handling

To provide the equipment required for unloading, conveying, preparing, and storing the limestone delivered to the plant. The scope of the system is from the trestle bottom dumper and limestone receiving hoppers up to the pulverizer fuel inlet.

Limestone Handling and Preparation System

Function of the limestone handling and preparation system is to receive, store, convey, and grind the limestone delivered to the plant. Limestone will be delivered to the plant by 25-ton trucks. Limestone is unloaded onto a storage pile located above vibrating feeders, fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder.

Ash Handling System

The ash handling system scope is from the bag house hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). Fly ash collected in the bag house and the air heaters is conveyed to the fly ash storage silo with pneumatic transport.

CO_2 Removal and Compression

Part of the criteria of this power plant design is the limitation of CO_2 emissions, based on removing 90 percent of the CO_2 in the flue gas exiting the baghouse. An inhibited aqueous solution of MEA is used to remove the CO_2. CO_2 from the stripper is compressed to a pipeline pressure of 1200 psig by a multi-stage CO_2 compressor and dried.

<u>Steam Turbine Generator</u>

The turbine consists of a very-high-pressure (VHP) section, HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. sections. Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system.

<u>Condensate and Feedwater Systems</u>

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

2.3 Supporting Data for the Economic Analysis

2.3.1 Capital Cost Estimate, Production Cost/Expense Estimate, and Economic Basis

Capital cost estimates were developed for the PC, NGCC, IGCC, and AFBC power plants based on a combination of adjusted vendor-furnished cost data and Parsons cost estimating database. The capital costs at the Total Plant Cost (TPC) level include equipment, materials, labor, indirect construction costs, engineering, and contingencies. Production, operation and maintenance, including any fuel, cost values were determined on a first-year basis to form a part of the economic analysis. Quantities for major consumables such as fuel, sorbent, and ash were taken from technology-specific heat and material balance diagrams developed for each plant application. Annual costs were determined on the basis of unit costs taken from EPRI-TAG (1998) and those supplied by vendors. Other consumables were evaluated on the basis of the quantity required using reference data. Operating labor cost was determined on the basis of the number of operators, operating jobs, and the average wage rate. Maintenance costs were evaluated on the basis of requirements for each major plant section. The operating and maintenance costs were then converted to unit values of $/MWh. Each major system capital cost was based on a reference bottoms-up estimate and subsequently adjusted for the case specific requirements.

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies. The engineering costs represent the cost of architect/engineer (A/E) services for home office engineering, design, drafting, and project construction management services. The cost was determined at a nominal rate of 6 percent applied to the bare erected cost on an individual account basis. Any cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Consistent with conventional power plant practices, project contingencies were added to the TPC accounts to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. The contingencies represent costs that are expected to occur. Each TPC cost account is evaluated against the level of estimate detail and field experience to define project contingency. As a result, nominal contingency values of 5 to 30 percent were applied to arrive at the TPC values. The cumulative impact of this contingency approach is a composite result of approximately 15 percent. Total plant costs, or "Overnight Construction Costs" values, are expressed in January 2001 dollars.

In addition to the TPC, other capital costs were added to reach a Total Capital Requirement (TCR), which was used to determine annual capital charges. These included Accumulated Funds During Construction (2.5 years for the NGCC and 4 years for the coal plants), process licensing fees ($1.5 million for Selexol and $1.0 million for MEA), working capital (0.5 percent TPC) and appropriate land costs. The annual factor applied to determining annual capital charges is 13.8 percent TCR.

The operating and maintenance expenses and consumable costs were developed on a quantitative basis and are shown as production costs. Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. The exception was maintenance cost for the combustion turbine, which is a function of operating hours. Cost of consumables was determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours. Each of these expenses and costs is determined on a first-year basis, assuming a 65 percent annual plant capacity factor.

Byproduct credits were considered for IGCC elemental sulfur production, which is a marketable commodity. It is assumed that a local demand exists for sulfur at market price of $55/long ton. Table 2-9 is a listing of the cost data applied to the four power plants.

Table 2-9
Plant Consumables Cost Data

Natural Gas as Received	$2.70/MMBtu
Coal as Received	$1.25/MMBtu
Limestone as Received	$13.14/ton
Ammonia for SCR	$288/ton
Caustic for SO_2 Polisher	$160/ton
Raw Makeup Water	$0.92/1,000 gallons
MEA Makeup	$0.50/ton CO_2 removed
Selexol Makeup	$0.05/ton CO_2 removed
Solid Disposal Costs	$15/ton

2.3.2 CO_2 Captured and CO_2 Avoided

The four power plants described in this report were designed to remove and capture 90 percent of the carbon in the coal as compressed CO_2. The penalty for doing this is reflected in decreased efficiency and increased costs. The four designs in this task were limited to CO_2 capture plants, so there are no other plants in this report that can be directly compared to get the differential emissions and costs. However, the four plants were derived from baseline plants, which are referenced as follows (source: "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," EPRI, U.S. DOE/NETL, 2000):

Referenced plants:

- PC and AFBC Plant Case 7C, Conventional Supercritical PC Plant without CO_2 Removal
- NGCC Plant Case 1C, Base NGCC Plant without CO_2 Removal (Class F Turbine)

Baseline Texaco IGCC information was obtained from the recently completed Clean Coal Reference Plant report, NETL 2001.

A table has been prepared for each plant to indicate cost of avoided CO_2 operating at 65 percent capacity factor; see tables 3-6, 4-6, 5-6, and 6-6 in later sections.

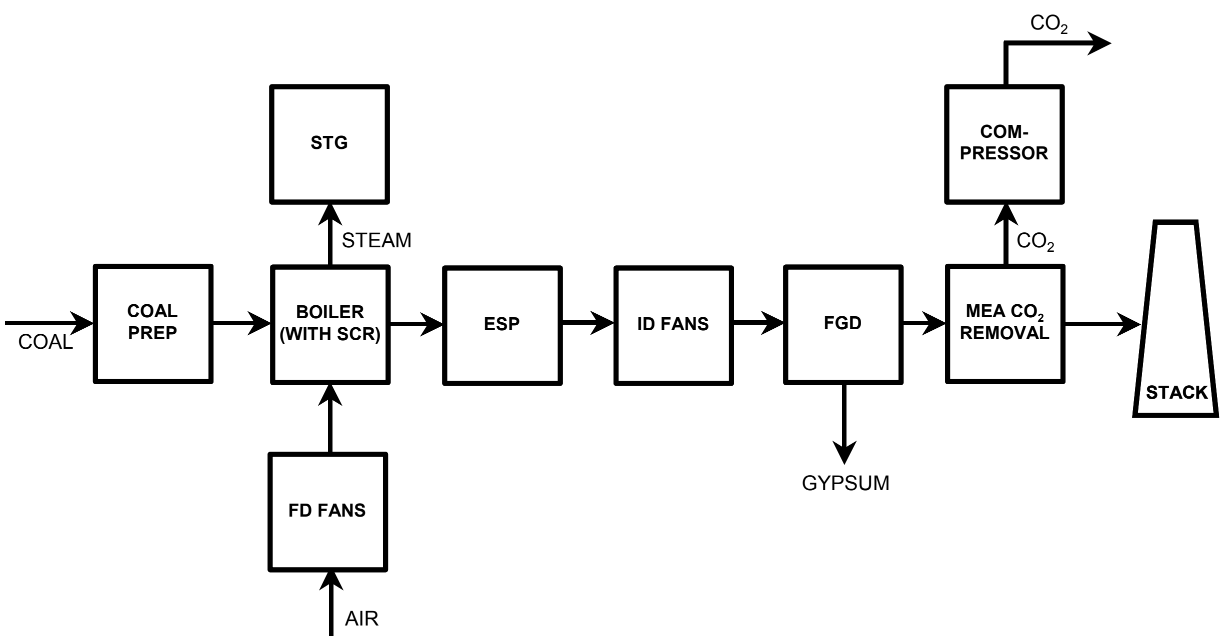
3. COAL-FIRED SUPERCRITICAL PC PLANT WITH CO_2 REMOVAL

3.1 INTRODUCTION

This section describes a coal-fired supercritical steam plant with CO_2 removal and recovery from the flue gas. The plant design approach is market-based, and the configuration reflects current information and design preferences, the availability of a newer generation steam turbine, and the relative latitude of a greenfield site.

Figure 3-1 is a block flow diagram of the power plant. The coal-fired boiler is staged for low NOx formation. The boiler is also equipped with selective catalytic reduction (SCR). Wet limestone forced oxidation FGD is used to limit SO_2 emissions, followed with a caustic scrubber to remove remaining SO_2 and protect the MEA process. A once-through steam generator is used to power a double-reheat supercritical steam turbine with a net power output of 497 MWe. The steam turbine conditions correspond to 3500 psig/1050°F throttle with 1050°F at both reheats. Net plant power, after consideration of the auxiliary power load, is 402 MWe with an estimated HHV efficiency of 28.7 percent.

Figure 3-1
Block Flow Diagram – PC



Flue gas exiting the FGD system is routed to an inhibited MEA absorber-stripper system. In this system, a solution of aqueous MEA is used to remove 90 percent of the CO_2 in the flue gas. Low-pressure steam is used to strip and purify the CO_2. Low-pressure CO_2 removed from the system is compressed to supercritical conditions.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

3.2 THERMAL PLANT PERFORMANCE

Table 3-1 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, wet limestone FGD system capabilities, and CO_2 removal through an aqueous solution of inhibited MEA.

Gross power output for the steam turbine is estimated to be 490.0 MWe. Plant auxiliary power is estimated to be 88.5 MWe. This auxiliary load value, much higher than that anticipated for a traditional coal-fired supercritical steam plant, is due to the presence of the CO_2 removal/ compression equipment. In particular, the flue gas ID fan, which requires 24.3 MWe of auxiliary power, and the CO_2 compressor, which requires 36.3 MWe of auxiliary power, are responsible.

Net plant power output, which considers generator losses and auxiliary power, is estimated as 401.5 MWe. This plant power output results in a net system thermal efficiency of 28.7 percent (HHV) with a corresponding heat rate of 11,897 Btu/kWh (HHV). Plant efficiency and heat rate numbers are low in comparison to those expected for coal-fired steam plants utilizing state-of-the-art supercritical steam turbines. There are two reasons for the low system thermal efficiency: (1) the increased auxiliary power associated with the CO_2 removal equipment (see above), and, (2) the large amount of steam diverted to the MEA stripper reboiler. Diverting this low-pressure (LP) steam results in a marked decrease in steam turbine power output.

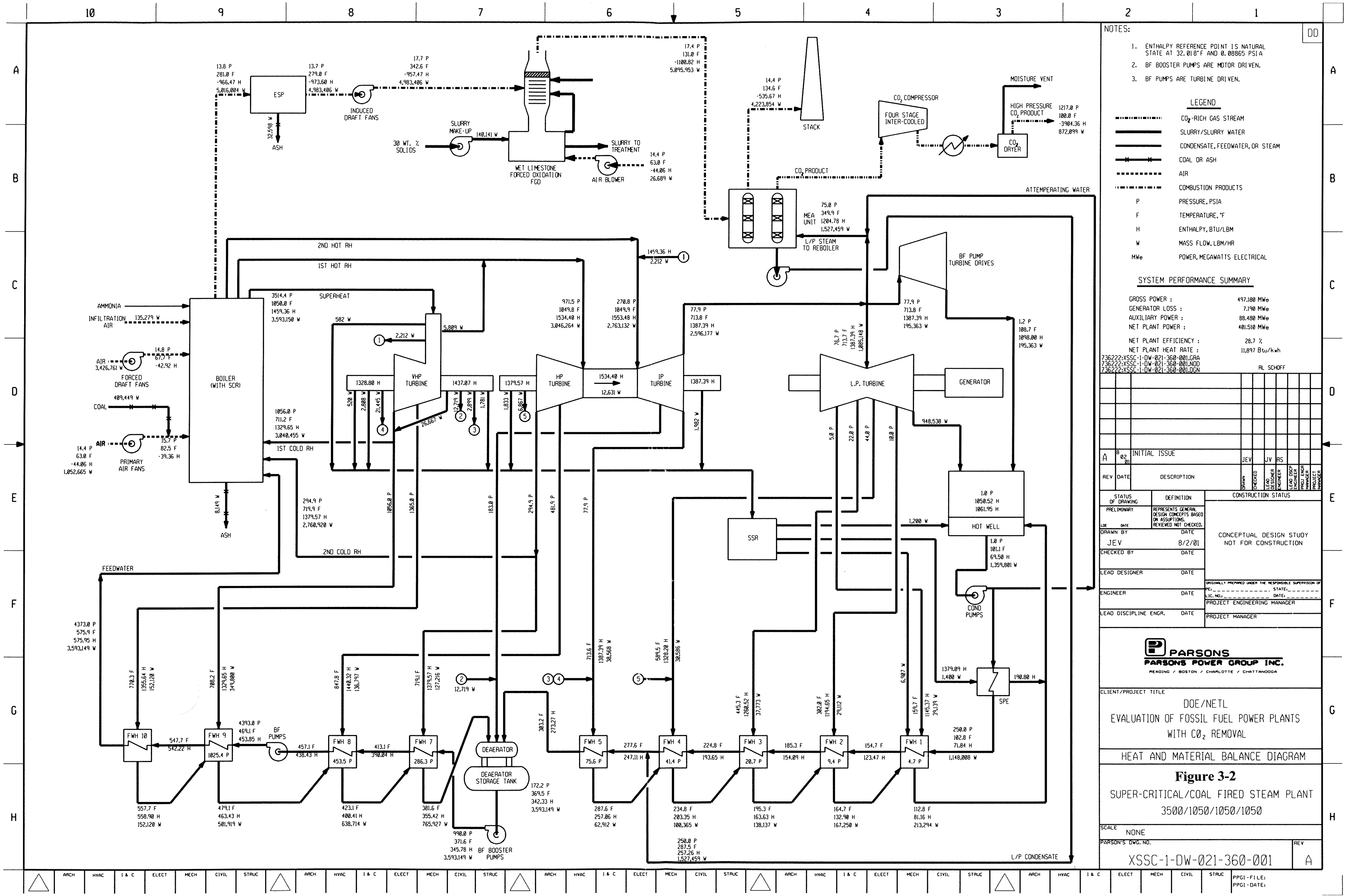
A heat and material balance diagram for this convention coal-fired steam plant is shown in Figure 3-2. The steam turbine power cycle is shown at 100 percent of design load. The supercritical Rankine cycle used for this case is based on a 3500 psig/1050°F/1050°F/1050°F double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters. Boiler feedwater is heated in the high-pressure feedwater heaters. Steam generation, superheat, and reheat are accomplished in the boiler house. Also shown in the diagram is the basic equipment of the FGD and that required to remove CO_2 from the flue gas stream and concentrate it as a pure, high-pressure product.

Table 3-1
Supercritical PC Plant with CO_2 Removal
Plant Performance Summary – 100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	3,500
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
2nd Reheat Outlet Temperature, °F	1,050
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	497,189
Generator Loss	(7,190)
Gross Plant Power	489,990
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	480
Limestone Handling & Reagent Preparation	1,130
Pulverizers	2,280
Ash Handling	2,050
Primary Air Fans	1,500
Forced Draft Fans	1,190
Induced Draft Fans	24,280
SCR	100
Seal Air Blowers	50
Precipitators	1,230
FGD Pumps and Agitators	4,230
Condensate Pumps	370
Boiler Feedwater Booster Pumps	3,760
High Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	2,300
Cooling Tower Fans	1,310
MEA Unit	2,380
CO_2 Compressor (Note 3)	36,310
Transformer Loss	1,130
Total Auxiliary Power Requirement	88,480
NET PLANT POWER, kWe	401,510
CO_2 Recovered, lb/MWh	2,172
CO_2 Avoided, lb/MWh	1,469
PLANT EFFICIENCY	
Net Efficiency, % HHV	28.7%
Net Heat Rate, Btu/kWh (HHV)	11,897
CONDENSER COOLING DUTY, 10^6 Btu/h	1,147
CONSUMABLES	
As-Received Coal Feed, lb/h (Note 4)	409,450
Thermal Input, kW_{th}	1,399,897
Sorbent, lb/h	42,052

Note 1 – Boiler feed pumps are turbine driven
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 1200 psig
Note 4 – As-received coal heating value: 11,666 Btu/lb (HHV)

Figure 3-2


NOTES:
1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018°F AND 0.08865 PSIA
2. BF BOOSTER PUMPS ARE MOTOR DRIVEN.
3. BF PUMPS ARE TURBINE DRIVEN.
LEGEND
CO2-RICH GAS STREAM
SLURRY/SLURRY WATER
CONDENSATE, FEEDWATER, OR STEAM
COAL OR ASH
AIR
COMBUSTION PRODUCTS
P PRESSURE, PSIA
F TEMPERATURE, °F
H ENTHALPY, BTU/LBM
W MASS FLOW, LBM/HR
MWe POWER, MEGAWATTS ELECTRICAL
SYSTEM PERFORMANCE SUMMARY
GROSS POWER : 497.180 MWe
GENERATOR LOSS : 7.190 MWe
AUXILIARY POWER : 88.480 MWe
NET PLANT POWER : 401.510 MWe
NET PLANT EFFICIENCY : 28.7 %
NET PLANT HEAT RATE : 11,897 Btu/kwh
736222:XSSC-1-DW-021-360-001.GRA
736222:XSSC-1-DW-021-360-001.NOD
736222:XSSC-1-DW-021-360-001.DGN
RL SCHOFF
ESP
INDUCED DRAFT FANS
WET LIMESTONE FORCED OXIDATION FGD
SLURRY MAKE-UP
30 WT. % SOLIDS
SLURRY TO TREATMENT
AIR BLOWER
STACK
CO2 COMPRESSOR
FOUR STAGE INTER-COOLED
MOISTURE VENT
HIGH PRESSURE CO2 PRODUCT
CO2 DRYER
CO2 PRODUCT
MEA UNIT
L/P STEAM TO REBOILER
ATTEMPERATING WATER
BF PUMP TURBINE DRIVES
AMMONIA
INFILTRATION AIR
FORCED DRAFT FANS
COAL
PRIMARY AIR FANS
BOILER (WITH SCR)
ASH
2ND HOT RH
1ST HOT RH
SUPERHEAT
1ST COLD RH
2ND COLD RH
FEEDWATER
VHP TURBINE
HP TURBINE
IP TURBINE
L.P. TURBINE
GENERATOR
HOT WELL
SSR
COND PUMPS
SPE
FWH 10
FWH 9
FWH 8
FWH 7
FWH 5
FWH 4
FWH 3
FWH 2
FWH 1
BF PUMPS
DEAERATOR
DEAERATOR STORAGE TANK
BF BOOSTER PUMPS
L/P CONDENSATE
INITIAL ISSUE
CONCEPTUAL DESIGN STUDY NOT FOR CONSTRUCTION
PARSONS
PARSONS POWER GROUP INC.
DOE/NETL
EVALUATION OF FOSSIL FUEL POWER PLANTS WITH CO2 REMOVAL
HEAT AND MATERIAL BALANCE DIAGRAM
Figure 3-2
SUPER-CRITICAL/COAL FIRED STEAM PLANT
3500/1050/1050/1050
SCALE NONE
XSSC-1-DW-021-360-001
REV A

3.2.1 Power Plant Emissions

This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of this century. A summary of the plant emissions is presented in Table 3-2.

Table 3-2
Airborne Emissions
Supercritical PC Plant with FGD and CO_2 Removal

	Values at Design Condition (65% and 85% Capacity Factor)			
	Lb/10^6 Btu (HHV)	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	nil	nil	nil	nil
NOx	0.126	1,715	2,242	1.50
Particulates	0.01	135	175	0.12
CO_2	20.04	272,484	356,325	238.4

The extremely low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system with a design basis SO_2 removal rate set at 98 percent. Following the FGD, a caustic polisher is used to remove the remaining SO_2 from the flue gas to protect the MEA process sorbent.

The minimization of NOx production and subsequent emission is achieved by a combination of low-NOx burners, overfire air staging, and selective catalytic reduction (SCR). The low-NOx burners utilize zoning and staging of combustion. Overfire air staging is employed in the design of this boiler. SCR utilizes the injection of ammonia and a catalyst to reduce the NOx emissions.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

CO_2 emissions are reduced by the installation of an inhibited MEA CO_2 removal system. This unit treats flue gas exiting the FGD unit. CO_2 emissions are limited by 90 percent through contact with the MEA solution. CO_2 absorbed in the MEA is concentrated and released from the solution through the addition of heat in the stripper. CO_2 is then dried and compressed to 1200 psia.

3.2.2 System Description

This greenfield power plant is a 402 MW coal-fired supercritical steam plant with FGD and CO_2 removal through inhibited MEA. The major subsystems of the power plant are:

- Coal handling
- Coal combustion system
- Ash handling system
- Flue gas desulfurization

- CO_2 removal and compression
- Steam turbine generator
- Condensate and feedwater systems
- Balance of plant

This section provides a brief description of these individual power plant subsystems. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of CO_2 removal.

3.2.2.1 Coal Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1/4" x 0, which is transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the six silos.

The crushed coal is fed through pairs (six in parallel) of weight feeders and mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls.

3.2.2.2 Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air handling and preheat
- Coal burners
- Steam generation and reheat
- NOx control
- Soot and ash removal

Each of these is described below.

Air Handling and Preheat

Air from the FD fans is heated in two vertical Ljungstrum regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the primary air fans, is heated in the Ljungstrum type air preheaters for use as combustion air to the pulverizers. A portion of the air from the primary air fans is routed around the air preheaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the wall-fired furnace. The hot combustion products rise to the top of the boiler and pass horizontally through the secondary superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater, economizer, and air preheater. The gases exit the air preheater at this point and flow to the electrostatic precipitator (ESP).

Coal Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air to cool the rising combustion products to inhibit NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition and flame stabilization at startup and low loads.

Steam Generation and Reheat

The steam generator in this supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. It is assumed for the purposes of this study that the power plant is designed for operation as a base-loaded unit for the majority of its life, with some weekly cycling the last few years.

Feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the lower and then the upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater. The fluid is mixed in cross-tie headers at various locations throughout this path.

The steam then exits the steam generator en route to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to either the HP or IP turbine.

NOx Control

The plant is designed to achieve 0.126 lb/10^6 Btu (1.50 lb/MWh) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. Low-NOx burners and overfire air reduce the emissions by 65 percent as compared to a boiler installed without low-NOx burners.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The

SCR system consists of three subsystems – reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed to remove 63 percent of the incoming NOx. This, along with the low-NOx burners, will achieve the emission limit of 0.126 lb/10^6 Btu.

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor grid. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, transfer pumps, dilution air skid, and injection grid. The flue gas flow control consists of ductwork, dampers, and flow-straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer and SCR reactor bypass duct and dampers are also included.

Soot and Ash Removal

The soot-blowing system utilizes an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Electric motors drive the soot blowers through their cycles. The soot-blowing medium is steam.

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with 9-inch-thick refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to the ash pond. Particulate removal is achieved with an ESP.

3.2.2.3 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash).

The fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

3.2.2.4 Flue Gas Desulfurization

The flue gas desulfurization system is broken down into three subgroups:

- Limestone handling and reagent preparation system
- Flue gas desulfurization system
- Byproduct dewatering

Each of these three subtopics is presented below.

Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (30 days). Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

Limestone is delivered to the plant by 25-ton trucks. The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create a limestone slurry. The reduced limestone slurry is then discharged into the mill slurry tank. Mill recycle pumps, two for the tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow is directed back to the mill for further grinding. The hydroclone overflow is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Flue Gas Desulfurization System

The function of the FGD system is to scrub the boiler exhaust gases to remove 98 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet.

The flue gas exiting the air preheater section of the boiler passes through an ESP, then through ID fans and into one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through a tray, which provides enhanced contact between gas and reagent. Multiple sprays above the tray maintain a consistent reagent concentration in the tray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These will consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is routed to the plant stack.

Formic acid is used as a buffer to enhance the SO_2 removal characteristics of the FGD system. The system will include truck unloading, storage, and transfer equipment.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite, contained in the slurry, to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps transfer the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

Chemical equilibrium in the absorber is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The spent reagent is routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack. The system is designed to support operation on a 20-year life cycle.

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions process. Maintenance of the quality of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off spent reagent and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The gypsum slurry, at approximately 15 percent solids, is pumped to a gypsum stacking area. A starter dike is constructed to form a settling pond so that the 15 percent solid gypsum slurry is pumped to the sedimentation pond, where the gypsum particles settle and the excess water is decanted and recirculated back to the plant through the filtrate system. A gypsum stacking system allows for the possibility of a zero discharge system. The stacking area consists of approximately 42 acres, enough storage for 20 years of operation. The gypsum stack is rectangular in plan shape, and is divided into two sections. This allows one section to drain while the other section is in use. There is a surge pond around the perimeter of the stacking area, which accumulates excess water for recirculation back to the plant. The stacking area includes all necessary geotechnical liners and construction to protect the environment.

3.2.2.5 CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the flue gas exiting the FGD system. An inhibited aqueous solution of MEA is used to remove the CO_2.

Flue gases from the boiler FGD are blown by two 50 percent capacity ID fans for transmission to the SO_2 scrubbing section of the flue gas pretreatment system. The gases are quenched and scrubbed in a two-stage scrubber with dilute caustic solution for particulate, NOx, and SO_2 removal. In the scrubber, the NOx and SO_2 in the flue gas react with the caustic solution to form soluble salts. These salts are removed by taking a purge stream from the caustic recirculation loop. A blowdown pot for scrubber samples and water seal flush for the first-stage scrubber recirculation pumps is provided. The flue gas from the caustic scrubber is further cooled in the flue gas cooler to remove additional water.

The purge stream from the recirculation loop is stored in an 8,000-gallon, aboveground 316L stainless steel tank. This tank is supplied with caustic solution to neutralize the scrubber waste, if required. A pump from this tank is used to feed the scrubber waste to the pug mill system located in the power plant.

Cool flue gas exiting the FGD at 131°F enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 2-inch stainless steel rings. There are four absorber and regeneration trains. In each absorber train there are four absorber columns, operating in parallel, each 14.5 feet in diameter and 80 feet vertical. MEA circulation through each absorber is approximately 1,850 gpm. A small slipstream of 0.75 percent MEA solution circulation rate is removed from the process for a continuous MEA reclaim. This economically minimizes the amount of MEA makeup. The MEA makeup rate for this process is 0.8 lb per ton of CO_2 at $0.60 per pound.

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. The vapor leaving the CO_2 stripper is partially condensed at 120°F to provide reflux to the stripper. The CO_2 gas leaving the reflux drum is fed to the CO_2 purification and liquefaction section. The condenser vapor phase, which is saturated CO_2, is routed to the multi-staged, intercooled CO_2 compressor. The regenerated lean solution is returned to the absorber, via an 18,000-gallon solvent surge tank and pump between the absorber and stripper. A solvent drain sump pump is used to transfer MEA from low point drains in the amine equipment to the solvent surge tank. This tank will also be used to store make-up solvent.

There are four stripper trains operating in parallel. Each stripper column is 16 feet in diameter and equipped with stainless steel trays that promote good inter-phase contact. The height of each stripper column is 75 feet. Total reboiler steam requirement is approximately 1,500,000 lb/hour of 55 psig low-pressure steam.

The MEA solvent and proprietary additives are circulated between the stripper and the absorber and over a period of time degrade due to reactions with contaminates in the flue gas (SO_2, NOx, etc.). In order to refine the degraded solution, a reclaimer reboiler is provided to periodically distill the solution, reclaiming usable MEA. The higher boiling point waste material left in the reclaimer is transferred to CO_2 plant wastewater tank for off-site disposal.

NOx components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed before the absorber as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than 10 percent of the NOx species, should not pose much of a problem to this system because of the SCR for NOx reduction.

CO_2 from the stripper is compressed to a pressure of 1217 psia by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor. Water vapor stripped from the CO_2 is vented to the atmosphere. After drying, the dense phase CO_2 enters the pipeline for transport and/or disposal/sequestration.

3.2.2.6 Steam Turbine Generator

The turbine consists of a very-high-pressure (VHP) section, high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 955 psig/1050°F. The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 270 psig/1050°F. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is divided into four paths that flow through the LP sections exhausting downward into the condenser.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

3.2.2.7 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; three 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. Two turbine-driven boiler feed pumps are provided to pump feedwater through the HP feedwater heaters. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

3.2.2.8 Balance of Plant

The balance-of-plant items for the PC plant include:

- Steam systems
- Circulating water system
- Ducting and stack
- Waste treatment
- Accessory electric plant
- Instrumentation and control
- Buildings and structures

These items are discussed in more detail below.

Steam Systems

The steam cycle is depicted in Figure 3-2. Although this diagram presents detailed stream data at many points or nodes in the steam thermodynamic cycle, it does not depict details of the steam and water flow path in every item of equipment, as this would require a significant expansion of the diagram. An expanded level of detail is not suitable for a conceptual level study. A general description of the operation of the steam cycle follows:

The description starts at the condenser hotwell, which is a receptacle for the condensed steam from the exhaust of the steam turbine. The condensate flows to the suction of the condensate pumps, which increase the pressure of the fluid by a nominal 250 psi to transport it through the piping system and enable it to enter the open contact heater, or deaerator. The condensate passes through a gland steam condenser (SPE) first, followed in series by five low-pressure feedwater heaters. The heaters successively increase the condensate temperature to a nominal 303°F by condensing and partially subcooling steam extracted from the low-pressure steam turbine section. Each heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (now referred to as heater drain) is progressively passed to the next lower pressure heater, with the drains from the lowest heater draining to the condenser.

The condensate entering the deaerator is heated and stripped of non-condensable gases by contact with the steam entering the unit. The steam is condensed and, along with the heated condensate, flows by gravity to a deaerator storage tank. The boiler feedwater booster pumps take suction from the storage tank and increase the fluid pressure to a nominal 975 psig. The boosted condensate flows through two more feedwater heaters (FWH 7 and FWH 8), increasing in temperature to 457°F at the suction of the boiler feedwater pumps. These pumps increase the feedwater pressure to a nominal 4380 psig for passage through the remaining two high-pressure feedwater heaters (FWH 9 and FWH 10), which heat the feedwater to a final temperature of 576°F for induction to the boiler.

The boiler is depicted in a simplified manner on the drawing. The internal feedwater circuitry is not presented herein. The complete feedwater-to-steam circuitry in a supercritical boiler, such as the one considered here, involves numerous feedwater sections comprising the boiler water-walls, followed by transition sections, and then includes several superheat tube bundles that are suspended in the gas path. The reheat circuit is relatively simple by comparison, involving one or more tube bundles suspended in the gas path.

The steam turbine is shown on a simplified basis on the diagram, although the Aspen model for the steam turbine incorporates numerous internal leakage flow paths that are not shown. These internal steam flows are used to seal the shaft from steam leakage out and air leakage in. These steam seal flows are collected and controlled by the steam seal regulator (SSR). A portion of the flow is sent to one of the low-pressure heaters, with the rest sent to the gland steam condenser. The condensate from the gland steam condenser flows to the condenser, while the non-condensables (principally air) are exhausted to the atmosphere by the steam packing exhauster (SPE). Both the gland steam condenser and the steam packing exhauster are shown as a combined unit labeled SPE on the diagram.

The steam turbine is comprised of four sections to match the requirements of this heat and mass balance. These are labeled VHP, HP, IP, and LP. The steam turbine sections are equipped with nozzles that allow steam to exit the turbine at various locations between stages. The steam exit points are selected by the manufacturer to match the feedwater heating requirements set by the heat and mass balance.

The high-pressure steam leaving the boiler enters the VHP turbine section at 3500 psig and expands to a nominal 1040 psig. Most of this steam is directed to the boiler first reheat tube bundle (a portion of the steam is diverted for feedwater heating in the second highest pressure feedwater heater, FWH 9). The reheated steam exiting the boiler at 1050°F as the first reheat is sent to the HP turbine to expand to a nominal 280 psig, with a steam extraction point located part-way in the expansion path. Again, a portion of the HP turbine exhaust steam is diverted to one of the feedwater heaters.

The boiler exit pressure is set higher than the design basis turbine inlet pressure to allow for pressure drop in the connecting piping. In the case presented here, a boiler exit pressure of 3650 psig is used with a steam turbine inlet pressure of 3500 psig. Pressure drops in the reheat steam legs are much lower, with about 5 percent used as a design allowance for each of the two reheat piping circuits (first reheat and second reheat). The 5 percent is for both the cold and hot reheat piping runs.

The HP turbine exhaust steam reenters the boiler through the second reheat tube bundle, heating the steam back to the design basis value of 1050°F. The reheated steam as the second hot reheat passes to the IP turbine section for expansion to a nominal pressure of 63 psig. The steam continues through a crossover pipe to the LP turbine to continue the expansion to the final condensing pressure of 1.0 psia. The IP and LP turbine sections are also equipped with extraction steam nozzles that provide steam for feedwater heating. A portion of the IP to LP steam flow is used for driving the feedwater pump drive turbines.

Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a multi-cell mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of each condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

Ducting and Stack

One stack is provided with a single 19.5-foot-diameter FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 70 feet. The stack is 480 feet high for adequate particulate dispersion.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0-1000 lb/hour dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

The oxidation system consists of a 50 scfm air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 200,000-gallon storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

Buildings and Structures

A soil-bearing load of 5,000 pounds per square foot is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

3.2.3 Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 3-2. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

Fourteen codes of account are used. They are summarized below in conjunction with the equipment list.

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6" x 0 - 3" x 0	1
12	Crusher	Impactor reduction	3" x 0 - 1" x 0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor 1	30" belt	115 tph	1
4	Conveyor 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	500 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Feeder	Gravimetric	50 tph	6
2	Pulverizer	B&W type MPS-75	50 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Bin Activator		20 tph	1
2	Weigh Feeder	Gravimetric	20 tph	1
3	Limestone Ball Mill	Rotary	20 tph	1
4	Mill Slurry Tank with Agitator		10,000 gal	1
5	Mill Recycle Pumps	Horizontal centrifugal	600 gpm	2
6	Hydroclones	Radial assembly		1
7	Distribution Box	Three-way		1
8	Reagent Storage Tank with Agitator	Field erected	200,000 gal	1
9	Reagent Distribution Pumps	Horizontal centrifugal	300 gpm	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fabricated	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	1.15×10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vertical canned	1,420 gpm/800 ft	3
5	LP Feedwater Heater	Horizontal U tube	1,148,000 lb/h 102°F to 160°F	1
6	LP Feedwater Heater	Horizontal U tube	1,148,000 lb/h 160°F to 185°F	1
7	LP Feedwater Heater 3	Horizontal U tube	1,148,000 lb/h 185°F to 225°F	1
8	LP Feedwater Heater 4	Horizontal U tube	1,148,000 lb/h 225°F to 227°F	1
9	LP Feedwater Heater 5	Horizontal U tube	1,148,000 lb/h 277°F to 300°F	1
10	Deaerator and Storage Tank	Horizontal spray type	3,600,000 lb/h 300°F to 370°F	1
11	Boiler Feed Water Booster Pump	Horizontal split	8,300 gpm @ 2,400 ft	2
12	HP Feedwater Heater 7	Horizontal U tube	3,600,000 lb/h 370°F to 390°F	1
13	HP Feedwater Heater 8	Horizontal U tube	3,600,000 lb/h 410°F to 460°F	1
14	Boiler Feed Pump/ Turbine Drive	Barrel type, multi-staged, centr.	8,300 gpm @ 11,500 ft	2
15	Startup Boiler Feed Pump	Barrel type, multi-staged, centr.	2,500 gpm @ 11,500 ft	2
16	HP Feedwater Heater 9	Horizontal U tube	3,600,000 lb/h 450°F to 550°F	1
17	HP Feedwater Heater 10	Horizontal U tube	3,600,000 lb/h 550°F to 580°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fabricated water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell and tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water Pumps	S.S., single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1
18	CR System	Aqueous ammonia	400 MWe PC	1

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty
1	Once-Through Steam Generator with Air Heater. SCR Before Air Heater Surface.	Universal pressure, wall-fired	3,593,000 pph steam at 3700 psig/ 1050°F	1
2	Primary Air Fan	Axial	523,000 pph, 118,000 acfm, 35" wg, 790 hp	2
3	FD Fan	Centrifugal	1,700,000 pph, 382,000 acfm, 10" wg, 630 hp	2
4	ID Fan	Centrifugal	2,475,000 pph, 802,000 acfm, 110" wg 15,000 hp	2
5	Seal Air Blower	3-stage recip	1300 acfm/350 psig	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty
1	Electrostatic Precipitator	Rigid frame, single-stage	800,000 acfm, +99% removal efficiency	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty
1	Absorber Module	Spray/tray	1,356,000 acfm	1
2	Recirculation Pump	Horizontal centrifugal	35,000 gpm	4
3	Bleed Pump	Horizontal centrifugal	800 gpm	2
4	Oxidation Air Blower	Centrifugal	7,000 scfm	1
5	Agitators	Side entering	25 hp motor	6
6	Formic Acid Storage Tank	Vertical, diked	1,000 gal	1
7	Formic Acid Pumps	Metering	0.1 gpm	2
8	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2

9	Gypsum Stacking Area		42 acres	1
10	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
11	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
12	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

ACCOUNT 5C **CO_2 REMOVAL AND COMPRESSION**

Equipment No.	Description	Type	Design Condition	Qty
1	Absorber	14.5-foot-diameter packed bed 2" rings, three 20-foot stages	30 psig / 300°F	16
2	Stripper	Tray tower	50 psig / 300°F	4
3	Reflux Drum	Horizontal cooling water	50 psig / 250°F	4
4	Reboiler	Horizontal shell 50 psig steam	75 psig / 350°F	4
5	Cartridge Filter	Horizontal	100 psig / 200°F	4
6	Carbon Filter	Horizontal	100 psig / 200°F	4
7	Rich Amine Pump	Centrifugal	7,400 gpm @ 250 ft	4
8	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
9	Lean Amine Pump	Centrifugal	7,400 gpm @ 250 ft	4
10	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1300 psia	1
11	Final CO_2 Cooler	Shell and tube	66 x 10^6 Btu/h	1
12	Dehydration Package	Triethylene glycol	1300 psia	1

ACCOUNT 6 **COMBUSTION TURBINE AND AUXILIARIES**

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty
1	Stack	Reinforced concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 19.5 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	497 MW Turbine Generator	TC2F26	3500 psig/1050°F/ 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Shell and tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell and tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cooling Tower	Mechanical draft	200,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vertical wet pit	100,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Economizer Hopper (part of boiler scope of supply)			4
2	Bottom Ash Hopper (part of boiler scope of supply)			2
3	Clinker Grinder		6 tph	2
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		40,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1,000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	ESP Hoppers (part of ESP scope of supply)			24
2	Air Heater Hopper (part of boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinforced concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

3.2.4 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate and levelized economics of the supercritical pulverized coal power plant with CO_2 removal, were developed consistent with the approach and basis identified in the Design Basis. The capital cost estimate is expressed in January 2001 dollars. The production cost and expenses were developed on a first-year basis with a January 2001 plant in-service date. The resultant cost of electricity is expressed in first year $/MWh.

The capital cost for the PC plant represents a plant with a net output of 401.5 MWe and is summarized in Table 3-3.

Table 3-3
PC Power Plant Capital Costs

Account Number	Title	Cost ($x1000)	$/kW
1	Coal/Sorbent Receiving and Handling	23,939	60
2	Coal & Sorbent Preparation and Feed	18,774	47
3	Feedwater & Miscellaneous BOP Systems	35,509	88
4	PC Boiler and Accessories	151,106	376
5	Flue Gas Treatment	69,272	173
5a	CO_2 Removal & Compression	170,293	424
6	Combustion Turbine & Auxiliaries	N/A	N/A
7	Stack	26,469	66
8	Steam Turbine Generator	88,293	220
9	Cooling Water System	25,780	64
10	Ash/Sorbent Recovery & Handling	27,954	70
11	Accessory Electric Plant	45,934	114
12	I&C	12,610	31
13	Site Improvements	13,850	34
14	Buildings & Structures	53,104	132
	Total Plant Cost	762,887	1,900
	AFDC	67,897	169
	Royalty Allowance	1,000	2
	Working Capital	3,814	10
	Land Cost	544	1
	Total Capital Requirement	836,142	2,083

The production costs consist of plant operating labor, maintenance (material and labor), an allowance for administrative and support labor, consumables, solid waste disposal and fuel costs. The costs were determined on a first-year basis that includes evaluation at an equivalent plant operating capacity factor of 65 percent. The results are summarized in Table 3-4.

Table 3-4
Annual Operating Costs

	$x1,000
Operating Labor	5,272
Maintenance	8,725
Administration	1,196
Water	63
Disposal	4,030
MEA Makeup	1,229
Limestone	1,573
SCR Ammonia	820
Caustic Makeup	117
Total Annual Operating Costs	23,025

A revenue requirement analysis was performed to determine the cost of electricity on a constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Summary economic results are provided in Table 3-5.

Table 3-5
Cost of Electricity

	$/MWh
Capital Charges	50.47
Fuel Cost @ $1.25/MMBtu HHV	14.88
O&M Costs	10.07
Byproduct Credit	0.00
First-Year COE	75.42

3.2.5 CO_2 Captured and CO_2 Avoided

The PC power plant was designed to remove and capture 90 percent of the carbon in the coal as compressed CO_2. The penalty for doing this is reflected in decreased efficiency and increased costs. There are no other plants in this report that can be directly compared to get the differential emissions and costs. However, the PC plant was derived from the following baseline plant (source: "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," EPRI, U.S. DOE/NETL, 2000):

Referenced plant: Case 7C: Conventional Supercritical PC Plant without CO_2 Removal

Table 3-6 shows the cost of avoided CO_2 for the PC plant operating at 65 percent capacity factor.

Table 3-6
Cost of Avoided CO_2 from the PC Plant

	Without CO_2 Capture	**With CO_2 Capture**	**Delta**
Capital Cost, $/kW	$1,143/kW	$1,900/kW	+$757/kW
Cost of Electricity, $/MWh	$51.50/MWh	$75.42/MWh	+$23.92/MWh
Thermal Efficiency, HHV %	40.5%	28.7%	−11.8%
Specific CO_2 Emissions, lb/MWh	1,707 lb/MWh	238 lb/MWh	−1,469 lb/MWh
Avoided CO_2	1,469 lb/MWh		
Energy Penalty, %	29.14%		
Cost of Avoided CO_2, $/ton	$32.57/ton		
Cost of Avoided CO_2, $/MT	$29.53/MT		

4. NATURAL GAS COMBINED CYCLE (NGCC), F CLASS TURBINE WITH CO_2 REMOVAL

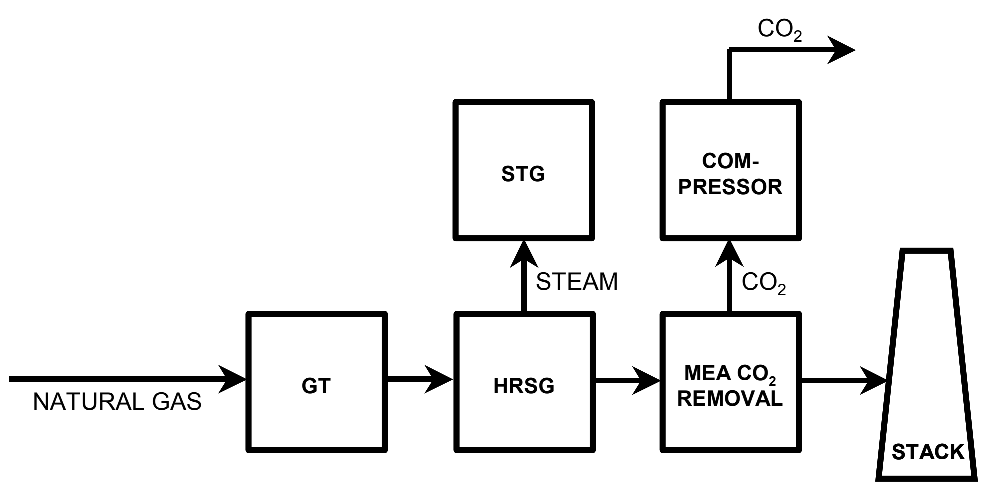
4.1 INTRODUCTION

This design is based on the use of two natural gas-fired combustion turbines (CTs), each coupled with a heat recovery steam generator (HRSG) to generate steam for a single steam turbine generator. CO_2 is removed from the HRSG flue gas with an amine-based absorption system. Plant configuration and performance reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

This rendition of CT/HRSG technology is based on selection of gas turbines exemplified by the General Electric 7FA machine. This particular machine provides values of power output, airflow, and exhaust gas temperature that effectively couple with a HRSG to generate steam for the companion steam turbine plant to produce an estimated total net output of 399 MWe at an efficiency of 43.5 percent (LHV) and 39.2 percent (HHV). For this study, two gas turbines are used in conjunction with one 1800 psig/1050°F/1050°F steam turbine.

Cool flue gas exiting the two HRSGs is further cooled and partially compressed and routed to an inhibited MEA absorber-stripper system. In the absorber, a solution of aqueous inhibited MEA is used to remove 90 percent of the CO_2 in the flue gas. In the stripper, low-pressure steam is used to strip (remove) CO_2 from the solution. Low-pressure, concentrated CO_2 from the stripper is then compressed to supercritical conditions for subsequent transportation off-site. A simplified block flow diagram, Figure 4-1, illustrates the overall system configuration.

Figure 4-1
Block Flow Diagram – NGCC



The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance including a breakdown of individual auxiliary power consumption is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

4.2 THERMAL PLANT PERFORMANCE

Table 4-1 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant. Gross power output (prior to the generator terminals) for the two General Electric 7FA gas turbines is estimated to be 335 MWe. Also shown in Table 4-1 is the gross steam turbine power output of 120 MWe. This number is much lower than that expected for an NGCC with a gross CT power output of 335 MWe. However, in this case, most of the low-pressure steam available at the steam turbine crossover is diverted from the low-pressure (LP) turbine and used in the MEA stripper reboiler. Diverting this LP steam results in a marked decrease in steam turbine power output.

Plant auxiliary power is also summarized in Table 4-1. The total is estimated to be 48 MWe. This value, higher than that anticipated for a gas-fired combined cycle, is due to the presence of the CO_2 removal/compression equipment, in particular, the flue gas blower, which requires 22.4 MWe of auxiliary power, and the CO_2 compressor, which requires 16.2 MWe of auxiliary power.

Net plant power output, which considers generator losses and auxiliary power, is 398.9 MWe. This plant power output results in a net system thermal efficiency of 43.5 percent (LHV) with a corresponding heat rate of 7,841 Btu/kWh (LHV). The corresponding HHV values for efficiency and heat rate are 39.2 percent and 8,701 Btu/kWh, respectively.

Figure 4-2 contains a heat and material balance diagram for the 100 percent load condition. CT and ST cycles are shown schematically along with the appropriate state point condition data. An open Brayton cycle (CT) using air and combustion products as working fluid is used in conjunction with the conventional subcritical Rankine cycle (ST). The two cycles are coupled by the generation and superheating of steam in the HRSG, and by feedwater heating in the HRSG. The HRSG uses a triple-pressure configuration. The low-pressure drum provides steam for an integral deaerator. Also shown in the diagram is the basic equipment required to remove CO_2 from the flue gas stream and concentrate it as a relatively pure, high-pressure product.

Table 4-1
Two 7FA x 1 NGCC with CO_2 Removal
Plant Performance Summary - 100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	334,892
Steam Turbine Power	120,037
Generator Loss	(8,062)
Gross Plant Power (Note 1)	446,867
AUXILIARY POWER SUMMARY, kWe	
Condensate Pumps	320
High-Pressure Boiler Feed Pump	2,270
Miscellaneous Balance of Plant (Note 2)	500
Gas Turbine Auxiliaries	600
Steam Turbine Auxiliaries	200
Circulating Water Pumps	1,700
Cooling Tower Fans	960
Flue Gas Blower	22,410
MEA CO_2 Removal	1,440
CO_2 Compression and Drying (Note 3)	16,220
Transformer Loss	1,370
Total Auxiliary Power Requirement	47,990
NET PLANT POWER, kWe	398,877
CO_2 Recovered, lb/MWh	952
CO_2 Avoided, lb/MWh	704
PLANT EFFICIENCY, kWe	
Net Efficiency, % LHV	43.5
Net Heat Rate, Btu/kWh (LHV)	7,841
Net Efficiency, % HHV	39.2
Net Heat Rate, Btu/kWh (HHV)	8,701
CONDENSER COOLING DUTY, 10^6 Btu/h	637
CONSUMABLES	
Natural Gas, lb/h (Note 4)	158,986
Thermal Input, kWth	1,016,872

Note 1 – Loads are presented for two gas turbines, and one steam turbine
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 1200 psia
Note 4 – Heating value: 19,666 Btu/lb (LHV), 21,824 Btu/lb (HHV)

Figure 4-2

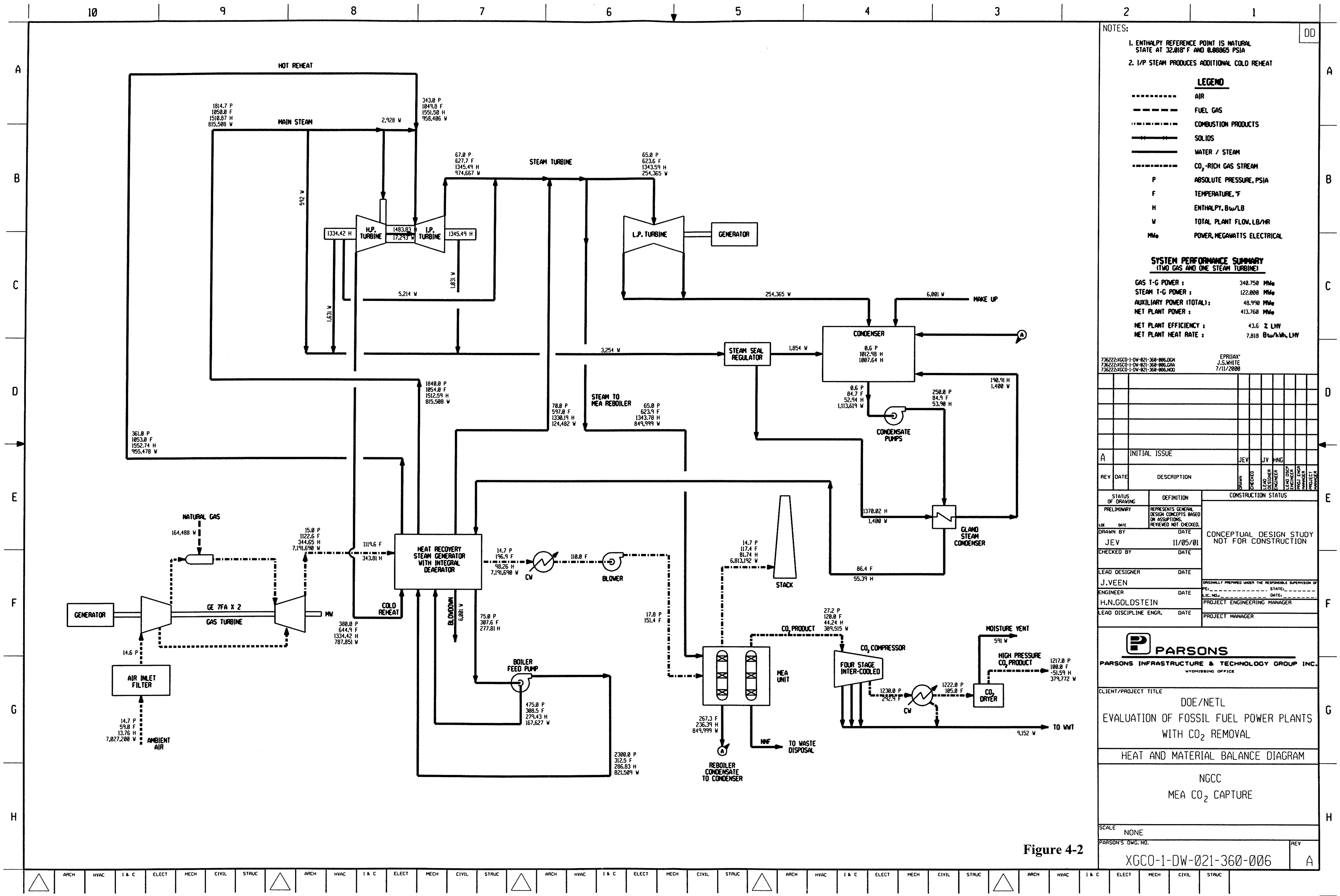


Figure 4-2

4.2.1 Power Plant Emissions

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, is projected to result in very low levels of SO_2, NOx, and CO_2 emissions. A summary of the estimated plant emissions for this case is presented in Table 4-2.

Table 4-2
Airborne Emissions
Two 7FA x 1 NGCC with CO_2 Removal

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu (HHV)	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	Neg.	Neg.	Neg.	Neg.
NOx	< 0.033	325	420	0.28
Particulate	Neg.	Neg.	Neg.	Neg.
CO_2	11.36	112,266	146,809	98.86

As shown in the table, values of SO_2 emission and particulate discharge are negligible. This is a direct consequence of using natural gas as the plant fuel supply. Regarding particulate discharge, when natural gas is properly combusted in a state-of-the-art CT, the amount of solid particulate produced is very small (less than 20 lb/h, 0.06 lb/MWh, for both 7FA machines).

The low level of NOx production is achieved through use of GE's dry low-NOx (DLN) combustion system. This combustor arrangement should limit NOx emissions to 9 ppm adjusted to 15 percent O_2 content in the flue gas.

In this power plant configuration, approximately 90 percent of the CO_2 in the flue gas is removed and concentrated into a highly pure product stream. This greatly limits CO_2 emissions, as can be seen in Table 4-2.

4.2.2 System Description

The major subsystems in this natural gas-fired combined cycle power plant are:

- Combustion turbine
- Heat recovery steam generator
- CO_2 removal and compression
- Steam turbine generator
- Condensate and feedwater systems
- Balance of plant

This section provides a brief discussion about the power plant equipment and operating conditions. This discussion is based on the heat and material balance diagram shown in Figure 4-2. The equipment list, which follows this section, is based on the material presented here.

4.2.2.1 Combustion Turbine

The CT, or gas turbine, generator selected for this application is based on the General Electric MS 7001FA model. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Each CT operates in an open cycle mode. Two 7FAs, each equipped with an individual HRSG, are used to power a single steam turbine in a traditional 2 on 1 arrangement.

Inlet air at 976 lb/sec (per CT) is compressed in a single spool compressor to a pressure ratio of approximately 15.5:1. The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the natural gas. Compressed air is also used in burner, transition, and film cooling services.

Pressurized pipeline natural gas at a rate of 82,244 lb/hour (per CT) is combusted in several (14) parallel dry low-NOx combustors that use staged combustion to limit NOx formation. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 2400°F.

Hot combustion products are expanded in the three-stage turbine-expander. The CT exhaust temperature is estimated as 1123°F, given the assumed ambient conditions, back-end loss, and HRSG pressure drop.

Gross turbine power, as measured prior to the generator terminals, is estimated as 334.9 MWe. The CT generator is a standard hydrogen-cooled machine with static exciter. Net CT power from the generator is estimated at 329.2 MWe.

4.2.2.2 Heat Recovery Steam Generator (HRSG)

High-temperature flue gas at 3,596,000 lb/hour (per turbine) exiting the CT is conveyed through a HRSG (one for each turbine) to recover the large quantity of thermal energy that remains. It is assumed that the flue gas heat loss through the HRSG duct corresponds to 3°F. Flue gases travel through the HRSG gas path and exit at 197°F.

The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

The HRSG tube surface is typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 material; the low-temperature portions (< 750°F) will be carbon steel.

4.2.2.3 NGCC CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the HRSG flue gas. An inhibited aqueous solution of approximately 15 percent MEA is used to remove the CO_2.

Cool flue gas exiting the HRSG at 197°F is indirectly cooled to 110°F with circulating cooling water. The cool flue gas is partially compressed to 17.5 psia in a centrifugal blower in order to overcome the gas-path pressure drop. There are four flue gas coolers and blowers operating in parallel. The partially compressed flue gas stream is then routed to a traditional absorber/stripper arrangement.

Flue gas enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 2-inch stainless steel rings. There are four absorber and regeneration trains. In each absorber train there are four absorber columns, operating in parallel, each 14.5 feet in diameter and 80 feet vertical. MEA circulation through each absorber is approximately 1,200 gpm. A small slipstream of 0.75 percent MEA solution circulation rate is removed from the process for a continuous MEA reclaim. This economically minimizes the amount of MEA makeup. The MEA makeup rate for this process is 0.8 pound per ton of CO_2 at $0.60 per pound.

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is preheated in the rich-lean heat exchanger through indirect contact with lean solution flowing from the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. The vapor leaving the CO_2 stripper is partially condensed at 120°F to provide reflux to the stripper. The CO_2 gas leaving the reflux drum is fed to the CO_2 purification and liquefaction section. The condenser vapor phase, which is saturated CO_2, is routed to the multi-staged, intercooled CO_2 compressor. The regenerated lean solution is returned to the absorber, via an 18,000-gallon solvent surge tank and pump between the absorber and stripper. A solvent drain sump pump is used to transfer MEA from low point drains in the amine equipment to the solvent surge tank. This tank will also be used to store makeup solvent.

There are four stripper trains operating in parallel. Each stripper column is 16 feet in diameter and equipped with stainless steel trays that promote good interphase contact. The height of each stripper column is 75 feet. Total reboiler steam requirement is approximately 821,600 lb/hour of 50 psig LP steam.

SO_2 in the flue gas may react with the MEA solvent to form heat stable salts. Once formed, the MEA cannot be easily regenerated and must be removed from the reclaimer system as a solid. If solvent makeup becomes unacceptable, an alkali scrubber system can be installed before the absorber. However, solvent losses through salt formation are expected to be low for NGCC.

NOx components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than 10 percent of the NOx species, should not pose much of a problem to this system.

CO_2 from the stripper is compressed to a pressure of 1230 psia by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor. Water vapor stripped from the CO_2 is vented to the atmosphere. After drying, the dense phase CO_2 enters the pipeline for transport and/or disposal/sequestration.

4.2.2.4 Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 1800 psig/1050°F/1050°F single reheat configuration. The steam turbine is a single machine consisting of tandem HP, IP, and double-flow LP turbine sections connected via a common shaft and driving a 3,600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a pitch diameter of 60 inches and a last-stage bucket length of 20 inches.

Main steam at a rate of 815,500 lb/hour from the HP boiler located in the HRSG passes through HP stop valves and control valves and enters the turbine at 1800 psig/1050°F. Steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. Reheat steam enters the IP section at 343 psig/1050°F. After passing through the IP section, the steam enters a crossover pipe. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the crossover line. A tee is provided to extract a controlled amount of LP steam from the crossover. This steam is used in the MEA reboiler located below the MEA stripper column. The remaining crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

The generator is a synchronous type rated at 140 MWe. It operates with a 0.85 power factor and generates power at 23 kV. A static, transformer type exciter is provided. Gross generator output is 120.04 MWe. The generator operates with an efficiency of approximately 98 percent. Net steam turbine generator power output is 117.67 MWe. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

The steam turbine generator is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

4.2.2.5 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/IP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

4.2.2.6 Balance of Plant

The balance-of-plant items discussed in this section include:

- Natural gas lines and metering
- Circulating water system
- Accessory electric plant
- Instrumentation and control

<u>Natural Gas Lines and Metering</u>

In this design, it is assumed that a natural gas main with adequate capacity and pressure is at the fence line of the site and that a suitable right of way is available to install a branch line to the site. A gas line comprised of Schedule 40 carbon steel pipe, 16 inches nominal OD, is required to convey the gas to the site. The buried pipeline is coated and wrapped, and cathodically protected with a zinc ribbon-type sacrificial anode to protect the pipe from corrosion.

A new gas metering station is located on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

<u>Circulating Water System</u>

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

4.2.3 Case 1A Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 4-2. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and was used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped.

ACCOUNT 1 COAL AND SORBENT HANDLING

Not Applicable

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Gas Pipeline	Underground, carbon steel, coated and wrapped, cathodic protection	165,000 lb/h @ 600 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		200,000 lb/h	1

ACCOUNT 2B SORBENT PREPARATION AND FEED

Not Applicable

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cyl., outdoor	70,000 gal	1
2	Condensate Pumps	Vertical canned	1080 gpm @ 580 ft	2
3	Boiler Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	870 gpm @ 5,800 ft	2

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal	2
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 5 gpm	2
5	Service Air Compressors	Recip., single-stage, double-acting, horizontal	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horizontal centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchanger	Plate and frame	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horizontal cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1000 gpm	1
13	Raw Water	S.S., single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A CO_2 REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Design Condition	Qty
1	Flue Gas Cooler	Shell and tube cooling water service	5 psig / 250°F 43 x 10^6 Btu/h	4
2	Flue Gas Fan	Centrifugal	1,750,000 lb/h 441,000 acfm 90 in.H_2O (gauge) 7,250 hp	4
3	Absorber	14.5-foot-diameter packed bed 2" rings, three 20-foot stages	30 psig / 300°F	16
4	Stripper	Tray tower	50 psig / 300°F	4
5	Reflux Drum	Horizontal cooling water	50 psig / 250°F	4
6	Reboiler	Horizontal shell 50 psig steam	75 psig / 350°F	4
7	Cartridge Filter	Horizontal	100 psig / 200°F	4
8	Carbon Filter	Horizontal	100 psig / 200°F	4
9	Rich Amine Pump	Centrifugal	4,700 gpm @ 250 ft	4
10	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
11	Lean Amine Pump	Centrifugal	4,700 gpm @ 250 ft	4
12	CO_2 Compressor and Auxiliaries	Centrifugal Multi-staged	25 psia / 1300 psia	1
13	Dehydration Package	Triethylene glycol	1300 psia	1
14	Final CO_2 Cooler	Shell and tube cooling water service	28.9 x 10^6 Btu/h	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	170 MWe Gas Turbine Generator	Axial flow single spool based on GE 7FA	975 lb/sec airflow 2410°F rotor inlet temp. 15.5 pressure ratio	2
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two-stage	975 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	2
5	Air to Air Cooler			2
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		2
7	Oil Cooler	Air-cooled, fin fan		2
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	2
9	Generator Glycol Cooler	Air-cooled, fin fan		2
10	Compressor Wash Skid			2
11	Fire Protection Package	Halon		2

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple-pressure, with economizer section and integral deaerator	HP-1950 psig/632°F 791,600 lb/h, superheat to 1050°F IP-410 psig/447°F 163,000 lb/h, superheat to 600°F LP-60 psig/307°F 120,182 lb/h, superheat to 600°F	2
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	2

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	135 MW Turbine Generator	TC2F20, triple admissions	1815 psia 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,081,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water-sealed	2000/20 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vertical wet pit	70,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	83°F WB/88°F CWT/ 96°F HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

4.2.4 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate, and levelized economics of the NGCC power plant with CO_2 removal were developed consistent with the approach and basis identified in the Design Basis. The capital cost estimate is expressed in January 2001 dollars. The production cost and expenses were developed on a first-year basis with a January 2001 plant in-service date. The resultant cost of electricity is expressed in first year $/MWh.

The capital cost for the NCCC plant represents a plant with a net output of 398.9 MWe and is summarized in Table 4-3.

Table 4-3
NGCC Power Plant Capital Costs

Account Number	Title	Cost ($x1000)	$/kW
1	Gas Receiving and Handling (by others)	0	0
2	Fuel Preparation and Feed (by others)	0	0
3	Feedwater & Miscellaneous BOP Systems	16,933	42
4	Boiler/Gasifier & Accessories	N/A	N/A
5	CO_2 Removal and Compression	161,449	405
6	Combustion Turbine & Auxiliaries	87,748	220
7	Heat Recovery Boiler & Stack	40,590	102
8	Steam Turbine Generator	30,284	76
9	Cooling Water System	14,195	36
10	Ash/Sorbent Recovery & Handling	N/A	N/A
11	Accessory Electric Plant	33,368	84
12	I&C	5,969	15
13	Site Improvements	9,519	24
14	Buildings & Structures	8,952	22
	Total Plant Cost	409,007	1,025
	AFDC	21,677	54
	Royalty Allowance	1,000	3
	Working Capital	2,045	5
	Land Cost	164	0
	Total Capital Requirement	433,893	1,088

The production costs consist of plant operating labor, maintenance (material and labor), an allowance for administrative and support labor, consumables, solid waste disposal, and fuel costs. The costs were determined on a first-year basis that includes evaluation at an equivalent plant operating capacity factor of 65 percent. The results are summarized in Table 4-4.

Table 4-4
Annual Operating Costs

	$x1,000
Operating Labor	2,064
Maintenance	6,805
Administration	1,196
Water	4
Disposal	0
MEA Makeup	526
Total Annual Operating Costs	10,595

A revenue requirement analysis was performed to determine the cost of electricity on a constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Summary economic results are provided in Table 4-5.

Table 4-5
Cost of Electricity

	$/MWh
Capital Charges	26.36
Fuel Cost @ $2.70/MMBtu HHV	23.49
O&M Costs	4.66
Byproduct Credit	0.00
First-Year COE	54.51

4.2.5 CO_2 Captured and CO_2 Avoided

The NGCC power plant was designed to remove and capture 90 percent of the carbon in the coal as compressed CO_2. The penalty for doing this is reflected in decreased efficiency and increased costs. There are no other plants in this report that can be directly compared to get the differential emissions and costs. However, the NGCC plant was derived from the following baseline plant (source: "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," EPRI, U.S. DOE/NETL, 2000):

Referenced plant: Case 1C: Base NGCC Plant without CO_2 Removal (Class F Turbine)

Table 4-6 shows the cost of avoided CO_2 for the NGCC plant operating at 65 percent capacity factor.

Table 4-6
Cost of Avoided CO_2 from the NGCC Plant

	Without CO_2 Capture	With CO_2 Capture	Delta
Capital Cost, $/kW	$510/kW	$1,025/kW	+$515/kW
Cost of Electricity, $/MWh	$34.20/MWh	$54.51/MWh	+$20.31/MWh
Thermal Efficiency, HHV %	50.5%	39.2%	−11.3%
Specific CO_2 Emissions, lb/MWh	803 lb/MWh	99 lb/MWh	−704 lb/MWh
Avoided CO_2	704 lb/MWh		
Energy Penalty, %	22.38%		
Cost of Avoided CO_2, $/ton	$57.70/ton		
Cost of Avoided CO_2, $/MT	$52.31/MT		

5. TEXACO-BASED INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) PLANT WITH CO_2 REMOVAL

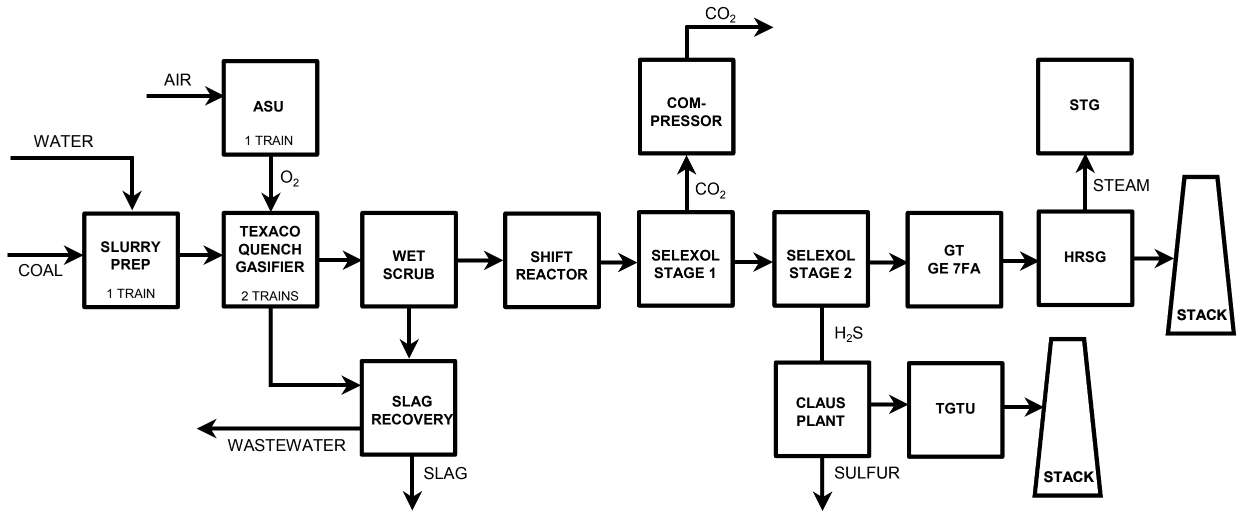
5.1 INTRODUCTION

This design centers on the use of two combustion turbines coupled with a heat recovery system that generates steam for a single steam turbine generator. The gas turbine technology chosen for this IGCC study is based on General Electric's 7FA turbine system. A high-pressure Texaco quench gasifier was chosen as the basis for this IGCC configuration. Raw fuel gas exiting the gasifier is cooled and cleaned of particulate before being routed to a series of water-gas shift reactors and raw gas coolers. These components convert CO and steam present in the raw gas to CO_2 and hydrogen, thereby concentrating CO_2 in the high-pressure raw fuel gas stream. Once concentrated, CO_2 can be removed during the desulfurization process through use of a double-staged Selexol unit. CO_2 is then dried and compressed to supercritical conditions for pipeline transport. Clean fuel gas from the Selexol unit, now rich in hydrogen, is fired in the combustion turbine, then expanded. Waste heat is recovered from this process and used to raise steam to feed to a steam turbine.

The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The thermal performance section contains a block flow diagram annotated with state point information, along with a summary of plant performance, including a breakdown of individual auxiliary power consumption. The system description section gives a more detailed account of the individual power plant subsections, including a series of heat and material balance diagrams that completely describe the thermodynamics and chemistry of the power plant. An equipment list supports the detailed plant description. The equipment list and heat and material balance diagrams were used to estimate plant cost.

Figure 5-1 is a simplified block flow diagram for the IGCC plant, illustrating the overall configuration.

Figure 5-1
Block Flow Diagram – IGCC



5.2 THERMAL PLANT PERFORMANCE

Table 5-1 shows a detailed breakdown of the estimated system performance for the entire combined cycle power plant; including gross plant power, auxiliary power load, net plant power, and net plant efficiency.

Plant auxiliary power is also summarized in Table 5-1. The total is estimated to be 117.2 MWe. This value, much higher than that anticipated for a coal-fired IGCC of this size, is due to the presence of the CO_2 removal/compression equipment. In particular, the auxiliary power load of the CO_2 compressors, which require 33 MWe of auxiliary power, accounts for 28 percent of the total auxiliary power load for the entire plant.

Net plant power output for this IGCC configuration is estimated at 457 MWe. This power output is generated with a net plant thermal efficiency of 30.1 percent, HHV, with a corresponding heat rate of 11,344 Btu/kWh. Plant efficiency and heat rate numbers are low in comparison to those expected for coal-fired IGCC. Low system thermal efficiency is primarily due to the increased auxiliary power requirements of the CO_2 removal equipment.

Figure 5-2 is the process flow diagram depicting the overall layout of this IGCC power plant configuration. The gasifier trains and combustion turbine and steam turbine cycles are shown schematically, along with the appropriate state point data.

Table 5-1
Texaco-Based IGCC with CO_2 Removal
Plant Performance Summary – 100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
GROSS POWER SUMMARY, kWe	
Gas Turbine Power	408,163
Steam Turbine Power	162,747
Generator Loss	(11,418)
Fuel Gas Expander Power	14,378
Gross Plant Power	573,870
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	500
Coal Milling	1,150
Coal Slurry Pumps	350
Slag Handling and Dewatering	210
Air Separation Plant	36,130
Oxygen Boost Compressor	22,060
Selexol Plant	12,200
Claus/TGTU	300
Humidification Tower Pump	100
Humidifier Makeup Pump	180
Low-Pressure CO_2 Compressor	1,060
High-Pressure CO_2 Compressor (Note 3)	32,300
Condensate Pumps	440
High-Pressure Boiler Feed Pump	2,930
Low-Pressure Boiler Feed Pump	100
Miscellaneous Balance of Plant (Note 2)	1,000
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	300
Circulating Water Pumps	1,990
Cooling Tower Fans	1,180
Flash Bottoms Pump	50
Incinerator Blower	20
Wastewater Treatment Auxiliaries	20
Transformer Loss	1,780
Total Auxiliary Power Requirement	117,150
NET PLANT POWER, kWe	456,720
CO_2 Recovered, lb/MWh	2,018
CO_2 Avoided, lb/MWh	1,601
PLANT EFFICIENCY	
Net Efficiency, % HHV	30.1
Net Heat Rate, Btu/kWh (HHV)	11,344
CONDENSER COOLING DUTY, 10^6 Btu/h	1,003.0
CONSUMABLES	
As-Received Coal Feed, lb/h (Note 4)	444,020
Thermal Input, kW_{th}	1,518,091
Oxygen (95% pure), lb/h	371,493
Water, lb/h	21,073

Note 1 – Single shaft turbo set.
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure 1200 psia.
Note 4 – As-received coal heating value: 11,666 Btu/lb (HHV).

Figure 5-2

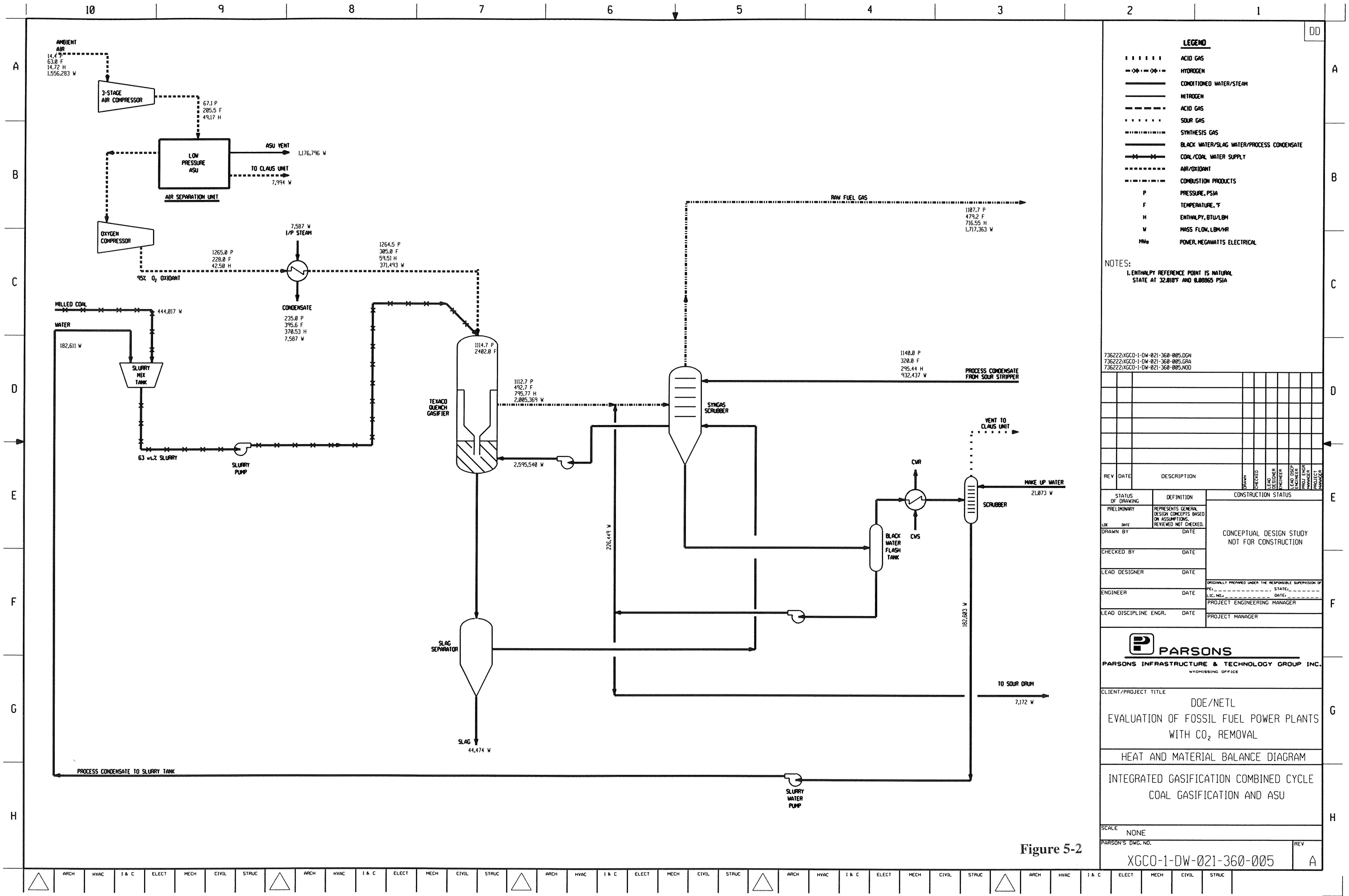


Figure 5-2

5.2.1 Power Plant Emissions

The operation of a modern, state-of-the-art gas turbine fueled by coal-derived hydrogen is projected to result in very low levels of SO_2, NOx, and particulate (fly ash) emissions. Also, the inclusion of a CO_2 removal system will greatly decrease the ambient release of CO_2 from the power plant. A summary of the estimated plant emissions for this case is presented in Table 5-2.

Table 5-2
Airborne Emissions
IGCC with CO_2 Removal

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu (HHV)	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	Neg.	Neg.	Neg.	Neg.
NOx	< 0.028	285	370	0.25
Particulate	Neg.	Neg.	Neg.	Neg.
CO_2	22.5	331,200	433,100	255

As shown in Table 5-2, values of SO_2 emissions are negligible. This is a direct consequence of using the Selexol absorption process to remove H_2S from the fuel gas stream prior to combustion. The Selexol process removes more than 99.8 percent of the sulfur present in the raw fuel gas stream. The sulfur is subsequently concentrated and processed in a Claus plant and tail gas treating unit to produce an elemental sulfur product that may be sold. Overall sulfur capture and recovery is approximately 99.7 percent. These steps result in very low sulfur emissions from the plant.

NOx emissions are limited to less than 10 ppm adjusted to 15 percent O_2 content in the flue gas. This low level of NOx production is achieved by diluting the heating value of the incoming combustion turbine fuel gas stream to less than 150 Btu/scf. Dilution is accomplished by humidifying the desulfurized fuel gas stream and steam injection at the combustion turbine inlet. This water dilution serves a dual role; not only does water dilution mitigate NOx emissions, it also helps maintain a relatively lowered burner temperature with increased fuel input.

Particulate discharge to the atmosphere is limited by the use of the gas washing effect achieved by raw gas condensate knockout and the Selexol absorption process.

In this power plant configuration, approximately 90 percent of the CO_2 in the fuel gas is removed and concentrated into a highly pure product stream.

5.2.2 System Description

This greenfield power plant is a 457 MW net coal-fired IGCC power plant with CO_2 removal through the Selexol absorption process. The gasifier technology choice is Texaco quench, and the combustion turbine choice is based on GE's 7FA turbine system. The major subsystems of the power plant are:

- Coal receiving and handling
- Coal-water slurry preparation and feeding
- Coal gasification and air separation unit
- Water-gas shift / syngas humidification
- Sulfur removal and recovery / carbon dioxide removal and compression
- Combined cycle power generation
- Condensate and feedwater systems
- Balance of plant

This section provides a brief description of these individual power plant subsystems. Also presented are heat and material balance diagrams for the individual plant sections, each annotated with state point data. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of electricity.

5.2.2.1 Coal Receiving and Handling

The function of the coal handling system is to provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the rod mill inlet.

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1" x 0, then it is transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three storage silos.

5.2.2.2 Coal-Water Slurry Preparation and Feeding

The slurry preparation and feeding system mills crushed coal and generates a 63 weight percent slurry for the gasifier, including coal moisture. Three trains at 50 percent are provided.

Crushed coal is reclaimed from the storage silo by a vibrating feeder, which delivers the coal to a weigh-belt feeder. Crushed coal is fed through the rod-mill (pulverizer) and then routed to a product storage tank. In the rod mill, recycled water from the sour gas stripper is added to the coal in order to form a slurry. Slurry from the rod mill storage tank is then either fed to the gasifier or routed to an agitated storage tank. The slurry storage tank is sized to hold 8 hours of slurry product.

Coal-water slurry is pumped to the gasifier via positive displacement pumps. The high-pressure slurry is heated to 305°F with condensing, intermediate-pressure steam.

5.2.2.3 Coal Gasification and Air Separation Unit

This section gives a description of the gasification process and air separation unit.

Air Separation Unit

One ASU train will be used to produce a nominal 4,500 tpd of 95 percent oxygen product. The plant consists of a multi-staged air compressor, an air separation cold box, and an oxygen compression system. A liquid oxygen storage tank will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

Ambient air at 14.4 psia and 63ºF is compressed in a three-stage, intercooled compressor to 67 psia. The high-pressure air stream is cooled and routed to a thermal swing absorption system, which removes H_2O, CO_2, and other ambient contaminants before flowing to the vendor-supplied cold box. In the cold box, cryogenic distillation is used to provide a 95 percent pure oxygen stream for use in the gasifier.

The low-pressure oxidant stream from the cold box is compressed to 1265 psia in a six-staged, intercooled compressor. This high-pressure stream is then heated indirectly with condensing intermediate-pressure steam to 305°F before being routed to the gasifier injection system.

Gasification Island

This design is based on the utilization of two oxygen-blown, Texaco quench entrained-bed gasifiers. The syngas produced in the gasifiers is cooled and further cleaned downstream of the gasifiers. The syngas stream from the syngas scrubber enters the high-temperature shift converter. Following the shift converter, the cooled gas stream passes through a Selexol acid gas removal (AGR) process, which removes H_2S and CO_2. Regeneration gas from the AGR plant is fed to the Claus plant, where elemental sulfur is produced.

The clean gas exiting the AGR system is expanded in a turbine before being conveyed to the combustion turbines where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from each combustion turbine and HRSG is released to the atmosphere via a conventional stack.

Based on the selection of the General Electric 7FA combustion turbine, a fuel gas pressure at the fuel gas expander battery limits of 385 psia was established to provide a margin above the compressor discharge pressure (300 psia at this site), allowing for necessary system and valve pressure drop.

Gasification

This case utilizes two gasifier trains to process a total of 5,328 tons per day of coal. Each gasifier has a capacity of 2,500 tons per day, resulting in each gasifier operating at 100 percent capacity. The gasifier vessel is a refractory-lined, high-pressure combustion chamber. Coal slurry is transferred from the slurry storage tank to the gasifier with a high-pressure pump. At the top of the gasifier vessel a combination fuel injector is located through which coal slurry feedstock and oxygen are fed. These materials flow co-currently downward through the gasifier where they are partially combusted to form syngas.

The coal slurry and oxygen react in the gasifier at a very high temperature to produce a syngas at approximately 1300°C (2372°F) consisting of hydrogen, carbon monoxide, water vapor, and carbon dioxide. It also contains small amounts of hydrogen sulfide, carbonyl sulfide, methane, and nitrogen. Particles of soot and slag are also entrained in the syngas. Hot syngas from the reactor flows downward into a water-filled quench chamber where the syngas is cooled and the particulates are separated. The slag particulates collect in the water sump and are removed with filtration of the syngas cooler water. The quench gasifier operates at more than 1265 psia pressure to ensure reduced water evaporation from the quench chamber and an exit temperature of 493°F.

<u>Quench/Scrubbing</u>

The cooled raw synthesis gas from the gasifier is water-scrubbed in a soot scrubber to remove essentially all traces of entrained particles, principally unconverted carbon, slag, and metals. This soot-scrubbing equipment utilizes several stages for particulate removal from the gas stream and has been used in commercial operations for many years.

The saturated syngas enters the syngas scrubber and is directed downward by the dip tube into a water sump at the bottom of the scrubber. Most of the solids are separated from the syngas at the bottom of the dip tube as the syngas rises through the water. At the top of the syngas scrubber, the syngas passes through two impingement trays and a vane-type entrainment separator. These are designed to remove the last traces of solids carried by the entrained water droplets.

5.2.2.4 Water Gas Shift / Syngas Humidification

A set of high-temperature shift reactors is used to shift the bulk of the CO in the fuel gas to CO_2. A schematic of the shift converters can be found in Figure 5-3 (see page 5-10). Heat exchange between reaction stages helps maintain a moderate reaction temperature. The shift catalyst also promotes COS hydrolysis. A two-staged shift was utilized in order to maximize CO conversion while maintaining reasonable reactor volumes.

The shifted raw gas temperature exiting the second shift converter is approximately 553°F. This stream is cooled to 370°F in a low-temperature economizer. The fuel gas stream is cooled in a series of low-temperature economizers and then routed to the Selexol unit. Fuel gas condensate is recovered and routed to a sour drum.

The fuel gas saturator can also be seen in Figure 5-3. Sweet, hydrogen-rich fuel gas from the Selexol unit is piped to the bottom of the saturator. The sweet fuel gas rises up through the column while warm water flows downward counter-currently. Internal trays are used to enhance the mass transfer of water vapor into the fuel gas. This process both humidifies the fuel gas and increases its sensible heat content.

Warm, humid fuel gas exits the top of the saturator at 381°F and 950 psia. It is indirectly heated further to 520°F by condensing high-pressure steam. The high-pressure fuel gas stream is then expanded to 385 psia to recover approximately 14 MWe of electrical energy. Fuel gas out of the expander is then indirectly reheated to 535°F by condensing high-pressure steam and then routed to the combustion turbine burner inlet.

Saturator water exits the column at 200°F after being cooled down from 455°F. The water is then pumped through a series of raw gas coolers that economize the water back to 455°F. To avoid the buildup of soluble gases, a small blowdown to the sour water drum is taken from the pump discharge.

5.2.2.5 Sulfur Removal and Recovery / Carbon Dioxide Removal and Compression

A unique feature of this power plant configuration is that H_2S and CO_2 are removed within the same process system, the Selexol unit. Heat and mass balance diagrams of these systems can be seen in Figure 5-3 and Figure 5-4.

Selexol Unit

The purpose of the Selexol unit is to preferentially remove H_2S as a product stream and then to preferentially remove CO_2 as a separate product stream. This is achieved in the double-stage Selexol unit.

Cool, dry, and particulate-free synthesis gas enters the first absorber unit at approximately 983 psia and 105°F. In this absorber, H_2S is preferentially removed from the fuel gas stream. This is achieved by "loading" the lean Selexol solvent with CO_2. The solvent, saturated with CO_2, preferentially removes H_2S. The rich solution leaving the bottom of the absorber is regenerated in a stripper through the indirect application of thermal energy via condensing low-pressure steam in a reboiler. The stripper acid gas stream, consisting of 34 percent H_2S and 58 percent CO_2 (with the balance mostly H_2O), is then sent to the Claus unit.

Sweet fuel gas flowing from the first absorber is cooled and routed to the second absorber unit. In this absorber, the fuel gas is contacted with "unloaded" lean solvent. The solvent removes approximately 97 percent of the CO_2 remaining in the fuel gas stream. A CO_2 balance is maintained by hydraulically expanding the CO_2-saturated rich solution and then flashing CO_2 vapor off the liquid at reduced pressure. Sweet fuel gas off the second absorber is warmed and humidified in the fuel gas saturator, reheated and expanded, and then sent to the burner of the combustion turbine.

Figure 5-3

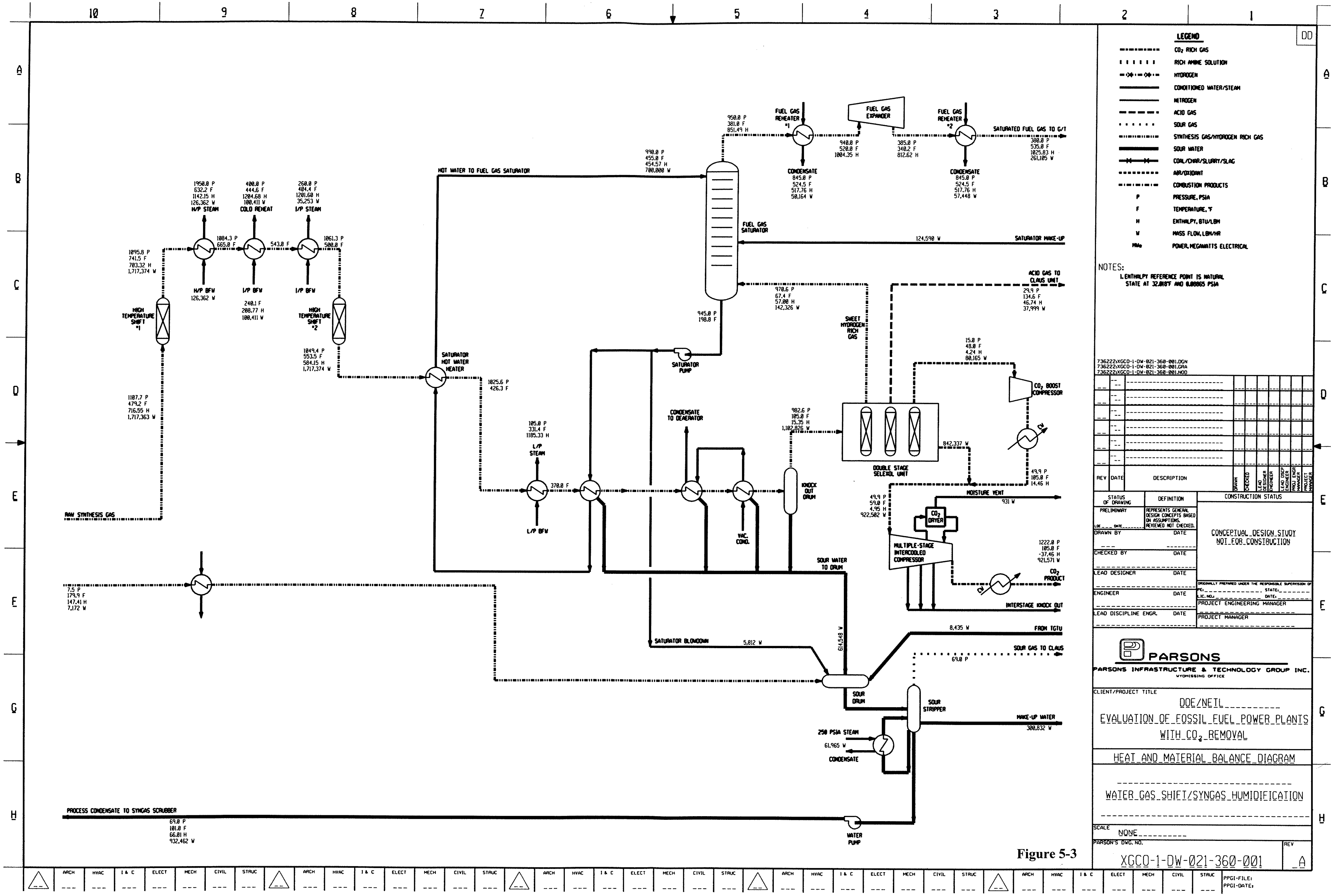
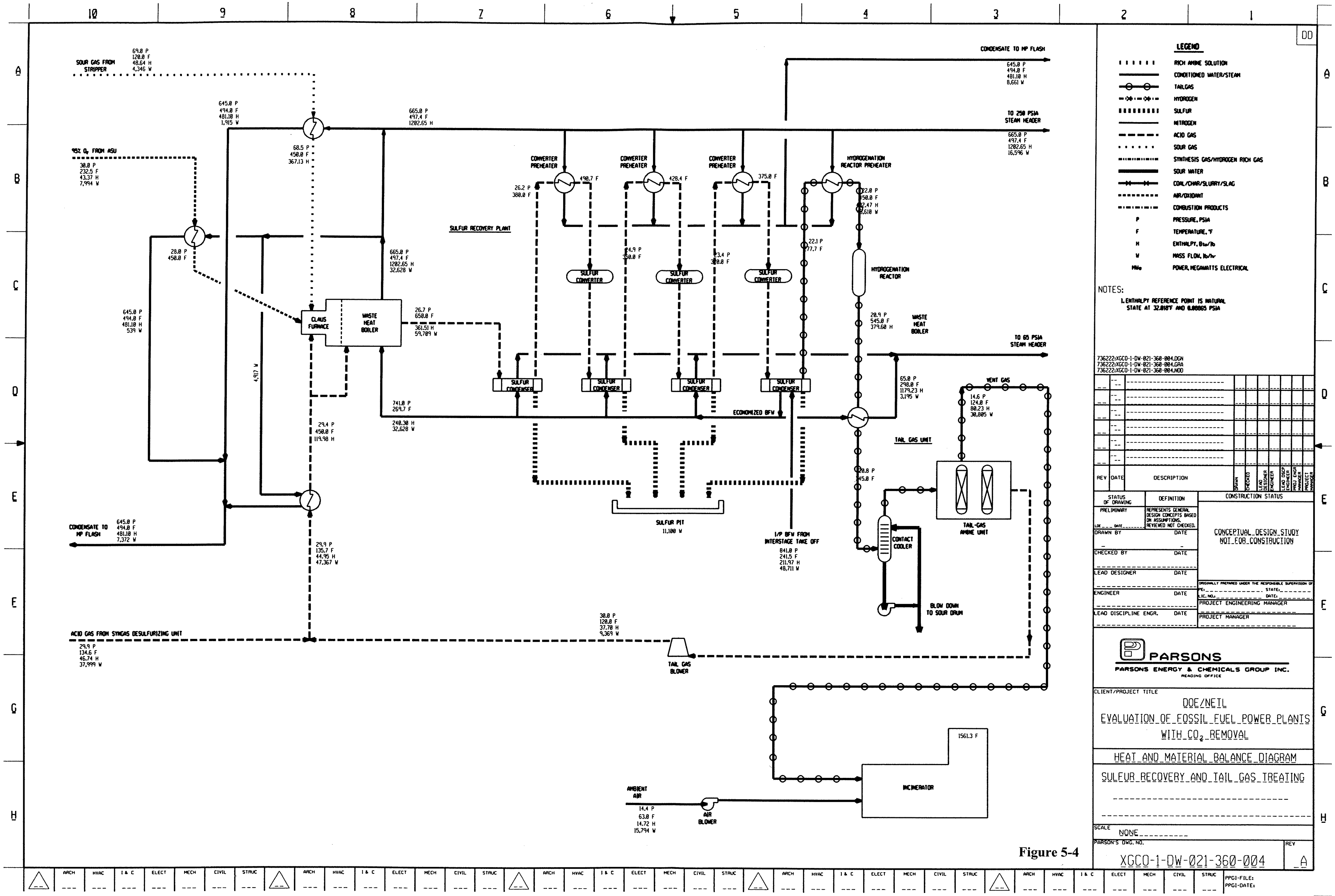


Figure 5-3

Figure 5-4



SOUR GAS FROM STRIPPER
69.0 P
120.0 F
48.64 H
4,346 W
645.0 P
494.0 F
481.10 H
1,915 W
665.0 P
497.4 F
1202.65 H
68.5 P
450.0 F
367.13 H
95% O2 FROM ASU
30.0 P
232.5 F
43.37 H
7,994 W
28.0 P
450.0 F
665.0 P
497.4 F
1202.65 H
32,628 W
645.0 P
494.0 F
481.10 H
539 W
4,917 W
CLAUS FURNACE
WASTE HEAT BOILER
26.7 P
650.0 F
361.51 H
59,709 W
741.0 P
269.7 F
240.30 H
32,628 W
29.4 P
450.0 F
119.98 H
CONDENSATE TO MP FLASH
645.0 P
494.0 F
481.10 H
7,372 W
29.9 P
135.7 F
44.95 H
47,367 W
ACID GAS FROM SYNGAS DESULFURIZING UNIT
29.9 P
134.6 F
46.74 H
37,999 W
SULFUR RECOVERY PLANT
CONVERTER PREHEATER
CONVERTER PREHEATER
CONVERTER PREHEATER
26.2 P
380.0 F
490.7 F
428.4 F
375.0 F
SULFUR CONVERTER
SULFUR CONVERTER
SULFUR CONVERTER
SULFUR CONDENSER
SULFUR CONDENSER
SULFUR CONDENSER
SULFUR CONDENSER
ECONOMIZED BFW
SULFUR PIT
11,100 W
I/P BFW FROM INTERSTAGE TAKE OFF
841.0 P
241.5 F
211.97 H
48,711 W
CONDENSATE TO MP FLASH
645.0 P
494.0 F
481.10 H
8,661 W
TO 250 PSIA STEAM HEADER
665.0 P
497.4 F
1202.65 H
16,596 W
HYDROGENATION REACTOR PREHEATER
HYDROGENATION REACTOR
20.9 P
545.0 F
379.60 H
WASTE HEAT BOILER
TO 65 PSIA STEAM HEADER
65.0 P
298.0 F
1179.23 H
3,195 W
VENT GAS
14.6 P
124.0 F
80.23 H
30,805 W
TAIL GAS UNIT
TAIL-GAS AMINE UNIT
CONTACT COOLER
BLOW DOWN TO SOUR DRUM
30.0 P
120.0 F
37.70 H
9,369 W
TAIL GAS BLOWER
1561.3 F
INCINERATOR
AMBIENT AIR
14.4 P
63.0 F
14.72 H
15,794 W
AIR BLOWER
DD
LEGEND
RICH AMINE SOLUTION
CONDITIONED WATER/STEAM
TAILGAS
HYDROGEN
SULFUR
NITROGEN
ACID GAS
SOUR GAS
SYNTHESIS GAS/HYDROGEN RICH GAS
SOUR WATER
COAL/CHAR/SLURRY/SLAG
AIR/OXIDANT
COMBUSTION PRODUCTS
P PRESSURE, PSIA
F TEMPERATURE, °F
H ENTHALPY, Btu/lb
W MASS FLOW, lb/hr
MWe POWER, MEGAWATTS ELECTRICAL
NOTES:
1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018°F AND 0.08865 PSIA
736222:XGCO-1-DW-021-360-004.DGN
736222:XGCO-1-DW-021-360-004.GRA
736222:XGCO-1-DW-021-360-004.NOD
REV
DATE
DESCRIPTION
DRAWN
CHECKED
LEAD DESIGNER
ENGINEER
LEAD DSCP ENGINEER
PROJ ENGR MANAGER
PROJECT MANAGER
STATUS OF DRAWING
DEFINITION
CONSTRUCTION STATUS
PRELIMINARY
REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
CONCEPTUAL DESIGN STUDY
NOT FOR CONSTRUCTION
DRAWN BY
DATE
CHECKED BY
DATE
LEAD DESIGNER
DATE
ENGINEER
DATE
LEAD DISCIPLINE ENGR.
DATE
ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE:
STATE:
LIC. NO.:
DATE:
PROJECT ENGINEERING MANAGER
PROJECT MANAGER
PARSONS
PARSONS ENERGY & CHEMICALS GROUP INC.
READING OFFICE
CLIENT/PROJECT TITLE
DOE/NETL
EVALUATION OF FOSSIL FUEL POWER PLANTS WITH CO2 REMOVAL
HEAT AND MATERIAL BALANCE DIAGRAM
SULFUR RECOVERY AND TAIL GAS TREATING
SCALE
NONE
PARSON'S DWG. NO.
XGCO-1-DW-021-360-004
REV
A
Figure 5-4
ARCH
HVAC
I & C
ELECT
MECH
CIVIL
STRUC
PPGI-FILE:
PPGI-DATE:

<u>CO_2 Compression and Drying</u>

CO_2 is flashed from the rich solution at two pressures. The bulk of the CO_2 is flashed off at approximately 50 psia, while the remainder is flashed off at atmospheric pressure. The second low-pressure CO_2 stream is "boosted" to 50 psia and then combined with the first CO_2 stream. The combined flow is then compressed in a multiple-stage, intercooled compressor to supercritical conditions. During compression, the CO_2 stream is dehydrated with triethylene glycol. The virtually moisture-free supercritical CO_2 steam is then ready for pipeline transportation.

<u>Claus Unit</u>

Acid gas from the first-staged absorber of the Selexol unit is routed to the Claus plant. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. Approximately 11,000 lb/hour of elemental sulfur is recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.7 percent.

Acid gas from the Selexol unit and tail gas amine unit are preheated to 450°F. Sour gas from the sour stripper and 95 percent O_2 oxidant from the ASU are likewise preheated. A portion of the acid gas along with all of the sour gas and oxidant are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2. A furnace temperature greater than 2450°F must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Combustion and decomposition products from the furnace are mixed with the remaining acid gas stream and cooled in a waste heat boiler. These gases are further cooled, and any sulfur formed during the catalytic and thermal furnace stages is condensed out and routed to the sulfur pit. The remaining gas stream is heated and sent to the sulfur converter, which catalytically oxidizes H_2S with SO_2 to elemental sulfur. The stream is then cooled, and any condensed sulfur removed and routed to the sulfur pit.

Three preheaters and three sulfur converters are used to obtain a per-pass H_2S conversion of approximately 97.8 percent. In the furnace waste heat boiler, 32,600 lb/hour of 650 psia steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as 16,600 lb/hour of steam to the medium-pressure steam header. The sulfur condensers produce 50 psig steam for the low-pressure steam header.

<u>Tail Gas Treating Unit</u>

Tail gas from the Claus unit contains unreacted sulfur species such as H_2S, COS, and SO_2 as well as elemental sulfur species of various molecular weight. In order to maintain low sulfur emissions, this stream is processed in a tail gas treating unit in order to recycle sulfur back to the Claus plant.

Tail gas from the Claus plant is preheated to 450°F and then introduced to the hydrogenation reactor. In the hydrogenation reactor, SO_2 and any elemental sulfur specie are catalytically reduced with H_2 to H_2S. Also, COS is hydrolyzed to H_2S. This gas stream is then cooled and treated in an amine absorber unit. H_2S is removed by the amine solution, regenerated in a reboiler-stripper and recycled back to the Claus furnace. Sweet gas from the amine absorber, which contains fuel gas species such as H_2 and CO, is compressed and recycled to the Claus plant.

Combustion Turbine

The CT or gas turbine generator selected for this application is based on the General Electric MS 7001FA model. This machine is an axial flow, constant speed unit, with variable inlet guide vanes. Each CT operates in an open cycle mode. Two 7FAs, each equipped with an individual HRSG, are used to power a single steam turbine in a traditional 2 on 1 arrangement. The heat and material balance diagram for this system is shown in Figure 5-5.

Inlet air at 880 lb/sec (per CT) is compressed in a single spool compressor to a pressure ratio of approximately 15.5:1. The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the natural gas. Compressed air is also used in burner, transition, and film cooling services.

Pressurized syngas at a rate of 179,405 lb/hour (per CT) is combusted in several (14) parallel dry low-NOx combustors that use staged combustion to limit NOx formation. In the estimated performance provided here, the machine will develop a rotor inlet temperature of about 2400°F.

Hot combustion products are expanded in the three-stage turbine-expander. The CT exhaust temperature is estimated as 1134°F, given the assumed ambient conditions, back-end loss, and HRSG pressure drop.

Gross turbine power, as measured prior to the generator terminals, is estimated as 408.2 MWe. The CT generator is a standard hydrogen-cooled machine with static exciter. Net CT power from the generator is estimated at 400.1 MWe.

Heat Recovery Steam Generator (HRSG)

High-temperature flue gas at 3,476,000 lb/hour (per turbine) exiting the CT is conveyed through a HRSG (one for each turbine) to recover the large quantity of thermal energy that remains. It is assumed that the flue gas heat loss through the HRSG duct corresponds to 3°F. Flue gases travel through the HRSG gas path and exit at 297°F.

The HRSG is configured with high-pressure (HP), intermediate-pressure (IP), and LP steam drums and circuitry. The HP drum is supplied with feedwater by the HP boiler feed pump while the IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. IP steam from the drum is mixed with cold reheat steam; the combined flow is then passed to the reheat section. The LP drum produces steam for superheat as well as saturated steam for an integral deaerator.

The HRSG tube surface is typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 material; the low-temperature portions (< 750°F) will be carbon steel.

Figure 5-5

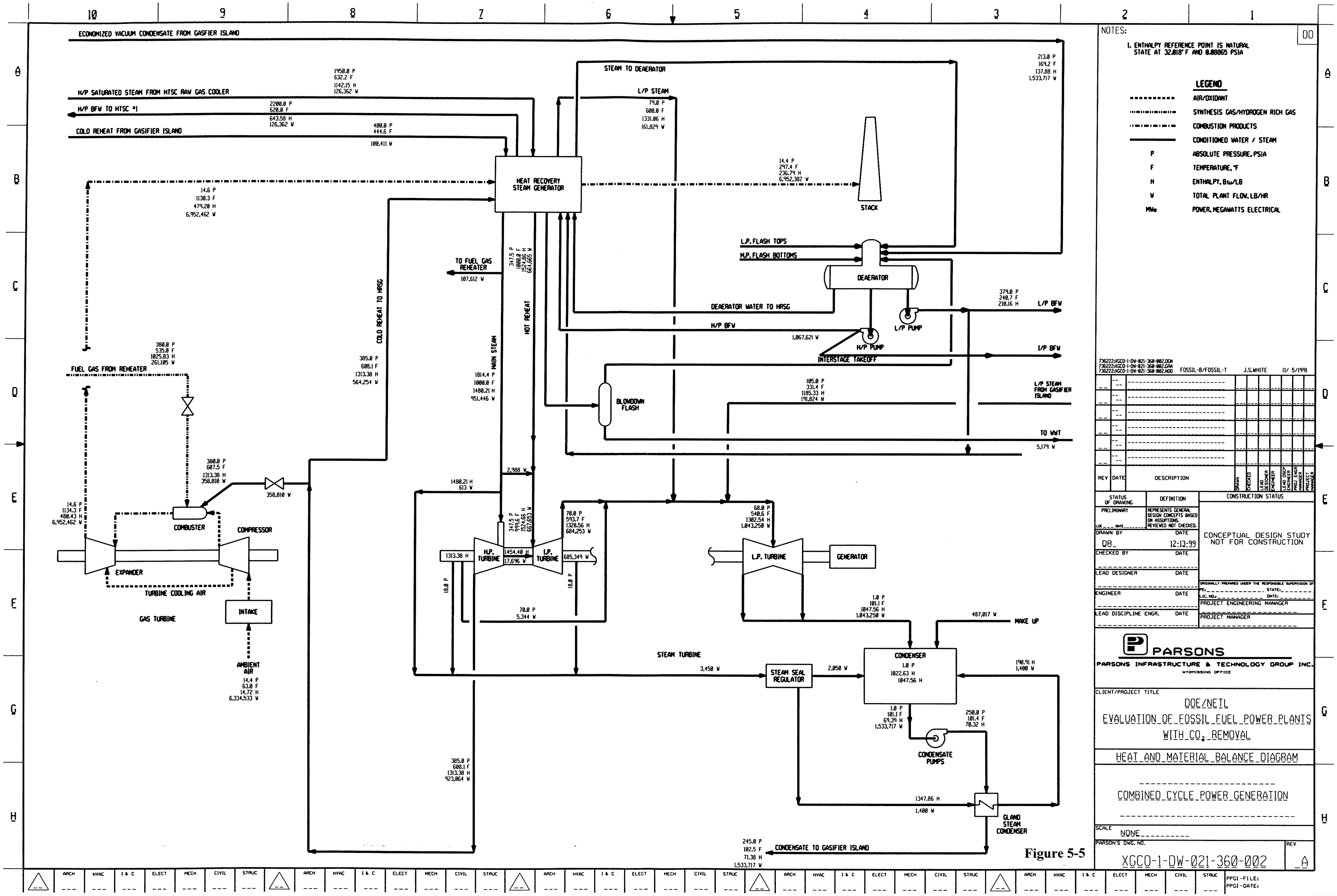


Figure 5-5

Steam Turbine Generator

The Rankine cycle used in this case is based on a state-of-the-art 1800 psig/1000°F/1000°F single reheat configuration. The steam turbine is a single machine consisting of tandem HP, IP, and double-flow LP turbine sections connected via a common shaft and driving a 3,600 rpm hydrogen-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a pitch diameter of 60 inches and a last-stage bucket length of 20 inches. The heat and material balance diagram for this system is shown in Figure 5-6.

Main steam at a rate of 951,000 lb/hour from the HP boiler located in the HRSG passes through HP stop valves and control valves and enters the turbine at 1800 psia/1000°F. Steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. Reheat steam enters the IP section at 343 psig/1000°F. After passing through the IP section, the steam enters a crossover pipe. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the crossover line. A tee is provided to extract a controlled amount of LP steam from the crossover. This steam is used in the Selexol reboiler located below the Selexol stripper column. The remaining crossover steam is divided into two paths and flows through the LP sections exhausting downward into the condenser.

The generator is a synchronous type rated at 140 MWe. It operates with a 0.85 power factor and generates power at 23 kV. A static, transformer type exciter is provided. Gross generator output is 162.7 MWe. The generator operates with an efficiency of approximately 98 percent. Net steam turbine generator power output is 159.0 MWe. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

The steam turbine generator is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Figure 5-6

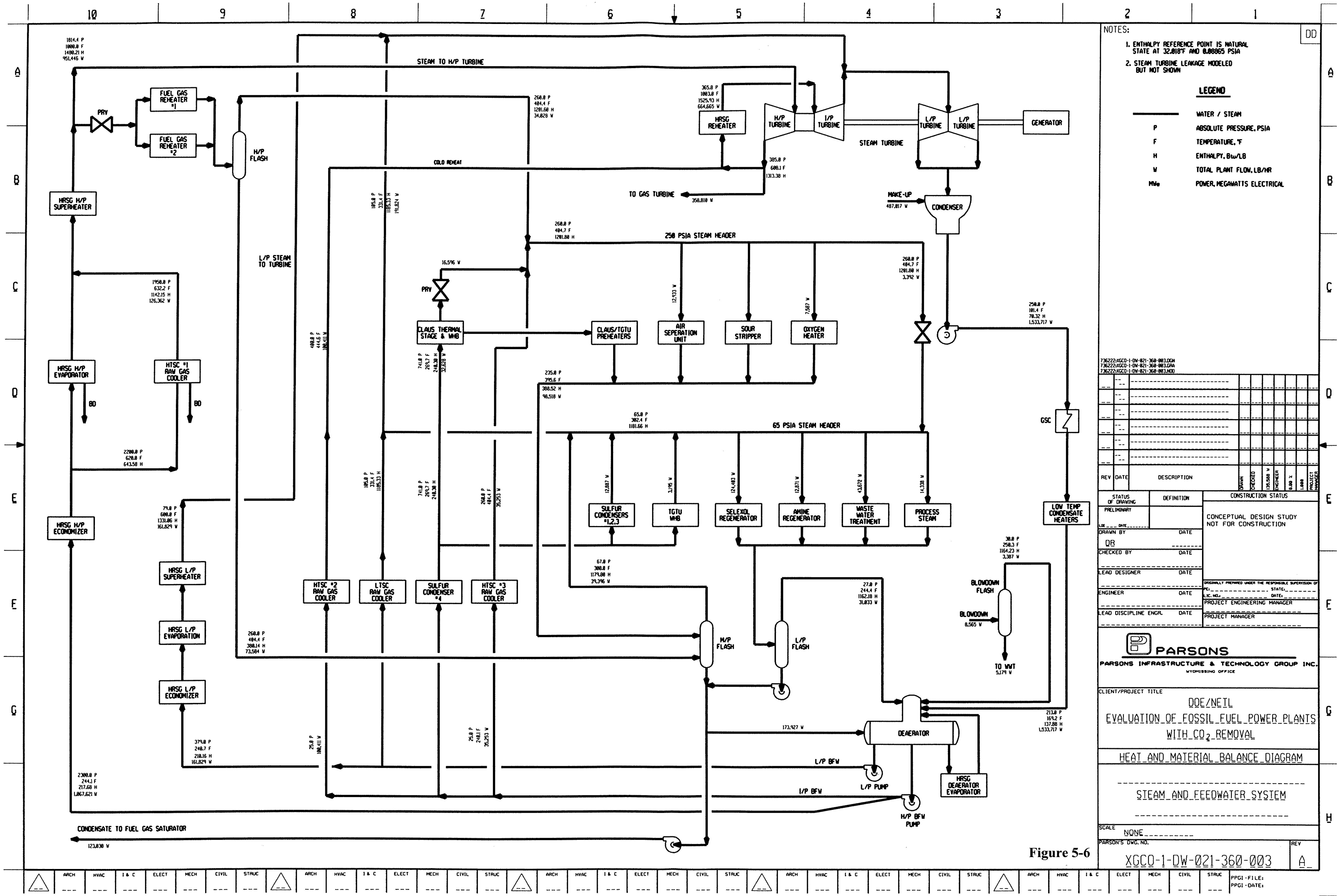


Figure 5-6

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity motor-driven feed pumps are provided for HP/IP service. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

5.2.2.6 Balance of Plant

The balance-of-plant items discussed in this section include:

- Steam systems
- Circulating water system
- Accessory electric plant
- Instrumentation and control
- Waste treatment

Steam Systems

The steam cycle is depicted in Figure 5-6. Although this diagram presents detailed stream data at many points or nodes in the steam thermodynamic cycle, it does not depict details of the steam and water flow path in every item of equipment, as this would require a significant expansion of the diagram. An expanded level of detail is not suitable for a conceptual level study. A general description of the operation of the steam cycle follows.

The description starts at the condenser hotwell, which is a receptacle for the condensed steam from the exhaust of the steam turbine. The condensate flows to the suction of the condensate pumps, which increase the pressure of the fluid by a nominal 250 psi to transport it through the piping system and enable it to enter the open contact heater, or deaerator. The condensate passes through a gland steam condenser (GSC) first, followed in series by low-pressure condensate heaters. The heaters successively increase the condensate temperature to a nominal 169°F by condensing and partially subcooling steam extracted from the low-pressure steam turbine section. Each heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (now referred to as heater drain) is progressively passed to the next lower pressure heater, with the drains from the lowest heater draining to the condenser.

The condensate entering the deaerator is heated and stripped of non-condensable gases by contact with the steam entering the unit. The steam is condensed and, along with the heated condensate, flows by gravity to a deaerator storage tank. The high-pressure boiler feedwater booster pumps take suction from the storage tank and increase the fluid pressure to a nominal 2300 psig. IP pumps boost feedwater to a nominal 750 psig, and LP pumps to 375 psig. The IP and LP streams are integrated with the plant steam headers to maintain thermal balance throughout. The HP stream enters the HRSG where it is economized, evaporated to steam, and superheated to 1800 psig and 1000°F. Approximately 10 percent of the HP feedwater is used as feed for the No. 1 high-temperature syngas cooler.

The boiler is depicted in a simplified manner on the drawing. The internal feedwater circuitry is not presented herein. The complete feedwater-to-steam circuitry in a supercritical boiler, such as the one considered here, involves numerous feedwater sections comprising the boiler water-walls, followed by transition sections, and then includes several superheat tube bundles that are suspended in the gas path. The reheat circuit is relatively simple by comparison, involving one or more tube bundles suspended in the gas path.

The steam turbine is shown on a simplified basis on the diagram, although the Aspen model for the steam turbine incorporates numerous internal leakage flow paths that are not shown. These internal steam flows are used to seal the shaft from steam leakage out and air leakage in. These steam seal flows are collected and controlled by the steam seal regulator. A portion of the flow is sent to one of the low-pressure heaters, with the rest sent to the gland steam condenser. The condensate from the gland steam condenser flows to the condenser, while the non-condensables (principally air) are exhausted to the atmosphere by the steam packing exhauster.

The steam turbine is comprised of three sections to match the requirements of this heat and mass balance. These are labeled HP, IP, and LP. The steam turbine sections are equipped with nozzles that allow steam to exit the turbine at various locations between stages. The steam exit points are selected by the manufacturer to match the feedwater heating requirements set by the heat and mass balance.

The high-pressure steam leaving the HRSG enters the HP turbine section at 1800 psig and expands to a nominal 370 psig. Most of this steam is directed to the HRSG first reheat tube bundle along with IP steam generated in the No. 2 raw gas cooler. A portion of the steam is diverted to the gas turbine combustor for NO_x control and for feedwater heating in the second highest pressure feedwater heater (FWH 9).

The IP turbine exhaust steam is combined with additional LP steam at 90 psig and passes to the LP turbine (IP) section to continue the expansion to the final condensing pressure of 1.0 psia.

Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main power transformer, all required foundations, and standby equipment.

Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0-1000 lb/hour dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

The oxidation system consists of a 50 scfm air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed off-site. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 200,000-gallon storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

5.2.3 Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 5-2. This list, along with the heat and material balance and supporting performance data, was used both to generate plant costs and in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

ACCOUNT 1 COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1"x0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	600 ton	3

ACCOUNT 2 COAL-WATER SLURRY PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Qty
1	Feeder	Vibrating	110 tph	3
2	Weigh Belt Feeder		48" belt	3
3	Rod Mill	Rotary	110 tph	3
4	Slurry Water Pumps	Centrifugal	180 gpm @ 500 ft	3
5	Slurry Water Storage Tank	Vertical	2,600 gal	1
6	Rod Mill Product Tank	Vertical	35,000 gal	3
7	Slurry Storage Tank with Agitator	Vertical	150,000 gal	3
8	Coal-Slurry Feed Pumps	Positive displacement	1000 gpm @ 2,500 ft	2
9	LT Slurry Heater	Shell and tube	30×10^6 Btu/h	2
10	HT Slurry Heater	Shell and tube	10×10^6 Btu/h	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS BOP SYSTEMS

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vertical canned	2,900 gpm @ 400 ft	2
3	Low Temperature Economizers	Shell and tube	40×10^6 Btu/h	3
4	Deaerator	Horizontal spray type	1,500,000 lb/h 205°F to 240°F	1
5	LP Feed Pump	Horizontal centrifugal single stage	300 gpm/185 ft	2
6	HP Feed Pump	Barrel type, multi-staged, centr.	2,400 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fabricated water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Recip., single stage, double acting, horizontal	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horizontal centrifugal, double suction	200 ft, 1,200 gpm	2
5	Closed Cycle Cooling Heat Exchangers	Plate and frame	50% cap. each	2
6	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 1,200 gpm	2
7	Fire Service Booster Pump	Two-stage horizontal centrifugal	250 ft, 1,200 gpm	1
8	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1,000 gpm	1
9	Raw Water Pumps	S.S., single suction	60 ft, 300 gpm	2
10	Filtered Water Pumps	S.S., single suction	160 ft, 120 gpm	2
11	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
12	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
13	Sour Water Stripper System	Vendor supplied	180,000 lb/h sour water	1
14	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 GASIFIER AND ACCESSORIES

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Oxygen-blown Slurry feed Pressurized entrained bed Quench mode design	2,500 tpd (dry-coal basis) @ 1100 psia	3
4	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	770,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	350,000 scfm, 67 psia discharge pressure	1
2	Cold Box	Vendor supplied	4,500 ton/day O_2	1
3	Oxygen Compressor	Centrifugal, multi-stage	75,000 scfm, 1250 psig discharge pressure	1
4	Liquid Oxygen Storage Tank	Vertical	60 ft dia x 80 ft vertical	1
5	Oxygen Heater	Shell and tube	5.0×10^6 Btu/h @ 1250 psia and 300ºF	1

ACCOUNT 5 FUEL GAS SHIFT AND CLEANUP

ACCOUNT 5A WATER-GAS SHIFT, RAW GAS COOLING AND HUMIDIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	High-Temperature Shift Reactor 1	Fixed bed	1100 psia, 750ºF	23
2	High-Temperature Shift Reactor 2	Fixed bed	1100 psia, 750ºF	2
3	HP Steam Generator	Shell and tube	50 x 10^6 Btu/h @ 2800 psia and 700ºF	2
4	IP Steam Generator	Shell and tube	30 x 10^6 Btu/h @ 300 psia and 500ºF	2
5	LP Steam Generator	Shell and tube	15 x 10^6 Btu/h @ 200 psia and 500ºF	2
6	Saturation Water Economizers	Shell and tube	50 x 10^6 Btu/h @ 1000 psia and 500ºF	2
7	Raw Gas Coolers	Shell and tube with condensate drain	150 x 10^6 Btu/h	6
8	Raw Gas Knockout Drum	Vertical with mist eliminator	1000 psia, 130ºF	2
9	Fuel Gas Saturator	Vertical tray tower	20 stages 750 psia, 450ºF	1
10	Saturator Water Pump	Centrifugal	1,500 gpm @ 120 ft	1
11	Fuel Gas Reheater 1	Shell and tube	41 x 10^6 Btu/h @ 690 psia, 550ºF	1
12	Fuel Gas Expander	Axial	PR=1.8 @ 940 psia	1
13	Fuel Gas Reheater 2	Shell and tube	39 x 10^6 Btu/h @ 690 psia, 550ºF	1

ACCOUNT 5B SULFUR REMOVAL AND RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
1	Double-Stage Selexol Unit	Vendor design	360,000 scfm @ 1000 psia	2
2	CO_2 Compressor and Auxiliaries	Centrifugal, multi-staged	25 psia / 1300 psia	1
3	Dehydration Package	Triethylene glycol	1300 psia, 100ºF	1
4	Claus Unit	Vendor design	100 tpd sulfur product	1
5	Hydrogenation Reactor	Vertical fixed bed	7,000 scfm @ 22 psia	1
6	Contact Cooler	Spray contact, tray wash tower	7,000 scfm @ 21 psia	1
7	TGTU Amine Unit	Proprietary amine absorber/stripper	5,100 scfm @ 20 psia	1
8	Tail Gas Recycle Compressor	Centrifugal, multi-staged	3,610 scfm, PR = 58	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	200 MWe Gas Turbine Generator	Axial flow single spool based on GE 7FA	950 lb/sec airflow 2410°F rotor inlet temp. 15.5 pressure ratio	2
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two-stage	950 lb/sec airflow 4.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	2
5	Air to Air Cooler			2
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		2
7	Oil Cooler	Air-cooled, fin fan		2
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	2
9	Generator Glycol Cooler	Air-cooled, fin fan		2
10	Compressor Wash Skid			2
11	Fire Protection Package	Halon		2

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, triple-pressure, with economizer section and integral deaerator	HP-1950 psig/632°F 791,600 lb/h, superheat to 1000°F	2
			IP-410 psig/447°F 163,000 lb/h, superheat to 600°F	
			LP-60 psig/307°F 120,182 lb/h, superheat to 600°F	
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	2

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	135 MW Turbine Generator	TC2F20, triple admissions	1800 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,081,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water-sealed	2000/20 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. Water Pumps	Vertical wet pit	75,000 gpm @ 60 ft	2
2	Cooling Tower	Mechanical draft	160,000 gpm	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING AND REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Dewatering System	Vendor proprietary	384 tpd	1

5.2.4 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate, and levelized economics of the IGCC power plant with CO_2 removal were developed consistent with the approach and basis identified in the Design Basis. The capital cost estimate is expressed in January 2001 dollars. The production cost and expenses were developed on a first-year basis with a January 2001 plant in-service date. The resultant cost of electricity is expressed in first-year $/MWh.

The capital cost for the IGCC plant represents a plant with a net output of 456.7 MWe and is summarized in Table 5-3.

Table 5-3
IGCC Power Plant Capital Costs

Account Number	Title	Cost ($x1000)	$/kW
1	Gas Receiving and Handling	24,445	54
2	Coal Preparation and Feed	39,848	87
3	Feedwater & Miscellaneous BOP Systems	20,111	44
4	Gasifier & Accessories	26,696	58
4a	Air Separation Unit	80,863	177
5	Acid Gas Treatment	120,210	263
5a	CO_2 Compression	83,945	184
6	Combustion Turbine & Auxiliaries	87,748	192
7	Heat Recovery Boiler & Stack	27,753	61
8	Steam Turbine Generator	32,426	71
9	Cooling Water System	16,532	36
10	Slag Recovery & Handling	13,789	30
11	Accessory Electric Plant	35,224	77
12	I&C	11,727	26
13	Site Improvements	11,811	26
14	Buildings & Structures	11,513	25
	Total Plant Cost	644,641	1,412
	AFDC	57,373	126
	Royalty Allowance	1,500	3
	Working Capital	3,223	7
	Land Cost	700	2
	Total Capital Requirement	707,437	1,549

The production costs consist of plant operating labor, maintenance (material and labor), an allowance for administrative and support labor, consumables, solid waste disposal, and fuel costs. The costs were determined on a first-year basis that includes evaluation at an equivalent plant operating capacity factor of 65 percent. The results are summarized in Table 5-4.

Table 5-4
Annual Operating Costs

	$x1000
Operating Labor	5,503
Maintenance	12,862
Administration	2,662
Water	242
Disposal	1,447
Selexol Makeup	110
Total Annual Operating Costs	22,826

A revenue requirement analysis was performed to determine the cost of electricity on a constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Summary economic results are provided in Table 5-5.

Table 5-5
Cost of Electricity

	$/MWh
Capital Charges	37.54
Fuel Cost @ $1.25/MMBtu HHV	14.18
O&M Costs	8.78
Byproduct Credit (sulfur @ $55/LT)	−0.60
First-Year COE	59.90

5.2.5 CO_2 Captured and CO_2 Avoided

The IGCC power plant was designed to remove and capture 90 percent of the carbon in the coal as compressed CO_2. The penalty for doing this is reflected in decreased efficiency and increased costs. There are no other plants in this report that can be directly compared to get the differential emissions and costs. However, the IGCC plant was derived from the recently completed Clean Coal Reference Plant report, NETL 2001.

Table 5-6 shows the cost of avoided CO_2 for the IGCC plant operating at 65 percent capacity factor.

Table 5-6
Cost of Avoided CO_2 from the IGCC Plant

	Without CO_2 Capture	With CO_2 Capture	Delta
Capital Cost, $/kW	$1,169/kW	$1,549/kW	+$380/kW
Cost of Electricity, $/MWh	$43.40/MWh	$59.90/MWh	+$16.50/MWh
Thermal Efficiency, HHV %	37.6%	30.1%	−7.5%
Specific CO_2 Emissions, lb/MWh	1,856 lb/MWh	255 lb/MWh	−1,601 lb/MWh
Avoided CO_2	1,601 lb/MWh		
Energy Penalty, %	19.95%		
Cost of Avoided CO_2, $/ton	$20.61/ton		
Cost of Avoided CO_2, $/MT	$18.69/MT		

6. COAL-FIRED SUPERCRITICAL AFBC PLANT WITH CO_2 REMOVAL

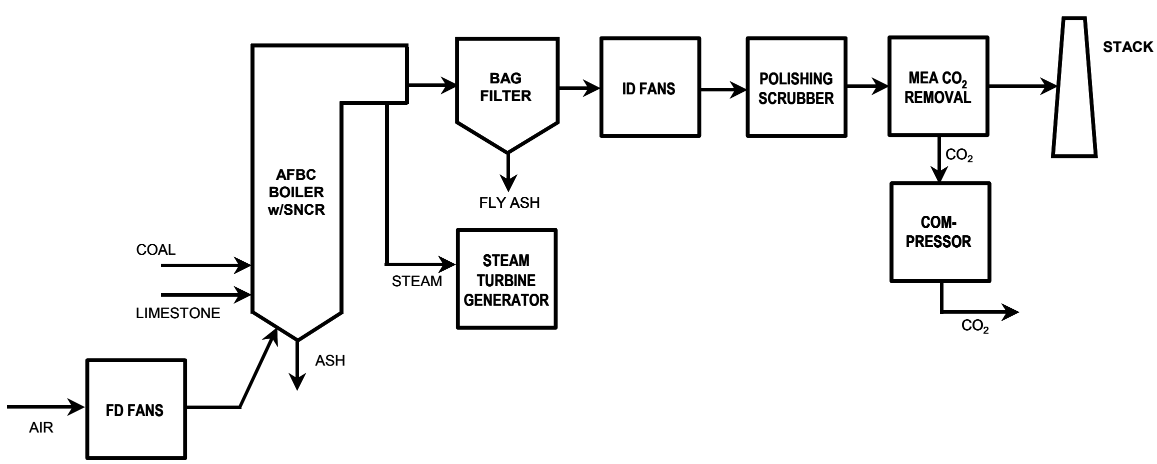
6.1 INTRODUCTION

This section describes a coal-fired AFBC supercritical steam plant with CO_2 removal and recovery from the flue gas. The plant design approach is market-based, and the configuration reflects current information and design preferences, the availability of a newer generation steam turbine, and the relative latitude of a greenfield site.

The coal-fired AFBC produces low levels of NOx by combusting the coal in the circulating bed, where temperatures are maintained in the vicinity of 1600°F. This low temperature minimizes the formation of NOx, while allowing the oxidation of carbon and the capture of sulfur by calcium to proceed to completion. Further NOx reduction is achieved with selective non-catalytic reduction (SNCR) ammonia injection. Addition of dry limestone to the bed, in appropriate particle sizes, provides the calcium carbonate for sulfur capture. Sulfur dioxide levels are further reduced to essentially zero by a polishing scrubber. A once-through steam generator is used to power a double-reheat supercritical steam turbine with a net power output of 497 MWe. The steam turbine conditions correspond to 3500 psig/1050°F throttle with 1050°F at both reheats. Net plant power, after consideration of the auxiliary power load, is 402 MWe. The plant operates with an estimated HHV efficiency of 28.2 percent with a corresponding heat rate of 12,102 Btu/kWh.

Flue gas exiting the AFBC boiler is routed through a baghouse to remove particulate matter, then through a polishing scrubber for additional SO_2 removal and finally to an inhibited MEA absorber-stripper system. In this system, a solution of aqueous MEA is used to remove 90 percent of the CO_2 in the flue gas. Low-pressure steam is used to strip and purify the CO_2. Low-pressure CO_2 removed from the system is compressed to supercritical conditions. A simplified block flow diagram, Figure 6-1 illustrates the overall system configuration.

Figure 6-1
Block Flow Diagram – AFBC



The following sections provide a more detailed discussion of plant performance, equipment descriptions, and plant cost estimates. The thermal performance section contains a heat and material balance diagram annotated with state point information. A summary of plant performance, including a breakdown of individual auxiliary power consumption, is also included. The system description section gives a more detailed account of the individual power plant subsections. A corresponding equipment list supports the detailed plant description and, along with the heat and material balance diagram, was used in generating estimated plant cost.

6.2 Thermal Plant Performance

Table 6-1 shows a detailed breakdown of the estimated system performance for this conventional coal-fired steam turbine power plant. Plant performance is based on the use of Illinois No. 6 coal as fuel and reflects current state-of-the art turbine adiabatic efficiency levels, AFBC boiler performance, and CO_2 removal through an aqueous solution of inhibited MEA.

Gross power output for the steam turbine is estimated to be 497.2 MWe. Plant auxiliary power is estimated to be 88.2 MWe. This auxiliary load value, much higher than that anticipated for a traditional coal-fired supercritical steam plant, is due to the presence of the CO_2 removal/ compression equipment. In particular, the flue gas ID blower, which requires 23.9 MWe of auxiliary power, and the CO_2 compressor, which requires 37.6 MWe of auxiliary power, are responsible.

Net plant power output, which considers generator losses and auxiliary power, is estimated as 401.8 MWe. This plant power output results in a net system thermal efficiency of 28.2 percent (HHV) with a corresponding heat rate of 12,102 Btu/kWh (HHV). Plant efficiency and heat rate numbers are low in comparison to those expected for coal-fired steam plants utilizing state-of-the-art supercritical steam turbines. There are two reasons for the low system thermal efficiency: (1) the increased auxiliary power associated with the CO_2 removal equipment (see above), and, (2) the large amount of steam diverted to the MEA stripper reboiler. Diverting this LP steam results in a marked decrease in steam turbine power output.

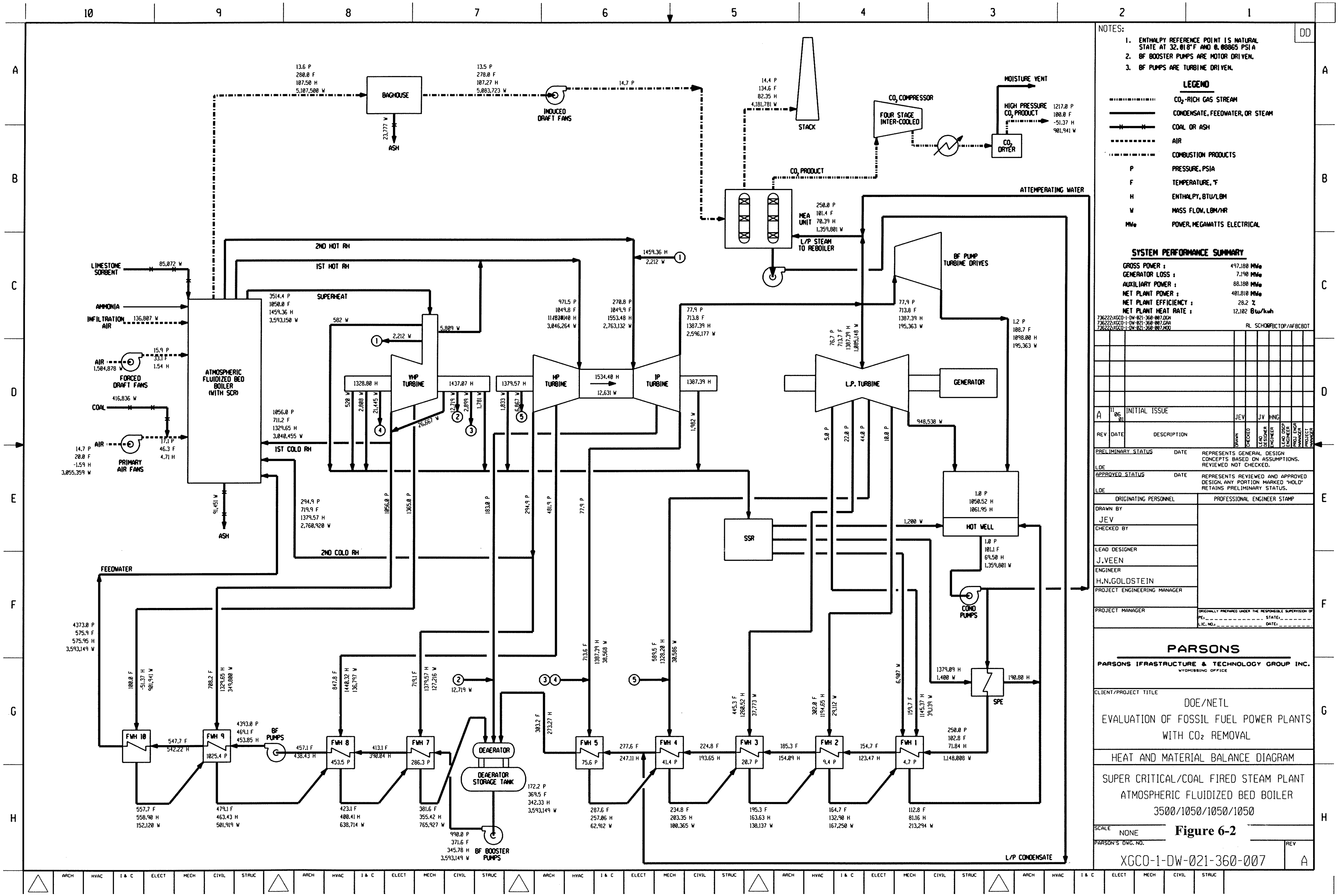
A heat and material balance diagram for this convention coal-fired steam plant is shown in Figure 6-2. The steam turbine power cycle is shown at 100 percent of design load. The supercritical Rankine cycle used for this case is a 3500 psig/1050°F/1050°F/1050°F double-reheat configuration. Condensate is heated in the low-pressure feedwater heaters, boiler feedwater is heated in the high-pressure feedwater heaters. Steam generation, superheat, and reheat are accomplished in the boiler house. Also shown in the diagram is the basic equipment required to remove CO_2 from the flue gas stream and concentrate it as a pure, high-pressure product.

Table 6-1
Supercritical AFBC Plant with CO_2 Removal
Plant Performance Summary - 100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	3,500
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
2nd Reheat Outlet Temperature, °F	1,050
GROSS POWER SUMMARY, kWe	
Steam Turbine Power	497,180
Generator Loss	(7,190)
Gross Plant Power	489,990
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	490
Limestone Handling & Reagent Preparation	750
Pulverizers	2,320
Ash Handling	2,090
Primary Air Fans	5,850
Forced Draft Fans	1,430
Induced Draft Fans	23,900
SNCR	100
Seal Air Blowers	50
Condensate Pumps	370
Boiler Feed Water Booster Pumps	3,760
High-Pressure Boiler Feed Pump	(Note 1)
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	2,300
Cooling Tower Fans	1,310
MEA Unit	2,380
CO_2 Compressor (Note 3)	37,550
Transformer Loss	1,130
Total Auxiliary Power Requirement	88,180
NET PLANT POWER, kWe	401,810
CO_2 Recovered, lb/MWh	2,245
CO_2 Avoided, lb/MWh	1,470
PLANT EFFICIENCY	
Net Efficiency, % HHV	28.2%
Net Heat Rate, Btu/kWh (HHV)	12,102
CONDENSER COOLING DUTY, 10^6 Btu/h	1,147
CONSUMABLES	
As-Received Coal Feed, lb/h (Note 4)	416,836
Thermal Input, kW_{th}	1,425,149
Sorbent, lb/h	85,071

Note 1 – Boiler feed pumps are turbine driven
Note 2 – Includes plant control systems, lighting, HVAC, etc.
Note 3 – Final CO_2 pressure is 1200 psig
Note 4 – As-received coal heating value: 11,666 Btu/lb (HHV)

Figure 6-2



NOTES:
1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018°F AND 0.08865 PSIA
2. BF BOOSTER PUMPS ARE MOTOR DRIVEN.
3. BF PUMPS ARE TURBINE DRIVEN.
LEGEND
CO2-RICH GAS STREAM
CONDENSATE, FEEDWATER, OR STEAM
COAL OR ASH
AIR
COMBUSTION PRODUCTS
P PRESSURE, PSIA
F TEMPERATURE, °F
H ENTHALPY, BTU/LBM
W MASS FLOW, LBM/HR
MWe POWER, MEGAWATTS ELECTRICAL
SYSTEM PERFORMANCE SUMMARY
GROSS POWER : 497,180 MWe
GENERATOR LOSS : 7,190 MWe
AUXILIARY POWER : 88,180 MWe
NET PLANT POWER : 401,810 MWe
NET PLANT EFFICIENCY : 28.2 %
NET PLANT HEAT RATE : 12,102 Btu/kwh
BAGHOUSE
INDUCED DRAFT FANS
STACK
CO2 COMPRESSOR
FOUR STAGE INTER-COOLED
MOISTURE VENT
HIGH PRESSURE CO2 PRODUCT
CO2 DRYER
CO2 PRODUCT
MEA UNIT
L/P STEAM TO REBOILER
ATTEMPERATING WATER
BF PUMP TURBINE DRIVES
LIMESTONE SORBENT
AMMONIA
INFILTRATION AIR
FORCED DRAFT FANS
PRIMARY AIR FANS
COAL
ASH
ATMOSPHERIC FLUIDIZED BED BOILER (WITH SCR)
2ND HOT RH
1ST HOT RH
SUPERHEAT
1ST COLD RH
2ND COLD RH
FEEDWATER
VHP TURBINE
HP TURBINE
IP TURBINE
L.P. TURBINE
GENERATOR
HOT WELL
SSR
COND PUMPS
SPE
FWH 10
FWH 9
FWH 8
FWH 7
FWH 5
FWH 4
FWH 3
FWH 2
FWH 1
BF PUMPS
DEAERATOR
DEAERATOR STORAGE TANK
BF BOOSTER PUMPS
L/P CONDENSATE
A INITIAL ISSUE
REV DATE DESCRIPTION
PRELIMINARY STATUS DATE REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
APPROVED STATUS DATE REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
ORIGINATING PERSONNEL
PROFESSIONAL ENGINEER STAMP
DRAWN BY JEV
CHECKED BY
LEAD DESIGNER J.VEEN
ENGINEER H.N.GOLDSTEIN
PROJECT ENGINEERING MANAGER
PROJECT MANAGER
PARSONS
PARSONS INFRASTRUCTURE & TECHNOLOGY GROUP INC.
CLIENT/PROJECT TITLE
DOE/NETL
EVALUATION OF FOSSIL FUEL POWER PLANTS WITH CO2 REMOVAL
HEAT AND MATERIAL BALANCE DIAGRAM
SUPER CRITICAL/COAL FIRED STEAM PLANT
ATMOSPHERIC FLUIDIZED BED BOILER
3500/1050/1050/1050
SCALE NONE
Figure 6-2
PARSON'S DWG. NO.
XGCO-1-DW-021-360-007
REV A

6.2.1 Power Plant Emissions

This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the first decade of this century. A summary of the plant emissions is presented in Table 6-2.

Table 6-2
Airborne Emissions
Supercritical AFBC Plant with CO_2 Removal

	Values at Design Condition (65% and 85% Capacity Factor)			
	Lb/10^6 Btu (HHV)	Tons/year 65%	Tons/year 85%	Lb/MWh
SO_2	nil	nil	nil	nil
NOx	0.124	1,716	2,244	1.50
Particulates	0.01	110	143	0.12
CO_2	20.2	223,303	292,011	237

The extremely low level of SO_2 in the plant emissions is achieved by capture of 95 percent of the sulfur in the AFBC limestone injection. Following the boiler baghouse, a caustic polisher is used to remove the remaining SO_2 from the flue gas to protect the MEA process sorbent.

The minimization of NOx production and subsequent emission is achieved by the combustion characteristics of the circulating fluidized bed, enhanced by use of selective non-catalytic reduction (SNCR), which relies on addition of ammonia at discrete locations in the furnace to react with and destroy NOx.

Particulate discharge to the atmosphere is reduced by the use of a modern fabric filter, which provides a particulate removal rate of 99.9 percent.

CO_2 emissions are reduced by the installation of an inhibited MEA CO_2 removal system. This unit treats flue gas exiting the FGD unit. CO_2 emissions are limited by 90 percent through contact with the MEA solution. CO_2 absorbed in the MEA is concentrated and released from the solution through the addition of heat in the stripper. CO_2 is then dried and compressed to 1200 psia.

6.2.2 System Description

This greenfield power plant is a 402 MW coal-fired supercritical steam plant with FGD and CO_2 removal through inhibited MEA. The major subsystems of the power plant are:

- Coal handling
- Coal combustion system (AFBC boiler)
- Ash handling system
- Flue gas desulfurization

- CO_2 removal and compression
- Steam turbine generator
- Condensate and feedwater systems
- Balance of plant

This section provides a brief description of these individual power plant subsystems. The equipment list, which follows this section, is based on the system descriptions provided here. The equipment list, in turn, was used to generate plant cost and cost of CO_2 removal.

6.2.2.1 Coal Handling and Preparation

The function of the coal handling and preparation system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the inlets of the prepared fuel silos.

The 6" x 0 bituminous Illinois No. 6 coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor and then transferred to a second conveyor that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron, and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 by the first of two coal crushers. The coal then enters a second crusher that reduces the coal size to 1/4" x 0, which is transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the six prepared coal silos.

The prepared coal is fed to the AFBC boiler via the fuel and sorbent feed system.

6.2.2.2 Coal Combustion System (AFBC Steam Generator)

The AFBC steam generator scope of supply includes the following:

- Circulating fluidized-bed steam generator
- Fans and blowers
- Air heaters
- Startup gas burner system
- Fly ash recycle system
- Ducts and flues, dampers
- Fuel feed system
- Sorbent feed system

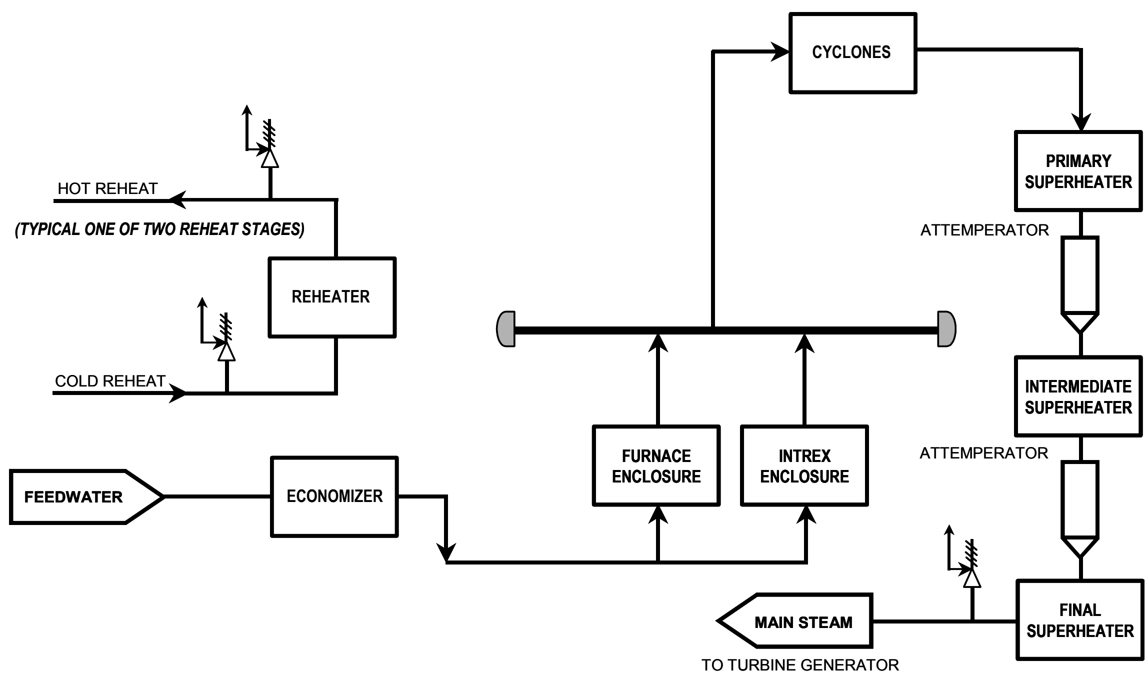
- Soot blower system
- Bottom ash removal system
- Piping, valves, instruments, and controls
- Structural steel, integral steel, insulation, and lagging

The steam generator operates as follows:

Feedwater and Steam

The feedwater and steam flow circuit in the AFBC steam generator are shown schematically in Figure 6-3.

Figure 6-3
AFBC – Typical Steam and Water Flow Circuit Diagram



Feedwater enters the economizer, recovering heat from combustion gases exiting the steam generator, and then passes to the waterwall sections. The water flows through multiple downcomers to several headers located near the bottom elevation of the unit. Multiple sections of waterwall act as risers for the feedwater to rise to headers at the top of the waterwall sections.

Steam exiting the drum passes through separators and dryers located internal to the drum; the steam then passes, in succession, through the primary superheater, an intermediate superheater, and a finishing superheater. The latter two stages of superheat surface are associated with the integrated recycle heat exchanger (INTREX). Two stages of attemperators are provided for control of final superheat temperature, located ahead of the intermediate and final superheater stages.

Cold reheat steam from the very-high-pressure turbine (VHP) enters the reheater, preceded by an emergency attemperator, and exits as hot reheat steam en route to the high-pressure (HP) turbine. A second-stage reheater receives steam leaving the HP turbine, boosts its temperature to 1050°F, and sends it to the inlet of the intermediate-pressure (IP) turbine. A similar reheat section is provided for the second reheat stage.

Air and Combustion Products

A forced draft primary air fan provides combustion air, which is split into several flow paths, as follows:

- An air stream flows to the fuel feeders and flows with the fuel into the furnace via a complement of fuel/air downcomers and feed spouts. This air stream proves initial fluidization of the coal mixture.
- A second air stream flows to, and cools, the complement of four ash coolers.
- A third air stream flows through a steam coil air heater followed by a regenerative air heater; this preheated air then flows to the front and rear wall coal feed spouts. This air stream acts to sweep the fuel/air mixture into the furnace and to support the initial stages of combustion. This air stream is also used for pre-mixing and firing of natural gas or No. 2 oil used for startup and warmup.

A forced draft secondary air fan provides an air stream that is preheated in a steam coil air heater and a regenerative air preheater, and is then introduced into the furnace as secondary air.

Combustion gases exit the furnace and flow through a complement of four cyclones, which separate out ash and partially burned fuel particles. These solids are recycled back to the furnace, passing through J-valves, or seals, below the cyclones, and then through the INTREX units before reentering the furnace at the back wall.

The gas exiting the cyclones passes to the heat recovery part of the AFBC, flowing through the reheater and primary superheater in parallel, and then through the economizer. The gases pass through the primary and secondary tubular air preheaters and then exit the AFBC steam generator to the baghouse for particulate capture.

Fuel and Sorbent Feed

Crushed coal flows by gravity from the prepared coal silos to gravimetric belt feeders, which feed the coal to an array of downspouts on the furnace walls. Eight feeders serve the front wall; two feeders serve the rear wall via drag conveyors.

Crushed and ground limestone flows out of each of the four day bins into gravimetric feeders and into four surge hoppers, through a series of gate valves, and then through four rotary air lock valves. The limestone passes through the air locks into a pneumatic system, which conveys it to the downspouts, which direct it into the fluidized bed. Four positive displacement type blowers provide air at sufficient pressure to transport the limestone from the rotary valves to the bed.

Ash Removal

Bottom ash, or bed drain material, constitutes approximately two-thirds of the solid waste material discharged by the AFBC steam generator. This bottom ash is discharged through a complement of four bed material stripper/coolers (any two of which must operate at 100 percent load on the design coal). The stripper/coolers cool the bed material to a temperature in the range of 300°F (design coal) to a maximum of 500°F (worst fuel) prior to discharge via rotary valves to the bed material conveying system. The steam generator scope terminates at the outlets of the rotary valves.

Fly ash comprises approximately one-third of the solid waste discharged from the AFBC steam generator. Approximately 8 percent of the total solids (fly ash plus bed material) is separated out in the economizer and air heater hoppers; 25 percent of the total solids is carried in the gases leaving the steam generator en route to the baghouse.

<u>Economizer and Air Heater</u>

The economizer is a vertical, bare tube, continuous loop type, with counter flow heat transfer (water up/gas down). The air heaters (primary air and secondary air) are vertical tubular type units.

<u>Fans and Blowers</u>

The following fans and blowers are provided with the scope of supply of the AFBC steam generator:

- Primary air fan, which provides forced draft primary airflow. This fan is a centrifugal type unit, supplied with electric motor drive, inlet screen, inlet vanes, and silencer.
- Secondary air fan, which provides forced draft secondary airflow. This fan is a centrifugal type unit supplied with electric motor drive, inlet screen, inlet vanes, and silencer.
- Induced draft fan, a centrifugal unit supplied with electric motor drive and inlet damper.
- INTREX blowers, centrifugal units that provide air for cooling the INTREX heat exchangers.
- J-seal blowers, centrifugal units that provide air for cooling and sealing the J-seals, and for assisting in the conveyance of cyclone bottoms through the INTREX heat exchangers to the furnace reentry ports.

<u>Soot Blowing</u>

The AFBC steam generator utilizes steam from the primary superheater exit for soot blowing. A complement of 30 motor-operated rotary soot blowers uses this steam for periodic soot blowing to remove deposits from tubewall surfaces.

6.2.2.3 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the bag filter hoppers, air heater hopper collectors, and bottom ash hoppers to the truck filling stations.

The fly ash collected in the bag filter and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is drained from the bed, cooled in a stripper cooler, and discharged to a drag chain type conveyor for transport to the bottom ash silo. Ash from the INTREX heat exchangers is drained to a complement of screw coolers, which discharge the cooled ash to a drag chain conveyor for transport to a surge bin. The ash is pneumatically conveyed to the bottom ash silo from the surge bin.

6.2.2.4 AFBC CO_2 Removal and Compression

Part of the criteria of this combined cycle power plant design is the limitation of CO_2 emissions. This power plant configuration is based on removing 90 percent of the CO_2 in the flue gas exiting the FGD system. An inhibited aqueous solution of approximately 15 percent MEA is used to remove the CO_2.

Flue gases from the boiler baghouse are blown by two 50 percent capacity ID fans for transmission to the SO_2 scrubbing section of the flue gas pretreatment system. The gases are quenched and scrubbed in a two-stage scrubber with dilute caustic solution for particulate, NOx, and SO_2 removal. In the scrubber, the NOx and SO_2 in the flue gas react with the caustic solution to form soluble salts. These salts are removed by taking a purge stream from the caustic recirculation loop. A blowdown pot for scrubber samples and water seal flush for the first-stage scrubber recirculation pumps is provided. The flue gas from the caustic scrubber is further cooled in the flue gas cooler to remove additional water.

The purge stream from the recirculation loop is stored in an 8,000-gallon, aboveground 316L stainless steel tank. This tank is supplied with caustic solution to neutralize the scrubber waste, if required. A pump from this tank is used to feed the scrubber waste to the pug mill system located in the power plant.

Cool flue gas exiting the FGD at 131°F enters the bottom of the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact of MEA. The packing is 2-inch stainless steel rings. There are four absorber and regeneration trains. In each absorber train there are four absorber columns, operating in parallel, each 14.5 feet in diameter and 80 feet vertical. MEA circulation through each absorber is approximately 1,500 gpm. A small slipstream of 0.75 percent MEA solution circulation rate is removed from the process for a continuous MEA reclaim. This economically minimizes the amount of MEA makeup. The MEA makeup rate for this process is 0.8 pounds per ton of CO_2 at $0.60 per pound.

Flue gas exiting the top of the absorber columns is collected in a common duct and routed to an exhaust stack. Rich solution off the bottom of the columns is heated in the rich-lean heat exchanger through indirect contact with lean solution flowing off the bottom of the stripper column.

Hot rich solution enters the top of the stripper column and flows downward and counter to the stripping agent, which is primarily steam. LP steam from the steam turbine crossover generates the stripping steam in the reboiler. CO_2 liberated through the application of heat flows upward along with the stripping steam. The vapor leaving the CO_2 stripper is partially condensed at 120°F to provide reflux to the stripper. The CO_2 gas leaving the reflux drum is fed to the CO_2

purification and liquefaction section. The condenser vapor phase, which is saturated CO_2, is routed to the multi-staged, intercooled CO_2 compressor. The regenerated lean solution is returned to the absorber, via an 18,000-gallon solvent surge tank and pump between the absorber and stripper. A solvent drain sump pump is used to transfer MEA from low point drains in the amine equipment to the solvent surge tank. This tank will also be used to store makeup solvent.

There are four stripper trains operating in parallel. Each stripper column is 16 feet in diameter and equipped with stainless steel trays that promote good interphase contact. The height of each stripper column is 75 feet. Total reboiler steam requirement is approximately 1,216,000 lb/hour of 55 psig low-pressure steam.

The MEA solvent and proprietary additives are circulated between the stripper and the absorber and over a period of time degrades due to reactions with contaminates in the flue gas (SO_2, NOx, etc.). In order to refine the degraded solution, a reclaimer reboiler will be provided to periodically distill the solution, reclaiming usable MEA. The higher boiling point waste material left in the reclaimer is transferred to CO_2 plant wastewater tank for off-site disposal.

Carried-over fly ash and reagent precipitates are removed from the MEA solution by a pressure leaf filtration package. Approximately 20 percent of the circulating MEA solution is diverted through the filter, and the filtrate is then returned to the circulating solution. The filtration package utilizes precoating and body feed of filter aid for more efficient filtration. Filter aid/ precoat slurry tanks, agitators, and pumps will be provided as part of the filtration package. The solid waste from the filter is discarded into a tilt dump hopper, then carried by forklift truck and dumped into a roll-off container.

NOx components NO and NO_2 will be present in the flue gas stream. NO is unreactive with the solvent. NO_2, on the other hand, may react with the solvent to form nitrates. If nitrate formation cannot be controlled with normal filtering and treating systems, a cold-water scrubber may be installed before the absorber as a means to control NO_2 flow into the absorber. NO_2, which usually accounts for less than 10 percent of the NOx species, should not pose much of a problem to this system due to SCR NOx control.

CO_2 from the stripper is compressed to a pressure of 1230 psia by the multi-stage CO_2 compressor. The compression includes interstage cooling as well as knockout drums to remove and collect condensate. CO_2 is dehydrated to remove water vapor. Water vapor stripped from the CO_2 is vented to the atmosphere. After drying, the dense phase CO_2 enters the pipeline for transport and/or disposal/sequestration.

6.2.2.5 Steam Turbine Generator

The turbine consists of a very-high-pressure (VHP) section, high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the HP section at 955 psig/1050°F. The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 270 psig/1050°F. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is divided into four paths that flow through the LP sections, exhausting downward into the condenser.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

6.2.2.6 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

The function of the feedwater system is to pump feedwater from the deaerator storage tank to the boiler economizer. One turbine-driven boiler feed pump is provided to pump feedwater through the HP feedwater heaters. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

6.2.2.7 Balance of Plant

The balance-of-plant items for the AFBC plant include:

- Steam systems
- Circulating water system
- Ducting and stack
- Waste treatment
- Accessory electric plant
- Instrumentation and control
- Buildings and structures

These items are discussed in more detail below.

<u>Steam Systems</u>

The steam cycle is depicted in Figure 6-2. Although this diagram presents detailed stream data at many points or nodes in the steam thermodynamic cycle, it does not depict details of the steam and water flow path in every item of equipment, as this would require a significant expansion of the diagram. An expanded level of detail is not suitable for a conceptual level study. A general description of the operation of the steam cycle follows:

The description starts at the condenser hotwell, which is a receptacle for the condensed steam from the exhaust of the steam turbine. The condensate flows to the suction of the condensate pumps, which increase the pressure of the fluid by a nominal 250 psi to transport it through the piping system and enable it to enter the open contact heater, or deaerator. The condensate passes through a gland steam condenser (SPE) first, followed in series by five low-pressure feedwater heaters. The heaters successively increase the condensate temperature to a nominal 303°F by condensing and partially subcooling steam extracted from the low-pressure steam turbine section. Each heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (now referred to as heater drain) is progressively passed to the next lower pressure heater, with the drains from the lowest heater draining to the condenser.

The condensate entering the deaerator is heated and stripped of non-condensable gases by contact with the steam entering the unit. The steam is condensed and, along with the heated condensate, flows by gravity to a deaerator storage tank. The boiler feedwater booster pumps take suction from the storage tank and increase the fluid pressure to a nominal 975 psig. The boosted condensate flows through two more feedwater heaters (FWH 7 and FWH 8), increasing in temperature to 457°F at the suction of the boiler feedwater pumps. These pumps increase the feedwater pressure to a nominal 4380 psig for passage through the remaining two high-pressure feedwater heaters (FWH 9 and FWH 10), which heat the feedwater to a final temperature of 576°F for induction to the boiler.

The boiler is depicted in a simplified manner on the drawing. The internal feedwater circuitry is not presented herein. The complete feedwater-to-steam circuitry in a supercritical boiler, such as the one considered here, involves numerous feedwater sections comprising the boiler water-walls, followed by transition sections, and then includes several superheat tube bundles that are suspended in the gas path. The reheat circuit is relatively simple by comparison, involving one or more tube bundles suspended in the gas path.

The steam turbine is shown on a simplified basis on the diagram, although the Aspen model for the steam turbine incorporates numerous internal leakage flow paths that are not shown. These internal steam flows are used to seal the shaft from steam leakage out and air leakage in. These steam seal flows are collected and controlled by the steam seal regulator (SSR). A portion of the flow is sent to one of the low-pressure heaters, with the rest sent to the gland steam condenser. The condensate from the gland steam condenser flows to the condenser, while the non-condensables (principally air) are exhausted to the atmosphere by the steam packing exhauster (SPE). Both the gland steam condenser and the steam packing exhauster are shown as a combined unit labeled SPE on the diagram.

The steam turbine is comprised of four sections to match the requirements of this heat and mass balance. These are labeled VHP, HP, IP, and LP. The steam turbine sections are equipped with nozzles that allow steam to exit the turbine at various locations between stages. The steam exit points are selected by the manufacturer to match the feedwater heating requirements set by the heat and mass balance.

The high-pressure steam leaving the boiler enters the VHP turbine section at 3500 psig and expands to a nominal 1040 psig. Most of this steam is directed to the boiler first reheat tube bundle (a portion of the steam is diverted for feedwater heating in the second highest pressure feedwater heater, FWH 9). The reheated steam exiting the boiler at 1050°F as the first reheat is sent to the HP turbine to expand to a nominal 280 psig, with a steam extraction point located part-way in the expansion path. Again, a portion of the HP turbine exhaust steam is diverted to one of the feedwater heaters.

The boiler exit pressure is set higher than the design basis turbine inlet pressure to allow for pressure drop in the connecting piping. In the case presented here, a boiler exit pressure of 3650 psig is used with a steam turbine inlet pressure of 3500 psig. Pressure drops in the reheat steam legs are much lower, with about 5 percent used as a design allowance for each of the two reheat piping circuits (first reheat and second reheat). The 5 percent is for both the cold and hot reheat piping runs.

The HP turbine exhaust steam reenters the boiler through the second reheat tube bundle, heating the steam back to the design basis value of 1050°F. The reheated steam as the second hot reheat passes to the IP turbine section for expansion to a nominal pressure of 63 psig. The steam continues through a crossover pipe to the LP turbine to continue the expansion to the final condensing pressure of 1.0 psia. The IP and LP turbine sections are also equipped with extraction steam nozzles that provide steam for feedwater heating. A portion of the IP to LP steam flow is used for driving the feedwater pump drive turbines.

Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a multi-cell mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of each condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

Ducting and Stack

One stack is provided with a single 19.5-foot-diameter FRP liner. The stack is constructed of reinforced concrete, with an outside diameter at the base of 70 feet. The stack is 480 feet high for adequate particulate dispersion.

Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment will be housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0-1000 lb/hour dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water will be provided. A 200,000-gallon storage tank will provide a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

Instrumentation and Control

An integrated plant-wide control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

Buildings and Structures

A soil-bearing load of 5,000 lb/ft^2 is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building
- Coal crusher building
- River water intake structure
- Guard house

- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

6.2.3 Major Equipment List

This section contains the equipment list corresponding to the power plant configuration shown in Figure 6-2. This list, along with the heat and material balance and supporting performance data, was used to generate plant costs and used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped. All other symbols can be referenced in the nomenclature section.

Fourteen codes of account are used. They are summarized below in conjunction with the equipment list.

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	2
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor 3	48" belt	450 tph	1
9	Crusher Tower	N/A	450 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	450 ton	1
11	Crusher	Granulator reduction	6" x 0 - 3" x 0	1
12	Crusher	Impactor reduction	3" x 0 – 1/4" x 0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor 4	48" belt	450 tph	1
15	Transfer Tower	N/A	450 tph	1
16	Tripper	N/A	450 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	600 ton	6

ACCOUNT 1B LIMESTONE RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibrator	115 tph	2
3	Conveyor 1	30" belt	115 tph	1
4	Conveyor 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	600 tons	1

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A COAL PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Feeder	Gravimetric	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Bin Activator		20 tph	1
2	Weigh Feeder	Gravimetric	20 tph	1
3	Limestone Rod Mill	Rotary	20 tph	1
4	Blowers	Roots	20 tph	3

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER

Equipment No.	Description	Type	Design Condition	Qty
1	Cond. Storage Tank	Field fabricated	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	1.15 x 10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vertical canned	1,420 gpm/800 ft	3
5	LP Feedwater Heater 1	Horizontal U tube	1,148,100 lb/h 102°F to 160°F	1
6	LP Feedwater Heater 2	Horizontal U tube	1,148,100 lb/h 160°F to 185°F	1
7	LP Feedwater Heater 3	Horizontal U tube	3,593,000 lb/h 185°F to 225°F	1
8	LP Feedwater Heater 4	Horizontal U tube	3,593,000 lb/h 225°F to 277°F	1
9	LP Feedwater Heater 5	Horizontal U tube	3,593,000 lb/h 277°F to 300°F	1
10	Deaerator and Storage Tank	Horizontal spray type	3,593,000 lb/h 300°F to 370°F	1
11	Boiler Feed Water Booster Pump	Horizontal split	8,300 gpm @ 2,400 ft	2
12	HP Feedwater Heater 7	Horizontal U tube	3,593,000 lb/h 370°F to 390°F	1
13	HP Feedwater Heater 8	Horizontal U tube	3,593,000 lb/h 410°F to 460°F	1
14	Boiler Feed Pump/ Turbine Drive	Barrel type, multi-staged, centr.	8,300 gpm @ 11,500 ft	2
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	2,500 gpm @ 11,500 ft	2
16	HP Feedwater Heater 9	Horizontal U tube	3,593,000 lb/h 450°F to 550°F	1
17	HP Feedwater Heater 10	Horizontal U tube	3,593,000 lb/h 550°F to 580°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fabricated water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell and tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	Two-stage centrifugal	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water Pumps	S.S., single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., single suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25-hour storm	1
18	SNCR System	Aqueous Ammonia	400 MW	1

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty
1	AFBC Once-Through Steam Generator with Air Heater	Universal pressure	3,593,000 lb/h steam at 3700 psig/ 1055°F	1
2	Primary Air Fan	Axial	1,500,000 pph, 342,000 acfm, 35" wg, 1,500 hp	2
3	FD Fan	Centrifugal	750,000 pph, 150,000 acfm, 10" wg, 630 hp	2
4	ID Fan	Centrifugal	2,500,000 pph, 600,000 acfm, 110" wg 13,000 hp	2
5	Seal Air Blower	3-stage recip	1300 acfm/350 psig	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty
1	Bag Filter	Pulse-jet cleaned	656,500 acfm, total removal efficiency = 99.9%+	1

ACCOUNT 5B FLUE GAS DESULFURIZATION

Not Applicable

ACCOUNT 5C CO_2 REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Design Condition	Qty
1	Absorber	14.5-foot-diameter packed bed 2" rings, three 20-foot stages	30 psig / 300°F	16
2	Stripper	Tray tower	50 psig / 300°F	4
3	Reflux Drum	Horizontal cooling water	50 psig / 250°F	4
4	Reboiler	Horizontal shell 50 psig steam	75 psig / 350°F	4
5	Cartridge Filter	Horizontal	100 psig / 200°F	4
6	Carbon Filter	Horizontal	100 psig / 200°F	4
7	Rich Amine Pump	Centrifugal	7,400 gpm @ 250 ft	4
8	Lean/Rich Amine Heat Exchanger	Horizontal shell	100 psig / 280°F	4
9	Lean Amine Pump	Centrifugal	7,400 gpm @ 250 ft	4
10	CO_2 Compressor and Auxiliaries	Centrifugal, multi-staged	25 psia / 1300 psia	1
11	Final CO_2 Cooler	Shell and tube	66 x 10^6 Btu/h	1
12	Dehydration Package	Triethylene glycol	1300 psia	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Not Applicable

ACCOUNT 7 WASTE HEAT BOILER, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Qty
1	Stack	Reinforced concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 15 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	410 MW Turbine Generator	TC2F30	3500 psig/1050°F/ 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Plate and frame	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell and tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid state brushless	-	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Cooling Tower	Mechanical draft	120,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vertical wet pit	60,000 gpm @ 80 ft	2

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A BOTTOM ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Economizer Hopper (part of boiler scope of supply)			4
2	Bottom Ash Hopper (part of boiler scope of supply)			2
3	Stripper Cooler			2
4	Screw Cooler			4
5	Drag Chain Conveyor			4
6	Surge Bin			2
7	Blower	Roots		2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	ESP Hoppers (part of ESP scope of supply)			24
2	Air Heater Hopper (part of boiler scope of supply)			10
3	Air Blower		1,800 cfm	2
4	Fly Ash Silo	Reinforced concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

6.2.4 Capital Cost, Production Cost, and Economics

The capital cost estimate, first-year production cost estimate, and levelized economics of the supercritical AFBC coal power plant with CO_2 removal were developed consistent with the approach and basis identified in the Design Basis. The capital cost estimate is expressed in January 2001 dollars. The production cost and expenses were developed on a first-year basis with a January 2001 plant in-service date. The resultant cost of electricity is expressed in first year $/MWh.

The capital cost for the AFBC plant represents a plant with a net output of 401.8 MWe and is summarized in Table 6-3.

Table 6-3
AFBC Power Plant Capital Costs

Account Number	Title	Cost ($x1000)	$/kW
1	Coal Receiving and Handling	23,939	60
2	Fuel & Sorbent Preparation and Feed	20,869	52
3	Feedwater & Miscellaneous BOP Systems	35,509	88
4	Boiler and Accessories	166,216	414
5	Gas Treatment	22,541	56
5a	CO_2 Removal & Compression	176,108	438
6	Combustion Turbine & Auxiliaries	N/A	N/A
7	Heat Recovery Boiler & Stack	N/A	N/A
8	Steam Turbine Generator	88,293	220
9	Cooling Water System	25,780	64
10	Ash/Sorbent Recovery & Handling	55,908	139
11	Accessory Electric Plant	45,934	114
12	I&C	12,610	31
13	Site Improvements	13,850	34
14	Buildings & Structures	42,680	106
	Total Plant Cost	730,237	1,817
	AFDC	64,991	162
	Royalty Allowance	1,000	2
	Working Capital	3,651	9
	Land Cost	164	0
	Total Capital Requirement	800,043	1,991

The production costs consist of plant operating labor, maintenance (material and labor), an allowance for administrative and support labor, consumables, solid waste disposal and fuel costs. The costs were determined on a first-year basis that includes evaluation at an equivalent plant operating capacity factor of 65 percent. The results are summarized in Table 6-4.

Table 6-4
Annual Operating Costs

	$x1000
Operating Labor	2,064
Maintenance	6,805
Administration	1,196
Water	3,758
Disposal	5,150
Limestone	3,182
MEA Makeup	526
Caustic Makeup	298
SCR Ammonia	820
Total Annual Operating Costs	23,800

A revenue requirement analysis was performed to determine the cost of electricity on a constant dollar basis. The evaluation was based on the 65 percent capacity factor basis used to determine the annual production costs. Summary economic results are provided in Table 6-5.

Table 6-5
Cost of Electricity

	$/MWh
Capital Charges	48.26
Fuel Cost @ $1.25/MMBtu HHV	15.13
O&M Costs	10.40
Byproduct Credit	0.00
First-Year COE	73.79

6.2.5 CO_2 Captured and CO_2 Avoided

The AFBC power plant was designed to remove and capture 90 percent of the carbon in the coal as compressed CO_2. The penalty for doing this is reflected in decreased efficiency and increased costs. There are no other plants in this report that can be directly compared to get the differential emissions and costs. However, the AFBC plant was derived from the following baseline plant (source: "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," EPRI, U.S. DOE/NETL, 2000):

Referenced plant Case 7C: Conventional Supercritical PC Plant without CO_2 Removal

Table 6-6 shows the cost of avoided CO_2 for the AFBC plant operating at 65 percent capacity factor.

Table 6-6
Cost of Avoided CO_2 from the AFBC Plant

	Without CO_2 Capture	With CO_2 Capture	Delta
Capital Cost, $/kW	$1,143/kW	$1,991/kW	+$848/kW
Cost of Electricity, $/MWh	$51.50/MWh	$73.79/MWh	+$22.29/MWh
Thermal Efficiency, HHV %	40.5%	28.2%	−12.3%
Specific CO_2 Emissions, lb/MWh	1,707 lb/MWh	237 lb/MWh	−1,470 lb/MWh
Avoided CO_2	1,470 lb/MWh		
Energy Penalty, %	30.37%		
Cost of Avoided CO_2, $/ton	$30.33		
Cost of Avoided CO_2, $/MT	$27.50		

7. CONCLUSIONS

The primary objective of this study was to evaluate the performance and economic impact of CO_2 removal on a conventional PC power plant, NGCC power plant, IGCC power plant, and AFBC power plant. The conceptual design, cost estimate, and the performance and economic impact of a CO_2 removal system for each power plant was to be compared at the same nominal 400 MWe capacity. All plants were designed to deliver concentrated CO_2 at a purity suitable for pipeline transport. The plant descriptions are:

- A conventional PC plant using wet FGD for sulfur capture and MEA unit for CO_2 capture in the flue gas.
- A NGCC power plant using an MEA unit for CO_2 capture in the flue gas.
- An IGCC power plant with CO_2 recovery (shifting to hydrogen and a Selexol unit for CO_2 capture and H_2S removal).
- A 400 MWe AFBC power plant, including limestone injection for sulfur capture and an MEA unit for CO_2 capture in the flue gas.

A comparison of the plant performance is shown in Table 7-1. As expected, as a result of recovering and compressing 90 percent of the carbon as CO_2, each plant incurred a significant lowering in efficiency. The removal of CO_2 has a positive effect on the emissions from the plants. SO_2 for the fossil-fired plants with MEA processes for stack gas is reduced to essentially zero. This is due to the requirement for gas polishing before the MEA absorber. Table 7-2 shows the summary of plant emissions.

Table 7-1
Summary Plant Performance Comparisons

	PC Boiler	NGCC	IGCC	AFBC
Throttle Pressure (psig)	3500	1800	1800	3500
Throttle Temperature (°F)	1050	1050	1000	1050
First Reheat Outlet Temperature (°F)	1050	1050	1000	1050
Second Reheat Outlet Temperature (°F)	1050	---	---	1050
Gross Plant Power (MWe)	489,990	446,867	573,870	489,990
Auxiliary Power (MWe)	88,480	47,990	117,150	88,180
Net Plant Power (MWe)	401,510	398,877	456,720	401,810
Net Plant Efficiency (HHV)	28.7%	39.2%	30.1%	28.2%
Net Plant Heat Rate (HHV)	11,897	8,701	11,344	12,102
As-Received Coal Feed (lb/h)	409,450	158,986	444,020	416,836
Thermal Input (kW_{th})	1,399,897	1,016,872	1,518,091	1,425,149
Sorbent Feed (lb/h)	42,052	---	---	85,071
CO_2 Recovered (lb/MWh)	2,172	952	2,000	2,245
CO_2 Avoided (lb/MWh)	1,469	704	1,601	1,470

Table 7-2
Summary Plant Air Emissions Comparisons

	PC Plant		NGCC		IGCC		AFBC	
	Lb/MMBtu	Lb/MWh	Lb/MMBtu	Lb/MWh	Lb/MMBtu	Lb/MWh	Lb/MMBtu	Lb/MWh
SO_2	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
NOx	0.126	1.50	0.033	0.28	0.022	0.25	0.127	1.50
Particulate	0.01	0.12	Nil	Nil	Nil	Nil	0.01	0..12
CO_2	20.0	238	11.4	99	20	230	20.2	237

Also because of CO_2 recovery and compression, the plant capital requirement is increased as well as the operating costs. Table 7-3 is a summary comparison of the plant economics.

Table 7-3
Summary Plant Economic Conditions

	PC	NGCC	IGCC	AFBC
	$1,000 ($/kW)	**$1,000 ($/kW)**	**$1,000 ($/kW)**	**$1,000 ($/kW)**
Total Capital Cost	$762,887 ($1,900)	$409,007 ($1,025)	$644,641 ($1,412)	$730,237 ($1,817)
Total Capital Requirement	$836,142 ($2,083)	$433,893 ($1,088)	$707,437 ($1,549)	$800,043 ($1,991)
Annual Operating Costs	$23,025	$10,595	$22,826	$23,800
Cost of Electricity	**$/MWh**	**$/MWh**	**$/MWh**	**$/MWh**
Capital Charge	$50.47	$26.36	$37.54	$48.26
Fuel Cost	$14.88	$23.49	$14.18	15.13
O&M Costs	$10.07	$4.66	$8.78	$10.40
Byproduct Credit	0	0	($0.60)	0
Net COE	$75.42	$54.51	$59.90	$73.79
Cost of Avoided CO_2	$29.53/MT	$52.31/MT	$18.69/MT	$27.50/MT