DOE/FE-0400

MARKET-BASED ADVANCED COAL POWER SYSTEMS

FINAL REPORT

MAY 1999

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Office of Fossil Energy
Washington, DC 20585

1. INTRODUCTION

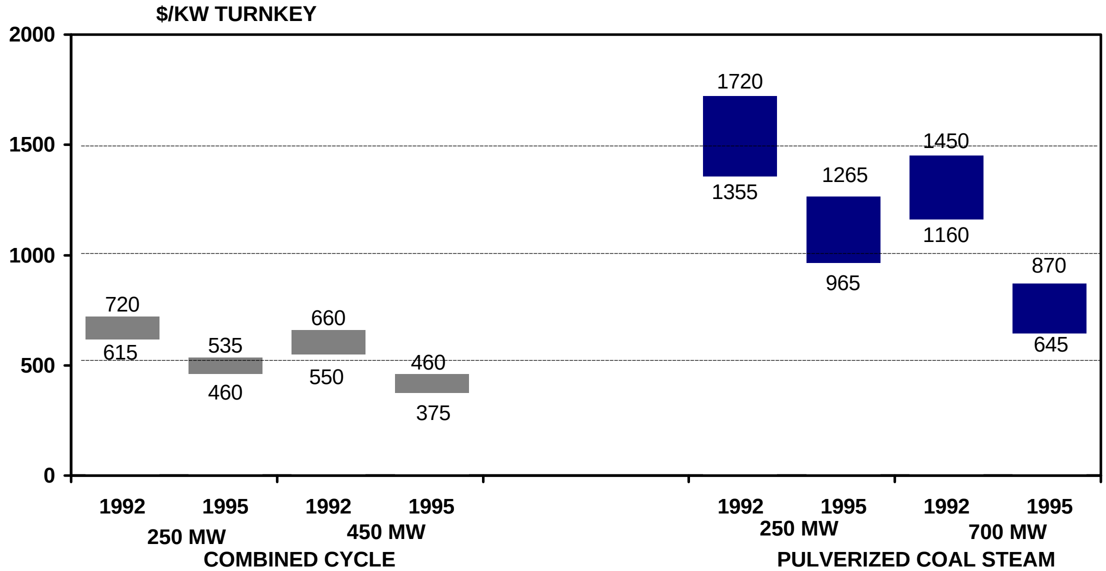
As deregulation unfolds and privatization of the utility market takes shape, priorities for power plant economics have shifted toward those of a “bottom-line” business and away from a regulated industry. Competition in utility generation and the exposure risks of large capital investments have led to a preference to minimize capital costs and fixed and variable operation and maintenance costs. With global competition from independent power producers (IPPs), non-utility generators, and utilities, the present trend of investments is with conventional pulverized coal and natural gas-fired power plants, which can be brought on-line quickly at minimum cost.

Aligned with these trends, the power plant investor is oriented toward highly reliable, modular designed power plants that can be brought on-line quickly, comply with emissions requirements, and support both base load and dispatch operation. In addition, a top priority is placed on flexibility in both fuel and operations. This places a premium on technologies that can operate on multi-fuels with minimum sacrifice in performance, availability, and efficiency. Flexibility in operation is related to load-following capability as the investor seeks to recover capital in a market becoming dominated by low-cost providers.

Dramatic improvements in the economics of the pulverized coal (PC) and the natural gas combined cycle (NGCC) power plant over the last decade have occurred in response to the concerns of the decision-maker in assuring the financial success of power projects, as illustrated in Figure 1-1. During the 1980s through the 1990s, commercially supplied PC plants with flue gas desulfurization (FGD) with nominal capacities of 500 MWe were priced in the mid $1,300 per kWe (1995$). Presently, the total plant costs (TPC), which are essentially overnight construction costs, for U.S. plants can be commercially offered for under $1,000 per kWe. Technology and economic advancements contributing to this reduction can be summarized by the following categories:

- Performance Improvements
- Plant Automation and Reliability Improvements
- Direct Equipment Cost Reductions

Figure 1-1
DECREASING COSTS FOR PULVERIZED COAL AND NATURAL GAS



SOURCE: CAMBRIDGE ENERGY RESEARCH ASSOC.

- Reduced Construction and Startup Schedule
- Increased Market Competition

Circulating pressurized fluidized-bed combustors (CPFBC) and integrated gasification combined cycles (IGCC) coal-based electric power generation systems are now in demonstration under the U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) Program. Despite the performance and emission advantages of these technologies, high capital costs threaten competitiveness in the utility market. As a result, it is critical to determine if the same improvements in capital cost experienced by the pulverized coal technology can be achieved by these advanced power generation technologies.

1.1 OBJECTIVE AND APPROACH

The objective of the work discussed in this report is to provide economic data and supporting analyses in determining commercially mature costs for clean coal technologies through evaluation and correlation to the cost improvement trends of the state-of-the-art PC and gas turbine power plants. Key issues include:

- Development of market-based economics for advanced coal-based technology.
- Application of innovative methods to reduce capital cost while maintaining plant availability.
- Reduction of capital and indirect costs through shorter construction periods and lower interest during construction.
- Application of advanced gas turbine technology from DOE's Advanced Turbine System (ATS) program.

The approach to determine market-based costs for IGCC and CPFBC technologies included:

- Establishment of cost changes in PC plants experienced since the implementation of New Source Performance Standards (NSPS) Subpart Da (Electric Utility Steam Generating Units for which Construction Commenced after September 18, 1978).
- Definition of the base-line economic data for the early commercial offerings for IGCC and CPFBC from information developed from DOE's CCT program.
- Identification of IGCC and CPFBC process and generation systems that are expected to mature through CCT demonstration and commercial application through the year 2015.
- Application of cost improvements in process and generation, which can be expected for commercially mature IGCC and CPFBC technologies from correlation to the evolution of the PC plant.

1.2 BACKGROUND

Competition in utility generation and the risks of large capital investments have led to a preference to minimize both capital costs and fixed and variable operation and maintenance costs. Many of the issues confronting the decision-maker when selecting technology options are tied to evaluating a project's economic risk. Economic issues include those directly related to capital and fixed operating cost, such as equipment or process availability, economy of scale, construction, and startup schedule, just to name a few. The PC plants of the 1990s have experienced increases in thermal and emission performance at lower capital and production cost compared to plants a decade earlier. Both process and generation improvements contributed to this evolution. Examples of these include:

- Performance Improvements

  During the 1970s and 1980s new steam plant efficiencies remained in the 36 to 39 percent range with average system pressure at 2400 psig and single reheat at 1000°F. Increases in plant power consumption occurred due to the additional environmental control equipment including FGD and larger precipitators. These parasitic loads were in addition to the effects of widespread adoption of evaporative cooling towers as heat sinks, which replaced the once-through cooling used on older power plants. The combined effects of these measures contributed to a virtual freeze on steam power plant thermal efficiencies that lasted for over three decades.

  The 1990s have brought about increasing thermal efficiencies as a result of improvements in steam turbine performance, lower auxiliary loads for environmental control systems, and performance optimization through automated controls.

- Plant Automation and Reliability Improvements

  Integrated automation and data access systems are achieving lower electrical production costs through optimizing plant performance and reliability while meeting dispatch and environmental constraints. Typically, plant automation involves:

  – Upgrades to higher accuracy instruments

  – Performance improvement through the plant's distributed control system (DCS) providing on-line plant performance calculations, heat rate, and operator controllable losses

- Operator interface with real-time information for immediate performance
- Access to plant-wide information to balance operational parameters including dispatch, emission compliance, and efficiency.

- Direct Equipment Cost Reductions

  With the development of more reliable components and the need to lower capital investments, PC plants are now designed with fewer redundant or reduced capacity components, while achieving high availability client standards. As an example, the reduction in cost for FGD has been significant, from over $220 per kWe to under $125 per kWe in the last 10 years. This decrease is directly related to the developments in performance improvements through increased sulfur capture, better process control and availability, the elimination of absorber redundancy, and reduction in supporting equipment redundancy.

- Reduced Construction and Startup Schedule

  Construction and startup schedules typical to the PC plant just five years ago could extend beyond four or five years. With today's competitive influence of reducing up-front costs and funds during construction, these same plants are experiencing construction schedules of less than three years. Engineering techniques, which include parallel design and field erection, partnering between owners and suppliers, and enhanced computer aided design capability, provide the tools necessary to shorten construction and startup.

- Increased Market Competition

  In response to these market and regulatory changes, the power generation sector has begun aggressive restructuring, mergers and acquisitions, and the development of lower cost power generators. The baseline for comparison is the existing generators on the grid selling power. From the perspective of the power generator owner, the economics of the project are fundamental to the success of the project in that the financial community is looking for a reasonable return on investment.

1.3 REPORT OVERVIEW

The design basis for the generation evaluations is presented in Section 2, including site and coal characteristics and plant configurations. The performance, environmental, and cost data developed for this evaluation are the result of maintaining a consistent design basis throughout. Common design inputs for site, ambient, and fuel characteristics were used for each technology under consideration. Power plant configurations were identified to fit the expected load demand for the years 2005 to 2010.

Section 3 provides a technical description and costs for the market-based pulverized coal power plants including subcritical, supercritical, and ultra-supercritical. Cost improvements in PC plants experienced since the implementation of NSPS Subpart Da (Electric Utility Steam Generating Units for which Construction Commenced after September 18, 1978) are defined for key equipment areas.

First-of-a-kind (FOAK) configuration, performance, and costs for IGCC are presented in Section 4. As this technology is in its demonstration phase of commercial development, cost and performance data were defined on the basis of existing data modified to determine expectations for early commercial offerings.

Three advanced IGCC concepts, which are expected to mature through CCT demonstration and commercial application through the year 2020, are also presented in Section 4. Hot gas cleanup systems, including particulate removal and desulfurization, for IGCC have been reviewed for sensitivity to capital cost, operating cost, and cost of electricity against operating parameters. These data, together with other key components such as the advanced gas turbine, are defined as to baseline plant design and cost figures.

A third advanced coal-based power plant concept using CPFBC technology is presented in Section 5. Initial generations of the CPFBC technology have undergone demonstration in the CCT program. Advanced generations are expected to mature through an existing CCT demonstration program with Lakeland Electric & Water that was initiated in 1998 and subsequent commercial applications through the year 2020.

Section 6 provides a technical description and costs for two market-based NGCC power plants. This technology is presented as a benchmark upon which decision-makers base comparisons between natural gas and solid fuel systems.

One of the technology advancements taking place in the power generation industry is in the area of process and equipment control. Its impact is resulting in significant capital cost reductions, improved performance and reliability. A discussion on the advancement in instrumentation and controls is presented in Section 7.

Issues including licensing and environmental overview; air quality, water resources, and solid waste considerations; and potential regulatory impacts are addressed in an overview format in Section 8. A regulatory timeline is provided to demonstrate the relationship between coal-based power generation performance and cost, and emission requirements.

Capital cost and economic comparisons are provided for all generation technologies in Section 9. Market-based economics are established on the basis of project financing and return on investment criteria.

Appendices A and B provide an overview of data collected to establish the cost and performance improvements for supercritical PC and atmospheric fluidized-bed combustion power plants, respectively. Appendix C provides a similar review for the NGCC power plant. Appendix D contains information on the reliability and availability of market-based power plants versus conventional regulated utility power plants. Appendix E includes supporting cost data for each power plant described in this report.

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2. GENERAL EVALUATION BASIS

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. Power plant configurations were identified to fit the expected load demand for the years 2000 to 2010.

2.1 SITE AND COAL CHARACTERISTICS

The plant designs utilize a common generic site with conditions typical to a south central United States location. Table 2-1 lists the ambient characteristics of this site.

Table 2-1
SITE CHARACTERISTICS

Topography	Level
Elevation	500 feet
Design Air Pressure	14.4 psia
Design Temperature, Dry Bulb	63°F
Design Temperature, Wet Bulb	54°F
Relative Humidity	55%
Transportation	Rail access
Water	Municipal
Ash Disposal	Off site

The site consists 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 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.

The coal-based plants utilize Illinois No. 6 coal, delivered by unit train. Limestone is delivered by car loads, which are individually handled. The coal specification in Table 2-2 is based on the

Illinois No. 6 Seam from Old Ben No. 26 Mine. Table 2-3 presents the limestone analysis for the Greer limestone used as the basis in all technologies that utilize limestone.

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
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

2.2 GENERATING UNIT CONFIGURATIONS

Generating duty cycles for the subcritical PC, supercritical, ultra-supercritical PC, IGCC, CPFBC, and gas turbine plants are a result of the plants having been evaluated for baseload operation. The PC subcritical, supercritical, and ultra-supercritical plants are classified as baseload plants, primarily because the cycle is best suited operationally for this dispatch mode. IGCC plants are characterized as having higher than average capital costs, low fuel costs, high efficiency, and relatively long construction lead time. Because of the baseload classification, IGCC duty cycles are projected to be nominally 65 to 85 percent. The CPFBC plants are also characterized as having higher than average capital costs, low fuel costs, high efficiency, and relatively long construction lead times. The CPFBC duty cycles are projected to be nominally 65 to 85 percent. The gas turbine could be classified as either a baseload or a peaking unit, having low capital and good turndown capability.

The configurations for the PC plants were based on current operating plants. The configurations were established based on consideration given to process flows, costs, construction requirements, rail access, and roadways. The steam conditions selected for the state-of-the-art PC plant were 2400 psig/1000°F/1000°F for the subcritical, 3500 psig/1050°F/1050°F for the supercritical, and 4500 psig/1100°F/1100°F/1100°F for the ultra-supercritical cycle.

The configurations for the IGCC power plants were derived from the CCT plants nearing the demonstration phase. The configurations utilize the gasifiers and gas turbines, which are expected to be commercially offered in the period of 2000 to 2010, thereby minimizing both actual and perceived risk associated with the project. The economic viability of IGCC plants is dependent upon the successful demonstration and commercialization of advanced technology attributes currently under development.

Accordingly, the IGCC plant configurations described in this report utilize advanced gas cleanup concepts. Table 2-4 lists the featured components of the IGCC plant configurations as well as those of the state-of-the-art pulverized coal plants, CPFBC plant, and the NGCC plants.

Table 2-4
GENERATING PLANT CONFIGURATIONS

	IGCC FOAK	**IGCC Intermediate**	**IGCC Advanced #1**	**IGCC Advanced #2**	**PC Plant Subcritical**	**PC Plant Supercritical**	**PC Plant Ultra-Supercritical**	**CPFBC**	**NGCC #1**	**NGCC #2**
Year Available to Build	2001	2005	2010	2010	1998	2000	2010	2005	1998	2005
Net Electric Output, MWe	543	349	398	428	397	402	399	380	326	395
Heat Rate, Btu/kWh	8,522	7,514	6,870	6969	9,077	8,568	8,251	7,269	6,743	6,396
Coal Flow Rate, lb/h	396,794	224,910	234,442	255,510	309,270	295,100	282,675	236,260		
Natural Gas Flow Rate, lb/h									100,700	115,700
Gasifier	Destec O_2-blown	Destec O_2-blown	MW Kellogg air-blown transport	Destec O_2-blown						
Gas Turbine	GE MS 7001FA	Westinghouse W501G	GE "H" ATS	GE "H" ATS				Westinghouse W501G	Westinghouse W501G	GE "H" ATS
Gas Cleanup, Particulates	Ceramic candle	Ceramic candle	Ceramic candle	Ceramic candle	ESP	Fabric filter	Fabric filter	Ceramic candle		
Gas Cleanup, Desulfurization	COS Hydrolysis	Transport reactor with Zn sorbent	Transport reactor with Zn sorbent	Transport reactor with Zn sorbent	Wet limestone FGD	Wet limestone FGD	Wet limestone FGD	Limestone injection		
Sulfur Recovery	Sulfuric acid	Sulfuric acid	Sulfuric acid	Sulfuric acid	Gypsum landfill	Gypsum landfill	Gypsum landfill	Landfill		
Gas Cleanup, NOx	Combustion	Combustion	Combustion	Combustion	Combustion	Combustion and SCR	Combustion and SNCR	Combustion	Combustion	Combustion

The first-of-a-kind IGCC plant presented herein is based on the Dynegy Power Corporation (referred to as "Destec" in this report) oxygen-blown gasifier configuration demonstrated at Wabash River, with the addition of gas cleanup utilizing a ceramic candle filter for particulate removal and an amine-based acid gas process for sulfur removal. The gasifier supplies medium-Btu gas to two GE M57001FA gas turbines, which exhaust through a heat recovery steam generator (HRSG) to generate steam for an 1800 psi/1000°F/1000°F steam cycle. Total net plant output for this case is a nominal 550 MWe.

The intermediate IGCC plant presented in this report is based on an advanced version of the Destec oxygen-blown gasifier, offering higher coal-to-gas conversion ratios than the first-of-a-kind unit. For this configuration, a transport reactor is used for desulfurization of the syngas. A ceramic candle filter is retained for particulate removal. The intermediate IGCC gasifier supplies medium-Btu gas to a Westinghouse 501G gas turbine, exhausting through a HRSG to provide steam for a 1800 psig/1000°F/1000°F steam cycle. Total net plant output is a nominal 350 MWe for this case.

Advanced IGCC plant No. 1 described in this report is based on the air-blown transport reactor concept under development by M.W. Kellogg Co. A transport reactor desulfurizer and ceramic candle filter are used for sulfur and particulate removal, respectively. This gasifier case is based on a conceptual model of the General Electric "H" gas turbine, which incorporates ATS technology. The exhaust gas passes through a HRSG generating steam for an 1800 psig/1000°F/1000°F steam cycle to generate a total net plant output of 400 MWe, nominal.

Advanced IGCC plant No. 2 described in this report is based on an advanced version of the Destec oxygen-blown gasifier, offering higher coal-to-gas conversion ratios than the first-of-a-kind unit. For this configuration, a transport reactor is used for desulfurization of the syngas. A ceramic candle filter is retained for particulate removal. The intermediate IGCC gasifier supplies medium-Btu gas to a conceptual model of the General Electric "H" gas turbine, which incorporates ATS technology. The exhaust gas passes through a HRSG generating steam for an 1800 psig/1000°F/ 1000°F steam cycle to generate a total net plant output of 500 MWe, nominal.

The configuration for the CPFBC power plant is derived from the plant nearing the demonstration phase. This configuration utilizes a carbonizer and gas turbine that are expected to be commercially offered in the period of 2000 to 2010, thereby minimizing both actual and perceived risk associated with the project. The CPFBC plant configuration described in this report utilizes advanced gas cleanup concepts.

The CPFBC generating unit is sized to be in a greenfield mode of design. The CPFBC plant is sized for a nominal 400 MW utilizing a modified Westinghouse Type 501G gas turbine. The exhaust gas from the turbine operating in a combined cycle mode goes through a HRSG, which is a drum-type, double-pressure design. Also used to generate steam is the fluidized-bed heat exchanger (FBHE). The two steam generators are matched to generate steam at 2400 psig/1050°F/1050°F, which is used in the steam turbine. The steam turbine chosen for this application contains three pressure sections.

Two NGCC configurations are presented. The first configuration is based on commercially operating systems. The gas turbine chosen for this case is the commercially available Westinghouse 501G. The exhaust gases from the gas turbine enter the HRSG, which is a triple-pressure design. The steam turbine associated with the NGCC is a triple-admission turbine with inlet steam conditions of 1650 psig/1000°F, 375 psig/1000°F, and 57 psig/585°F.

The second configuration is based on the selection of a gas turbine represented by the General Electric "H" machine. The exhaust gas from the gas turbine enters the HRSG, which is a triple-pressure design. The steam turbine associated with this NGCC is a triple-admission turbine with inlet conditions of 1800 psig/1050°F, 395 psig/1050°F, and 66 psig/630°F.

Section 3.1

Pulverized Coal-Fired Subcritical Plant
400 MWe

3. PULVERIZED COAL

The market-based pulverized coal power plant design is based on the utilization of pulverized coal feeding a conventional steam boiler and steam turbine. The plant configuration is based on current state-of-the-art technology, commercially available components, and current industry trends. The traditional pulverized coal power plant of the 1970s and 1980s contained reliable equipment with built-in redundancy and several levels of safeguards against unplanned downtime. During the 1980s, the level of redundancy and the design margins were decreased in an effort to reduce cost, yet maintain availabilities in the 82 to 86 percent range. During the 1990s, construction schedules were shortened, design time was decreased by use of "reference plants," and equipment design margins were reduced, all in an effort to enhance the pulverized coal power plant's competitive position. "Reference plants," or modular plant designs, are standard packaged component designs developed by the design firms to enable owners to pick and choose the plant configuration from these pre-designed modules with minimal engineering time.

This section provides technical descriptions and costs for market-based pulverized coal power plants representing state-of-the-art technology, including subcritical, supercritical, and ultra-supercritical operation. A nominal capacity of 400 MWe was used as the basis for design in a typical greenfield application. The subcritical design uses a 2400 psig/1000°F/1000°F single reheat steam power cycle. The steam generator is a natural circulation, wall-fired, subcritical unit arranged with a water-cooled dry-bottom furnace, superheater, reheater, economizer, and air heater components. There are three rows of six burners per each of two walls. All burners are low-NOx type; in addition, overfire air is used to reduce the formation of NOx in the combustion zone.

The supercritical design is based on a 3500 psig/1050°F/1050°F single reheat configuration. This supercritical pulverized coal-fired plant is designed for compliance with national clean air standards anticipated to be in effect in the year 2005.

The ultra-supercritical design is based on a 4500 psig/1100°F/1100°F/1100°F double reheat configuration. This ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the year 2010.

3.1 PULVERIZED COAL-FIRED SUBCRITICAL PLANT - 400 MWe

3.1.1 Design Basis

The design basis of this pulverized coal plant is a nominal 400 MWe subcritical cycle. Support facilities are all encompassing, including rail spur (within the plant fence line), coal handling, (including receiving, crushing, storing, and drying), limestone handling (including receiving, crushing, storing, and feeding), solid waste disposal, flue gas desulfurization, wastewater treatment and equipment necessary for an efficient, available, and completely operable facility. The plant is designed using components suitable for a 30-year life, with provision for periodic maintenance and replacement of critical parts. The plant design and cost estimate are based on equipment manufactured in industrialized nations (United States, Germany, England, etc.) with the standard manufacturer's warranties. The design is based on a referenced design approach to engineering and construction. All equipment is designed and procured in accordance with the latest applicable codes and standards. ASME, ANSI, IEEE, NFPA, CAA, state regulations, and OSHA codes are all adhered to in the design.

3.1.2 Heat and Mass Balance

The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 3.1-1). The diagram shows state points at each of the major components for the conventional plant. Overall performance is summarized in Table 3.1-1, which includes auxiliary power requirements.

The plant uses a 2400 psig/1000°F/1000°F single reheat steam power cycle. The high-pressure (HP) turbine uses 2,734,000 lb/h steam at 2415 psia and 1000°F. The cold reheat flow is 2,425,653 lb/h of steam at 604 psia and 635°F, which is reheated to 1000°F before entering the intermediate-pressure (IP) turbine section.

NOTES:

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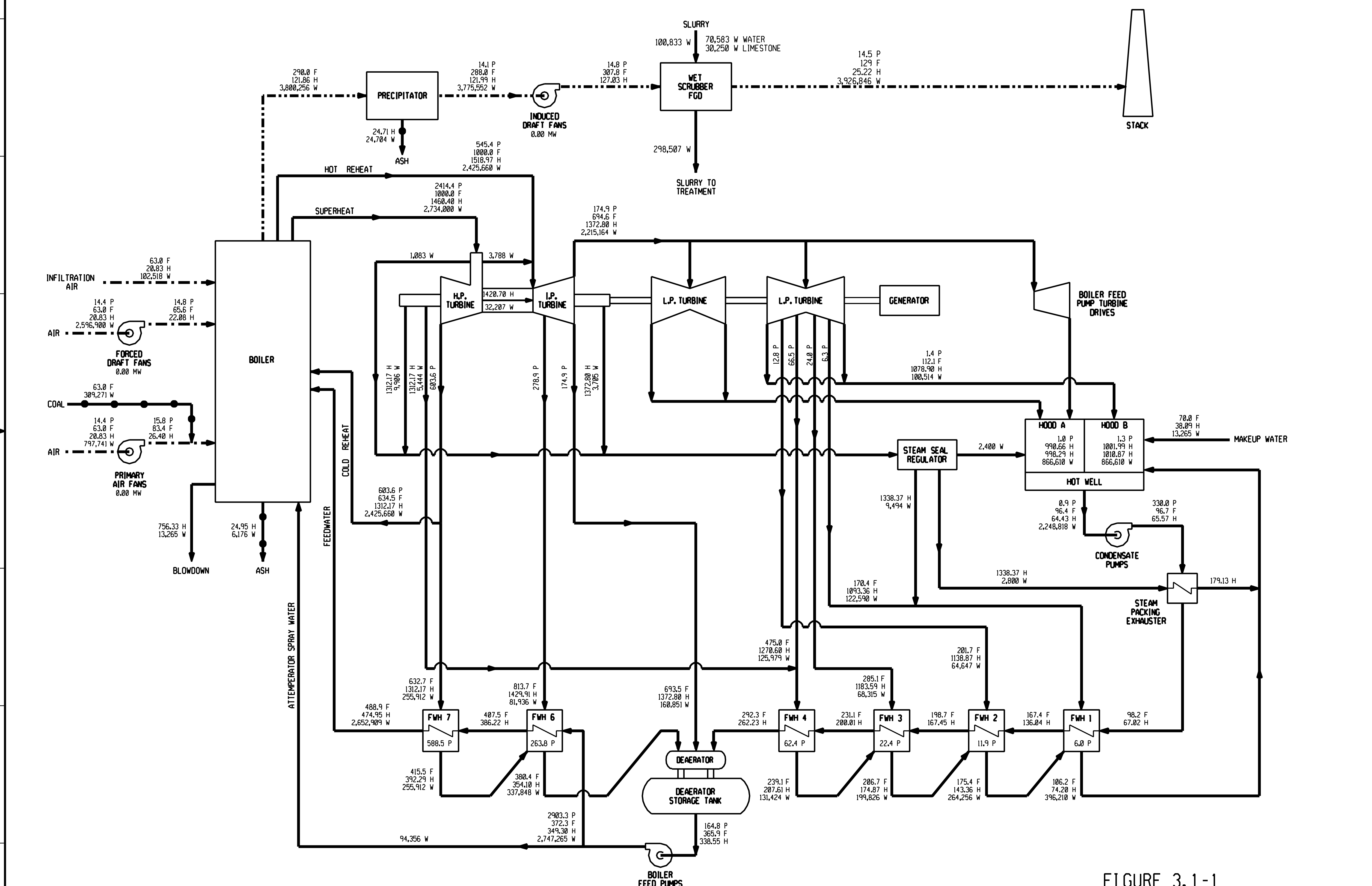

FIGURE 3.1-1

LEGEND

(solid line)	CONDENSATE, FEEDWATER, OR STEAM
(line with dots)	COAL OR ASH
(dash-dot line)	AIR
(dash-dot-dot line)	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	429.586	MWe
GENERATOR LOSS :	7.362	MWe
AUXILIARY POWER :	24.742	MWe
NET PLANT POWER :	397.482	MWe
NET PLANT EFFICIENCY :	37.6	%
NET PLANT HEAT RATE :	9,077	Btu/kwh

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REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | ENGINEER | LEAD DISCP ENGR | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING | DEFINITION | CONSTRUCTION STATUS

PRELIMINARY | REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

DRAWN BY: CLR DATE: 12/17/97

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 POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
PULVERIZED COAL SUBCRITICAL REF PLANT
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-001 REV A

PPGI-FILE:
PPGI-DATE:

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Table 3.1-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	422,224
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	200
Limestone Handling & Reagent Preparation	850
Pulverizers	1,730
Condensate Pumps	780
Main Feed Pump (Note 1)	8,660
Miscellaneous Balance of Plant (Note 2)	2,000
Primary Air Fans	1,000
Forced Draft Fans	1,000
Induced Draft Fans	4,302
Seal Air Blowers	50
Precipitators	1,100
FGD Pumps and Agitators	3,200
Steam Turbine Auxiliaries	700
Circulating Water Pumps	3,360
Cooling Tower Fans	1,900
Ash Handling	1,550
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	24,742
Net Power, kWe	397,482
Net Efficiency, % HHV	37.6
Net Heat Rate, Btu/kWh (HHV)	9,077
CONDENSER COOLING DUTY, 10^6 Btu/h	1,740
CONSUMABLES	
As-Received Coal Feed, lb/h	309,270
Sorbent, lb/h	30,250

Note 1 - Driven by auxiliary steam turbine; electric equivalent not included in total.
Note 2 - Includes plant control systems, lighting, HVAC, etc.

Tandem HP, IP, and low-pressure (LP) turbines drive one 3600 rpm hydrogen-cooled generator. The LP turbines consist of two condensing turbine sections. They employ a dual-pressure condenser operating at 2.0 and 2.4 inches Hg at the nominal 100 percent load design point at an ambient wet bulb temperature of 52°F. For the LP turbines, the last-stage bucket length is 30.0 inches, the pitch diameter is 85.0, and the annulus area per end is 55.6 square feet.

The feedwater train consists of six closed feedwater heaters (four LP and two HP), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from all of the turbine cylinders.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 397 MWe. The overall plant efficiency is 37.6 percent.

The major features of this plant include the following:

- Boiler feed pumps are steam turbine driven.
- Turbine configuration is a 3600 rpm tandem compound, four-flow exhaust.
- Plant has six stages of closed feedwater heaters plus a deaerator.

3.1.3 Emissions Performance

The plant pollution emission requirements under New Source Performance Standards (NSPS), prior to the Clean Air Act Amendments (CAAA) of 1990, are as shown in Table 3.1-2.

Table 3.1-2
PLANT POLLUTION EMISSION REQUIREMENTS

SOx	90 percent removal
NOx	0.6 lb/10^6 Btu
Particulates	0.03 lb/10^6 Btu
Visibility	20 percent opacity

The 1990 CAAA imposed a two-phase capping of SO_2 emissions on a nationwide basis. For a new greenfield plant, the reduction of SO_2 emissions that would be required depends on possessions or availability of SO_2 allowances by the utility, and on local site conditions. In many cases, Prevention of Significant Deterioration (PSD) Regulations will apply, requiring that Best Available Control Technology (BACT) be used. BACT is applied separately for each site, and results in different values for varying sites. In general, the emission limits set by BACT will be significantly lower than NSPS limits. The ranges specified in Table 3.1-3 will cover most cases.

Table 3.1-3
EMISSION LIMITS SET BY BACT

SOx	92 to 95 percent removal
NOx	0.2 to 0.45 lb/10^6 Btu
Particulates	0.015 to 0.03 lb/10^6 Btu
Visibility	10 to 20 percent opacity

For this study, plant emissions are capped at values shown in Table 3.1-4.

Table 3.1-4
PULVERIZED COAL-FIRED BOILER REFERENCE PLANT EMISSIONS

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.34	3,534	4,621	3.13
NOx	0.45	4,622	6,045	4.09
Particulates	0.03	305	400	0.272
CO_2	203.1	2,086,106	2,727,985	1,846

BACT is not applied to the plant described in this report. This report is a base, reference plant design; therefore, the emission limits are set at the industry standard.

3.1.4 Steam Generator and Ancilliaries

The steam generator is a market-based subcritical PC-fired unit plant that 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 to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

3.1.4.1 Scope and General Arrangement

The steam generator is comprised of the following:

- Once-through type boiler
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater
- Startup circuit, including integral separators
- Fin-tube economizer
- Coal feeders and bowl mills (pulverizers)
- Coal and oil burners
- Air preheaters (Ljungstrom type)
- Spray type desuperheater
- Soot blower system
- Forced draft (FD) fans
- Primary air (PA) fans

The steam generator operates as follows:

Feedwater and Steam

The 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 enroute to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

Air and Combusting Products

Air from the FD fans is heated in the Ljungstrum 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 PA fans. This air is heated in the Ljungstrum type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA 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 steam generator at this point and flow to the precipitator, ID fan, FGD system, and stack.

Fuel Feed

The crushed coal is fed through pairs (three 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.

Ash Removal

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. The description of the balance of the bottom ash handling system is presented in Section 3.1.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in three 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.

Air Preheaters

Each steam generator is furnished with two vertical inverted Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

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.

3.1.5 Steam Turbine Generator and Auxiliaries

The turbine is tandem compound type, comprised of HP - IP - two LP (double flow) sections, and 30-inch last-stage buckets. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. The turbine is designed for 434,500 kW at generator terminals. The throttle pressure at the design point is 2400 psig at a throttle flow of 2,734,000 lb/h. The exhaust pressure is 2.0/2.4 inch Hg in the dual pressure condenser. There are seven extraction points.

The condenser is two shell, transverse, dual pressure with divided waterbox for each shell.

3.1.6 Coal Handling System

The function of the balance-of-plant 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 and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3), which 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. The coal is then transferred by conveyor (No. 4) to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 309,000 lb/h = 155 tph plus 10% margin = 170 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 262,000 lb/h = 130 tph (based on MCR rate multiplied by an 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Three (3) unit trains per week at maximum burn rate
  - Two (2) unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 11 cars/hour (maximum)
  - Total unloading time per unit train = 10 hours (minimum)
  - Conveying rate to storage piles = 900 tph
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 11,500 tons (72 hours at maximum burn rate)
  - Dead storage = 89,000 tons (30 days at average burn rate)

3.1.7 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.

Operation Description

For the purposes of this conceptual design, limestone will be 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 a mill slurry tank. Mill recycle pumps, two per 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.

Technical Requirements and Design Basis

- Limestone usage rate:
  - Maximum limestone usage rate = 30,250 lb/h = 15.15 tph plus 10% margin = 16.6 tph (based on operating at MCR; 155 tph firing rate for design coal and 80% $CaCO_3$ in the limestone)
  - Average limestone usage rate = 25,700 lb/h = 13 tph (based on maximum limestone usage rate multiplied by 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 16
- Total unloading time per day = 4 hours
- Total time, interval per truck = 15 minutes/truck

- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 12,000 tons (30 days supply at maximum burn rate)
- Storage pile size = 180 ft x 90 ft x 40 ft high
- Day bin storage = 300 tons (16-hour supply at maximum burn rate)
- Conveying rate to day bins = 150 tph
- Weigh feeder/limestone ball mill capacity, each = 17 tph (based on 24 hours per day of grinding operations)
- Mill slurry tank capacity = 10,000 gallons
- Mill recycle pump capacity = 600 gpm, each of two pumps, two per mill
- No. of hydroclones = 1 assembly, rated at 600 gpm
- Reagent storage tank capacity = 200,000 gallons, 1 tank
- Reagent distribution pump capacity = 300 gpm, each of two pumps

3.1.8 Emissions Control Systems

3.1.8.1 Flue Gas Desulfurization (FGD) System

The function of the FGD system is to scrub the boiler exhaust gases to remove 92 percent of the SO_2 content prior to release to the environment. The scope of the FGD system is from the outlet of the induced draft (ID) fans to the stack inlet. The system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

Operation Description

The flue gas exiting the air preheater section of the boiler passes through a pair of electrostatic precipitator units, then through the ID fans and into the 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. The FGD system for this reference plant is designed to continuously remove 92 percent of the SO_2.

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 sulfate, 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 recirculate 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.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the 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.

This FGD system is designed for “wet stack” operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature is not necessary.

<u>Technical Requirements and Design Basis</u>

- Number and type of absorber modules = One, 100% capacity, counter-current tower design, including quench, absorption and moisture separation zones, recirculated slurry inventory in lower portion of absorber vessel

- Slurry recirculation pumps = Four at 33% capacity each
- Slurry bleed pumps = Two at 100% capacity each
- Absorber tank agitator = Four each with 20 hp motor
- Oxidation air blowers = Two at 100% capacity each

3.1.8.2 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.

Operation Description

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.

3.1.8.3 Precipitator

The flue gas discharged from the boiler (air preheater) is directed through an electrostatic precipitator array comprised of two rigid frame single-stage units. Each precipitator unit is divided into five field sections, each in turn containing three cells. Each cell contains a number of gas passages comprised of discharge electrodes, collecting plates, and ash hoppers supported by a rigid steel casing. Each cell and ash hopper is provided with a rapping system, which periodically provides a mechanical shock to the unit to cause the fly ash particles to drop into the hopper, and then out into the collection piping. The precipitators are provided with necessary electrical power and control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

3.1.9 <u>Balance of Plant</u>

3.1.9.1 Condensate and Feedwater

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, variable speed electric motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with 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 downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP feedwater heaters 1 and 2 are 50 percent capacity, parallel flow and are located in the condenser neck. All remaining feedwater heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the HP feedwater heaters to the economizer. One turbine-driven boiler feed pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. The pump is provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank. The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbines.

3.1.9.2 Main, Reheat, and Extraction Steam Systems

<u>Main and Reheat Steam</u>

The function of the main steam system is to convey main steam from the boiler superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam at approximately 2400 psig/1000°F exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the boiler feed pump turbine during unit operation up to approximately 60 percent load.

Cold reheat steam at approximately 585 psig/635°F exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 530 psig/1000°F exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator
- From LP turbine extraction to heaters 1, 2, 3 and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.1.9.3 Circulating Water System

It is assumed that the plant is serviced by a river of capacity and quality for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, concrete, rectangular, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent circulating water pumps are provided. The circulating water system provides cooling water to the condenser and the auxiliary cooling water system.

The auxiliary cooling water system is a closed-loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

3.1.9.4 Ash Handling

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of 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 system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent guarantee point (15 days or more).

<u>Operation Description</u>

The fly ash collected in the precipitators 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. The clinker grinder is provided to break up any clinkers that may form. 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) is conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

Technical Requirements and Design Basis

- Bottom ash and fly ash rates:
  - Bottom ash generation rate, 6,000 lb/h = 3 tph
  - Fly ash generation rate, 24,000 lb/h = 12 tph
- Bottom ash:
  - Clinker grinder capacity = 5 tph
  - Conveying rate to ash pond = 5 tph
- Fly ash:
  - Collection rate = 12 tph
  - Conveying rate from precipitator and air heaters = 11.7 tph
  - Fly ash silo capacity = 900 tons (72-hour storage)
  - Wet unloader capacity = 30 tph

3.1.9.5 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (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. The stack has one 19.5-foot-diameter FRP stack liner.

3.1.9.6 Waste Treatment

An onsite water treatment facility will treat all runoff, cleaning wastes, blowdown, and backwash to within the U.S. Environmental Protection Agency (EPA) standards for suspended solids, oil and grease, pH, and miscellaneous metals. 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 0-1,000 lb/h 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.

3.1.10 Accessory Electric Plant

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

3.1.11 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.

3.1.12 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

3.1.13 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor No. 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 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer	450 tph	2
14	Conveyor No. 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	Vibratory	115 tph	2
3	Conveyor No. 1	30" belt	115 tph	1
5	Limestone Day Bin		350 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
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		17 tph	1
2	Weigh Feeder	Gravimetric	17 tph	1
3	Limestone Ball Mill	Rotary	17 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	600 gpm	1
7	Distribution Box	3-way		2
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 fab.	250,000 gal	1
2	Surface Condenser	Two shell, transverse tubes	2,250 x 10^6 lb/h 2.0/2.4 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,500 gpm @ 800 ft	2
5	LP Feedwater Heater 1A/1B	Horiz. U tube	1,124,409 lb/h	2
6	LP Feedwater Heater 2A/2B	Horiz. U tube	1,124,409 lb/h	2
7	LP Feedwater Heater 3	Horiz. U tube	2,248,818 lb/h	1
8	LP Feedwater Heater 4	Horiz. U tube	2,248,818 lb/h	1
9	Deaerator and Storage Tank	Horiz. spray type	2,248,818 lb/h	1
10	Boiler Feed Pump/ Turbine	Barrel type, multi-staged, centr.	6,190 gpm @ 7,200 ft	1
11	Startup Boiler Feed Pump	Barrel type, multi-staged, centr.	1,550 gpm @ 7,200 ft	1
12	HP Feedwater Heater 6	Horiz. U tube	2,652,909 lb/h	1
13	HP Feedwater Heater 7	Horiz. U tube	2,652,909 lb/h	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	200,000 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	Rotary screw	100 psig, 800 cfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 cfm	1
7	Service Water Pumps	S.S., double suction	100 ft, 7,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	50 ft, 700 gpm	2
10	Fire Service Booster Pump	Two-stage cent.	250 ft, 700 gpm	1
11	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
12	Riverwater Makeup Pumps	S.S., single suction	100 ft, 5,750 gpm	2
13	Filtered Water Pumps	S.S., single suction	200 ft, 220 gpm	2
14	Filtered Water Tank	vertical, cylindrical	15,000 gal	1
15	Makeup Demineralizer	Anion, cation, and mixed bed	100 gpm	2
16	Liquid Waste Treatment System	-	10 years, 25-hour storm	1
17	Condenste Demineralizer	-	1,600 gpm	1

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Boiler with Air Heater	Natural circ., wall-fired	550 MWe, 3,621,006 pph steam at 2660 psig/1000°F	1
2	Primary Air Fan	Axial	398,870 pph, 87,020 acfm, 39" WG, 650 hp	2
3	FD Fan	Cent.	1,298,450 pph, 283,260 acfm, 11" WG, 650 hp	2
4	ID Fan	Cent.	1,887,776 pph, 582,650 acfm, 33" WG, 4,100 hp	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Electrostatic Precipitator	Rigid frame, single stage	1,900,128 pph, 392,000 ft^2 plate area	2

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,165,300 acfm	1
2	Recirculation Pumps	Horizontal centrifugal	35,000 gpm	4
3	Bleed Pumps	Horizontal centrifugal	750 gpm	2
4	Oxidation Air Blowers	Centrifugal	6,500 scfm, 35 psia	2
5	Agitators	Side entering	25 hp motor	6

Byproduct Dewatering

Equipment No.	Description	Type	Design Condition	Qty.
6	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
7	Gypsum Stacking Area		42 acres	1
8	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
9	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
10	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

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	Reinf. concrete, one FRP flue	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	550 MW Turbine Generator	TC4F30	2400 psig, 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Shell & tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell & 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	Mech draft	222,000 gpm	1
2	Circ. Water Pumps	Vert. wet pit	111,000 gpm @ 95 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		5 tph	2
4	Pyrites Hopper (part of Pulverizer scope of supply included with Boiler)			6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank		38,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	1,500 gpm	1
8	Ash Seal Water Pumps	Vertical, wet pit	1,500 gpm	1

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Precipitator Hopper (part of Precipitator scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1,750 scfm	2
4	Fly Ash Silo	Reinf. concrete	860 tons	1
5	Slide Gate Valves			2
6	Unloader		100 tph	1
7	Telescoping Unloading Chute			1

3.1.14 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the 400 MW subcritical PC plant is shown in Table 3.1-5. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the other plants is that, unlike all of the other technologies, all of the power is generated from a single source, the steam turbine. As a result, the economy of scale influence is greatest for this plant.

Table 3.1-5

Client: DEPARTMENT OF ENERGY
Project: Market Based Advanced Coal Power Systems

Report Date: 14-Aug-98 07:54 AM

TOTAL PLANT COST SUMMARY

Case: Subcritical PC
Plant Size: 397.5 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,997	2,063	5,331	373		**$14,764**	1,181		3,189	**$19,134**	48
2	COAL & SORBENT PREP & FEED	8,789		2,748	192		**$11,729**	938		2,533	**$15,201**	38
3	FEEDWATER & MISC. BOP SYSTEMS	15,953		6,963	487		**$23,403**	1,872		6,002	**$31,276**	79
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	46,861		19,453	1,362		**$67,676**	5,414		7,309	**$80,400**	202
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,260		1,074	75		**$4,410**	353		476	**$5,239**	13
	SUBTOTAL 4	*50,122*		*20,528*	*1,437*		***$72,086***	*5,767*		*7,785*	***$85,639***	*215*
5	FLUE GAS CLEANUP	34,039		18,650	1,306		**$53,995**	4,320		5,831	**$64,146**	161
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,803	289	7,270	509		**$17,871**	1,430		2,992	**$22,293**	56
	SUBTOTAL 7	*9,803*	*289*	*7,270*	*509*		***$17,871***	*1,430*		*2,992*	***$22,293***	*56*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	30,684		5,055	354		**$36,093**	2,887		3,898	**$42,879**	108
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	11,740	358	6,439	451		**$18,988**	1,519		3,531	**$24,037**	60
	SUBTOTAL 8	*42,424*	*358*	*11,494*	*805*		***$55,081***	*4,406*		*7,429*	***$66,916***	*168*
9	COOLING WATER SYSTEM	7,623	3,966	7,208	505		**$19,301**	1,544		3,718	**$24,563**	62
10	ASH/SPENT SORBENT HANDLING SYS	6,025	80	11,018	771		**$17,893**	1,431		2,930	**$22,254**	56
11	ACCESSORY ELECTRIC PLANT	9,095	2,830	7,720	540		**$20,185**	1,615		3,574	**$25,373**	64
12	INSTRUMENTATION & CONTROL	6,037		5,006	350		**$11,393**	911		1,917	**$14,222**	36
13	IMPROVEMENTS TO SITE	1,871	1,076	3,747	262		**$6,957**	557		2,254	**$9,767**	25
14	BUILDINGS & STRUCTURES		15,586	18,701	1,309		**$35,597**	2,848		9,611	**$48,055**	121
	TOTAL COST	**$198,778**	**$26,247**	**$126,383**	**$8,847**		**$360,255**	**$28,820**		**$59,765**	**$448,840**	**1129**

Section 3.2

Pulverized Coal-Fired Supercritical Plant
400 MWe

3.2 PULVERIZED COAL-FIRED SUPERCRITICAL PLANT - 400 MWe

3.2.1 Introduction

This 400 MWe single unit (nominal) pulverized coal-fired electric generating station serves as a reference case for comparison with a series of Clean Coal Technology greenfield power generating stations. The principal design parameters characterizing this plant were established to be representative of a state-of-the-art facility, balancing economic and technical factors.

3.2.2 Heat and Mass Balance

Overall performance for the entire plant is summarized in Table 3.2-1, which includes auxiliary power requirements. The heat and mass balance is based on the use of Illinois No. 6 coal as fuel. The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram, Figure 3.2-1. The performance presented in this heat balance reflects current state-of-the art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities. The diagram shows state points at each of the major components for this conceptual design.

The steam cycle used for this case is based on a 3500 psig/1050°F/1050°F single reheat configuration. The HP turbine uses 2,699,000 lb/h steam at 3515 psia and 1050°F. The cold reheat flow is 2,176,000 lb/h of steam at 622 psia and 587°F, which is reheated to 1050°F before entering the IP turbine section.

The turbine generator is a single machine comprised of tandem HP, IP, and LP turbines driving one 3,600 rpm hydrogen-cooled generator. The turbine exhausts to a dual-pressure condenser operating at 1.5 and 2.0 inches Hga, low- and high-pressure shells, respectively, at the nominal 100 percent load design point. For the four-flow LP turbines, the last-stage bucket length is 30 inches, the pitch diameter is 85.0 inches, and the annulus area per end is 55.6 square feet.

Table 3.2-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	3,500
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	427,100
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	210
Limestone Handling & Reagent Preparation	810
Pulverizers	1,650
Condensate Pumps	520
Main Feed Pump (Note 1)	11,850
Miscellaneous Balance of Plant (Note 2)	2,050
Primary Air Fans	950
Forced Draft Fan	950
Induced Draft Fan	6,977
Baghouse	100
SCR	80
FGD Pumps and Agitators	2,950
Steam Turbine Auxiliaries	700
Circulating Water Pumps	3,090
Cooling Tower Fans	1,750
Ash Handling	1,480
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	25,277
Net Power, kWe	401,823
Net Efficiency, % HHV	39.9
Net Heat Rate, Btu/kWh (HHV)	8,568
CONDENSER COOLING DUTY, 10^6 Btu/h	1,584
CONSUMABLES	
As-Received Coal Feed, lb/h	295,100
Sorbent (Limestone)Feed, lb/h	30,060
Ammonia feed, lb/h	1,290

Note 1 - Driven by auxiliary steam turbine; electric equivalent not included in total.

Note 2 - Includes plant control systems, lighting, HVAC, etc.

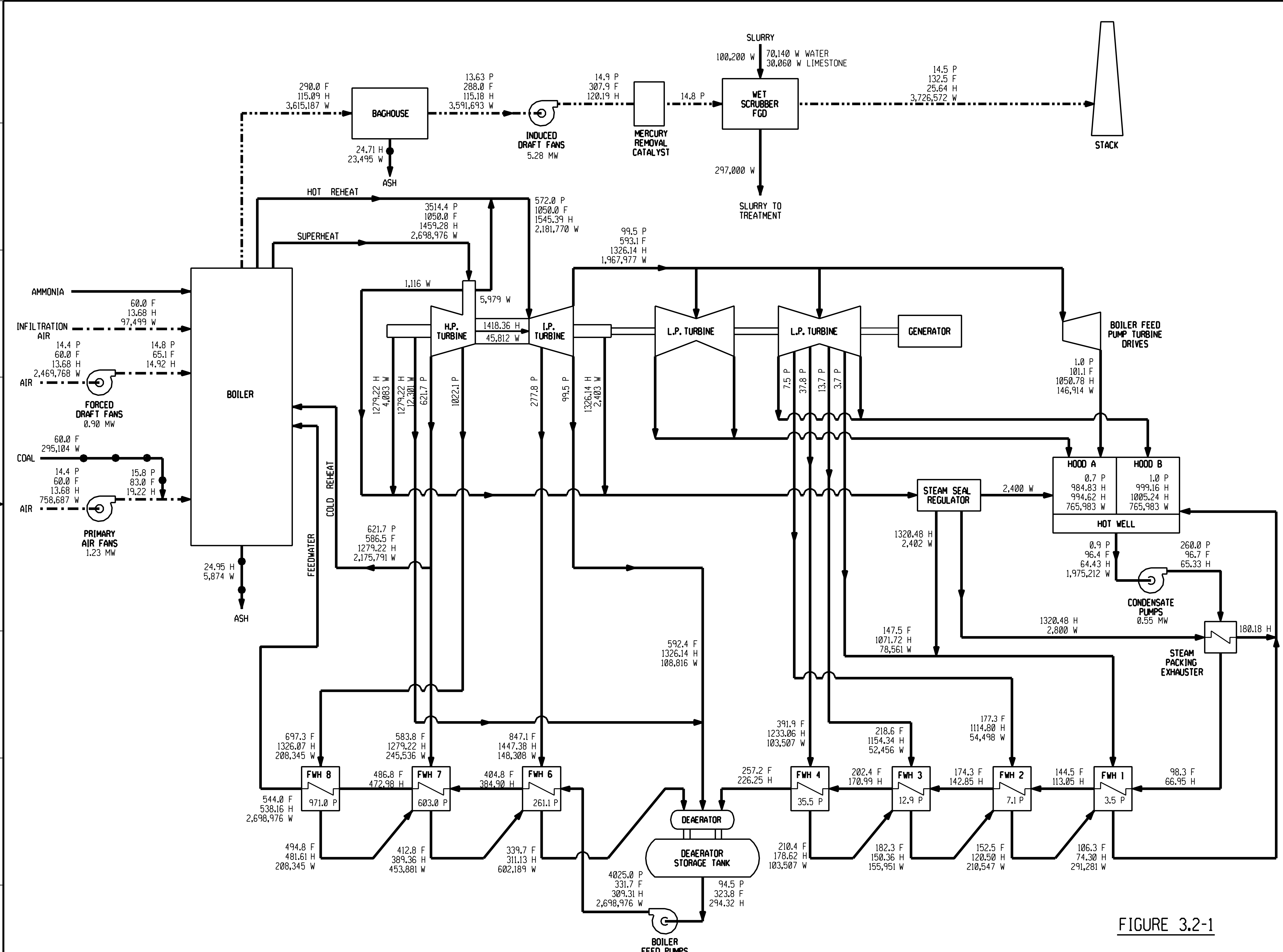

FIGURE 3.2-1

NOTES:

DD

LEGEND

solid line	CONDENSATE, FEEDWATER, OR STEAM
line with dots	COAL OR ASH
dash-dot line	AIR
dash-dot-dot line	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	434.5 MWe
GENERATOR LOSS :	7.4 MWe
AUXILIARY POWER :	25.28 MWe
NET PLANT POWER :	401.8 MWe
NET PLANT EFFICIENCY :	39.9 %
NET PLANT HEAT RATE :	8568 Btu/kwh

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | LEAD DESCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING | DEFINITION | CONSTRUCTION STATUS

PRELIMINARY | REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

DRAWN BY CLR 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 POWER GROUP INC.

READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE

CLEAN COAL TECHNOLOGY PROGRAM

PULVERIZED COAL SUPERCRITICIAL REF PLANT

DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE

100% RATED POWER

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-002

REV A

PPGI-FILE:

PPGI-DATE:

PC-SC01D / PCSC01DT

Hold for reverse side of Figure 3.2-1 (11x17)

The feedwater train consists of seven closed feedwater heaters (four low pressure and three high pressure), and one open feedwater heater (deaerator). Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the boiler inlet. Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 402 MWe. The overall net plant efficiency is 39.9 percent. An estimate of the auxiliary loads is presented in Table 3.2-1

3.2.3 Emissions Performance

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 the next century. A summary of the plant emissions is presented in Table 3.2-2.

Table 3.2-2
AIRBORNE EMISSIONS - SUPERCRITICAL PC WITH FGD

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	0.17	1,686	2,205	1.47
NOx	0.157	1,544	2,019	1.35
Particulates	0.01	97	127	0.08
CO_2	203.2	1,991,686	2,604,512	1,740

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 96 percent.

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 equal to those of other coal-burning facilities on an intensive basis (lb/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower than for a typical PC plant with this capacity due to the relatively high thermal efficiency.

3.2.4 <u>Steam Generators and Ancillaries</u>

The steam generator in this reference 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 to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

3.2.4.1 Scope and General Arrangement

The steam generator comprises the following:

- Once-through type boiler
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater
- Startup circuit, including integral separators
- Fin-tube economizer
- Coal feeders and bowl mills (pulverizers)
- Coal and oil burners

- Air preheaters (Ljungstrom type)
- Spray type desuperheater
- Soot-blower system
- Forced draft (FD) fans
- Primary air (PA) fans

The steam generator operates as follows:

Feedwater and Steam

The 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 enroute to the HP turbine. Returning cold reheat steam passes through the reheater and then returns to the IP turbine.

Air and Combusting Products

Air from the FD fans is heated in the Ljungstrum 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 PA fans. This air is heated in the Ljungstrum type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA 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 steam generator at this point and flow to the fabric filter, ID fan, FGD system, and stack.

Fuel Feed

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.

Ash Removal

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. The description of the balance of the bottom ash handling system is presented in Section 3.2.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet. The fly ash handling system is also presented in Section 3.2.9.

Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in three 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.

Air Preheaters

Each steam generator is furnished with two vertical inverted Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

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.

3.2.5 Turbine Generator and Auxiliaries

The turbine consists of an 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. 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 reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 557 psig/1050°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland leader pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

Operation Description

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.

3.2.6 Coal Handling System

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 system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

Operation Description

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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) 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. The coal is then transferred by conveyor No. 4 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.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 295,104 lb/h = 147 tph (based on 100% load); add a design margin of 5% to get a burn rate of 154 tph
  - Average coal burn rate = 250,000 lb/h = 125 tph (based on maximum coal burn rate multiplied by an 85% capacity factor), 131 tph with design margin
- Coal delivered to the plant by unit trains:
  - Two and one-half unit trains per week at maximum burn rate
  - Two unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 900 tph

  - Total unloading time per unit train = 13 hours
  - Conveying rate to storage piles = 900 tph
  - Reclaim rate = 450 tph

- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 12,000 tons (72 hours)
  - Dead storage = 270,000 tons (90 days)

3.2.7 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.

Operation Description

For the purposes of this conceptual design, limestone will be 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.

<u>Technical Requirements and Design Basis</u>

- Limestone usage rate:
  - Maximum limestone usage rate = 30,060 lb/h = 15 tph plus 10% margin = 16.5 tph (based on operating at MCR; 150 tph firing rate for design coal and 80% $CaCO_3$ in the limestone)
  - Average limestone usage rate = 25,600 lb/h = 12.7 tph (based on maximum limestone usage rate multiplied by 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 16
- Total unloading time per day = 4 hours
- Total time, interval per truck = 15 minutes/truck
- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 12,000 tons (30 days supply at maximum burn rate)
- Storage pile size = 180 ft x 90 ft x 40 ft high
- Day bin storage = 300 tons (16-hour supply at maximum burn rate.)
- Conveying rate to day bin = 115 tph
- Weigh feeder/limestone ball mill capacity = 17 tph (based on 24 hours per day of grinding operations)
- Mill slurry tank capacity = 10,000 gallons

- Mill recycle pump capacity = 600 gpm each of two pumps, two per mill
- No. of hydroclones = One assembly, rated at 600 gpm
- Reagent storage tank capacity = 200,000 gallons, 1 tank
- Reagent distribution pump capacity = 300 gpm, each of two pumps

3.2.8 Emissions Control Systems

3.2.8.1 Flue Gas Desulfurization (FGD) System

The function of the FGD system is to scrub the boiler exhaust gases to remove 96 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 system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

Operation Description

The flue gas exiting the air preheater section of the boiler passes through a fabric filter, then through the ID fans and into the 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. The FGD system for this plant is designed to continuously remove 96 percent of the SO_2.

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 sulfate, 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 recirculate 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.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the 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.

This FGD system is designed for "wet stack" operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature is not necessary.

<u>Technical Requirements and Design Basis</u>

- Number and type of absorber modules = One, 100% capacity, counter-current tower design, including quench, absorption and moisture separation zones, recirculated slurry inventory in lower portion of absorber vessel
- Slurry recirculation pumps = Four at 33% capacity each
- Slurry bleed pumps = Two at 100% capacity each
- Absorber tank agitators = Six each with 20 hp motor
- Oxidation air blowers = Two at 100% capacity each
- Formic acid system = One system at 100% capacity

- Stack = One reinforced concrete shell, 70-foot outside diameter at the base, 500 feet high with a fiberglass-reinforced plastic (FRP) chimney liner, 19 feet in diameter

3.2.8.2 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.

Operation Description

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.

3.2.8.3 NOx Control

The plant will be designed to achieve 0.158 lb/MMBtu (1.35 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. The 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 will be designed to remove 63 percent of the incoming NOx. This along with the low-NOx burners will achieve the emission limit of 0.158 lb/MMBtu.

Selective noncatalytic reduction (SNCR) was and could be considered for this application. However, with the installation of the low-NOx burners, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions of 0.157 lb/MMBtu difficult. SNCR works better in applications that contain medium to high quantities of NOx and removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

<u>Operation Description</u>

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 vessel. 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 consist 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 bypass as well as the SCR reactor bypass duct and dampers are also included.

Technical Requirements and Design Basis

- Process parameters:
  - Ammonia slippage — 5 mole %
  - Ammonia type — Aqueous (70% water)
  - Ammonia required — 1,290 lb/h
  - Dilution air — 16,000 lb/h
- Major components:
  - Reactor vessel

Quantity	Two
Type	Vertical flow
Catalyst quantity	Three layers with capacity for fourth
Catalyst type	Plate or honeycomb
Inlet damper	Louver
Outlet damper	Louver

  - Dilution air skid

Quantity	One
Capacity	4,000 scfm
Number of blowers	Two per skid (one operating and one spare)

  - Ammonia transport and storage

Quantity	One

Capacity	1,290 lb/h
Storage tank quantity	One
Storage tank capacity	32,000 gal

3.2.8.4 Particulate Removal

Particulate removal is achieved with the installation of a pulse jet fabric filter. The fabric filter will be designed to remove 99.9 percent of the particulates. This will achieve the emissions of 0.01 lb/MMBtu. The limit of the fabric filter is from the air preheater outlet to the ID fan inlets.

A fabric filter was chosen in anticipation of emission limits of particles less than 2.5 microns in diameter, called $PM_{2.5}$ particles. Although there is still debate, it appears that the fabric filters will be more effective in removing the $PM_{2.5}$ particles, as compared to the installation of an electrostatic precipitator. Also, fabric filters are currently being used successfully on coal-burning plants in the U.S., Europe, and other parts of the world.

<u>Operation Description</u>

The fabric filter chosen for this study is a pulse jet fabric filter. The boiler exhaust gas enters the inlet plenum of the fabric filter and is distributed among the modules. Gas enters each module through a vaned inlet near the bottom of the module above the ash hopper. The gas then turns upward and is uniformly distributed through the modules, depositing the fly ash on the exterior surface of the bags. Clean gas passes through the fabric and into the outlet duct through poppet dampers. From the outlet dampers the gas enters the ID fan.

Periodically each module is isolated from the gas flow, and the fabric is cleaned by a pulse of compressed air injected into each filter bag through a venturi nozzle. This cleaning dislodges the dust cake collected on the filter bag exterior. The dust falls into the ash hopper and is removed through the ash handling system.

<u>Technical Requirements and Design Basis</u>

- Flue gas flow 1,175,000 acfm

- Air-to-cloth ratio 4 acfm/ft^2
- Ash loading 23,600 lb/h
- Pressure drop 6 in. W.C.

3.2.8.5 Hazardous Air Pollutants (HAPs) Removal

The U.S. Environmental Protection Agency (EPA) has issued the "Interim Final Report" on HAPs. The report is based on on the findings of a study which estimated the emissions of HAPs from utilities. The study looked at 15 HAPs: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, hydrogen chloride, hydrogen fluoride, acrolein, dioxins, formaldehyde, n-nitrosodimethy-lamine, and radionuclides.

Analysis of the data obtained from coal fired plants shows that emissions from only two of the 426 plants studied pose a cancer risk greater than the study guidelines of 1 in 1 million. It appears that the HAPs emissions from coal fired plants are less than originally thought. Based on the interim report, extensive control of HAPs will not be required. However, due to the number of outstanding issues and the ever changing environment, it is difficult to predict the whether coal-fired utility boilers will be among those regulated with respect to HAPs.

Lower emissions of lead, nickel, chromium, cadmium, and some radionuclides, which are primarily particulate at typical air heater outlets, are achieved by the installation of high-efficiency particulate removal devices such as the fabric filter used in this study.

One HAP that has received a lot of attention over the last several years is mercury. Mercury has been found in fish and other aquatic life, and there is concern about the effects of mercury on the environment. Reducing mercury air emissions is complex, and several systems are being investigated to remove mercury, including:

- Activated carbon injection
- Injection of calcium based sorbents
- Pumice injection

- Injection of compounds prior to an FGD system to convert mercury to oxides of mercury
- Electrically induced oxidation of mercury to produce a mercury oxide that can be removed with particulate controls
- Introduction of a catalyst to promote the oxidation of elemental mercury and subsequent removal in an FGD system

Mercury controls are still being investigated and optimized and will require additional evaluation before optimal removal methods are established.

Mercury existing as oxidized mercury can be easily removed in a wet FGD system. Elemental mercury requires additional treatment for removal to occur. Unfortunately, coals contain various percentages of both elemental and oxidized mercury. The percentage of oxidized mercury in coal can range from 20 to 90 percent. DOE and EPA are still analyzing coals and do not have an extensive list available. Therefore, for this study it will be assumed that the coal will contain 50 percent oxidized mercury.

Since this plant will include a wet FGD system, a catalyst will be used to oxidize the elemental mercury. The catalyst bed will be installed between the fabric filter and the ID fans. The catalysts that show promise to oxidize mercury are iron- and carbon-based catalysts. One of these will be chosen as the catalyst for this application.

3.2.9 Balance of Plant

3.2.9.1 Condensate and Feedwater Systems

Condensate

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 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.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

Feedwater

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 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.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

3.2.9.2 Main, Reheat, and Extraction Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the turbine reheat stop valves.

Main steam at approximately 3650 psig/1050°F exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

Cold reheat steam at approximately 620 psig/587°F exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam at approximately 572 psig/1050°F exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine extraction to heater 8
- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6
- From LP turbine exhaust (cross-over) to the deaerator
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.2.9.3 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.

Each pump has a motor-operated discharge gate valve. A motor-operated cross-over gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled manually, but will automatically close when its respective pump is tripped.

3.2.9.4 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 system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

Operation Description

The fly ash collected in the fabric 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 fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. 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.

Technical Requirements and Design Basis

- Bottom ash and fly ash rates:
  - Bottom ash generation rate, 5,800 lb/h = 3 tph
  - Fly ash generation rate, 23,300 lb/h = 11.7 tph
- Bottom ash:
  - Clinker grinder capacity = 5 tph
  - Conveying rate to ash pond = 5 tph
- Fly ash:
  - Collection rate = 11.7 tph
  - Conveying rate from precipitator and air heaters = 11.7 tph
  - Fly ash silo capacity = 850 tons (72-hour storage)
  - Wet unloader capacity = 30 tph

3.2.9.5 Ducting and Stack

One stack is provided with a single 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. The stack has one 19.5-foot-diameter FRP stack liner.

3.2.9.6 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/h 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.

3.2.10 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.

3.2.11 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.

3.2.12 Buildings and Structures

A soil bearing load of 5000 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

3.2.13 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor No. 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 No. 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 No. 1	30" belt	115 tph	1
4	Conveyor No. 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	300 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
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		17 tph	1
2	Weigh Feeder	Gravimetric	17 tph	1
3	Limestone Ball Mill	Rotary	17 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 fab.	200,000 gal.	1
2	Surface Condenser	Two shell, transverse tubes	1.97×10^6 lb/h 1.4/2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2,500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,500 gpm/800 ft	2
5	LP Feedwater Heater 1A/1B	Horiz. U tube	987,600 lb/h 98.2°F to 144.5°F	2
6	LP Feedwater Heater 2A/2B	Horiz. U tube	987,600 lb/h 144.5°F to 174.3°F	2
7	LP Feedwater Heater 3	Horiz. U tube	1,975,200 lb/h 179.3°F to 202.4°F	1
8	LP Feedwater Heater 4	Horiz. U tube	1,975,200 lb/h 202.4°F to 257.2°F	1
9	Deaerator and Storage Tank	Horiz. spray type	1,975,200 lb/h 257.2°F to 294.3°F	1
10	Boiler Feed Pumps/ Turbines	Barrel type, multi-staged, centr.	6,000 gpm @ 9,900 ft	
11	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	1,500 gpm @ 9,900 ft	1
12	HP Feedwater Heater 6	Horiz. U tube	2,700,000 lb/h 331.7°F to 409.8°F	1
13	HP Feedwater Heater 7	Horiz. U tube	2,700,000 lb/h 409.89°F to 486.8°F	1
14	HP Feedwater Heater 8	Horiz. U. tube	2,700,000 lb/h 486.8°F to 544.0°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. 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	SS, double acting	100 psig, 800 scfm	3
6	Inst. Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	SS, double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & 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	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Riverwater Makeup Pumps	SS, single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	SS, 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	Condensate Demineralizer	Mixed bed	1,600 gpm	1

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater	Universal pressure, wall-fired	2,700,000 pph steam at 3650 psig/ 1050°F	1
2	Primary Air Fan	Axial	379,350 pph, 84,400 acfm, 39" WG, 600 hp	2
3	FD Fan	Cent.	1,235,000 pph, 275,000 acfm, 11" WG, 600 hp	2
4	ID Fan	Cent.	1,808,000 pph, 574,000 acfm, 49" WG 4,800 hp	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter	Pulse jet	3,615,200 lb/h, 290°F	1

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,106,000 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5,600 scfm	2
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

Byproduct Dewatering

Equipment No.	Description	Type	Design Condition	Qty.
6	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
7	Gypsum Stacking Area		42 acres	1
8	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
9	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
10	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

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	Reinf. concrete, two FRP flues	60 ft/sec exit velocity 480 ft high x 19 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	435 MW Turbine Generator	TC4F30	3500 psig, 1050°F/1050°F	1
2	Bearing Lube Oil Coolers	Shell & tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell & 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	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. wet pit	80,000 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		10 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	Fabric Filter Hoppers (part of FF 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	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

3.2.14 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the 400 MW supercritical PC plant is shown in Table 3.2-3. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the other plants is that, unlike all of the other technologies, all of the power is generated from a single source, the steam turbine. As a result, the economy of scale influence is greatest for this plant.

Table 3.2-3

Client: DEPARTMENT OF ENERGY **Report Date:** 14-Aug-98 08:20 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Supercritical PC
Plant Size: 401.8 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,782	2,004	5,174	362		**$14,321**	1,146		3,093	**$18,560**	46
2	COAL & SORBENT PREP & FEED	8,458		2,633	184		**$11,275**	902		2,435	**$14,613**	36
3	FEEDWATER & MISC. BOP SYSTEMS	16,550		7,175	502		**$24,227**	1,938		6,139	**$32,304**	80
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	60,723		23,331	1,633		**$85,688**	6,855		9,254	**$101,797**	253
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,163		1,042	73		**$4,278**	342		462	**$5,082**	13
	SUBTOTAL 4	*63,886*		*24,373*	*1,706*		***$89,966***	*7,197*		*9,716*	***$106,879***	*266*
5	FLUE GAS CLEANUP	33,591		18,834	1,168		**$53,593**	4,287		5,433	**$63,314**	158
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,491	280	7,038	493		**$17,302**	1,384		2,897	**$21,583**	54
	SUBTOTAL 7	*9,491*	*280*	*7,038*	*493*		***$17,302***	*1,384*		*2,897*	***$21,583***	*54*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	33,394		5,502	385		**$39,281**	3,143		4,242	**$46,666**	116
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	11,839	361	6,493	455		**$19,147**	1,532		3,561	**$24,240**	60
	SUBTOTAL 8	*45,234*	*361*	*11,995*	*840*		***$58,429***	*4,674*		*7,803*	***$70,906***	*176*
9	COOLING WATER SYSTEM	7,685	3,998	7,266	509		**$19,457**	1,557		3,748	**$24,761**	62
10	ASH/SPENT SORBENT HANDLING SYS	5,859	77	10,715	750		**$17,402**	1,392		2,849	**$21,643**	54
11	ACCESSORY ELECTRIC PLANT	9,175	2,859	7,797	546		**$20,376**	1,630		3,608	**$25,614**	64
12	INSTRUMENTATION & CONTROL	6,114		5,069	355		**$11,538**	923		1,941	**$14,401**	36
13	IMPROVEMENTS TO SITE	1,882	1,082	3,768	264		**$6,995**	560		2,266	**$9,821**	24
14	BUILDINGS & STRUCTURES		15,275	18,323	1,283		**$34,881**	2,790		9,418	**$47,090**	117
	TOTAL COST	**$214,705**	**$25,935**	**$130,160**	**$8,961**		**$379,761**	**$30,381**		**$61,347**	**$471,489**	**1173**

Section 3.3

Pulverized Coal-Fired Ultra-Supercritical Plant
400 MWe

3.3 PULVERIZED COAL-FIRED ULTRA-SUPERCRITICAL PLANT - 400 MWe

3.3.1 Introduction

This 400 MWe single unit (nominal) ultra-supercritical pulverized coal-fired electric generating station serves as a market-based reference design for comparison with a series of Clean Coal Technology greenfield power generating stations. The principal design parameters characterizing this plant were established to be representative of a state-of-the-art facility, balancing economic and technical factors.

3.3.2 Heat and Mass Balance

Overall performance for the entire plant is summarized in Table 3.3-1, which includes auxiliary power requirements. The heat and mass balance is based on the use of Illinois No. 6 coal as fuel. The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 3.3-1). The performance presented in this heat balance reflects current state-of-the-art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities. The diagram shows state points at each of the major components for this conceptual design.

The steam cycle used for this case is based on a 4500 psig/1100°F/1100°F/1100°F double reheat configuration. The very-high-pressure (VHP) turbine uses 2,554,000 lb/h steam at 4515 psia and 1100°F. The first cold reheat flow is 2,075,000 lb/h of steam at 1357 psia and 753°F, which is reheated to 1100°F before entering the HP turbine section. The second cold reheat flow is 1,737,178 lb/h of steam at 378 psia and 757°F, which is reheated to 1100°F before entering the IP turbine.

The turbine generator is a single machine comprised of tandem VHP, HP, IP, and LP turbines driving one 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga, at the nominal 100 percent load design point.

Table 3.3-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	4,500
Throttle Temperature, °F	1,100
First Reheat Outlet Temperature, °F	1,100
Second Reheat Outlet Temperature, °F	1,100
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	425,000
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	180
Limestone Handling & Reagent Preparation	790
Pulverizers	1,540
Condensate Pumps	780
Main Feed Pump (Note 1)	14,000
Booster Feed Pump	2,600
Miscellaneous Balance of Plant (Note 2)	2,050
Primary Air Fans	900
Forced Draft Fan	900
Induced Draft Fan	5,489
Baghouse	100
SNCR	80
FGD Pumps and Agitators	2,800
Steam Turbine Auxiliaries	650
Circulating Water Pumps	2,400
Cooling Tower Fans	1,650
Ash Handling	1,410
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	25,339
Net Power, kWe	399,661
Net Efficiency, % HHV	41.4
Net Heat Rate, Btu/kWh (HHV)	8,251
CONDENSER COOLING DUTY, 10^6 Btu/h	1,475
CONSUMABLES	
As-Received Coal Feed, lb/h	282,675
Sorbent (Limestone) Feed, lb/h	28,790
Ammonia Feed, lb/h	204

Note 1 - Driven by auxiliary steam turbine; electric equivalent not included in total.
Note 2 - Includes plant control systems, lighting, HVAC, etc.

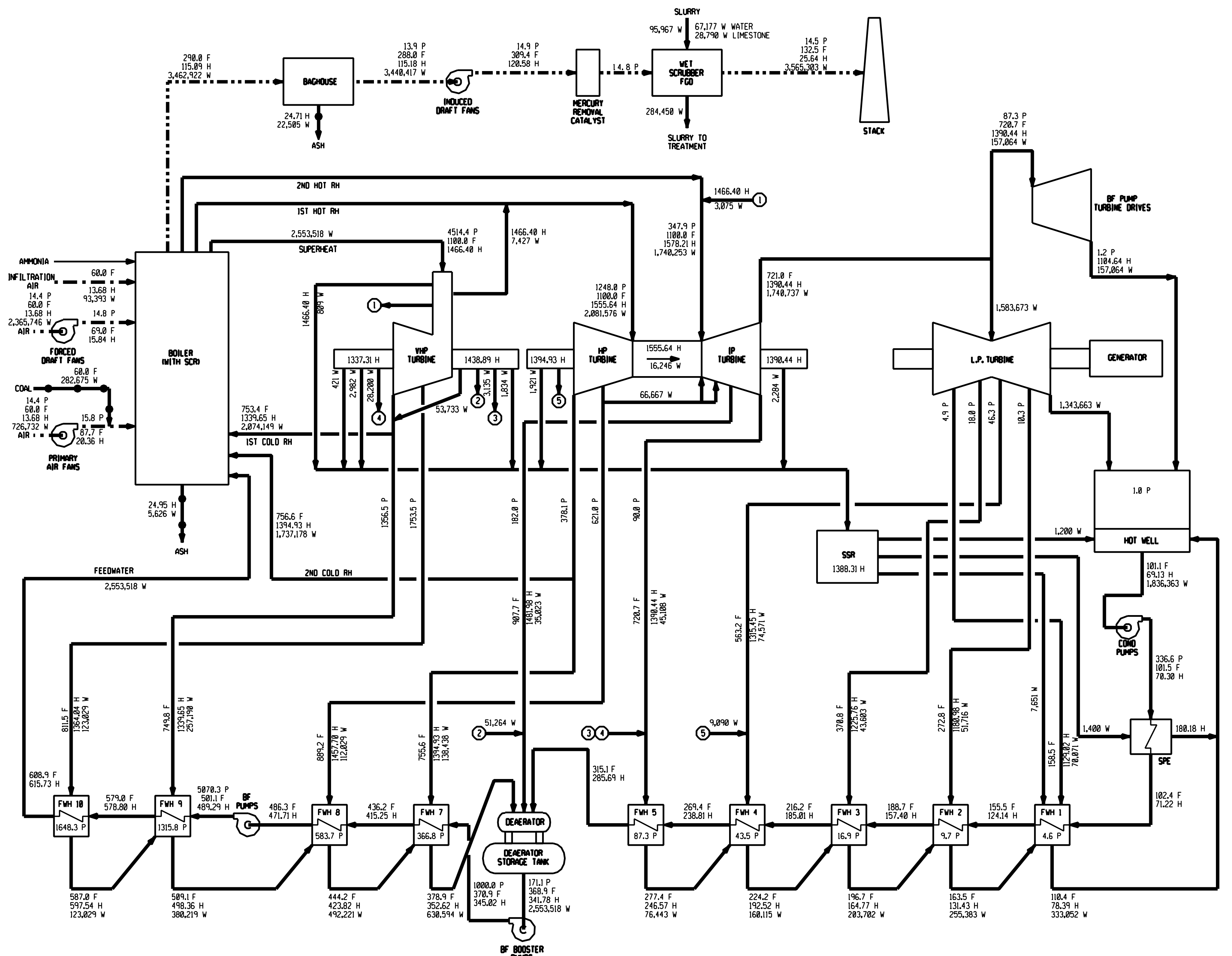

FIGURE 3.3-1

NOTES:

1. STEAM TURBINE PERFORMANCE BASED ON TC2F40 GE MACHINE.
2. STEAM CYCLE IS 4500/1100/1100/1100/2 IN HGA.
3. BF BOOSTER PUMPS ARE MOTOR DRIVEN.

LEGEND

(solid line)	CONDENSATE, FEEDWATER, OR STEAM
(line with dots)	COAL OR ASH
(dash-dot line)	AIR
(dash-dot-dot line)	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	432.4 MWe
GENERATOR LOSS :	7.4 MWe
AUXILIARY POWER :	25.3 MWe
NET PLANT POWER :	399.7 MWe
NET PLANT EFFICIENCY :	41.4 %
NET PLANT HEAT RATE :	8251 Btu/kwh

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | LEAD DISCP. ENGINEER | PROJ. ENGR. MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY: CLB

CHECKED BY / LEAD DESIGNER / ENGINEER / LEAD DISCIPLINE ENGR. — DATE

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGH PROGRAM
PULVERIZED COAL ULTRACRITICAL REF. PLANT
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER

SCALE: NONE

PARSON'S DWG. NO.: MBAC-1-400-314-003 — REV: A

PPGI-FILE: PC-UC03A / PCUC03AT
PPGI-DATE: 7/18/15/1997 11:02 7:37
P.M.WITMAN / J.S.WHITE

Reserved for reverse side of Figure 3.3-1 (11x17)

The feedwater train consists of nine closed feedwater heaters (five low-pressure and four high-pressure), and one open feedwater heater (deaerator). Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the boiler inlet. Extractions for feedwater heating, deaerating, and the boiler feed pump are taken from the HP, IP, and LP turbine cylinders, and from the cold reheat piping.

The net plant output power, after plant auxiliary power requirements are deducted, is 400 MWe. The overall net plant efficiency is 41.4 percent. An estimate of the auxiliary loads is presented in Table 3.3-1.

3.3.3 Emissions Performance

This ultra-supercritical pulverized coal-fired plant is designed for compliance with national clean air standards expected to be in effect in the year 2010. More stringent requirements that are applicable to non-attainment areas are not applied herein. A summary of the plant's emissions is presented in Table 3.3-2.

Table 3.3-2
AIRBORNE EMISSIONS - ULTRA-SUPERCRITICAL PC WITH FGD

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.17	1,615	2,112	1.42
NOx	0.16	1,526	1,996	1.35
Particulates	0.01	93	122	0.08
CO_2	203.2	1,907,827	2,494,851	1,679

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the wet limestone FGD system. The nominal overall design basis SO_2 removal rate is set at 96 percent.

The minimization of NOx production and subsequent emission are achieved by the zoning and staging of combustion in the low low-NOx burners and the overfire air staging employed in the design of this boiler. The technique of selective non-catalytic reduction (SNCR) will reduce NOx emissions further, and is applied to the subject plant in accordance with the projection of environmental restrictions required by the year 2010.

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

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower than for a typical PC plant with this capacity due to the relatively high thermal efficiency.

3.3.4 Steam Generators and Ancillaries

The steam generator in this reference market-based ultra-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 to be operated as a base-loaded unit for the majority of its life, with some weekly cycling the last few years. The following brief description is for reference purposes.

3.3.4.1 Scope and General Arrangement

The steam generator is comprised of the following:

- Once-through type boiler
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheaters (two stages)
- Startup circuit, including integral separators
- Fin-tube economizer
- Coal feeders and bowl mills (pulverizers)

- Coal and oil burners
- Air preheaters (Ljungstrom type)
- Spray type desuperheater
- Soot-blower system
- FD fans
- PA fans

The steam generator operates as follows:

Feedwater and Steam

The 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 enroute to the VHP turbine. Steam from the VHP turbine returns to the steam generator as first cold reheat and returns to the HP turbine as first hot reheat. Steam from the HP turbine returns to the steam generator as second cold reheat and returns to the IP turbine as second hot reheat.

Air and Combusting Products

Air from the FD fans is heated in the Ljungstrom 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 PA fans. This air is heated in the Ljungstrom type air preheaters and is used as combustion air to the pulverizers. A portion of the air from the PA 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 steam generator at this point and flow to the precipitator, ID fan, FGD system, and stack.

Fuel Feed

The crushed coal is fed through pairs (three 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.

Ash Removal

The furnace bottom is comprised of 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. The description of the balance of the bottom ash handling system is presented in Section 3.3.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

A boiler of this capacity will employ approximately 30 coal nozzles arranged in three elevations, divided between the front and rear walls of the furnace.

It is anticipated for this study that low-low-NOx burners will have been developed to reduce the NOx emissions exiting the boiler to 0.2 lb/MMBtu. The Low Emissions Boiler Systems (LEBS) program of DOE is currently involved in developing such burners. The burners operate on the principle of controlled separation of fuel and oxidant. Air is diverted away from the core of the flame, reducing local stoichometry during coal devolatization, and reducing initial NOx formation. The “internal staging” or delayed mixing of some of the combustion air with the fuel allows the released nitrogen volatiles to combine to form molecular nitrogen instead of NOx. In the reducing atmosphere produced by this internal staging, molecules of NOx that do form can be more readily reduced back to molecular nitrogen. In addition, at least one elevation of overfire air nozzles is provided to introduce additional air, which cools the rising combustion products and inhibits NOx formation.

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

Air Preheaters

Each steam generator is furnished with two vertical inverted Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

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.

3.3.5 Steam Turbine Generator and Auxiliaries

The turbine consists of a 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 4500 psig/1100°F. The steam initially enters the turbine near the middle of the VHP 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 1248 psig/1100°F. The second cold reheat leaves the HP section and returns to the boiler for reheating. The second reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 347 psig/1100°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop water-cooled pressured oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip, the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland leader pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters and deionizers, all skid-mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

Operation Description

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.

3.3.6 <u>Coal Handling System</u>

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 bottom trestle dumper and coal receiving hoppers up to the pulverizer fuel inlet.

<u>Operation Description</u>

The bituminous 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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0 in the first of two crushers. The coal then enters the second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three silos.

<u>Technical Requirements and Design Basis</u>

- Coal burn rate:
  - Maximum coal burn rate = 282,675 lb/h = 142 tph (based on 100% load); add a design margin of 5% to get a burn rate of 150 tph
  - Average coal burn rate = 240,000 lb/h = 120 tph (based on maximum coal burn rate multiplied by an 85% capacity factor)

- Coal delivered to the plant by unit trains
  - Two and one-half unit trains per week at maximum burn rate
  - Two unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 900 tph
  - Total unloading time per unit train = 13 hours
  - Conveying rate to storage piles = 900 tph
  - Reclaim rate = 430 tph
- Storage piles with liners, run-off collection, and treatment systems
  - Active storage = 11,000 tons (72 hours)
  - Dead storage = 112,000 tons (30 days)

3.3.7 Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and pulverize the limestone delivered to the plant, and mix it with water to form a slurry for feeding to the FGD system. The scope of the system is from the storage pile up to the FGD absorber module inlet. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation at the 100 percent guarantee point (30 days or more).

Operation Description

For the purposes of this reference conceptual design, limestone will be delivered to the plant by 25-ton trucks. Rail delivery is an alternative.

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 ball mill pulverizes the limestone to 90 to 95 percent passing 325 mesh (44 microns) and discharges the reduced material into a 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 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 modules.

<u>Technical Requirements and Design Basis</u>

- Limestone usage rate:
  - Maximum limestone usage rate = 282,790 lb/h = 14.4 tph plus 10% design margin = 15.8 tph (based on operating at 100% load, 142 tph firing rate for design coal and 80% $CaCO_3$ in the limestone)
  - Average limestone usage rate = 24,500 lb/h = 12.3 tph (based on maximum limestone usage rate multiplied by an 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 14
- Total unloading time per day = 4 hours
- Total time, interval per truck = 15 minutes/truck
- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 11,000 tons (30-day supply at maximum burn rate)

- Storage pile size = 180 ft x 90 ft x 40 ft high
- Day bin storage = 250 tons (16-hour supply at maximum burn rate)
- Conveying rate to day bins = 115 tph
- Weigh feeder/limestone ball mill capacity = 16 tph (based on 24-hour operation)
- Mill slurry tank capacity =10,000 gallons
- Mill recycle pump capacity = 600 gpm, each of four pumps, two per mill
- No. of hydroclones = one assembly, rated at 600 gpm
- Reagent storage tank capacity = 200,000 gallons, 1 tank (based on 24-hour storage)
- Reagent distribution pump capacity = 300 gpm, each of two pumps

3.3.8 Emissions Control Systems

3.3.8.1 Flue Gas Desulfurization (FGD) System

The function of the FGD system is to scrub the boiler exhaust gases to remove most 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 system is designed to support short-term operation (16 hours) and long-term operation at the 100 percent design point (30 days).

Operation Description

The flue gas exiting the air preheater section of the boiler passes through the fabric filter, then through the ID fans and into one 100 percent capacity absorber module. The module is designed to operate with counter-current flow of gas and reagent. Upon entering 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 typically consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating entrained droplets of liquid by inertial effects. The scrubbed and dried flue gas exits at the top of the absorber vessel and is then routed to the plant stack. The FGD system for this reference plant is designed to continuously remove 96 percent of the SO_2 with a high circulating liquid-to-gas ratio.

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. Multiple agitators operate continuously to prevent settling of solids. A blower forces air, taken from the atmosphere, through a sparger in the bottom of the vessel. This promotes oxidation of the calcium sulfite to calcium sulfate or gypsum. The gypsum is pumped to an onsite gypsum stacking operation as described in Section 3.3.8.2.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of spent reagent via the bleed pumps. The spent reagent is routed to the byproduct dewatering system, Section 3.3.8.2. The circulating reagent is continuously monitored, with pH and density the principal parameters of interest.

This FGD system is design for "wet stack" operation (i.e., no reheat or scrubber bypass is employed to raise exhaust gas temperature at the stack above saturation). This is acceptable since new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain, thereby reducing the potential for carryover and discharge of droplets.

<u>Technical Requirements and Design Basis</u>

- Number and type of absorber modules = One, 100% capacity, counter-current tower design, including quench, absorption and moisture separation zones, recirculated slurry inventory in lower portion of absorber vessel
- Slurry recirculation pumps = Four at 33% capacity each., 30,000 gpm each
- Slurry bleed pumps = Two at 100% capacity each, 600 gpm each
- Oxidation air blowers = Two at 50% capacity each, 5,000 cfm

- Absorber tank agitator = Six, each with 25 hp motor
- Formic acid system = One system at 100% capacity
- Stack = One reinforced concrete shell, 70-foot outside diameter at the base, 500 feet high with a fiberglass-reinforced plastic (FRP) chimney liner, 19 feet in diameter

3.3.8.2 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber module. The dewatering process selected for this reference 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 full-load operation on a 20-year life cycle.

Operation Description

The recirculating reagent in the FGD absorber vessels accumulates dissolved and suspended solids on a continuous basis, as byproducts from the SO_2 absorption reactions proceed. Maintenance of the recirculating reagent requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis, except for periodic intervals when the spent reagent density may be below predefined limits.

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.

3.3.8.3 NOx Control

The plant will be designed to achieve 0.163 lb/MMBtu (1.35 lb/MWh) NOx emissions. Two measures are taken to reduce the NOx. The first is a combination of low-low-NO_X burners and the introduction of staged overfire air in the boiler. The low-low-NOx burners and overfire air reduce the emissions by 83 percent as compared to a boiler installed without low-NOx burners. The low-low-NOx burners are described in Section 3.3.4.

The second measure taken to reduce the NOx emissions is the installation of an SNCR system prior to the air heater. SNCR uses ammonia injection to reduce NOx to N_2 and H_2O. The SNCR system consists of ammonia storage and injection. The SCR system will be designed to remove 20 percent of the incoming NOx. This, along with the low-NOx burners, will achieve the emission limit of 0.163 lb/MMBtu.

<u>Technical Requirements and Design Basis</u>

- Process parameters:
  - Ammonia slippage — 5 mole %
  - Ammonia type — Aqueous (70% water)
  - Ammonia required — 203 lb/h
  - Dilution air — 2,810 lb/h
- Major components:
  - Dilution air skid:

Quantity	One
Capacity	600 scfm
Number of blowers	Two per skid (one operating and one spare)

  - Ammonia transport and storage:

Quantity	One
Capacity	203 lb/h

Storage tank quantity	One
Storage tank capacity	6,000 gal

3.3.8.4 Particulate Removal

Particulate removal is achieved with the installation of a fabric filter. The fabric filter will be designed to remove 99.9 percent of the particulates. This will achieve the emissions of 0.01 lb/MMBtu. The limit of the fabric filter is from the air preheater outlet to the ID fan inlets.

A fabric filter was chosen in anticipation of emission limits of particles less than 2.5 microns in diameter, called $PM_{2.5}$ particles. Although there is still debate, it appears that the fabric filters will be more effective in removing the $PM_{2.5}$ particles, as compared to the electrostatic precipitators. Also, fabric filters are currently being used successfully on coal-burning plants in the U.S., Europe, and other parts of the world.

Operation Description

The fabric filter chosen for this study is a pulse jet fabric filter. The boiler exhaust gas enters the inlet plenum of the fabric filter and is distributed among the modules. Gas enters each module through a vaned inlet near the bottom of the module above the ash hopper. The gas then turns upward and is uniformly distributed through the modules, depositing the fly ash on the exterior surface of the bags. Clean gas passes through the fabric and into the outlet duct through poppet dampers. From the outlet dampers the gas enters the ID fan.

Periodically each module is isolated from the gas flow, and the fabric is cleaned by a pulse of compressed air injected into each filter bag through a venturi nozzle. This cleaning dislodges the dust cake collected on the filter bag exterior. The dust falls into the ash hopper and is removed through the ash handling system.

Technical Requirements and Design Basis

- Flue gas flow — 1,095,000 acfm
- Air-to-cloth ratio — 4 acfm/ft^2

- Ash loading 22,600 lb/h
- Pressure drop 6 in. W.C.

3.3.8.5 Hazardous Air Pollutants (HAPs) Removal

The U.S. Environmental Protection Agency (EPA) has issued the "Interim Final Report" on HAPs. The report is based on the findings of a study which estimated the emissions of HAPs from utilities. The study looked at 15 HAPs: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, hydrogen chloride, hydrogen fluoride, acrolein, dioxins, formaldehyde, n-nitrosodimethy-lamine, and radionuclides.

Analysis of the data obtained from coal-fired plants shows that emissions from only two of the 426 plants studied pose a cancer risk greater than the study guidelines of 1 in 1 million. It appears that the HAPs emissions from coal-fired plants are less than originally thought. Based on the interim report, extensive control of HAPs will not be required. However, due to the number of outstanding issues and the ever-changing environment, it is difficult to predict whether coal-fired utility boilers will be among those regulated with respect to HAPs.

Lower emissions of lead, nickel, chromium, cadmium, and some radionuclides, which are primarily particulate at typical air heater outlets, are achieved by the installation of high-efficiency particulate removal devices such as the fabric filter used in this study.

One HAP that has received a lot of attention over the last several years is mercury. Mercury has been found in fish and other aquatic life, and there is concern about the effects of mercury on the environment. Reducing mercury air emissions is complex, and several systems are being investigated to remove mercury, including:

- Activated carbon injection
- Injection of calcium-based sorbents
- Pumice injection
- Injection of compounds prior to an FGD system to convert mercury to oxides of mercury

- Electrically induced oxidation of mercury to produce a mercury oxide, which can be removed with particulate controls
- Introduction of a catalyst to promote the oxidation of elemental mercury and subsequent removal in an FGD system

Mercury controls are still being investigated and optimized and will require additional evaluation before optimal removal methods are established.

Mercury existing as oxidized mercury can be easily removed in a wet FGD system. Elemental mercury requires additional treatment for removal to occur. Unfortunately, coals contain various percentages of both elemental and oxidized mercury. The percentage of oxidized mercury in coal can range from 20 to 90 percent. DOE and EPA are still analyzing coal and do not have an extensive list available. Therefore, for this study it will be assumed that the coal will contain 50 percent oxidized mercury.

Since this plant will include a wet FGD system, a catalyst will be used to oxidize the elemental mercury. The catalyst bed will be installed between the fabric filter and the ID fans. The catalysts that show promise to oxidize mercury are iron-based and carbon-based catalysts. One of these will be chosen as the catalyst for this application.

3.3.9 Balance of Plant

The following section provides a description of the plant outside the PC boiler system and its auxiliaries.

3.3.9.1 Condensate and Feedwater Systems

Condensate

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 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.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain levels in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

Feedwater

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 sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. The feed pump is preceded by a motor-driven booster pump. 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 pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters is controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

3.3.9.2 Main, Reheat, and Extraction Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the VHP turbine stop valves. The function of the reheat system is to convey steam from the VHP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the HP turbine stop valves, and from the HP turbine exhaust to the second stage of reheat at the boiler and back to the IP turbine.

Main steam at approximately 4650 psig/1100°F exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to approximately 40 percent load.

First cold reheat steam at approximately 1400 psig/754°F exits the VHP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. First hot reheat steam at approximately 1248 psig/1100°F exits the boiler reheater through a motor-operated gate valve and is routed to the HP turbine. Second cold reheat steam at approximately 500 psig/757°F exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler second reheater. Second hot reheat steam at approximately 348 psig/1100°F exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the second cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From VHP turbine extraction to heaters 10 and 9
- From HP turbine extraction to heater 8

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disk non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.3.9.3 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.

Each pump has a motor-operated discharge gate valve. A motor-operated cross-over gate valve and reversing valves permit each pump to supply both sides of the condenser when the other pump is shut down. The pump discharge valves are controlled automatically.

3.3.9.4 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 system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (30 days or more).

Operation Description

The fly ash collected in the fabric filters 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. The clinker grinder is provided to break up any clinkers that may form. 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.

Technical Requirements and Design Basis

- Bottom ash:
  - Bottom ash and fly ash rates:

    Bottom ash generation rate, 5,625 lb/h = 2.8 tph

    Fly ash generation rate, 23,300 lb/h = 11.7 tph
  - Clinker grinder capacity = 5 tph
  - Conveying rate to ash pond = 5 tph
- Fly ash:
  - Collection rate = 11.7 tph
  - Conveying rate from precipitator and air heaters = 11.7 tph
  - Fly ash silo capacity = 850 tons (72-hour storage)

– Wet unloader capacity = 30 tph

3.3.9.5 Ducting and Stack

One stack is provided with a single 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. The stack has one 19-foot-diameter FRP stack liner.

3.3.9.6 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/h 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.

3.3.10 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.

3.3.11 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.

3.3.12 Buildings and Structures

Buildings and structures are the same as described in Section 3.2.12 for the supercritical plant.

3.3.13 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	225 tph	2
8	Conveyor No. 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 No. 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 No. 1	30" belt	115 tph	1
4	Conveyor No. 2	30" belt	115 tph	1
5	Limestone Day Bin	Vertical cylindrical	250 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
2	Pulverizer	B&W type MPS-75	40 tph	6

ACCOUNT 2B LIMESTONE PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Bin Activator		16 tph	1
2	Weigh Feeder	Gravimetric	16 tph	1
3	Limestone Ball Mill	Rotary	16 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 fab.	200,000 gal.	1
2	Surface Condenser	Single shell, transverse tubes	1.34×10^6 lb/h 2.0 in. Hg	1
3	Cond. Vacuum Pumps	Rotary water sealed	2500/25 scfm	2
4	Condensate Pumps	Vert. canned	2,000 gpm @ 800 ft	2
5	LP Feedwater Heater 1A/1B	Horiz. U tube	918,200 lb/h 102.4°F to 155.5°F	1
6	LP Feedwater Heater 2	Horiz. U tube	1,836,363 lb/h 155.5°F to 188.7°F	1
7	LP Feedwater Heater 3	Horiz. U tube	1,836,363 lb/h 188.7°F to 216.2°F	1
8	LP Feedwater Heater 4	Horiz. U tube	1,836,363 lb/h 216.2°F to 269.4°F	1
9	LP Feedwater Heater 5	Horiz. U tube	1,836,363 lb/h 269.4°F to 315.1°F	1
10	Deaerator and Storage Tank	Horiz. spray type	1,836,363 lb/h 315.1°F to 368.9°F	
11	Boiler Feed Booster Pump	Barrel type, multi-staged centr.	5,500 gpm @ 2,000 ft	1
12	HP Feedwater Heater 7	Horiz. U tube	2,554,000 lb/h 370.9°F to 436.2°F	1
13	HP Feedwater Heater 8	Horiz. U tube	2,554,000 lb/h 436.2°F to 486.3°F	1
14	Boiler Feed Pumps/Turbines	Barrel type, multi-staged, centr.	5,500 gpm @ 9,600 ft	1
15	Startup Boiler Feed Pump	Barrel type, multi-staged centr.	1,500 gpm @ 9,600 ft	1
16	HP Feedwater Heater 9	Horiz. U tube	2,554,000 lb/h 501.1°F to 579°F	1
17	HP Feedwater Heater 10	Horiz. U tube	2,554,000 lb/h 579°F to 608.9°F	1

ACCOUNT 3B MISCELLANEOUS SYSTEMS

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop fab. 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	SS, double acting	100 psig, 800 scfm	3
6	Instrument Air Dryers	Duplex, regenerative	400 scfm	1
7	Service Water Pumps	SS, double suction	100 ft, 6,000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & 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	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Riverwater Makeup Pumps	SS, single suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	SS, 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	Condensate Demineralizer	Mixed bed	1,600 gpm	1

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty.
1	Once-Through Steam Generator with Air Heater	Universal pressure, wall-fired, double reheat	2,550,000 pph steam at 4500 psig/1100°F	1
2	Primary Air Fan	Axial	363,400 pph, 80,900 acfm, 39" WG, 580 hp	2
3	FD Fan	Cent.	1,182,873 pph, 263,274 acfm, 11" WG, 580 hp	2
4	ID Fan	Cent.	1,724,000 pph, 570,000 acfm, 32" WG, 3,800 hp	2

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A PARTICULATE CONTROL

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter	Pulse jet	3,463,000 lb/h, 290°F	1

ACCOUNT 5B FLUE GAS DESULFURIZATION

Equipment No.	Description	Type	Design Condition	Qty.
1	Absorber Module	Spray/tray	1,060,000 acfm	1
2	Recirculation Pump	Horizontal centrifugal	31,500 gpm	4
3	Bleed Pump	Horizontal centrifugal	650 gpm	2
4	Oxidation Air Blower	Centrifugal	5600 scfm	2
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

Byproduct Dewatering

Equipment No.	Description	Type	Design Condition	Qty.
6	Gypsum Stacking Pump	Horizontal centrifugal	750 gpm	2
7	Gypsum Stacking Area		42 acres	1
8	Process Water Return Pumps	Vertical centrifugal	500 gpm	2
9	Process Water Return Storage Tank	Vertical, lined	200,000 gal	1
10	Process Water Recirculation Pumps	Horizontal centrifugal	500 gpm	2

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	Reinf. concrete, two FRP flues	60 fps exit velocity 480 ft high x 19 ft dia. (flue)	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty.
1	435 MW Turbine Generator		4500 psig, 1100°F/1100°F/ 1100°F	1
2	Bearing Lube Oil Coolers	Shell & tube	-	2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop	-	1
4	Control System	Electro-hydraulic	1600 psig	1
5	Generator Coolers	Shell & 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	Mech draft	160,000 gpm 95°F to 75°F	1
2	Circ. Water Pumps	Vert. wet pit	80,000 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		10 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	1000 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	1000 gpm	2

ACCOUNT 10B FLY ASH HANDLING

Equipment No.	Description	Type	Design Condition	Qty.
1	Fabric Filter Hoppers (part of FF scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower		1800 cfm	2
4	Fly Ash Silo	Reinf. concrete	890 tons	1
5	Slide Gate Valves			2
6	Wet Unloader		30 tph	1
7	Telescoping Unloading Chute			1

3.3.14 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the 400 MW ultra-supercritical PC plant is shown in Table 3.3-3. The estimate summarizes the detail estimate values that were developed consistent with Section 9, “Capital and Production Cost and Economic Analysis.” The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the other plants is that, unlike all of the other technologies, all of the power is generated from a single source, the steam turbine. As a result, the economy of scale influence is greatest for this plant.

Table 3.2-3

Client: DEPARTMENT OF ENERGY **Report Date:** 14-Aug-98 08:24 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Ultracritical PC
Plant Size: 399.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	6,617	1,951	5,042	353		**$13,962**	1,117		3,016	**$18,095**	45
2	COAL & SORBENT PREP & FEED	8,283		2,590	181		**$11,054**	884		2,388	**$14,326**	36
3	FEEDWATER & MISC. BOP SYSTEMS	16,924		7,397	518		**$24,839**	1,987		6,232	**$33,059**	83
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	58,543		23,892	1,672		**$84,107**	6,729		9,084	**$99,919**	250
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/FD & ID Fans)	3,076		1,014	71		**$4,160**	333		449	**$4,942**	12
	SUBTOTAL 4	*61,618*		*24,906*	*1,743*		***$88,267***	*7,061*		*9,533*	***$104,861***	*262*
5	FLUE GAS CLEANUP	32,690		18,332	1,137		**$52,159**	4,173		5,289	**$61,621**	154
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	9,202	271	6,824	478		**$16,774**	1,342		2,809	**$20,925**	52
	SUBTOTAL 7	*9,202*	*271*	*6,824*	*478*		***$16,774***	*1,342*		*2,809*	***$20,925***	*52*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	34,999		5,766	404		**$41,169**	3,294		4,446	**$48,909**	122
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	11,797	359	6,470	453		**$19,079**	1,526		3,548	**$24,153**	60
	SUBTOTAL 8	*46,796*	*359*	*12,236*	*857*		***$60,248***	*4,820*		*7,994*	***$73,062***	*183*
9	COOLING WATER SYSTEM	7,658	3,984	7,241	507		**$19,390**	1,551		3,735	**$24,676**	62
10	ASH/SPENT SORBENT HANDLING SYS	5,721	76	10,462	732		**$16,991**	1,359		2,782	**$21,132**	53
11	ACCESSORY ELECTRIC PLANT	9,164	2,859	7,797	546		**$20,365**	1,629		3,606	**$25,600**	64
12	INSTRUMENTATION & CONTROL	6,138		5,089	356		**$11,584**	927		1,949	**$14,459**	36
13	IMPROVEMENTS TO SITE	1,877	1,079	3,759	263		**$6,978**	558		2,261	**$9,798**	25
14	BUILDINGS & STRUCTURES		14,976	17,960	1,257		**$34,193**	2,735		9,232	**$46,161**	115
	TOTAL COST	**$212,688**	**$25,555**	**$129,634**	**$8,928**		**$376,805**	**$30,144**		**$60,825**	**$467,774**	**1170**

Section 4.1

Integrated Gasification Combined Cycle (IGCC)

4. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

4.1 FIRST-OF-A-KIND IGCC, OXYGEN-BLOWN ENTRAINED-BED GASIFIER

4.1.1 Introduction

This first-of-a-kind IGCC concept is based on the utilization of the Destec oxygen-blown coal gasification process supplying medium-Btu gas to a gas turbine/combined cycle power generating plant. The plant configuration is based on the technology demonstrated at the Wabash River Coal Gasification Repowering Project, but with the design configured for a greenfield site incorporating a new steam turbine. The specific design approach presented herein is based on DOE/Federal Energy Technology Center (FETC) and Parsons concepts, and does not necessarily reflect the approach that Destec Energy would take if they were to commercially offer a facility of this size (MWe) in this time frame.

This example of the IGCC technology is based on selection of a gas turbine derived from the General Electric MS 7001FA machine. Two of these machines are coupled with a single steam turbine to produce a nominal 540 MWe net output. The IGCC portion of the plant is configured with two gasifiers, each of which includes processes to progressively cool and clean the gas, making it suitable for combustion in the gas turbines. The resulting plant produces a net output of 543 MWe at a net efficiency of 40.1 percent on an HHV basis. Performance is based on the use of Illinois No. 6 coal.

4.1.2 Heat and Mass Balance

The pressurized Destec gasifier utilizes a combination of oxygen, water, and coal along with recycled fuel gas to gasify the coal and produce a medium-Btu hot fuel gas. The fuel gas produced in each entrained bed gasifier leaves at 1950°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to 650°F. High-pressure saturated steam is generated in the hot gas cooler and is joined with the main steam supply.

The gas goes through a series of gas cleanup processes including a ceramic candle filter, chloride guard, COS hydrolysis reactor, and an amine-based acid gas removal (AGR) plant. A fraction of the clean hot gas is cooled and recycled to each gasifier to aid in second-stage gasification. Particulates captured by the filter are recycled, resulting in complete carbon conversion. Regeneration gas from the AGR plant is fed to an H_2S-burning H_2SO_4 plant.

The air separation unit (ASU) is partially decoupled from the gas turbines, in that gas turbine compressor discharge air is not used as input to the air separation process. However, some of the nitrogen produced in the ASU is brought back to the gas turbine, where it is mixed with the syngas supplied by the gasifier. This N_2 addition to the syngas aids in minimizing formation of NOx during combustion in the gas turbine burner section.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling and sulfation modules).

Each gas turbine operates in an open cycle mode, as described below. The inlet air is compressed in a single spool compressor to the design basis discharge pressure. The compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the medium-Btu gas supplied by the gasifier island. The firing of medium-Btu gas in the combustion turbine is expected to require modifications to the burner and turbine sections of the machine. These modifications are discussed in later sections.

The hot combustion gases are conveyed to the inlet of the turbine section on each machine, where they enter and expand through each turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG (one for each turbine) to recover the large quantities of thermal energy that remain. Each HRSG exhausts to a separate stack.

Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.1-1, which includes auxiliary power requirements. The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 4.1-1).

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gases, as well as utilizing steam generation opportunities in the gasifier process. As the turbine exhaust gases pass through each HRSG, they progressively transfer heat for reheating steam (cold reheat to hot reheat), superheating main steam, generating main steam in an HP drum, generating and superheating steam from an IP drum (as reheat, and for use in the integral deaerator), and heating feedwater.

The gasifier train provides heat for condensate heating, feedwater heating (partial), and main steam generating. The HRSG and gasifier trains provide all the required condensate and feedwater heating. Therefore, conventional feedwater heaters using turbine extraction steam are not required.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one casing, with the LP section in a second casing. Other turbine design arrangements are possible; the configuration represented herein is typical of reheat machines in this size class.

The steam turbine drives a 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at a nominal 2.0 inches Hga at the 100 percent load design point. Two 50 percent capacity, motor-driven pumps are provided for feedwater and condensate.

Table 4.1-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for two IGCC islands, two gas turbines, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine (two)	394,000
Steam Turbine (one)	254,530
Total	648,530
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	330
Coal Slurry Pumps	370
Condensate Pumps	320
LP/IP Feed Pumps	40
HP Feed Pumps	3,700
Miscellaneous Balance of Plant (Note 1)	1,500
Boost Air Cpmpressor	270
Air Separation Plant	55,880
Oxygen Boost Compressor	10,730
Gasifier Recycle Blower	970
N_2 Compressor	22,950
H_2S Air Blower	1,350
Amine Plant	330
Sulfuric Acid Plant Air Blower	400
Gas Turbine Auxiliaries	800
Steam Turbine Auxiliaries	300
Circulating Water Pumps	2,160
Cooling Tower Fans	1,320
Slag Handling	840
Transformer Loss	1,440
TOTAL AUXILIARIES, kWe	105,340
Net Power, kWe	543,190
Net Efficiency, % HHV	40.1%
Net Heat Rate, Btu/kWh (HHV)	8,522
CONDENSER COOLING DUTY, 10^6 Btu/h	1,465
CONSUMABLES	
As-Received Coal Feed, lb/h	396,790
Oxygen (95% pure), lb/h	329,903
Water (for slurry), lb/h	163,000

Note 1 - Includes plant control systems, lighting, HVAC, etc.

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA.
2. DESTEC GASIFIER HAS 90/10 COAL SLURRY FEED SPLIT.
3. THIS CASE IS BASED ON TWO GASIFIER TRAINS, TWO GE FRAME 7FA GAS TURBINES, AND ONE GE TC4F STEAM TURBINE.
4. IP PROCESS STEAM TO ASU AND SLURRY HEATER.
5. LP PROCESS STEAM TO ACID GAS UNIT AND WASTE WATER TREATMENT.
6. PORTION OF L/P STEAM GENERATION PRODUCED BY GASIFIER ISLAND.

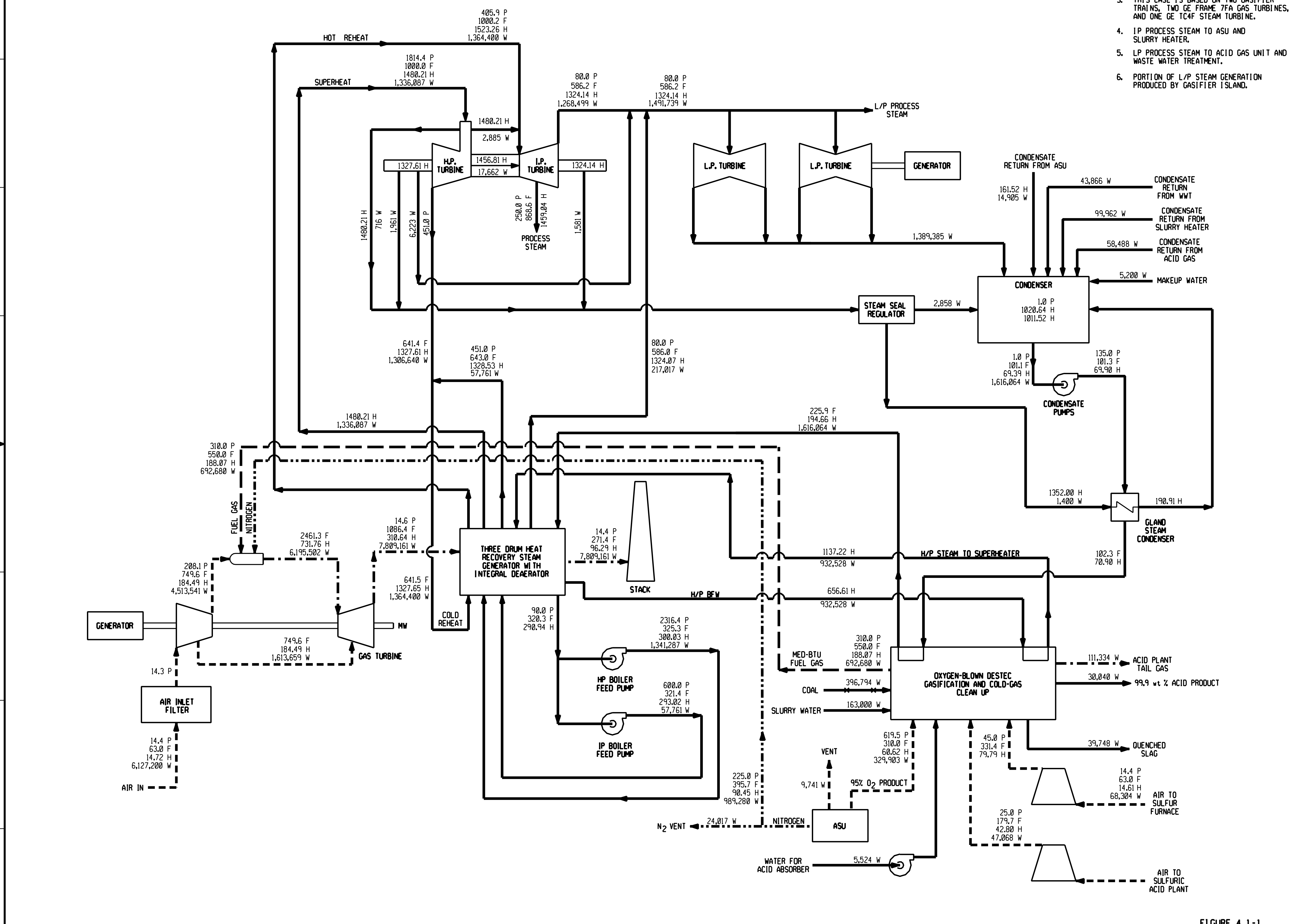

FIGURE 4.1-1

LEGEND

	NITROGEN
	AIR/OXIDANT
	FUEL GAS
	COMBUSTION PRODUCTS
	SOLIDS
	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

(TWO GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	400.000 MWe
STEAM T-G POWER :	258.406 MWe
GENERATOR LOSS (TOTAL):	9.876 MWe
AUXILIARY POWER (TOTAL):	105.340 MWe
NET PLANT POWER :	543.190 MWe
NET PLANT EFFICIENCY :	40.0 %
NET PLANT HEAT RATE :	8,522 Btu/kwh

DEIA-BTM/DSTC-EIA J.S.WHITE 4/23/1998

REV | DATE | DESCRIPTION

STATUS OF DRAWING: PRELIMINARY — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY CLR DATE 9/22/97

CHECKED BY DATE

LEAD DESIGNER DATE

ENGINEER DATE

LEAD DISCIPLINE ENGR. DATE

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
600MW INTERGRATED GASIFICATION COMB CYCLE
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
OXYGEN BLOWN ENTRAINED BED GASIFIER
MARKET BASED / FIRST OF A KIND

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-004 REV A

PPGI-FILE: 416006:041598.gra PPGI-DATE: 17-Apr-98 06:50

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4.1.3 Emissions Performance

The operation of the combined cycle unit in conjunction with oxygen-blown Destec IGCC technology is projected to result in very low levels of emissions of NOx, SO_2, and particulates (fly ash). A salable byproduct is produced in the form of sulfuric acid at 95 to 98 percent concentration (66.2 °Bé). A summary of the plant emissions is presented in Table 4.1-2.

Table 4.1-2
AIRBORNE EMISSIONS - IGCC, OXYGEN-BLOWN DESTEC

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.056	737	964	0.48
NOx	0.024	316	414	0.21
Particulates	< 0.002	< 26	< 34	< 0.018
CO_2	200.4	2,640,580	3,453,100	1,708

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the amine-based AGR process. The AGR process removes approximately 99.9 percent of the sulfur compounds in the fuel gas. The H_2S-rich regeneration gas from the AGR system is fed to a 99 percent efficient H_2S-burning H_2SO_4 plant. The actual overall sulfur removal capability is therefore about 98.9 percent.

NOx emissions are limited to approximately 30 ppm by the use of nitrogen injection from the ASU. The ammonia is removed with process condensate prior to the low-temperature AGR process. This helps lower NOx levels as well. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce emissions further, but are not applied to the subject plant.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the candle type particulate filter and the gas washing effect of the AGR absorber.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/10^6 Btu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

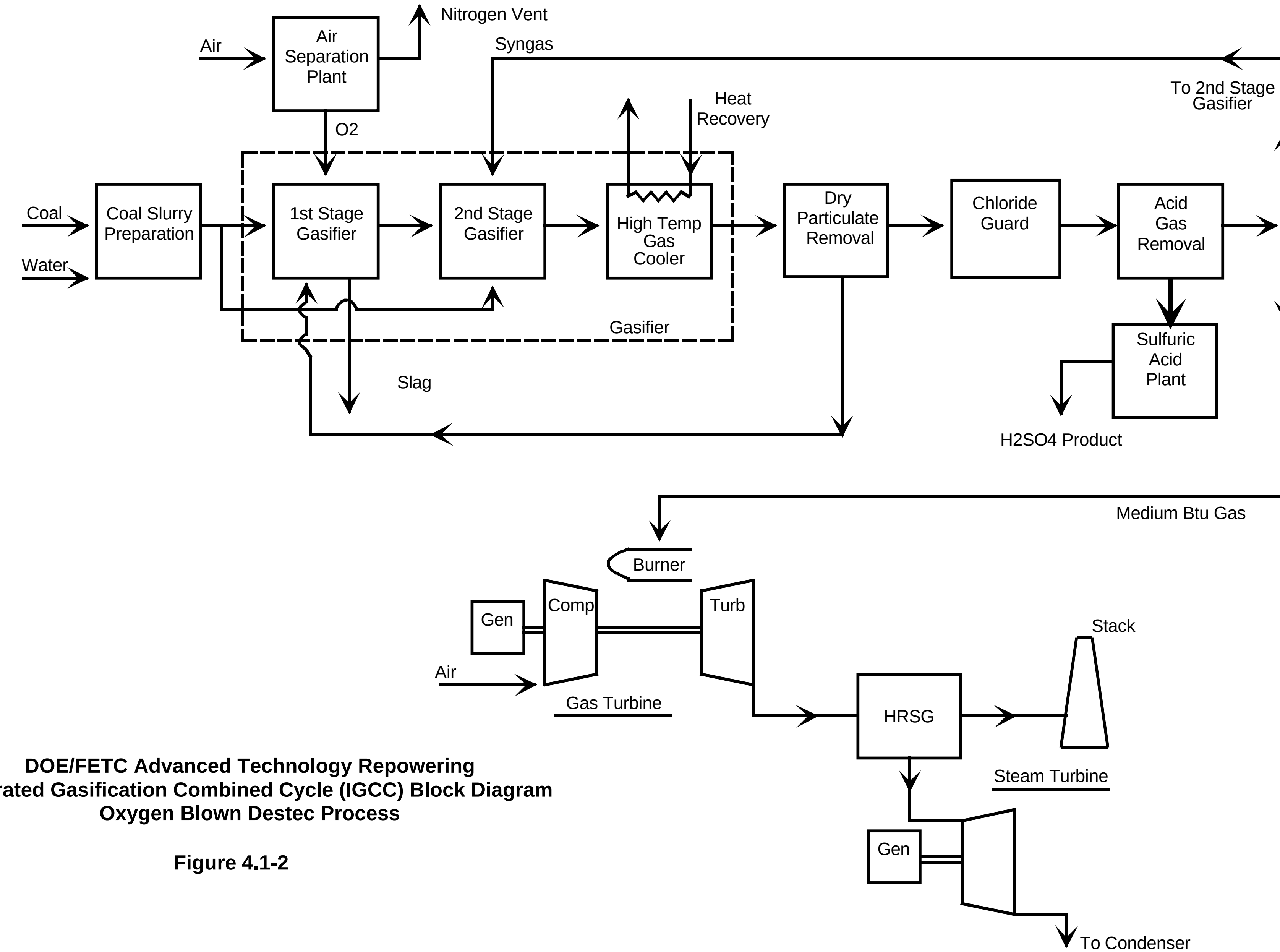
4.1.4 Description of Oxygen-Blown Destec Gasification Island

This design is based on the utilization of two oxygen-blown Destec entrained-bed gasifiers. The medium-Btu gas produced in the gasifiers is cooled and further cleaned downstream of the gasifiers. The final product gas is used to fire two combustion turbine generators, which are each coupled to an HRSG, producing steam for one steam turbine generator.

The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this case. (Refer to Figure 4.1-2.)

Illinois No. 6 coal is ground to 200 mesh and mixed with water to be fed to each pressurized Destec gasifier as a slurry. The slurry is fired with oxygen to produce medium-Btu gas, which is largely composed of CO, H_2, and CO_2, and is discharged from the gasifier at 1950°F and cooled in a gas cooler to 650°F. The oxygen fed to each gasifier is produced in two 50 percent capacity ASU trains, one for each gasifier.

The gas is then cleaned in the dry particulate removal system containing a candle-type barrier filter, resulting in very low levels of particulates. Fly ash from the filter is recycled to the gasifier to ensure complete carbon conversion. The particulate-free gas passes through the chloride guard containing a fixed-bed reactor, exposing the gas to nahcolite, thereby reducing the chloride level to less than 1 ppm to protect downstream equipment. The low-chloride gas passes to the AGR system, which contains a COS hydrolysis reactor and monoethanolamine (MEA) desulfurizer. From the AGR system sufficient sulfur is removed to result in a final sulfur level of about 30 ppm. The regeneration gas from the AGR system is a mixture of H_2S and CO_2, which is a suitable feedstock for a sulfuric acid plant.



DOE/FETC Advanced Technology Repowering
Integrated Gasification Combined Cycle (IGCC) Block Diagram
Oxygen Blown Destec Process

Figure 4.1-2

The clean gas exiting the AGR system is 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 MS 7001FA combustion turbine, a fuel gas pressure at the gasifier island battery limits of 300 psig was established to provide a margin above the compressor discharge pressure (220 psig at this site), allowing for necessary system and valve pressure drop.

Based on the above, a nominal gasifier pressure of 400 psig is required. At this pressure, two gasifiers are required that are similar in size to the commercial sized unit utilized in the Wabash River Coal Gasification Repowering Project.

4.1.4.1 Coal Grinding and Slurry Preparation

Coal is fed onto conveyor No. 1 by vibratory feeders located below each coal silo. Conveyor No. 1 feeds the coal to an inclined conveyor (No. 2) that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. The rod mill grinds the coal and wets it with treated slurry water from a slurry water tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

4.1.4.2 Gasifier

Note: The following description is taken from the Coal Gasification Guidebook: Status, Applications, and Technologies, prepared by SEA Pacific, Inc. for the Electric Power Research Institute.

The Destec coal gasifier is a slurry feed, pressurized, upflow, entrained slagging gasifier with two-stage operation. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. In the gasifier model considered herein, about 90 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 10 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1950°F.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 10 percent of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is easily gasified. The gasifier is refractory-lined and uncooled. The hotter first-stage section of the gasifier also includes a special slag-resistant refractory.

The 1950°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 650°F, generating saturated steam for the steam power cycle in the process.

4.1.4.3 Particulate Removal

The particulate removal stage in this gasification process is dependent upon a high-efficiency ceramic candle barrier filter. The filter is comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and conveyed to the gasifier. This filter provides a high degree of capture efficiency, resulting in very low levels of particulates in the hot gas supplied to the fixed-bed chloride guard bed, preventing guard bed clogging.

4.1.4.4 Chloride Guard

The chloride guard functions to remove HCl from the hot gas, prior to sulfur removal in the AGR system. This protects the AGR system vessels as well as the gas turbine downstream.

The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a natural form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and are fabricated of carbon steel, with an inner lining of a stabilized grade of stainless steel.

4.1.4.5 Acid Gas Removal (AGR)

Following the chloride guard bed, the gas is cooled to 365°F for feed to the COS hydrolysis reactor. The COS is hydrolized with steam in the gas, over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the sulfur removal process, it must be cooled to 105°F. During this cooling, part of the water vapor condenses. This water, which contains some NH_3, is sent to the wastewater treatment section. No separate HCN removal unit is needed due to the very low HCN concentration in the fuel gas. Following the hydrolysis reactor, the gas is further cooled to 105°F for feed to the AGR absorber.

The monoethanolamine (MEA) process was chosen because of its high selectivity towards H_2S and because of the low partial pressure of H_2S in the fuel gas, necessitating a chemical absorption process rather than a physical absorption process such as the Selexol. The AGR process utilizes a MEA sorbent and several design features to effectively remove and recover H_2S from the fuel gas stream. The MEA solution is relatively expensive, and measures are taken to conserve the solution during operations. As the presence of CO causes amine degradation in the form of heat stable salts, an amine reclaimer is included in the process. Also, additional water wash trays are included in the absorber tower to prevent excessive solvent loss due to vaporization.

Fuel gas enters the absorber tower at 105°F and 330 psia. Approximately 99 percent of the H_2S is removed from the fuel gas stream. The resulting clean fuel gas stream exits the absorber and is heated in a series of regenerative heaters to 505°F.

The rich MEA solution is pumped to a regeneration stripping tower in which the H_2S and CO_2 are stripped from the MEA by counter-current contact with CO_2 vapors generated in a steam-heated reboiler. The regenerated H_2S stream is cooled and separated from the condensed water, and flows to the H_2S recovery compressor for feed to the H_2S-burning sulfuric acid plant.

The only contaminants in the cleaned fuel gas leaving the acid gas removal unit are H_2S and HCN, both in very low concentrations. A small fraction of the cleaned fuel gas is compressed and recycled to the gasifier outlet for back-purging the ceramic candle filter.

4.1.4.6 Sulfuric Acid Plant

The AGR process produces an offgas from the regeneration process, which contains an H_2S concentration of about 50 percent. This is adequate for feed to an H_2S-burning contact process sulfuric acid plant that burns the H_2S acid gas with air, yielding SO_2, water vapor, and heat, which are fed to a conventional contact acid plant. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Key to the process is the four-pass converter developed by Monsanto. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.1.4.7 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, single spool, constant speed unit, with variable inlet guide vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 15.2:1 and a rotor inlet temperature of almost 2350°F. In this service, with medium-Btu gas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the medium-Btu gas and expand the combustion products in the turbine section of the machine. A reduction in rotor inlet temperature of about 50°F is expected, relative to a production model W501G machine firing natural gas. This temperature reduction is necessary in order to not exceed design basis gas path temperatures throughout the expander. If the first-stage rotor inlet temperature were maintained at the design value, gas path temperatures downstream of the inlet to the first (HP) turbine stage may increase, relative to natural gas-fired temperatures, due to gas property changes.

The modifications to the machine may include some redesign of the original can-annular combustors. A second potential modification involves increasing the nozzle areas of the turbine to accommodate the mass and volume flow of medium-Btu fuel gas combustion products, which is increased relative to those produced when firing natural gas. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement.

The generator is a standard hydrogen-cooled machine with static exciter.

4.1.4.8 Steam Generation

Heat Recovery Steam Generator (HRSG)

The HRSG is a drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. The HP drum produces steam at main steam pressure, while the IP drum produces steam for export to the cold reheat. The HRSG drum pressures are nominally 2000 psig/600 psig for the HP/IP, respectively. In addition to generating and superheating steam, the HRSG performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater heating, and also provides deaeration of the condensate.

Gas Cooler

The gas cooler is a fire tube design, which produces steam at main steam pressure, saturated conditions. This steam is conveyed to the HRSG where it is superheated.

4.1.4.9 Air Separation Plant

The air separation plant is designed to produce a nominal output of 3,850 tons/day of 95 percent pure O_2. The plant is designed with two 50 percent capacity production trains. Liquefaction and liquid oxygen storage provide an 8-hour backup supply of oxygen. The inventory of liquid O_2 would be used to enable the plant to produce additional power during peaking periods by shutting down the ASU. The air compressor in each train is powered by an electric motor.

In this air separation process, air is compressed to 70 psig and then cooled in a water scrubbing spray tower. The cooled air enters a reversing heat exchanger, where it is cooled to the liquefaction point prior to entering a double column (high/low pressure) separator. Refrigeration for cooling is provided by expansion of high-pressure gas from the lower part of the high-pressure column.

Onsite storage of liquid O_2 is provided to maintain continuous supply for the gasifier for an 8-hour time period, enhancing plant output during peak power demand periods.

4.1.4.10 Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is provided to combust and dispose of product gas during startup, shutdown, and upset conditions. The flare stack is provided with multiple pilot burners, fueled by natural gas or propane, with pilot home monitoring instrumentation.

4.1.5 IGCC Support Systems (Balance of Plant)

4.1.5.1 Coal Handling System

The function of the coal handling 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 and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous 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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) 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 crushers. The coal then enters the second crusher, which reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of the three silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 396,800 lb/h = 198 tph plus 10% margin = 218 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 330,000 lb/h = 165 tph (based on MCR rate multiplied by 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Three and one-half unit trains per week at maximum burn rate. Three unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 600 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 15,300 tons (72 hours at maximum burn rate)
  - Dead storage = 119,000 tons (30 days at average burn rate)

4.1.5.2 Slag Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. Slag exits through the slag tap into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids flows out of the bottom of the gasifier through a proprietary pressure letdown device into an array of dewatering bins. The components listed above, up to the pressure letdown device, are within the gasifier pressure boundary and at high pressure. Three dewatering bins are provided; these are used in cyclical fashion, one bin receiving, one in a separation phase, and one in an overflow phase for separation of liquids/solids. A flocculation agent is added to assist in separating out the fines during the settling or separation phase. The clear liquid is recycled to the slag quench water bath.

The cooled, dewatered slag is removed by drag chain conveyors and is stored in a storage bin. The bin is sized for a nominal holdup capacity of approximately 72 hours of full-load operation. At periodic intervals, a convoy of slag hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately 19 truck loads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power.

4.1.6 Steam Cycle Balance of Plant

The following section provides a description of the steam turbines and their auxiliaries.

4.1.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. 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 last-stage bucket length of 33.5 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 400 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

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.

4.1.6.2 Condensate and Feedwater Systems

Condensate

The condensate system pumps condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG.

The 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 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.

<u>Feedwater</u>

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 boiler feed pumps of each type are provided. Each pump is provided with inlet and outlet isolation valves, outlet check valve, and minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.1.6.3 Main and Reheat Steam Systems

<u>Main and Reheat Steam</u>

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1900 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 450 psig/640°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 405 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

4.1.6.4 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.

4.1.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.1-3.

4.1.7 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.

Table 4.1-3
INTEGRATED GASIFICATION COMBINED CYCLE

Major Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	1,600,000	135	100	A106 Gr. B	10	Sch. 40
HP Feedwater, Pump to HRSG (Total)	1,340,000	2316	325	A106 Gr. B	10	Sch. 160
IP Feedwater, Pump to HRSG (Total)	57,800	600	321	A106 Gr. B	6	Sch. 40
HP Feedwater to Gasifier	932,500	2290	630	A106 Gr. B	10	Sch. 160
HP Steam to HRSG Turbine (Total)	932,500	2260	670	A335 Gr. P22	6	1.50
Main Steam to Steam Turbine (Total)	1,336,100	1814	1000	A335 Gr. P22	8	1.50
Cold Reheat/ST to HRSG	1,300,000	450	640	A106 Gr. B	18	0.50
Hot Reheat/HRSG to ST	1,364,000	405	1000	A335 Gr. P22	20	0.875
Fuel Gas/Gasifier Islands to Gas Turbines (Total)	693,000	310	550	A106 Gr. B	18	Sch. 40
O_2 Piping to Gasifiers (Total)	329,000	620	310	A106 Gr. B	8	Sch. 40

4.1.8 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.

4.1.9 Site, Structures, and System Integration

4.1.9.1 Plant and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

4.1.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate structures required for this technology is based on the assumption of a flat site. The IGCC gasifiers and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the south, as shown in the conceptual general arrangement in Figure 4.1-3.

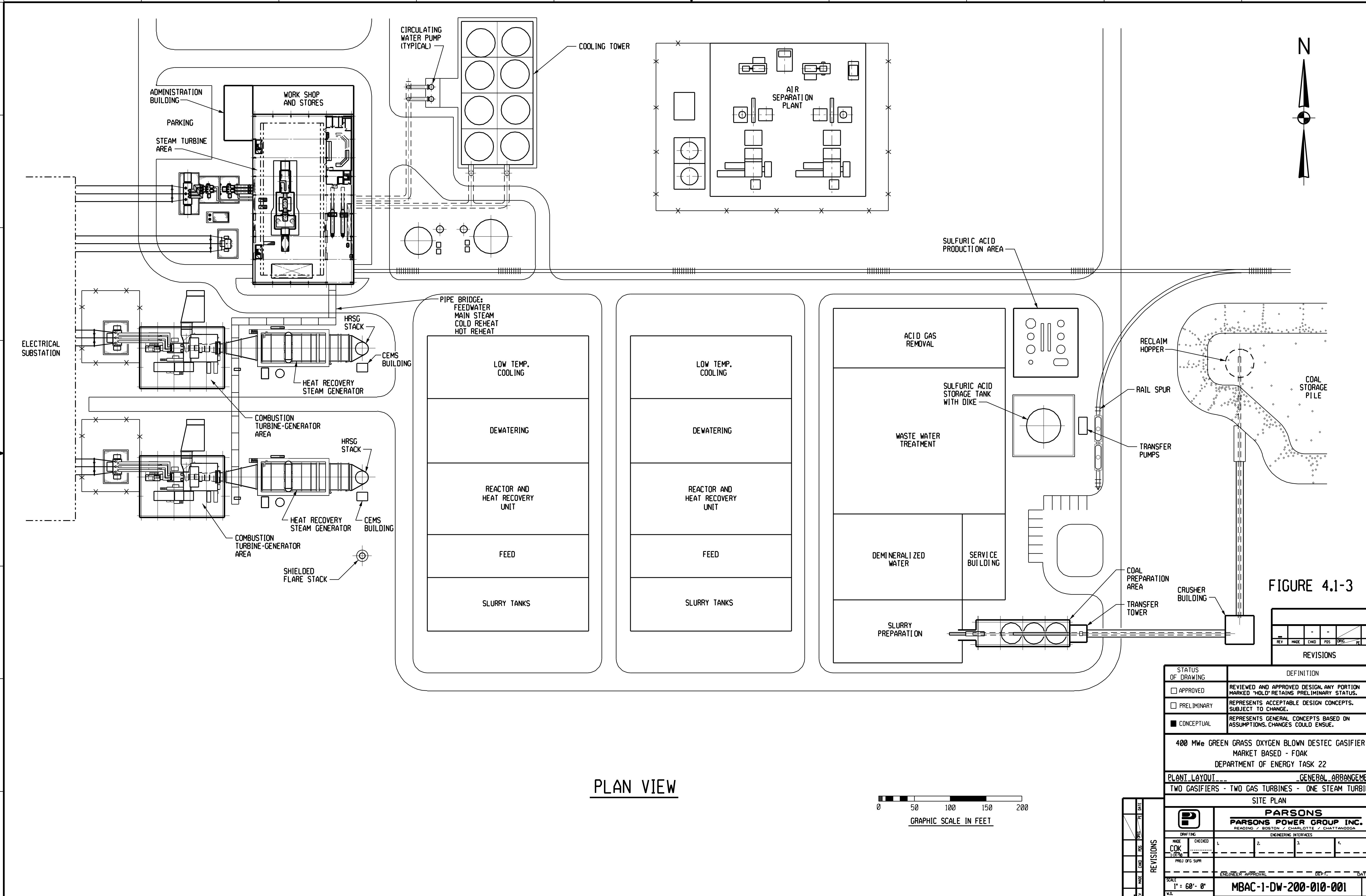
The gasifiers and their associated process blocks are located west of the coal storage pile. The gas turbines and their ancillary equipment are sited west of the gasifier island, in a turbine building. The HRSGs and stacks are east of the gas turbines, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the west side of the steam turbine building.

The cooling tower heat sink for the steam turbine is located to the east of the steam turbine building. The air separation plant is further to the east, with storage tanks for liquid O_2 and N_2 located near the gasifier and its related process blocks. Sulfur recovery and wastewater treatment areas are located east and south of the air separation plant.

The arrangement described above provides good alignment and positioning for major interfaces; relatively short steam, feedwater, and fuel gas pipelines; and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located north of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through the HRSGs and then the 213-foot stacks. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.



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4.1.10 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	300 tph	2
8	Conveyor No. 3	48" belt	600 tph	1
9	Crusher Tower	N/A	600 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	600 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		2
14	Conveyor No. 4	48" belt	600 tph	1
15	Transfer Tower	N/A	600 tph	1
16	Tripper	N/A	600 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	1,600 ton	3

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Not Applicable

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		140 tph	3
2	Conveyor No. 1	Belt	280 tph	1
3	Conveyor No. 2	Belt	280 tph	1
4	Rod Mill Feed Hopper	Vertical, double hopper	300 tons	1
5	Vibratory Feeder		140 tph	2
6	Weight Feeder	Belt	140 tph	2
7	Rod Mill	Rotary	140 tph	2
8	Slurry Water Storage Tank	Field erected	100,000 gal	1
9	Slurry Water Pumps	Horizontal, centrifugal	1,200 gpm	2
10	Rod Mill Product Tank	Field erected	200,000 gal	1
11	Rod Mill Product Pumps	Horizontal, centrifugal	2,000 gpm	2
12	Slurry Storage Tank	Field erected	365,000 gal	1
13	Centrifugal Slurry Pumps	Horizontal centrifugal	3,000 gpm	2
14	PD Slurry Pumps	Progressing cavity	500 gpm	4
15	Slurry Blending Tank	Field erected	100,000 gal	1
16	Slurry Blending Tank Pumps	Horizontal centrifugal	450 gpm	2

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, cylindrical, outdoor	50,000 gal	1
2	Condensate Pumps	Vert. canned	1,650 gpm @ 400 ft	2
3	Deaerator (integral with HRSG)	Horiz. spray type	795,000 lb/h 205°F to 240°F	2
4	IP Feed Pump	Horiz. centrifugal single stage	60 gpm/1,200 ft	2
5	HP Feed Pump	Barrel type, multi-staged, centr.	1,400 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. 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	Recip., single stage, double acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchangers	Plate and frame	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
10	Fire Service Booster Pump	Two-stage horiz. centrifugal	250 ft, 700 gpm	1
11	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
12	Raw Water Pumps	SS, single suction	60 ft, 300 gpm	2
13	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
14	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
15	Makeup Demineralizer	Anion, cation, and mixed bed	150 gpm	2
16	Liquid Waste Treatment System		10 years, 25-hour storm	1

ACCOUNT 4 BOILER AND ACCESSORIES

ACCOUNT 4A GASIFICATION (Total for plant)

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed	2400 ton/day/400 psig	2
2	Gas Cooler	Firetube	275 x 10^6 Btu/h	2
3	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	675,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT (Total for plant)

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	150,000 scfm, 70 psig discharge pressure	2
2	Cold Box		1,900 ton/day O_2	2
3	Oxygen Compressor	Centrifugal, multi-stage	25,000 scfm, 650 psig discharge pressure	2

ACCOUNT 5 FLUE GAS CLEANUP

(Per each of two gasifiers)

Equipment No.	Description	Type	Design Condition	Qty
1	MEA Absorber	Column	306,000 scfm (35,000 acfm) 385 psia, 1100°F	1
2	MEA Regenerator	Column	30 psia, 1450°F	1
3	Recycle Gas Compressor		36,000 acfm, P/P = 1.8 inlet 22 psia, 300°F	1
4	Recycle Gas Heat Exchanger	Fin tube	3 x 10^6 Btu/h	1
5	Recycle Gas Cooler	Shell & tube	50 x 10^6 Btu/h	1
6	Ceramic Candle Filter		20,000 acfm at 385 psig/650°F	1
7	Sulfuric Acid Plant		225 ton/day @ 98%	1
8	Chloride Guard	Pebble bed, vertical cylindrical pressure vessel	20,000 acfm at 385 psig/625°F	2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	185 MWe Gas Turbine Generator	Axial flow single spool based on W501G	920 lb/sec airflow 2350°F rotor inlet temp. 15.2:1 pressure ratio	2
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	2
3	Air Inlet Filter/Silencer	Two stage	920 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	2
4	Starting Package	Electric motor, torque converter drive, turning gear	2,000 hp, time from turning gear to full load ~30 minutes	2
5	Air to Air Cooler			2
6	Mechanical Package	CS oil reservoir & 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 (Total for plant)

Equipment No.	Description	Type	Design Condition Drums	Qty
1	Heat Recovery Steam Generator	Drum, multi-pressure, with economizer section and integral deaerator	HP-2300 psig/1000°F 1,336,400 lb/h IP-90 psig/450°F 57,800 lb/h	2
2	Raw Gas Cooler Steam Generator	Fire tube boiler	2300 psig/850°F (drum) 932,528 lb/h	2
3	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 28 ft dia.	2

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	260 MW Steam Turbine Generator	TC2F40	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	1,353,000 lb/h steam @ 2.0 in. Hga with 74°F water, 20°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. Water Pumps	Vert. wet pit	75,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	52°F WB/74°F CWT/ 94° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING & REMOVAL

(Quantities in this account are per gasifier)

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath	12 tph	1
2	Slag Crusher	Roll	12 tph	1
3	Slag Depressurizer	Proprietary	12 tph	1
4	Slag Dewatering Bin	Horizontal, weir	4 tph	3
5	Slag Conveyor	Drag chain	4 tph	3
6	Slag Conveyor	Drag chain	8 tph	*1
7	Storage Bin	Vertical	1,400 tons	*1
8	Unloading Equipment	Telescoping chute	25 tph	*1

*Total for plant.

4.1.11 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the IGCC plant is shown in Table 4.1-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.1-4

Client: DEPARTMENT OF ENERGY **Report Date:** 14-Aug-98 10:59 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Destec (2000-90/10)
Plant Size: 543.2 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	7,603	1,526	6,640	465		**$16,233**	1,299		3,506	**$21,038**	39
2	COAL & SORBENT PREP & FEED	11,480	2,641	12,398	868		**$27,387**	2,191	919	4,022	**$34,519**	64
3	FEEDWATER & MISC. BOP SYSTEMS	8,097	4,016	6,386	447		**$18,946**	1,516		4,893	**$25,354**	47
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	15,536		15,824	1,108		**$32,468**	2,597	1,623	3,669	**$40,358**	74
4.2	High Temperature Cooling	24,846		25,317	1,772		**$51,935**	4,155	2,597	5,869	**$64,555**	119
4.3	ASU/Oxidant Compression	69,266		w/equip.			**$69,266**	5,541		7,481	**$82,288**	151
4.4-4.9	Other Gasification Equipment	12,543	4,800	11,788	825		**$29,956**	2,396	1,113	4,744	**$38,210**	70
	SUBTOTAL 4	*122,191*	*4,800*	*52,930*	*3,705*		***$183,625***	*14,690*	*5,334*	*21,762*	***$225,411***	*415*
5	HOT GAS CLEANUP & PIPING	37,832	2,554	9,016	631		**$50,033**	4,003	4,093	11,819	**$69,948**	129
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	61,888		3,868	271		**$66,026**	5,282	3,301	7,461	**$82,071**	151
6.2-6.9	Combustion Turbine Accessories		222	256	18		**$496**	40		161	**$696**	1
	SUBTOTAL 6	*61,888*	*222*	*4,124*	*289*		***$66,522***	*5,322*	*3,301*	*7,622*	***$82,767***	*152*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	21,702		3,119	218		**$25,040**	2,003		2,704	**$29,748**	55
7.2-7.9	HRSG Accessories, Ductwork and Stack	3,281	2,209	3,165	222		**$8,877**	710		1,455	**$11,042**	20
	SUBTOTAL 7	*24,983*	*2,209*	*6,284*	*440*		***$33,917***	*2,713*		*4,159*	***$40,790***	*75*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	19,353		3,189	223		**$22,765**	1,821		2,459	**$27,045**	50
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	8,114	247	4,450	311		**$13,122**	1,050		2,440	**$16,612**	31
	SUBTOTAL 8	*27,467*	*247*	*7,638*	*535*		***$35,887***	*2,871*		*4,899*	***$43,657***	*80*
9	COOLING WATER SYSTEM	5,766	3,281	5,428	380		**$14,855**	1,188		2,892	**$18,935**	35
10	ASH/SPENT SORBENT HANDLING SYS	5,750	883	5,042	353		**$12,027**	962	442	1,526	**$14,958**	28
11	ACCESSORY ELECTRIC PLANT	18,990	5,447	14,090	986		**$39,514**	3,161		6,985	**$49,660**	91
12	INSTRUMENTATION & CONTROL	5,902	1,654	6,143	430		**$14,129**	1,130		2,371	**$17,630**	32
13	IMPROVEMENTS TO SITE	2,294	1,319	4,595	322		**$8,530**	682		2,764	**$11,976**	22
14	BUILDINGS & STRUCTURES		5,432	7,129	499		**$13,060**	1,045		3,526	**$17,631**	32
	TOTAL COST	**$340,244**	**$36,230**	**$147,844**	**$10,349**		**$534,667**	**$42,773**	**$14,090**	**$82,746**	**$674,276**	**1241**

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Section 4.2

Market-Based Intermediate Oxygen-Blown Destec – 400 MWe

4.2 MARKET-BASED INTERMEDIATE OXYGEN-BLOWN DESTEC 400 MWe

4.2.1 Introduction

This IGCC concept is based on the utilization of the Destec oxygen-blown coal gasification process supplying medium-Btu gas to a gas turbine/combined cycle power generating plant. The plant configuration is based on a projection of state-of-the-art design for an in-service date of 2005. The availability of a combustion turbine comparable to the Westinghouse 501G is assumed, along with steam turbines incorporating state-of-the-art design features. The specific design approach presented herein is based on DOE/FETC and Parsons concepts, and does not necessarily reflect the approach that Destec Energy would take if they were to commercially offer a facility of this size (MWe) in this time frame.

This case illustrating IGCC technology is based on selection of a gas turbine derived from the Westinghouse "G" machine. This particular machine, coupled with an appropriate steam cycle, will produce a nominal 350 MWe net output. The IGCC portion of the plant is configured with one gasifier island, which includes a transport reactor type hot gas desulfurizer. The resulting plant produces a net output of 349 MWe at a net efficiency of 45.4 percent on an HHV basis. This performance is based on the use of Illinois No. 6 coal. Performance will vary with other fuels.

4.2.2 Heat and Mass Balance

The pressurized Destec gasifier utilizes a combination of oxygen, water, and coal along with recycled fuel gas to gasify the coal and produce a medium-Btu hot fuel gas. The fuel gas produced in the entrained bed gasifier leaves at 1900°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to 1100°F. High-pressure saturated steam is generated in the hot gas cooler and is joined with the main steam supply.

The gas goes through a series of hot gas cleanup processes including transport reactor type hot desulfurization process, barrier filter, and chloride guard. A fraction of the clean hot gas is cooled and recycled to the gasifier to aid in second-stage gasification. Char particulates are recycled to the gasifier, resulting in nearly complete carbon conversion. Regeneration gas from the desulfurizer is fed to an H_2SO_4 plant.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling and sulfation modules).

The gas turbine operates in an open cycle mode, as described below.

The inlet air is compressed in a single spool compressor to the design basis discharge pressure. Most of the compressor discharge air passes to the burner section of the machine to support combustion of the medium-Btu gas supplied by the gasifier island, and to cool the burner and turbine expander sections of the machine. The firing of medium-Btu gas in the combustion turbine is expected to require modifications to the burner and turbine sections of the machine. These modifications are discussed in Section 4.2.4.7.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The combustion turbine utilizes steam cooling for the transitions from the burners to the expander; the steam is returned to the steam cycle for performance augmentation. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain. The HRSG exhausts to the plant stack.

The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance Diagram (Figure 4.2-1). Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.2-1, which includes auxiliary power requirements.

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gases, as well as utilizing steam generation opportunities in the gasifier process. For this facility, a double-pressure HRSG configuration has been selected. In addition to the high-pressure (HP) drum, an intermediate-pressure (IP) drum is provided in the HRSG to raise steam that is joined with the reheat. Steam conditions at the HP turbine admission valves are set at 1800 psig/1000°F.

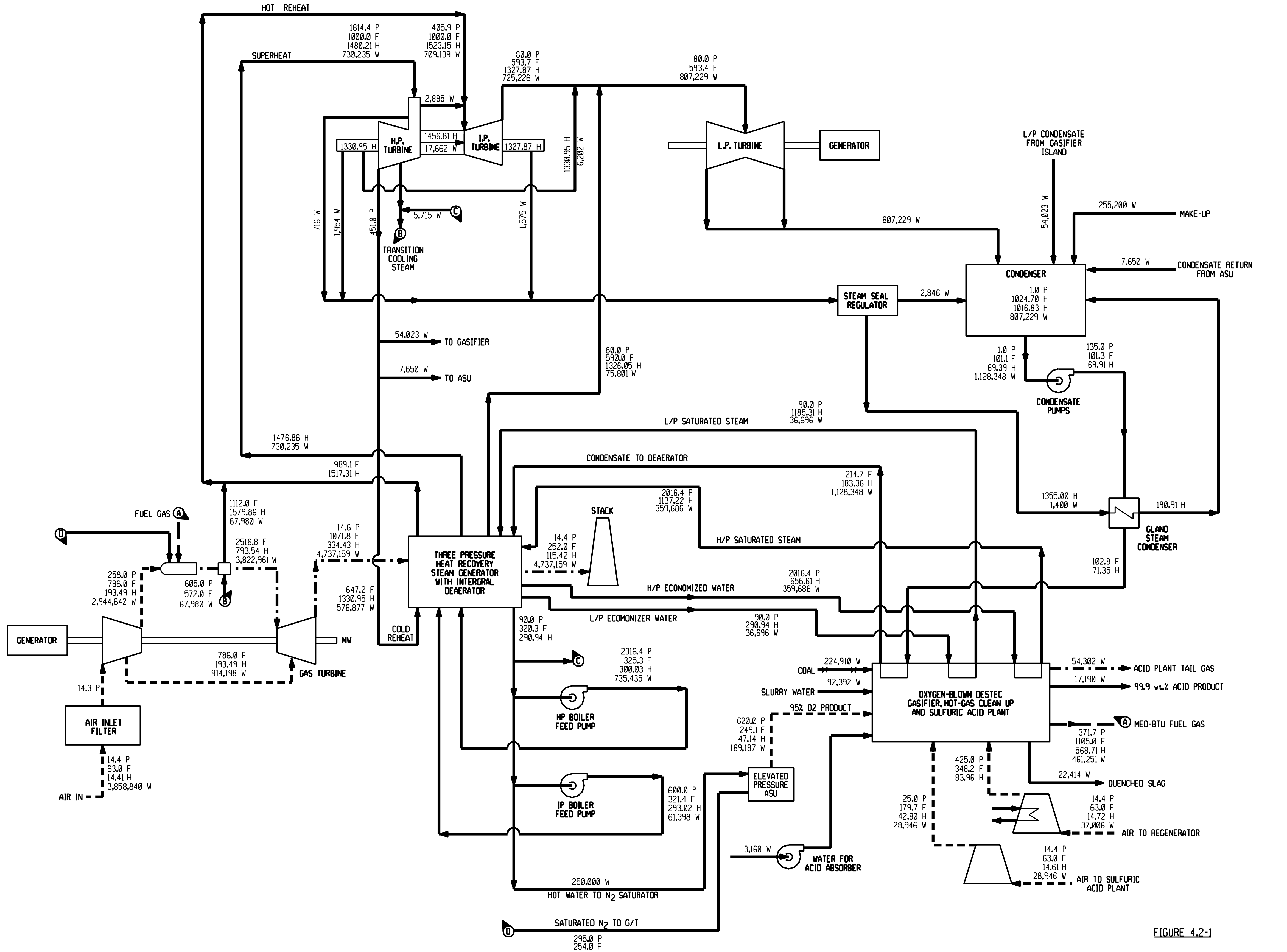

FIGURE 4.2-1

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.

LEGEND

- - - -	AIR / OXIDANT
— — —	FUEL GAS
—·—·—	COMBUSTION PRODUCTS
—×—×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	267.899 MWe
STEAM T-G POWER :	143.530 MWe
GENERATOR LOSS (TOTAL):	8.133 MWe
AUXILIARY POWER (TOTAL):	54.08 MWe
NET PLANT POWER :	349.211 MWe
NET PLANT EFFICIENCY :	45.4 %
NET PLANT HEAT RATE :	7,513 Btu/kwh

J.S.WHITE DESTECWG/DWG-BOTM 6/18/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | LEAD ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING — DEFINITION — CONSTRUCTION STATUS
PRELIMINARY — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

DRAWN BY CLB DATE 7/7/97
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 POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
400 MW INTEGRATED GASIFICATION COMB CYCL
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
OXYGEN BLOWN ENTRAINED BED GASIFIER

SCALE NONE
PARSON'S DWG. NO. MBAC-1-400-314-005
REV A

PPGI-FILE:
PPGI-DATE:

416006:61098.GRA
416006:61098.DGN

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Table 4.2-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for one IGCC island, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Net Electric Power at Generator Terminals, kWe)	
Gas Turbine	262,603
Steam Turbine	140,693
Total	403,296
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	190
Coal Slurry Pumps	170
Condensate Pumps	180
IP/IP Feed Pumps	50
HP Feed Pumps	2,030
Miscellaneous Balance of Plant (Note 1)	900
Air Separation Plant	28,505
Boost Air Compressor	370
Oxygen Boost Compressor	5,530
Clasifier Recycle Blower	180
Regenerator Recycle Blower	2,180
Sulfuric Acid Plant Air Blower	250
N2 Compressor	9110
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Saturated Water Pumps	80
Circulating Water Pumps	1,380
Cooling Tower Fans	840
Slag Handling	480
Transformer Loss	960
TOTAL AUXILIARIES, kWe	54,085
Net Power, kWe	349,211
Net Efficiency, % HHV	45.4
Net Heat Rate, Btu/kWh (HHV)	7,513
CONDENSER COOLING DUTY, 10^6 Btu/h	773
CONSUMABLES	
As-Received Coal Feed, lb/h	224,910
Oxygen (95% pure), lb/h	169,187
Water (for slurry), lb/h	92,392

Note 1 - Includes plant control systems, lighting, HVAC, etc.

The HRSG also contains an integral deaerating heater and several economizer sections. The economizer provides essentially all of the necessary feedwater heating (except for that provided by the deaerating heater) by heat recovery from the gas path. Therefore, conventional feedwater heaters using turbine extraction steam are not required.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one section, with the LP section in a second casing. Other turbine design arrangements are possible; the configuration represented herein is typical of reheat machines in this size class.

The steam turbine drives a 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at a nominal 2.0 inches Hga at the 100 percent load design point. For the low-pressure turbine, the last-stage bucket length is 30 inches. Two 50 percent capacity, motor-driven pumps are provided for feedwater and condensate.

4.2.3 Emissions Performance

The operation of the combined cycle unit in conjunction with oxygen-blown Destec IGCC technology is projected to result in very low levels of emissions of NOx, SO_2, and particulates (fly ash). A salable byproduct in the form of sulfuric acid at 99 percent concentration is produced. A summary of the plant emissions is presented in Table 4.2-2.

Table 4.2-2
AIRBORNE EMISSIONS - IGCC, OXYGEN-BLOWN DESTEC

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.017	129	168	0.13
NOx	0.024	179	234	0.182
Particulates	< 0.002	< 15	< 20	0.015
CO_2	200	1,496,745	1,957,282	1,506

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the transport hot gas desulfurizer (THGD) subsystem. The THGD process removes approximately 99.5 percent of the sulfur compounds in the fuel gas.

The reduction in NOx to below 10 ppm is achieved for a fuel gas containing fuel-bound nitrogen (NH_3) by the use of rich-quench lean (staged) combustion technology coupled with syngas dilution by nitrogen available from the ASU. Syngas dilution and staged combustion, sub-stoichiometric combustion followed by excess air dilution, promote the conversion of fuel bound nitrogen to N_2 rather than NOx. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce NOx emissions further, but are not applied to the subject plant.

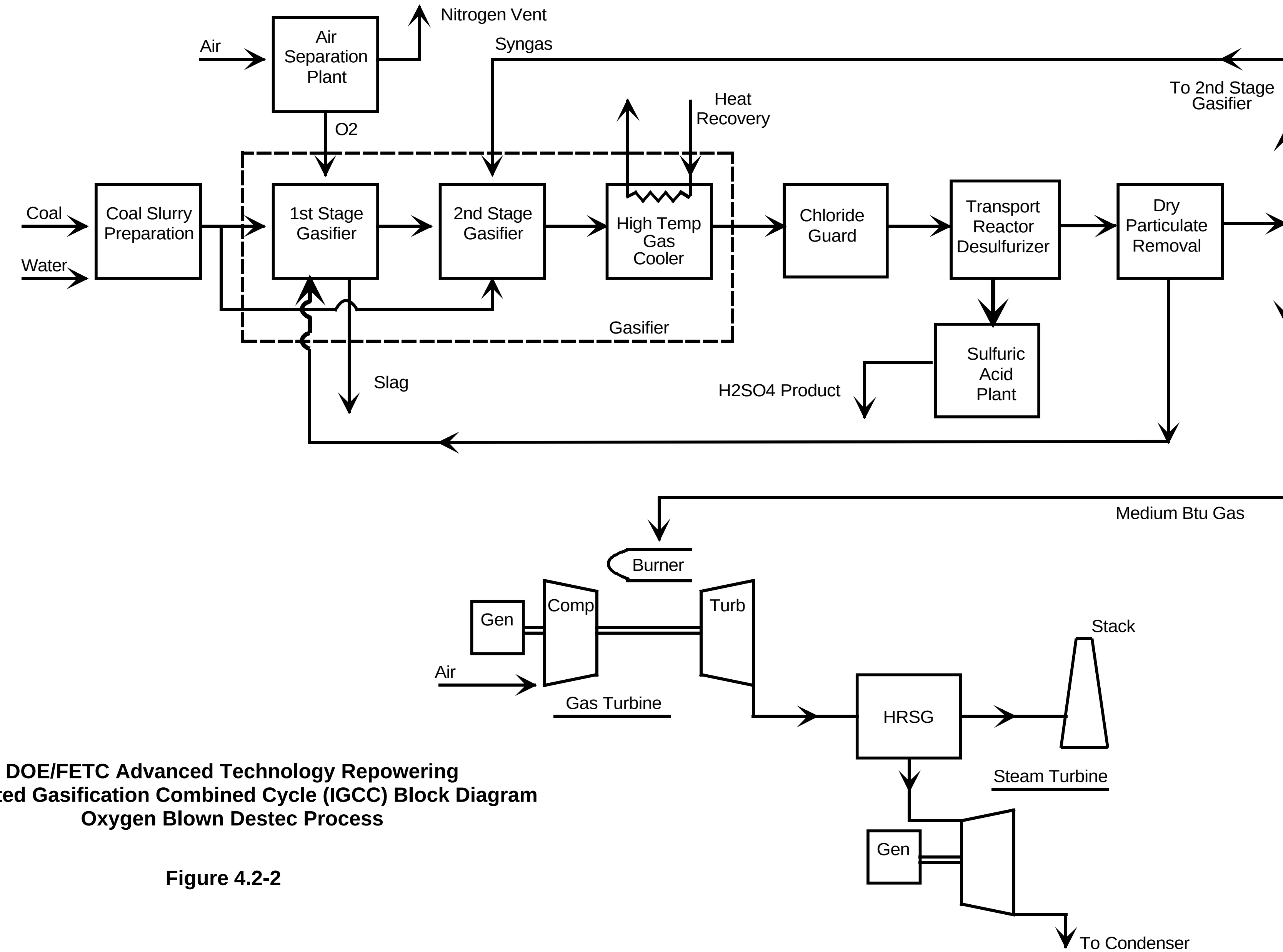
Particulate discharge to the atmosphere is limited by the use of a ceramic candle type barrier filter, which provides a particulate removal rate of greater than 99.99 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

4.2.4 Description of Oxygen-Blown IGCC

This reference design is based on the utilization of one oxygen-blown Destec entrained bed, slagging gasifier employing in-bed desulfurization. The medium-Btu gas produced in the gasifier is further cleaned in transport reactor type hot gas desulfurization and filtration processes downstream of the gasifier. The final product gas is used to fire a combustion turbine generator, which is coupled to a HRSG for driving one steam turbine generator.

The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this reference design. (Refer to Figure 4.2-2.)



DOE/FETC Advanced Technology Repowering
Integrated Gasification Combined Cycle (IGCC) Block Diagram
Oxygen Blown Destec Process

Figure 4.2-2

Illinois No. 6 coal is ground to 200 mesh and mixed with water to be fed to the pressurized Destec gasifier as a slurry. The slurry is fired with oxygen to produce medium-Btu gas, which is largely comprised of CO, H_2, and CO_2, and is discharged from the gasifier at 1900°F and cooled in a gas cooler to 1100°F.

The cooled gas passes through the chloride guard containing a fixed bed reactor, exposing the gas to nahcolite to reduce the chloride level to less than 1 ppm, thus protecting the sorbent and the combustion turbine downstream. The gas then enters the THGD, where sufficient sulfur is removed to result in a final sulfur level of approximately 30 ppm. The gas is then cleaned in the dry particulate removal system containing a final ceramic candle type barrier filter, resulting in very low levels of particulates. Fly ash from the filter is transferred to the fines combustor where it is oxidized. The regeneration gas from the THGD is a mixture of air and SO_2, which is a suitable feedstock for the sulfuric acid plant.

The gas exiting the THGD is conveyed to the combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the turbine and HRSG is released to the atmosphere via a conventional stack.

Based on the selection of a machine derived from Westinghouse “G” class combustion turbine, a fuel gas pressure of 400 psig was established to provide a margin above the compressor discharge pressure (275 psig for this reference case), allowing for necessary system and valve pressure drop.

Based on the above, a nominal gasifier pressure of 500 psig is required. At this pressure, a single gasifier is required. The gasifier is similar in size to the commercial-sized island utilized in the Wabash River Coal Gasification Repowering Project, which operates at a nominal pressure of 450 psig. The wall thickness of the gasifiers and other vessels and piping comprising the gasifier islands is increased by approximately 11 percent to compensate for the higher pressure (500 psig vs. 450 psig).

4.2.4.1 Coal Grinding and Slurry Preparation

Coal is fed onto conveyor No. 1 by vibratory feeders located below each coal silo. Conveyor No. 1 feeds the coal to an inclined conveyor (No. 2) that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. The rod mill grinds the coal and wets it with treated slurry water from a slurry water tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

4.2.4.2 Gasifier

Note: The following description is taken from the Coal Gasification Guidebook: Status, Applications, and Technologies, prepared by SFA Pacific, Inc. for the Electric Power Research Institute.

The Destec coal gasifier is a slurry feed, pressurized, upflow, entrained slagging gasifier whose two-stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. The slurry water consists of recycle water from the raw gas cooling together with makeup water. About 80 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 20 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1900°F.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 20 percent of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is easily gasified. The gasifier is refractory lined and uncooled. The hotter first-stage section of the gasifier also includes a special slag-resistant refractory. The 1900°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 1100°F, generating saturated steam for the steam power cycle in the process.

4.2.4.3 Acid Gas Removal (AGR)

The THGD section of the IGCC island serves to remove most of the sulfur from the gas produced by the gasifier. The gas delivered from the gasifier to the THGD system is at 1100°F and 425 psig. The sulfur compounds in the gas (predominantly H_2S) react with the sorbent to form zinc sulfides, yielding a clean gas containing less than 30 ppmv of sulfur compounds. The sorbent for this process is Z-sorb, a zinc-based material also containing nickel oxide.

The uncleaned gas enters the bottom of an absorber column, where it mixes with powdered sorbent, and then rises in the column. The gas/powder mixture exiting the column passes through a cyclone where the sorbent is stripped out for recycle. The clean gas discharged from the absorber flows to a high-efficiency barrier-type filter to remove any remaining particulates.

A regeneration column is used to regenerate the sorbent material from sulfide form to oxide form. Regeneration gas, laden with SO_2, is conveyed to the sulfator for capture of the sulfur and conversion to a disposable form.

4.2.4.4 Particulate Removal

The particulate removal stage in this gasification process is dependent upon a high-efficiency barrier filter comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and conveyed to the gasifier.

4.2.4.5 Chloride Guard

The chloride guard functions to remove HCl from the hot gas, prior to delivery to the combustion turbine.

The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a natural form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged, while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and are fabricated of carbon steel.

4.2.4.6 Sulfuric Acid Plant

The regeneration of the sorbent in the THGD subsystem produces an offgas from the regeneration process, which contains an SO_2 concentration of 13 percent. This is adequate for feed to a contact process sulfuric acid plant. Key to the process is the four-pass converter developed by Monsanto. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when about 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.2.4.7 Gas Turbine Generator

The gas turbine generator selected for this application is based on a derivative of the Westinghouse "G" class machine. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 19.2:1 and a rotor inlet temperature of almost 2600°F. In this service, with medium-Btu gas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the fuel gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include some redesign of the original can-annular combustors to allow firing of a medium-Btu gas derived from an IGCC plant. A second modification involves increasing the nozzle area of the first-stage turbine to accommodate the mass and volume flow of medium-Btu fuel gas combustion products, which is increased relative to those produced when firing natural gas. An increase in turbine nozzle areas of between 7 and 10 percent may be required. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement. The generator is a standard hydrogen-cooled machine with static exciter.

4.2.4.8 Steam Generation

<u>Heat Recovery Steam Generator (HRSG)</u>

The HRSG is a drum-type, triple-pressure design that is matched to the characteristics of the Westinghouse "G" turbine exhaust gas when firing medium-Btu gas. The HP drum produces steam at main steam pressure while the IP drum produces steam that is combined with the reheat.

<u>Gas Cooler</u>

The gas cooler contains a steam drum and heating surface for the production of saturated steam. This steam is conveyed to the HRSG where it is superheated.

4.2.4.9 Air Separation Plant

The air separation plant is designed to produce a nominal output of 2,050 tons/day of 95 percent pure O_2. The plant is designed with one 100 percent capacity production train. Liquefaction and liquid oxygen storage provide an 8-hour backup supply of oxygen.

In this air separation process, air is compressed to 70 psig and then cooled in a water scrubbing spray tower. The cooled air enters a reversing heat exchanger, where it is cooled to the liquefaction point prior to entering a double column (high/low pressure) separator. Refrigeration for cooling is provided by expansion of high-pressure gas from the lower part of the high-pressure column.

4.2.5 IGCC Support Systems (Balance of Plant)

4.2.5.1 Coal Handling System

The function of the balance-of-plant coal handling 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 unloader and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous 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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) 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 crushers. The coal then enters the second crusher, which reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the stationary tripper, which loads the coal into one of the two silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 225,000 lb/h = 113 tph plus 10% margin = 124 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 192,000 lb/h = 96 tph (based on MCR rate multiplied by an assumed 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Two unit trains per week at maximum burn rate
  - One and one-half unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 9,000 tons (72 hours at maximum burn rate)
  - Dead storage = 70,000 tons (30 days at average burn rate)

4.2.5.2 Slag Ash Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. The ash is removed from the process as slag. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary, through a proprietary pressure letdown device, to a series of dewatering bins. The separated liquid is recycled to the slag quench water bath.

The cooled, solidified slag is stored in a storage vessel. The hopper is sized for a nominal holdup capacity of approximately 72 hours of full-load operation. At periodic intervals, a convoy of slag hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately 12 truck loads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power.

4.2.6 <u>Steam Cycle Balance of Plant</u>

The following section provides a description of the steam turbines and their auxiliaries.

4.2.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. 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 last-stage bucket length of 30 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the HP turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 485 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Extraction steam from the HP section is used for the burner transition cooling in the G machine. The steam from the transition cooling is then routed to the hot reheat.

Turbine bearings are lubricated by a closed-loop water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by 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.

4.2.6.2 Condensate and Feedwater Systems

Condensate

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

Feedwater

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 motor-driven, HP and IP, 50 percent capacity boiler feed pumps are provided. Each pump is provided with a variable speed drive to support startup, shutdown, and part-load operation. 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 suction of each boiler feed pump is equipped with a startup strainer.

4.2.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1800 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 450 psig/650°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 400 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

4.2.6.4 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.

4.2.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.2-3.

4.2.7 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.

4.2.8 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 designedfor 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.

Table 4.2-3
INTEGRATED GASIFICATION COMBINED CYCLE

Major Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	1,128,400	135	100	A106 Gr. B	8	Sch. 40
HP Feedwater, Pump to HRSG	735,400	2316	325	A106 Gr. C	8	Sch. 160
IP Feedwater, Pump to HRSG	61,000	600	321	A106 Gr. B	3	Sch. 40
HP Feedwater to Gasifier	359,700	2016	420	A106 Gr. C	6	Sch. 160
HP steam from Gasifier`	359,700	2016	640	A106 Gr. C	6	Sch. 160
Main Steam/HRSG to Steam Turbine	730,200	1814	1000	A335 Gr. P91	8	1.375
Cold Reheat/ST to HRSG	577,000	451	647	A106 Gr. B	14	Sch. 40
Hot Reheat/HRSG to ST	709,000	406	1000	A335 Gr. P91	16	Sch. 40
Cold Reheat/GT for Cooling	68,000	451	647	A106 Gr. B	6	Sch. 40
Fuel Gas/Gasifier Island to Gas Turbine	461,300	372	1105	A335 Gr. P91	16	Sch. 40
O_2 Piping to Gasifier	170,000	620	250	A106 Gr B	6	Sch. 40

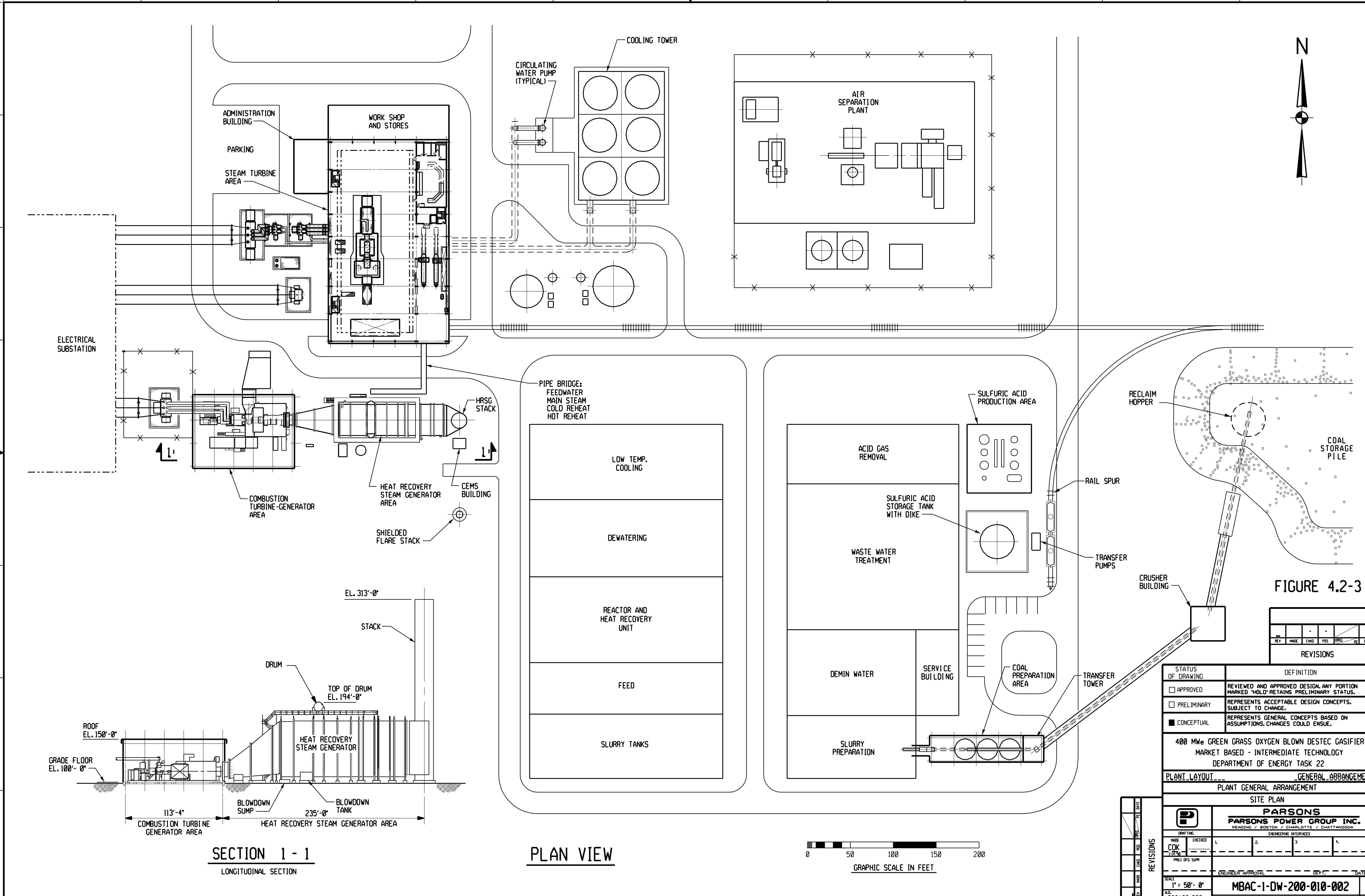
4.2.9 Site, Structures, and Systems Integration

4.2.9.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

4.2.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate structures required for this technology is based on the assumption of a flat site. The IGCC gasifier and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the south, as shown in the conceptual arrangement in Figure 4.2-3.



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The gasifier and its associated process blocks are located west of the coal storage pile. The gas turbine and its ancillary equipment are sited west of the gasifier island, in a turbine building designed expressly for this purpose. A HRSG and stack are east of the gas turbine, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the west side of the steam turbine building.

The cooling tower heat sink for the steam turbine is located to the east of the steam turbine building. The air separation plant is further to the east, with storage tanks for liquid O_2 located near the gasifier and its related process blocks. Sulfur recovery and wastewater treatment areas are located east and south of the air separation plant.

The arrangement described above provides good alignment and positioning for major interfaces; relatively short steam, feedwater, and fuel gas pipelines; and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located north of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through a triple-pressure HRSG and then to a new 213-foot stack. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.

4.2.10 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		1
14	Conveyor No. 4	48" belt	400 tph	1
15	Transfer Tower	N/A	400 tph	1
16	Tripper	N/A	400 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	1,500 ton	2

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Not Applicable

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		80 tph	2
2	Conveyor No. 1	Belt	160 tph	1
3	Conveyor No. 2	Belt	160 tph	1
4	Rod Mill Feed Hopper	Vertical, double hopper	200 ton	1
5	Vibratory Feeder		80 tph	2
6	Weight Feeder	Belt	80 tph	2
7	Rod Mill	Rotary	80 tph	2
8	Slurry Water Storage Tank	Field-erected	80,000 gal	1
9	Slurry Water Pumps	Horizontal, centrifugal	600 gpm	2
10	Rod Mill Product Tank	Field-erected	150,000	1
11	Rod Mill Product Pumps	Horizontal, centrifugal	800 gpm	2
12	Slurry Storage Tank	Field-erected	280,000	1
13	Centrifugal Slurry Pumps	Horizontal, centrifugal	1,600 gpm	2
14	PD Slurry Pumps	Progressing cavity	270 gpm	2
15	Slurry Blending Tank	Field-erected	80,000 gal	1
16	Slurry Blending Tank Pumps	Horizontal, centrifugal	300 gpm	2

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	50,000 gal	1
2	Condensate Pumps	Vert. canned	1,100 gpm @ 310 ft	2
3	Deaerator and Storage Tank	Horiz. spray type	1,130,000 lb/h 215°F	1
4	IP Feed Pumps	Interstage bleed from HP feed pump	60 gpm/1,100 ft	2
5	HP Feed Pumps	Barrel type, multi-staged, centr.	735 gpm / 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal No. 2 oil	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, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exch	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 horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, 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

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed	2860 tpd/500 psig	1
2	Gas Cooler	Firetube	167×10^6 Btu/h	1
3	Flare Stack	Shielded	465,000 lb/h medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	80,000 acfm, 70 psig discharge pressure	1
2	Cold Box		2,100 ton/day O_2	1
3	Oxygen Compressor	Centrifugal, multi-stage	33,200 scfm, 650 psig discharge pressure	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Qty
1	Sorbent Storage Hopper	*		1
2	Sorbent Feed Hopper	*		1
3	Transport Desulfurizer	*		1
4	Desulfurizer Cyclone	*		1
5	Transport Regenerator	*		1
6	Regenerator Cyclone	*		1
7	Sorbent Regeneration Air Heater	*		1
8	Regenerator Effluent Gas Cooler	*		1

* This information is proprietary and is not presented.

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	250 MWe Gas Turbine Generator	Axial flow single spool based on Westinghouse G-class	1,100 lb/sec airflow 2600°F rotor inlet temp. 19.2:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,100 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Air-to-Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1
11	Fire Protection Package	Halon		1

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 sections and integral deaerator	HP-2300 psig/325°F 730,000 lb/h superheat to 1000°F IP-600 psig/320°F 63,000 lb/h	1
2	Raw Gas Cooler Steam Generator	Drum and superheater	2000 psig/sat. steam 360,000 lb/h Superheat to 1000°F	1
3	Stack	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	140 MW Turbine Generator	TC2F30	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	716,000 lb/h steam @ 2.0 in. Hga with 78°F water, 19°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	40,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell counter-flow, film type fill	56°F WB/78°F CWT/ 97° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING & REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath		1
2	Slag Precrusher		12 tph solids	1
3	Slag Crusher	Roll	12 tph solids	1
4	Slag Depressurizing Unit	Proprietary	12 tph solids	1
5	Slag Dewatering Unit	Horizontal, weir	4 tph solids	3
5	Slag Conveyor	Drag chain	4 tph	3
6	Slag Conveyor	Drag chain	8 tph	*1
6	Slag Storage Vessel	Reinf. concrete vert. cylindrical	1,200 ton	*1
7	Slide Gate Valve			*1
8	Telescoping Unloader		25 tph	*1

*Total for plant.

4.2.11 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the market-based intermediate O_2-blown Destec 400 MW plant is shown in Table 4.2-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, “Capital and Production Cost and Economic Analysis.” The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.2-4

Client:	DEPARTMENT OF ENERGY
Project:	Market Based Advanced Coal Power Systems
Report Date:	14-Aug-98 11:00 AM

TOTAL PLANT COST SUMMARY

Case:	Destec (2005-80/20)
Plant Size:	349.2 MW,net
Estimate Type:	Conceptual
Cost Base (Jan)	1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	5,347	1,073	4,670	327		**$11,417**	913		2,466	**$14,796**	42
2	COAL & SORBENT PREP & FEED	6,455	1,485	6,972	488		**$15,400**	1,232	517	2,261	**$19,410**	56
3	FEEDWATER & MISC. BOP SYSTEMS	5,483	2,655	4,284	300		**$12,722**	1,018		3,309	**$17,049**	49
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	8,575		8,734	611		**$17,921**	1,434	1,792	2,115	**$23,261**	67
4.2	High Temperature Cooling	14,603		14,880	1,042		**$30,525**	2,442	3,052	3,602	**$39,621**	113
4.3	ASU/Oxidant Compression	45,518		w/equip.			**$45,518**	3,641		4,916	**$54,075**	155
4.4-4.9	Other Gasification Equipment		3,760	2,093	147		**$5,999**	480		1,700	**$8,179**	23
	SUBTOTAL 4	*68,696*	*3,760*	*25,707*	*1,800*		***$99,963***	*7,997*	*4,845*	*12,333*	***$125,137***	*358*
5	HOT GAS CLEANUP & PIPING	24,722	2,048	8,700	609		**$36,079**	2,886	4,305	8,814	**$52,084**	149
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	42,367		2,820	197		**$45,384**	3,631	3,404	5,242	**$57,660**	165
6.2-6.9	Combustion Turbine Accessories		136	157	11		**$305**	24		99	**$428**	1
	SUBTOTAL 6	*42,367*	*136*	*2,977*	*208*		***$45,689***	*3,655*	*3,404*	*5,341*	***$58,088***	*166*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,056		1,877	131		**$15,065**	1,205		1,627	**$17,897**	51
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,898	706	1,341	94		**$4,039**	323		605	**$4,967**	14
	SUBTOTAL 7	*14,955*	*706*	*3,217*	*225*		***$19,103***	*1,528*		*2,232*	***$22,864***	*65*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	12,044		1,984	139		**$14,168**	1,133		1,530	**$16,831**	48
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	5,263	160	2,887	202		**$8,513**	681		1,583	**$10,777**	31
	SUBTOTAL 8	*17,308*	*160*	*4,871*	*341*		***$22,680***	*1,814*		*3,113*	***$27,608***	*79*
9	COOLING WATER SYSTEM	3,714	2,055	3,501	245		**$9,514**	761		1,846	**$12,121**	35
10	ASH/SPENT SORBENT HANDLING SYS	3,463	642	2,949	206		**$7,261**	581	494	967	**$9,303**	27
11	ACCESSORY ELECTRIC PLANT	11,636	3,829	9,563	669		**$25,696**	2,056		4,571	**$32,323**	93
12	INSTRUMENTATION & CONTROL	5,117	1,434	5,327	373		**$12,251**	980		2,056	**$15,287**	44
13	IMPROVEMENTS TO SITE	1,831	1,053	3,667	257		**$6,807**	545		2,205	**$9,557**	27
14	BUILDINGS & STRUCTURES		4,241	5,471	383		**$10,096**	808		2,726	**$13,629**	39
	TOTAL COST	**$211,093**	**$25,277**	**$91,876**	**$6,431**		**$334,677**	**$26,774**	**$13,564**	**$54,240**	**$429,256**	**1229**

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Section 4.3

Advanced Air-Blown Transport Reactor IGCC

4.3 ADVANCED AIR-BLOWN TRANSPORT REACTOR IGCC

4.3.1 Introduction

This IGCC concept is based on the utilization of the MW Kellogg air-blown transport reactor coal gasification process supplying low-Btu gas to a gas turbine/combined cycle power plant. The plant configuration is based on current information and design preferences, a "market-based" design, the availability of newer combustion and steam turbines, and a greenfield site.

This version of IGCC technology is based on selection of a gas turbine derived from the General Electric "H" machine. This machine provides values of power output, airflow, and compressor pressure ratio that provide a good match with the gasifier and the steam plant cycle. For this study, one gas turbine is combined with a steam turbine on a single shaft, driving one electric generator. The IGCC portion of the plant is configured with two gasifier islands, including in-situ desulfurization with a hot gas polisher. The resulting performance for the market-based plant is significantly enhanced over the intermediate phase Destec oxygen-blown IGCC system described earlier in this document.

4.3.2 Heat and Mass Balance

This plant utilizes a combined cycle for combustion of the low-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the heat recovery steam generator (HRSG), by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooler and sulfator).

The pressurized transport reactor gasifier utilizes a combination of air and steam to gasify the coal and produce a low-Btu hot fuel gas. The fuel gas produced in the transport gasifier leaves at 1690°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to only 1100°F. High-pressure saturated steam is generated in the hot gas cooler and is superheated in the HRSG, which also performs reheating duty, steam generation (IP and LP pressure levels), and economizer duty (heats feedwater and condensate).

The gas flows through a series of hot gas cleanup processes including a chloride guard, transport reactor desulfurization polisher, and final particulate filter. A fraction of the clean hot gas is cooled and recycled to back purge the particulate filter. A separate fines combustor provides complete carbon conversion, handling the particulates captured by the barrier filter.

The gas turbine operates in an open cycle mode. The inlet air is compressed in a single spool compressor; a small portion of the compressed air is conveyed off-board the machine, after-cooled, boosted to a higher pressure in a separate compressor, and supplied to the gasification process. Most of the compressor discharge air remains on-board the machine; a small portion is used for cooling of certain hot section components. The major portion of the airflow passes to the burner section to support combustion of the low-Btu gas supplied by the gasifier islands.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they expand through the turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG to recover thermal energy, and then exhaust to the plant stack.

One aspect in which this application differs from the original “H” gas turbine design configuration concerns the increase in mass and volumetric flow rates of fuel gas. This results from the low-Btu gasification process used, which requires significant increases in fuel flow rates in order to deliver the required combustion heat input. The gas turbine is fitted with new combustors designed to fire the low-Btu gas. The increase in mass and volume flow rates also requires that the turbine nozzle areas increase by approximately 4 percent to pass the higher flow. The increase in nozzle area is considered to be within the capabilities of the basic design of the machine. The gas turbine used in this application thus requires modifications in several respects, and is considered a derivative of the GE “H” machine, and not an actual production model.

Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.3-1, which includes auxiliary power requirements. The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance diagram (Figure 4.3-1).

NOTES:
1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.

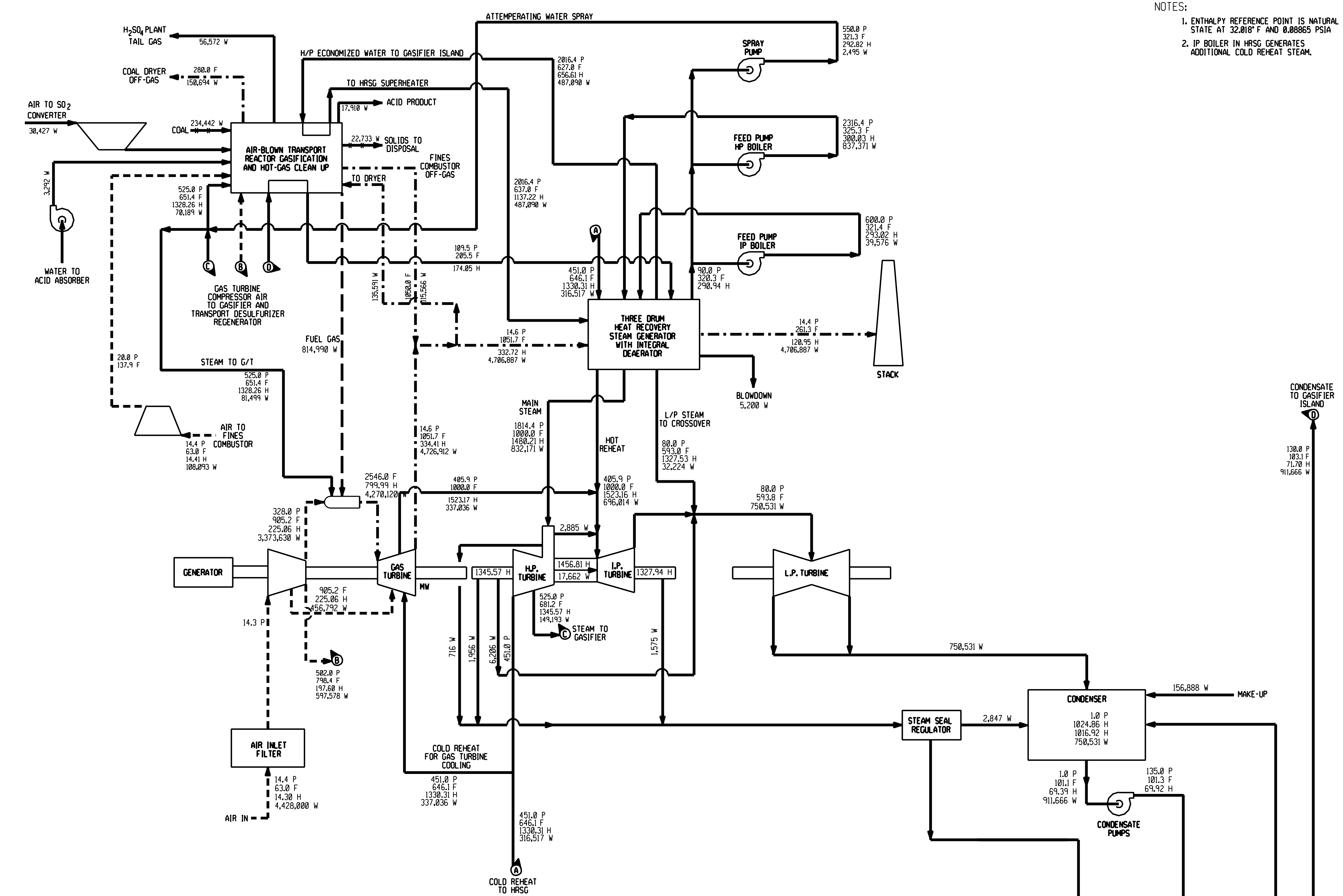

FIGURE 4.3-1

LEGEND

- - - -	AIR / OXIDANT
— — —	FUEL GAS
— · — ·	COMBUSTION PRODUCTS
—×—×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	275.443 MWe
STEAM T-G POWER :	142.230 MWe
GENERATOR LOSS (TOTAL):	6.265 MWe
AUXILIARY POWER (TOTAL):	13.28 MWe
NET PLANT POWER :	398.128 MWe
NET PLANT EFFICIENCY :	49.7 %
NET PLANT HEAT RATE :	6,870 Btu/kwh

BTMTRAN4/TRANATS4 J.S.WHITE 6/12/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | ENGINEER | LEAD DISCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY
DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUPTIONS. REVIEWED NOT CHECKED.
CONSTRUCTION STATUS: CONCEPTUAL DESIGN STUDY NOT FOR CONSTRUCTION

DRAWN BY: CLB DATE: 3/22/98
CHECKED BY
LEAD DESIGNER
ENGINEER
LEAD DISCIPLINE ENGR.
PROJECT ENGINEERING MANAGER
PROJECT MANAGER

PARSONS
PARSONS POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
AIR BLOWN TRANSPORT REACTOR
GASIFICATION COMBINED CYCLE
DEPARTMENT OF ENERGY TASK 22
PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER
GENERAL ELECTRIC "H" ATS

SCALE: NONE
PARSON'S DWG. NO.: MBAC-1-400-314-008
REV: A

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PPGI-DATE: 09-Apr-98 11:15

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Table 4.3-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for two transport gasifiers, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine	271,311
Steam Turbine	140,097
Total	411,408
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	200
Condensate Pumps	150
IP Feed Pump	30
HP Feed Pump	2,310
Acid Pumps	50
Miscellaneous Balance of Plant (Note 1)	900
Screw Feeders	100
Boost Air Compressor	4,530
Recycle Gas Compressor	290
Sulfuric Acid Plant Blower	260
Fines Combustor Blower	590
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Circulating Water Pumps	1,190
Cooling Tower Fans	820
Ash Handling	180
Transformer Loss	980
TOTAL AUXILIARIES, kWe	13,280
Net Power, kWe	398,128
Net Efficiency, % HHV	49.7
Net Heat Rate, Btu/kWh (HHV)	6,870
CONDENSER COOLING DUTY, 10^6 Btu/h	714
CONSUMABLES	
As-Received Coal Feed, lb/h	234,442

Note 1 - Includes plant control systems, lighting, HVAC, etc.

The Rankine cycle used herein is based on 1800 psig/1000°F/1000°F single reheat configuration. The high-pressure turbine is supplied with 832,171 lb/h steam at 1815 psia and 1000°F. Main steam is generated in a HRSG drum and in drums associated with the gasifier hot gas cooler and the sulfator. Superheat is provided by superheaters in the HRSG.

The cold reheat flow from the HP turbine is split into two streams. One stream is routed to the reheater in the HRSG (316,517 lb/h of steam at 451 psia and 687°F). The second stream (337,036) lb/h at the same pressure and temperature as the first stream) is conveyed to the gas turbine, where it provides closed-loop cooling of selected gas path components. The steam is reheated to 1000°F in the process, and rejoins the hot reheat steam from the HRSG en route to the IP turbine section.

In the unit, a single machine comprised of tandem HP, IP, and LP sections on the same shaft as the gas turbine, both driving one 3600 rpm hydrogen-cooled generator. The steam turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga at the nominal 100 percent load design point.

The condensate and feedwater heating is accomplished by heat recovery from the gas turbine exhaust, in the HRSG, with some heat recovery also available in the gasifier island. Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the various steam drums.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 398 MWe. The overall net plant efficiency is 49.7 percent HHV. An estimate of the auxiliary loads, including the gasifier island and existing balance of plant, is presented in Table 4.3-1.

In summary, the major features of the steam turbine cycle for this IGCC plant include the following:

- Subcritical steam conditions and single reheat (1800 psig/1000°F/1000°F).
- Boiler feed pumps are motor-driven.

- Turbine configuration is based on one 3600 rpm tandem compound, two-flow exhaust machines.
- A single open feedwater heater is used in the turbine cycle.
- Condensate and feedwater heating are principally accomplished in the HRSG, and by several heat recovery opportunities in the gasifier island.

4.3.3 Emissions Performance

The reference fossil unit with air-blown transport IGCC technology is projected to result in low emissions of NOx. The emission of SO_2 and particulates (fly ash) is expected to be at extremely low levels. CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu), since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency. The emissions levels are presented in Table 4.3-2.

Table 4.3-2
AIRBORNE EMISSIONS - IGCC - TRANSPORT REACTOR

	Values at Design Condition (65% and 85% Capacity Factor)			
	lb/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.017	134	175	0.12
NOx	0.024	187	244	0.16
Particulates	0.002	15	20	0.014
CO_2	200.4	1,560,180	2,040,200	1,376

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the transport hot gas desulfurizer (THGD) subsystem. The THGD process removes approximately 99.5 percent of the sulfur compounds in the fuel gas.

The reduction in NOx is achieved for a fuel gas containing fuel-bound nitrogen (NH_3) by the use of rich-quench lean (staged) combustion technology coupled with syngas dilution by steam from the steam cycle. Syngas dilution and staged combustion, sub-stoichiometric combustion followed by excess air dilution, promote the conversion of fuel bound nitrogen to N_2 rather than NOx. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce NOx emissions further, but are not applied to the subject plant in accordance with the ground rules stated in Section 3.

Particulate discharge to the atmosphere is reduced by the use of the ceramic candle barrier filters, which provide an efficiency of 99.9 percent.

CO_2 emissions are unchanged on an intensive basis (1b/MMBtu), since the same fuel is used (Illinois No. 6 coal). Total CO_2 emissions decrease slightly due to the large increase in net efficiency, even though output is increased significantly.

4.3.4 <u>Description of Air-Blown Transport Integrated Gasification Combined Cycle Gasification Island</u>

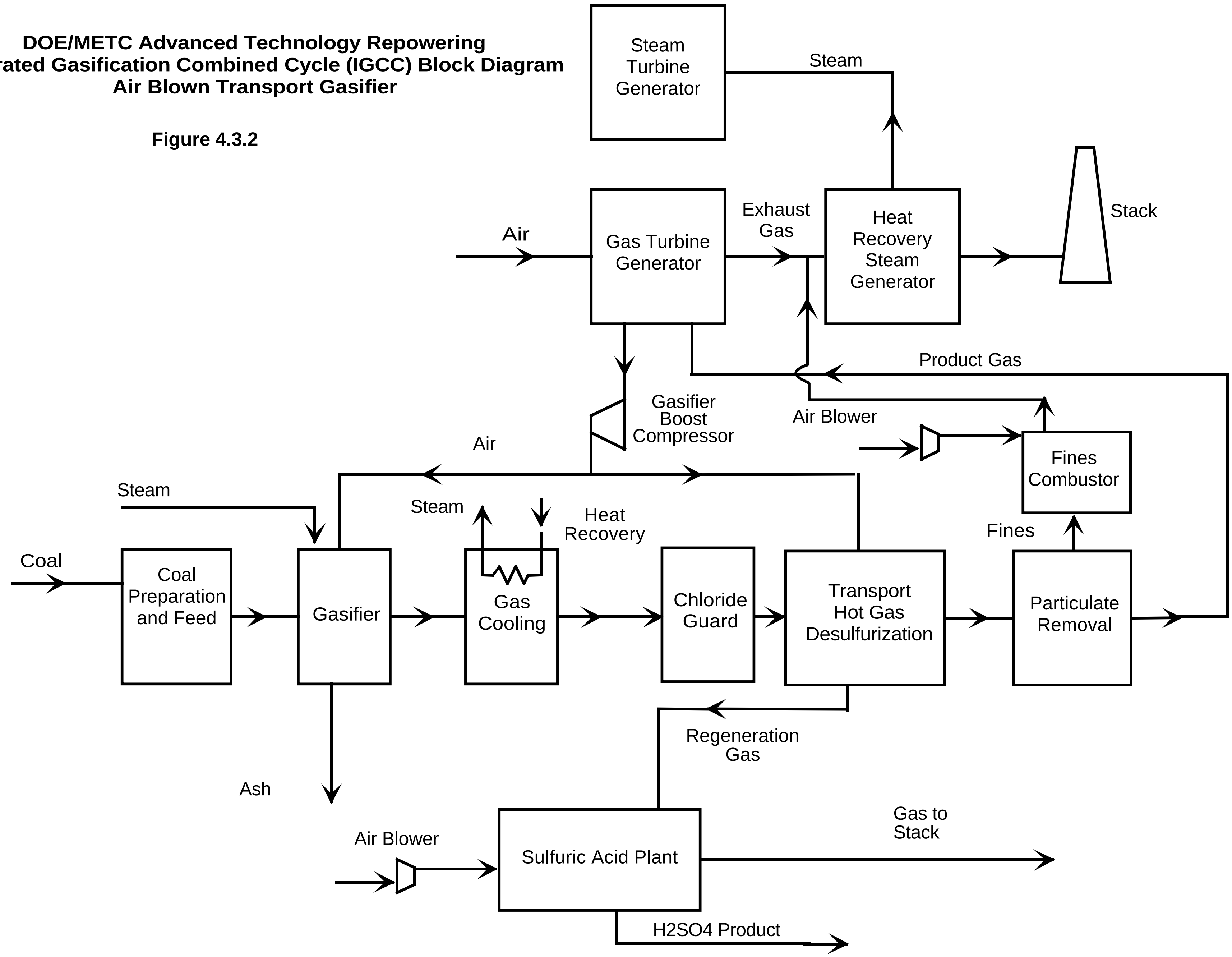
This case is based on the utilization of the air-blown M.W. Kellogg transport reactor gasifier employing in-bed desulfurization. The low-Btu gas produced in the gasifier is further cleaned in hot gas desulfurization and filtration processes downstream of the gasifier. The final product gas is used to fire a combustion turbine generator, which is coupled to a HRSG, which generates steam to drive a steam turbine generator.

The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this case (refer to Figure 4.3-2).

A portion of the air discharged from the gas turbine compressor is after-cooled and then further compressed in a boost compressor to the gasifier operating pressure. Crushed coal is fed to the gasifier where it reacts with the air and steam fed to the gasifier to produce low-Btu gas. The gas, which is largely comprised of CO, H_2, CH_4, and inerts, is discharged from the gasifier and cooled in a gas cooler to 1100°F.

DOE/METC Advanced Technology Repowering
Integrated Gasification Combined Cycle (IGCC) Block Diagram
Air Blown Transport Gasifier

Figure 4.3.2



The cooled gas passes to the chloride guard containing a fixed bed reactor exposing the gas to a nahcolite sorbent to reduce the chloride level to less than 1 ppm to protect the combustion turbine downstream.. The gas is then routed to the hot gas desulfurizer, where sufficient sulfur is removed to result in a final sulfur level of about 30 ppm. The gas is then cleaned in a particulate removal system containing a barrier filter containing a large number of ceramic candles arranged in a cylindrical vessel, resulting in very low levels of particulates.

The gas exiting the particulate removal system represents the final product gas and is conveyed to the combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the combustion turbine and HRSG is released to the atmosphere via a conventional stack.

Final "closure" of the process cycle is achieved in the fines combustor. The fines combustor is used to oxidize fines from the candle filter; no heat recovery is attempted from this very small stream.

Based on the GE "H" turbine selection, a fuel gas pressure of 450 psig was established to provide a margin above the compressor discharge pressure, allowing for necessary system and valve pressure drop. Based on the above, a gasifier pressure of 475 psig, nominal, is required.

4.3.4.1 Gasifier

The transport gasifier is comprised of a mixing zone, a riser, cyclones, a standpipe, and a non-mechanical valve. Air and steam are introduced at the bottom of the gasifier in the mixing zone. Coal is introduced in the upper section of the mixing zone. The top section of the gasifier discharges into the disengager or primary cyclone. The cyclone is connected to the standpipe, which discharges the solids at the bottom through a non-mechanical valve into the transport gasifier mixing zone at the bottom of the riser.

The gasifier system operates by circulating the entrained solids up through the gasifier riser, through the cyclone, and down through the standpipe. The solids re-enter the gasifier mixing zone through the non-mechanical valve. The steam and air jets provide the motive force to maintain the bed in circulation and oxidize the char as it enters the gasifier mixing zone. The hot gases react with coal/char in the mixing zone and riser to produce gasification products.

The gas and entrained solids leaving the primary cyclone are passed through the secondary cyclone to provide final de-entrainment of the solids from the gas. The solids separated in the secondary cyclone fall through the dipleg into the standpipe. A solids purge stream is withdrawn from the standpipe for solids inventory maintenance.

The gas leaving the secondary cyclone passes through a gas cooler, which reduces the gas temperature from about 1900°F to 1100°F. The cooled gas then passes in succession through a fixed bed chloride guard, transport gas desulfurizer, and a final-stage particulate removal in a candle type filter.

4.3.4.2 Gas Cooling

The hot gas leaving the gasifier is cooled in the product gas cooler to 1100°F, superheating and/or reheating steam from the steam power cycle in the process.

4.3.4.3 Chloride Guard

The chloride guard functions to remove HCl from the gas, prior to discharge to the combustion turbine. The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and are fabricated of carbon steel.

4.3.4.4 Transport Hot Gas Desulfurization

The transport reactor desulfurizer consists of a riser tube, disengager, and standpipe for both the absorber section and regeneration section. Two desulfurizer trains are provided, one for each gasifier. Each absorber contains a circulating inventory of Z-sorb sorbent.

The regenerator is a transport reactor, through which sorbent from each absorber passes through the regenerator riser, disengagers, and then back to the absorber through the standpipe. Assuming similar sorbent velocities and densities, as in the desulfurizer column, each regenerator is somewhat smaller in diameter compared to the desulfurizer, but is approximately the same in height. Regeneration is performed at 1200°F. The regeneration off-gas, containing predominantly SO_2, is sent to the sulfuric acid plant.

The particles are disengaged from gas passing through the high-efficiency cyclones at the top of the absorber. Some Z-sorb is also retained by the regeneration outlet gas. The total of 2750 lb/h fines elutriated from the transport desulfurization absorber, which are predominantly 20 micron particles from the gasifier and the balance being Z-sorb, are recovered in the ceramic gas filter.

4.3.4.5 Particulate Removal

The particulate removal stage in this gasification process consists of a ceramic candle filter. The individual filter elements, or candles, are distributed in an array inside a refractory-lined carbon steel pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and oxidized in the fines combustor.

4.3.4.6 Fines Combustor

The fines combustor is an atmospheric fluid bed combustor, which receives spent sorbent from the gasifier cyclone and regeneration gas from the THGD process.

4.3.4.7 Sulfuric Acid Plant

The AGR process produces an offgas from the regeneration process, which contains an H_2S concentration of about 50 percent. This is adequate for feed to an H_2S-burning contact process sulfuric acid plant that burns the H_2S acid gas with air, yielding SO_2, water vapor, and heat, which are fed to a conventional contact acid plant. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Key to the process is the four-pass converter developed by Monsanto. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.3.4.8 Gas Turbine Generator

The gas turbine generator selected for this application is based on the GE "H" machine. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes and four stages of variable stator vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 23:1 and a rotor inlet temperature of almost 2600°F. In this service, with low-Btu gas from an IGCC plant, the machine must be modified in order to properly combust the low-Btu gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include the replacement or modification of the original can-annular combustor with new combustors designed for efficient, low-NOx combustion of the low-Btu gas. A second modification involves increasing the nozzle area of the first-stage turbine to accommodate the mass and volume flow of low-Btu fuel gas combustion products which are increased relative to those produced when firing natural gas. An increase in turbine nozzle areas of approximately 4 percent is required. Other modifications include rearranging the various auxiliary skids that support the machine, to accommodate the spatial requirements of the design. The generator is a standard hydrogen-cooled machine with static exciter.

4.3.4.9 Steam Generation

Heat Recovery Steam Generator (HRSG)

The HRSG is a drum type, triple-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing low-Btu gas, and to the steam conditions of the steam turbine; namely, 1800 psig/1000°F/1000°F. The HP drum produces steam at main steam pressure, which is then superheated in the HRSG to 1000°F. A mid-pressure drum produces steam at the pressure required for steam cooling of portions of the "H" turbine. This steam is heated and returned to the steam cycle to mix with hot reheat steam. Some of the steam produced by the mid-pressure drum is conveyed to the gasifier for injection into the gasifier vessel. A low-pressure drum produces steam for the integral deaerator of the HRSG, and for admission to the LP section of the steam turbine.

Gas Cooler

The gas cooler contains a steam drum for the production of main steam at turbine throttle conditions (1800 psig). This steam is conveyed to the HRSG enroute to the steam turbine, where it is superheated and combined with the main steam produced by the HRSG for routing to the steam turbines.

4.3.4.10 Fuel Preparation and Injection System

The fuel preparation and injection system receives crushed coal, sized at 1" x 0, from the coal handling system. The system interface is at the slide gate valves at the discharge of the silos. The silos supply coal through slide gate valves to two vibratory feeders, which feed coal to two bowl mills. The ground coal (average particle size is less than 250 microns) exiting the mills is transported pneumatically to each of two storage (surge) hoppers, one for each gasifier train. The coal passes from the storage hopper to a weight feeder and then to a mixing screw conveyor, which conveys the coal to a dense phase pneumatic conveyor and on to the gasifier pressurization lock hoppers.

Each lock hopper train is comprised of a storage injector and a primary injector; these lock hoppers are pressurized by compressed air from the transport boost compressor. The storage injectors discharge into the primary injectors, which discharge the coal into the gasifier.

4.3.4.11 Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is provided to combust and dispose of product gas during startup, shutdown, and upset conditions. The flare stack is provided with multiple pilot burners, fueled by natural gas or propane, with pilot flame monitoring instrumentation.

4.3.5 IGCC Support Systems (Balance of Plant)

4.3.5.1 Coal Handling System

The function of the coal handling system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the bottom trestle car dumper and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous 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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0. The coal then enters a second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the stationary tripper that loads the coal into one of the two silos.

<u>Technical Requirements and Design Basis</u>

- Coal burn rate:
  - Maximum coal burn rate = 234,400 lb/h = 117.2 tph plus 10% margin = 129 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 203,000 lb/h = 102 tph (based on MCR rate multiplied by an 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Two unit trains per week at maximum burn rate
  - One and one-half unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 9,500 tons (72 hours at maximum burn rate)
  - Dead storage = 69,000 tons (30 days at average burn rate)

4.3.5.2 Ash Handling

The ash handling system conveys, stores, and disposes of ash removed from the gasification process.

Spent material drains from the gasifier into a receiver vessel, which provides several hours holdup capacity. The receiving hopper operate at atmospheric pressure. A slide gate valve at the bottom outlet of the hopper regulates the flow of material from the hopper to a screw cooler, which cools and transports the ash out and onto a system of drag chain conveyors. The conveyors transport the ash to a pair of storage silos for temporary holdup. The silos are sized for a nominal holdup capacity of 36 hours of full-load operation each. At periodic intervals, a convoy of ash hauling trucks will transit the unloading station underneath the silos and remove a quantity of ash for disposal. Approximately 32 truck loads per day are required to remove the total quantity of ash produced by the plant operating at nominal rated power.

4.3.6 Steam Cycle Balance of Plant

The following section provides a description of the steam turbines and their auxiliaries.

4.3.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. 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 last-stage bucket length of 33.5 inches.

Main steam from the HRSG passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns as cold reheat to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 400 psig/1000°F. A portion of the cold reheat is routed to the gas turbine and used for cooling. This steam is reheated to 1000°F performing the cooling duty, is combined with the hot reheat coming from the HRSG, and enters the IP section. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft.

The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

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 DCS, and incorporates on-line repair capability.

4.3.6.2 Condensate and Feedwater Systems

Condensate

The condensate system pumps condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The 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 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.

Feedwater

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 boiler feed pumps of each type are provided. Each pump is provided with inlet and outlet isolation valves, outlet check valve, and minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.3.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1800 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 437 psig/685°F exits the HP turbine and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam at approximately 391 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

A portion of the reheat is conveyed to the gas turbine, where it is provided closed-loop cooling of selected gas path components. The steam is reheated to 1000°F in the process, and rejoins the hot reheat steam from the HRSG en route to the IP turbine section.

4.3.6.4 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.

4.3.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.3-3.

4.3.7 <u>Accessory Electric Plant</u>

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.

4.3.8 <u>Site, Structures, and Systems Integration</u>

4.3.8.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

Table 4.3-3
INTEGRATED GASIFICATION COMBINED CYCLE

New Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	911,670	135	100	A106 Gr. B	8	Sch. 40
IP Feedwater, Pump to HRSG	39,580	600	321	A106 Gr. B	3	Sch. 40
HP Feedwater/Pump to HRSG	837,400	2316	325	A106 Gr. C	8	Sch. 160
HP Feedwater/HRSG to Gasifier Island	487,100	2016	627	A106 Gr. C	6	Sch. 160
Main Steam/Gasifier Island to HRSG	487,100	2016	637	A106 Gr. C	6	Sch. 160
Main Steam/HRSG to Steam Turbine	832,200	1815	1000	A335 Gr. P91	10	1.125
Cold Reheat/ST to GT	337,000	451	646	A106 Gr. C	12	Sch. 40
Cold Reheat/ST to HRSG	316,500	451	646	A106 Gr. C	12	Sch. 40
Hot Reheat/From GT	337,000	406	1000	A335 Gr. 91	10	Sch. 40
Hot Reheat/HRSG to ST	696,000	406	1000	A335 Gr. 91	18	Sch. 40
Fuel Gas/Gasifier Island to Gas Turbine	814,990	450	1070	A335 Gr. P91	20	0.50

4.3.8.2 New Structures and Systems Integration

The development of the reference plant site to incorporate new structures required for this technology is based on the assumption of a flat site.

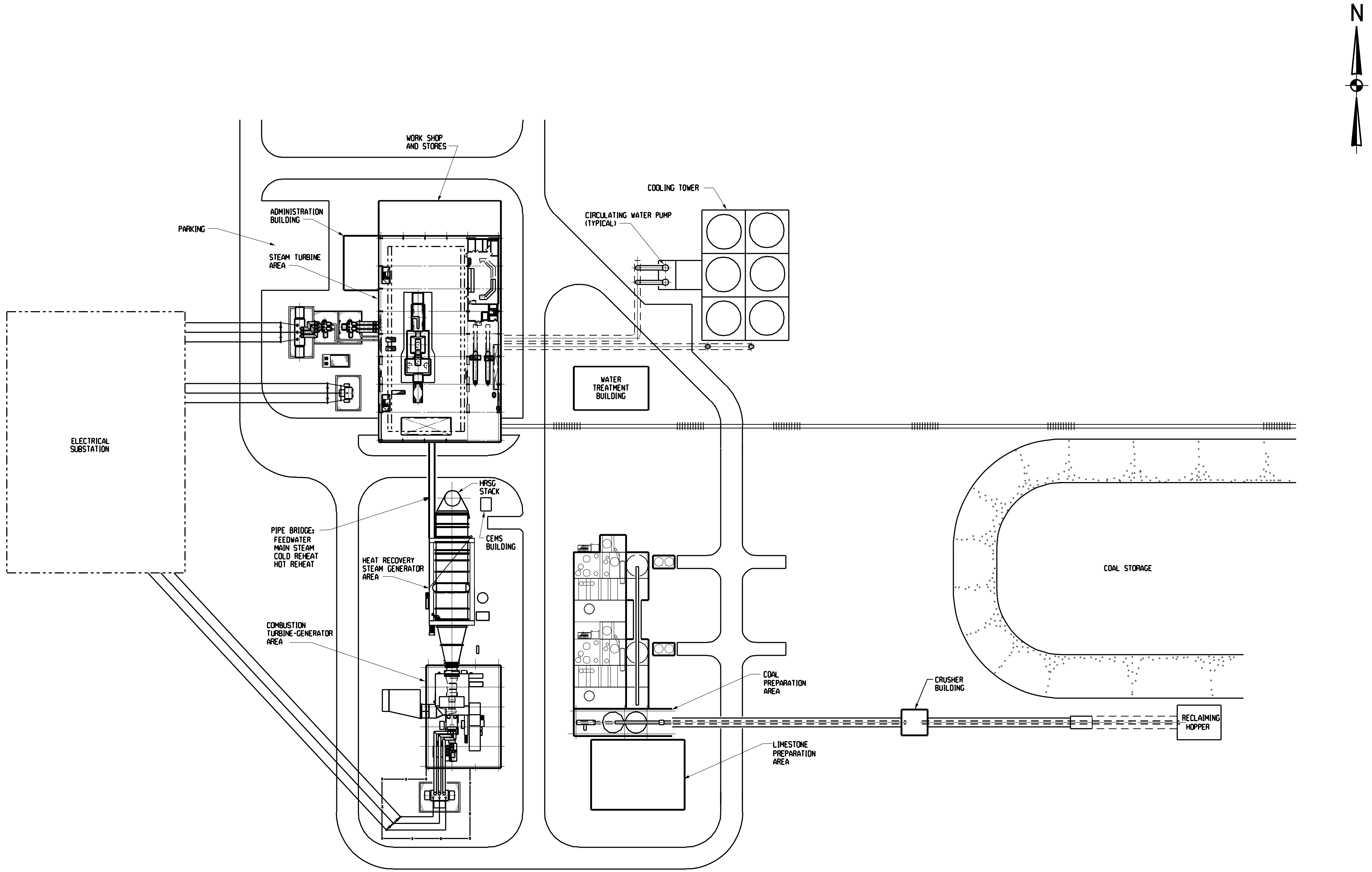
The two gasifier islands and the associated building enclosing it are located west of the coal preparation equipment. Ash silos are positioned due east of each gasifier island. The gas turbine and its ancillary equipment are sited west of the gasifier island, in a new turbine building designed expressly for this purpose. A HRSG and stack complete the development to the north of the gas turbine. The flare stack is located north of the gasifier island, at a sufficient distance to satisfy exclusion radius requirements. Figure 4.3-3 is included to show the layout of the plant.

The arrangement described above provides good alignment and positioning for major interfaces, relatively short steam, feedwater, and fuel gas pipelines, and allows good access for heavy trucks for ash removal. Transmission line access from the gas turbine step-up transformer to the existing switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located west of the gas turbine. Air taken from the compressor discharge flows to the two gasifier islands. The clean, hot, low-Btu gas is conveyed to the turbine topping combustors for mixing with the air that remains on board the machine.

NOTES:

DD



PLAN

0 50 100 150 200

GRAPHIC SCALE IN FEET

FIGURE 4.3-3

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DISCP ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS

DRAWN BY: CLR DATE: 12/21/98

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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

CLEAN COAL TECHNOLOGY PROGRAM

ADVANCED AIR-BLOWN TRANSPORT REACTOR

DEPARTMENT OF ENERGY TASK 22

PLANT GENERAL ARRANGEMENT

PLAN VIEW

SCALE 1"=50'

PARSON'S DWG. NO. 8436-1-200-010-001

REV

ARCH	HVAC	I & C	ELECT	MECH	CIVIL	STRUC

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4.3.9 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/ Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		1
14	Conveyor No. 4	48" belt	400 tph	1
15	Transfer Tower	N/A	400 tph	1
16	Tripper	N/A	400 tph	1
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	1,500 ton	2

ACCOUNT 2 COAL PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		175 tph	2
2	Pulverizer	Bowl	175 tph	2
3	Surge Hopper with Vent Filter and Slide Gate	Vertical, cylindrical	1,060 ton	2
4	Feeder	Gravimetric	70 tph	2
5	Screw Feeder	Mixing	75 tph	2
6	Dense Phase Transporter		75 tph	2

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	50,000 gal	1
2	Condensate Pumps	Vert. canned	900 gpm @ 300 ft	2
3	Deaerator and Storage Tank	Horiz. spray type	911,666 lb/h 205°F to 240°F	1
4	IP Feed Pumps	Interstage bleed from HP feed pump	40 gpm/1,200 ft	2
5	HP Feed Pumps	Barrel type, multi-staged, centr.	900 gpm/5,200 ft	2

Note: LP feedwater taken from condensate stream prior to deaerator inlet.

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F, 100,000 lb/h	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	100,000 gal No. 2 oil	1
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, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exch	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 horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, 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

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Riser	Refractory-lined	1,440 tpd/400 psig	2
2	Standpipe	Refractory-lined	167 x 10^6 Btu/h	2
3	Primary Cyclone	Conical bottom		2
4	Secondary Cyclone	Conical bottom		2
5	Non-Metallic Valve	Refractory-lined		2
6	Boost Air Compressor	Centrifugal, single stage, variable speed drive	4250 acfm, housing design: 550 psig, 350°F	2
7	Boost Air Receiver	Carbon steel vessel ASME VIII	2,200 ft^3	2
8	Exit Gas Cooler	Fin-tube	93 x 10^6 Btu/h	2
9	Recycle Gas Compressor	Screw	210 acfm, housing design 550 psig/200°F	2
10	Recycle Gas Cooler	Shell and tube	10 x 10^6 Btu/h	2
11	Filter Purge	Piston, single stage	20 acfm, housing design 800 psig/200°F	2
12	Flare Stack	Self-supporting, lined steel, pilot ignition	810,000 lb/h low-Btu gas	1

ACCOUNT 5 FLUE GAS CLEANUP

ACCOUNT 5A HIGH TEMPERATURE DESULFURIZATION

(Transport Hot Gas Desulfurizer)

Equipment No.	Description	Type	Design Condition	Qty
1	Sorbent Storage Hopper	*		2
2	Sorbent Feed Hopper	*		
3	Transport Desulfurizer	*		2
4	Desulfurizer Cyclone	*		2
5	Transport Regenerator	*		2
6	Regenerator Cyclone	*		2
7	Sorbent Regeneration Air Heater	*		2
8	Regenerator Effluent Gas Cooler	*		2

* This information is proprietary and is not presented.

ACCOUNT 5B SULFUR RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
7	Sulfuric Acid Plant		225 ton/day @ 98%	1

ACCOUNT 5C CHLORINE GUARD

Equipment No.	Description	Type	Design Condition	Qty
1	Chlorine Guard Reactor	Pebble bed, vertical cyl. pressure vessel	570,000 lb/h, 400 psig, 1100°F	4

ACCOUNT 5D PARTICULATE REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Fines Cyclone	Vertical cyl., conical bottom	570,000 lb/h, 400 psig 1100°F	2
2	Fines Cyclone Lock Hopper	Vertical cyl., conical bottom	90 ft^3, 400 psig	2
3	F. C. Depressurization Lock Hopper	Vertical cyl., conical bottom	90 ft^3, 400 psig	2
4	Burner Filter	Ceramic candle	570,000 lb/h	2
5	B.F. Lock Hopper	Vertical cyl., conical bottom		2
6	B.F. Depressurization Lock Hopper	Vertical cyl., conical bottom		2
7	Solids Conveyor	Drag chain	30 tph	2
8	Fines Combustor	Atmospheric fluid bed		2

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	300 MWe Gas Turbine Generator	Axial flow single spool based on General Electric “H” class	1,230 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 dB at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1,230 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	1
5	Air-to-Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1
11	Fire Protection Package	Halon		1

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 sections and integral deaerator	HP-2300 psig/629°F 832,171 lb/h superheat to 1000°F IP-585 psig/489°F 39,576 lb/h	1
2	Raw Gas Cooler Steam Generator	Drum and heater	2000 psig/629°F (drum) 487,000 lb/h Sat. Steam	1
3	Stack	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1
4	Bypass Stack and Diverter Valve	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

(on same shaft as gas turbine)

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	150 MW Steam Turbine	TC2F30	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	Electric Generator	Synchronous with static exciter	440 MWe/23 kV/ 3600 rpm	
6	Generator Coolers	Plate and frame		2
7	Hydrogen Seal Oil System	Closed loop		1
8	Surface Condenser	Single pass, divided waterbox	750,531 lb/h steam @ 2.0 in. Hga with 78°F water, 19°F temp rise	1
9	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	40,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell counter-flow, film type fill	56°F WB/78°F CWT/ 97° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Ash Lock Hopper	Vertical cyl., conical bottom	200 ft^3, 400 psig	2
2	Ash Receiver	Vertical cyl., conical bottom		2
3	Screw Feeder	Water cooled	30,000 lb/h	2
5	Cyclone	Vertical cyl., conical bottom		2
6	Heat Recovery HEX	Solids cooler	11×10^6 Btu/h	2
7	Ash Silo	Vertical cylindrical, reinf. concrete	500 tons	2

4.3.10 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the advanced IGCC plant is shown in Table 4.3-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.3-4

Client: DEPARTMENT OF ENERGY
Project: Market Based Advanced Coal Power Systems
Report Date: 14-Aug-98 08:50 AM

TOTAL PLANT COST SUMMARY

Case: Transport Reactor (2010)
Plant Size: 398.1 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	5,486	1,737	4,365	306		**$11,895**	952		2,569	**$15,416**	39
2	COAL & SORBENT PREP & FEED	5,568	775	3,580	251		**$10,173**	814	343	2,266	**$13,596**	34
3	FEEDWATER & MISC. BOP SYSTEMS	5,332	2,747	4,131	289		**$12,500**	1,000		3,236	**$16,736**	42
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries	14,365		7,725	541		**$22,631**	1,810	5,658	6,020	**$36,118**	91
4.2	High Temperature Cooling	4,394		2,363	165		**$6,923**	554	1,038	1,703	**$10,218**	26
4.3	Recycle Gas System	1,799		1,342	94		**$3,235**	259	485	796	**$4,775**	12
4.4-4.9	Other Gasification Equipment	5,936	3,684	3,555	249		**$13,424**	1,074	1,128	3,662	**$19,288**	48
	SUBTOTAL 4	*26,494*	*3,684*	*14,985*	*1,049*		***$46,212***	*3,697*	*8,310*	*12,181*	***$70,400***	*177*
5	HOT GAS CLEANUP & PIPING	33,305	4,211	12,718	890		**$51,124**	4,090	9,044	12,921	**$77,179**	194
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	43,435		3,306	231		**$46,973**	3,758	3,523	5,425	**$59,680**	150
6.2-6.9	Combustion Turbine Accessories		148	170	12		**$330**	26		107	**$463**	1
	SUBTOTAL 6	*43,435*	*148*	*3,477*	*243*		***$47,303***	*3,784*	*3,523*	*5,532*	***$60,143***	*151*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	12,666		1,821	127		**$14,614**	1,169		1,578	**$17,362**	44
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,876	698	1,325	93		**$3,993**	319		598	**$4,910**	12
	SUBTOTAL 7	*14,543*	*698*	*3,146*	*220*		***$18,607***	*1,489*		*2,176*	***$22,272***	*56*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	10,806		1,978	138		**$12,922**	1,034		1,396	**$15,351**	39
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	5,256	160	2,882	202		**$8,500**	680		1,581	**$10,761**	27
	SUBTOTAL 8	*16,061*	*160*	*4,860*	*340*		***$21,422***	*1,714*		*2,976*	***$26,112***	*66*
9	COOLING WATER SYSTEM	3,713	2,057	3,500	245		**$9,515**	761		1,846	**$12,123**	30
10	ASH/SPENT SORBENT HANDLING SYS	3,630	798	1,472	103		**$6,003**	480	252	1,019	**$7,754**	19
11	ACCESSORY ELECTRIC PLANT	8,939	2,252	5,834	408		**$17,434**	1,395		3,063	**$21,892**	55
12	INSTRUMENTATION & CONTROL	5,222	1,463	5,436	380		**$12,501**	1,000		2,098	**$15,599**	39
13	IMPROVEMENTS TO SITE	1,848	1,063	3,701	259		**$6,872**	550		2,226	**$9,648**	24
14	BUILDINGS & STRUCTURES		4,264	5,493	384		**$10,141**	811		2,738	**$13,691**	34
	TOTAL COST	**$173,578**	**$26,057**	**$76,699**	**$5,369**		**$281,703**	**$22,536**	**$21,471**	**$56,850**	**$382,559**	**961**

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Section 4.4

Market-Based Advanced Oxygen-Blown Destec
500 MWe

4.4 MARKET-BASED ADVANCED OXYGEN-BLOWN DESTEC 500 MWe

4.4.1 Introduction

This IGCC concept is based on the utilization of the Destec oxygen-blown coal gasification process supplying medium-Btu gas to a gas turbine/combined cycle power generating plant. The plant configuration is based on a projection of state-of-the-art design for an in-service date of 2010. The availability of a combustion turbine comparable to the General Electric "H" is assumed, along with steam turbines incorporating state-of-the-art design features. The specific design approach presented herein is based on DOE/FETC and Parsons concepts, and does not necessarily reflect the approach that Destec Energy would take if they were to commercially offer a facility of this size (MWe) in this time frame.

This case illustrating IGCC technology is based on selection of a gas turbine derived from the General Electric "H" machine. This particular machine, coupled with an appropriate steam cycle, will produce a nominal 500 MWe net output. The IGCC portion of the plant is configured with one gasifier island, which includes a transport reactor type hot gas desulfurizer. The resulting plant produces a net output of 427 MWe at a net efficiency of 49 percent on an HHV basis. This performance is based on the use of Illinois No. 6 coal. Performance will vary with other fuels.

4.4.2 Heat and Mass Balance

The pressurized Destec gasifier utilizes a combination of oxygen and water along with recycled fuel gas to gasify coal and produce a medium-Btu hot fuel gas. The fuel gas produced in the entrained bed gasifier leaves at 1900°F and enters a hot gas cooler. A significant fraction of the sensible heat in the gas is retained by cooling the gas to 1110°F. High-pressure steam is generated in the hot gas cooler and routed to the appropriate location in the HRSG.

The fuel gas goes through a series of hot gas cleanup processes including chloride guard, transport reactor type hot-gas desulfurization process and barrier filter. A fraction of the clean hot gas is cooled and recycled to the gasifier to aid in second-stage gasification. Char particulates are recycled to the gasifier, resulting in nearly complete carbon conversion. Regeneration gas from the desulfurizer is fed to an H_2SO_4 plant.

This plant utilizes a combined cycle for combustion of the medium-Btu gas from the gasifier to generate electric power. A Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the HRSG, by feedwater heating in the HRSG, and by heat recovery from the IGCC process (gas cooling and sulfation modules).

The gas turbine operates in an open cycle mode, as described below.

The inlet air is compressed in a single spool compressor to the design basis discharge pressure. Most of the compressor discharge air passes to the burner section of the machine to support combustion of the medium-Btu gas supplied by the gasifier island, and to cool the burner and turbine expander sections of the machine. The firing of medium-Btu gas in the combustion turbine is expected to require modifications to the burner and turbine sections of the machine. These modifications are discussed in Section 4.4.4.7.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The combustion turbine utilizes cold reheat from the steam turbine for cooling the stationary and rotating parts of the turbine, mainly the first- and second-stage stationary nozzle and buckets plus the stage one shroud. The steam is returned to the steam cycle for performance augmentation. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain. The HRSG exhausts to the plant stack.

The Rankine steam power cycle is also shown schematically in the 100 percent load Heat and Mass Balance Diagram (Figure 4.4-1). Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 4.4-1, which includes auxiliary power requirements.

The steam cycle is based on maximizing heat recovery from the gas turbine exhaust gases, as well as utilizing steam generation opportunities in the gasifier process. For this facility, a triple-pressure HRSG configuration has been selected. In addition to the high-pressure (HP) drum, an intermediate-pressure (IP) drum is provided in the HRSG to raise steam that is joined with the reheat.

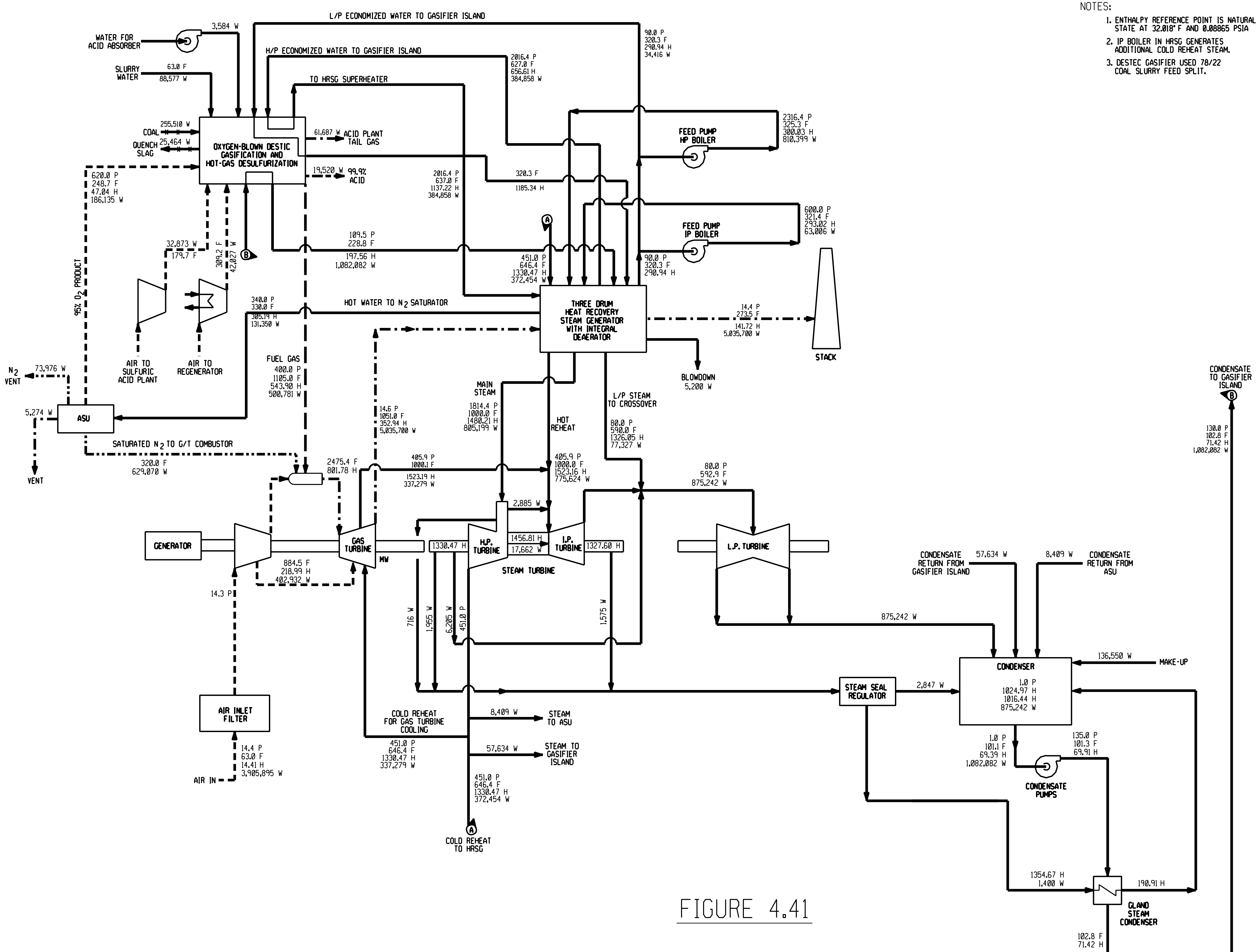

FIGURE 4.41

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.
3. DESTEC GASIFIER USED 78/22 COAL SLURRY FEED SPLIT.

DD

LEGEND

- SULFURIC ACID
- NITROGEN
- AIR / OXIDANT
- FUEL GAS
- COMBUSTION PRODUCTS
- SOLIDS
- WATER / STEAM
- P — ABSOLUTE PRESSURE, PSIA
- F — TEMPERATURE, °F
- H — ENTHALPY, Btu/LB
- W — TOTAL PLANT FLOW, LB/HR
- MWe — POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	340.314 MWe
STEAM T-G POWER :	157.244 MWe
GENERATOR LOSS (TOTAL):	7.463 MWe
TRANSFORMER LOSS (TOTAL):	1.180 MWe
AUXILIARY POWER (TOTAL):	61.180 MWe
NET PLANT POWER :	427.735 MWe
NET PLANT EFFICIENCY :	49.0 %
NET PLANT HEAT RATE :	6,968 Btu/kwh

DSTCATS3/DSTCHBT3 J.S.WHITE 4/22/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | LEAD DISCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS: CONCEPTUAL DESIGN STUDY NOT FOR CONSTRUCTION

DRAWN BY CLB DATE 3/22/98

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 POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
OXYGEN BLOWN DESTEC GASIFIER
GASIFICATION COMBINED CYCLE

DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER
GENERAL ELECTIRC "H" ATS

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-010 REV A

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Table 4.4-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for one IGCC island, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Net Electric Power at Generator Terminals, kWe)	
Gas Turbine	335,210
Steam Turbine	154,885
Total	490,095
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	210
Coal Slurry Pumps	180
Condensate Pumps	170
IP/IP Feed Pumps	5,030
HP Feed Pumps	2,240
Miscellaneous Balance of Plant (Note 1)	900
Air Separation Plant	31,340
Oxygen Boost Compressor	6,060
Nitrogen Compressor	13,640
Regenerator Compressor	2,370
Recycle Blower	60
Acid Pump	10
Acid Plant Air Blower	290
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Saturated Water Pumps	50
Circulating Water Pumps	1,420
Cooling Tower Fans	980
Slag Handling	530
Transformer Loss	1,180
TOTAL AUXILIARIES, kWe	62,360
Net Power, kWe	427,735
Net Efficiency, % HHV	49.0
Net Heat Rate, Btu/kWh (HHV)	6,969
CONDENSER COOLING DUTY, 10^6 Btu/h	900
CONSUMABLES	
As-Received Coal Feed, lb/h	255,510
Oxygen (95% pure), lb/h	186,135
Water (for slurry), lb/h	88,577

Note 1 - Includes plant control systems, lighting, HVAC, etc.

The low-pressure (LP) drum, not shown, supplies steam for feedwater deaeration. Steam conditions at the HP turbine admission valves are set at 1800 psig/1000°F.

The HRSG also contains an integral deaerating heater and several economizer sections. The economizer preheats the feedwater before it is sent to the gasifier for final heating by heat recovery from the gas path. Therefore, conventional feedwater heaters using turbine extraction steam are not required.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow (exhaust) machine, exhausting downward to the condenser. The HP and IP turbine sections are contained in one section, with the LP section in a second casing. Other turbine design arrangements are possible; the configuration represented herein is typical of reheat machines in this size class.

The steam turbine drives a 3600 rpm hydrogen-cooled generator. The turbine exhausts to a single-pressure condenser operating at a nominal 2.0 inches Hga at the 100 percent load design point. For the LP turbine, the last-stage bucket length is 30 inches. Two 50 percent capacity, motor-driven pumps are provided for feedwater and condensate.

4.4.3 Emissions Performance

The operation of the combined cycle unit in conjunction with oxygen-blown Destec IGCC technology is projected to result in very low levels of emissions of NOx, SO_2, and particulates (fly ash). A salable byproduct in the form of sulfuric acid at 99 percent concentration is produced. A summary of the plant emissions is presented in Table 4.4-2.

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the transport hot gas desulfurizer (THGD) subsystem. The THGD process removes approximately 99.5 percent of the sulfur compounds in the fuel gas.

Table 4.4-2
AIRBORNE EMISSIONS - IGCC, OXYGEN-BLOWN DESTEC

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**lb/MWh**
SO_2	0.017	146	191	0.12
NOx	0.024	204	266	0.167
Particulates	< 0.002	< 17	< 22	0.014
CO_2	200	1,700,400	2,2223,600	1,396

The reduction in NOx to below 10 ppm is achieved for a fuel gas containing fuel-bound nitrogen (NH_3) by the use of rich-quench lean (staged) combustion technology coupled with syngas dilution by saturated nitrogen available from the ASU. Syngas dilution, staged combustion, and sub-stoichiometric combustion followed by excess air dilution promote the conversion of fuel bound nitrogen to N_2 rather than NOx. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can reduce NOx emissions further, but are not applied to the subject plant.

Particulate discharge to the atmosphere is limited by the use of a ceramic candle type barrier filter, which provides a particulate removal rate of greater than 99.99 percent.

CO_2 emissions are equal to those of other coal-burning facilities on an intensive basis (1b/MMBtu) since a similar fuel is used (Illinois No. 6 coal). However, total CO_2 emissions are lower for a plant with this capacity due to the relatively high thermal efficiency.

4.4.4 Description of Oxygen-Blown IGCC

This reference design is based on the utilization of one oxygen-blown Destec entrained-bed, slagging gasifier. The medium-Btu gas produced in the gasifier is desulfurized in a transport reactor type hot gas desulfurization and filtration process downstream of the gasifier. The final product gas is used to fire a combustion turbine generator, which is coupled to a HRSG for driving one steam turbine generator.

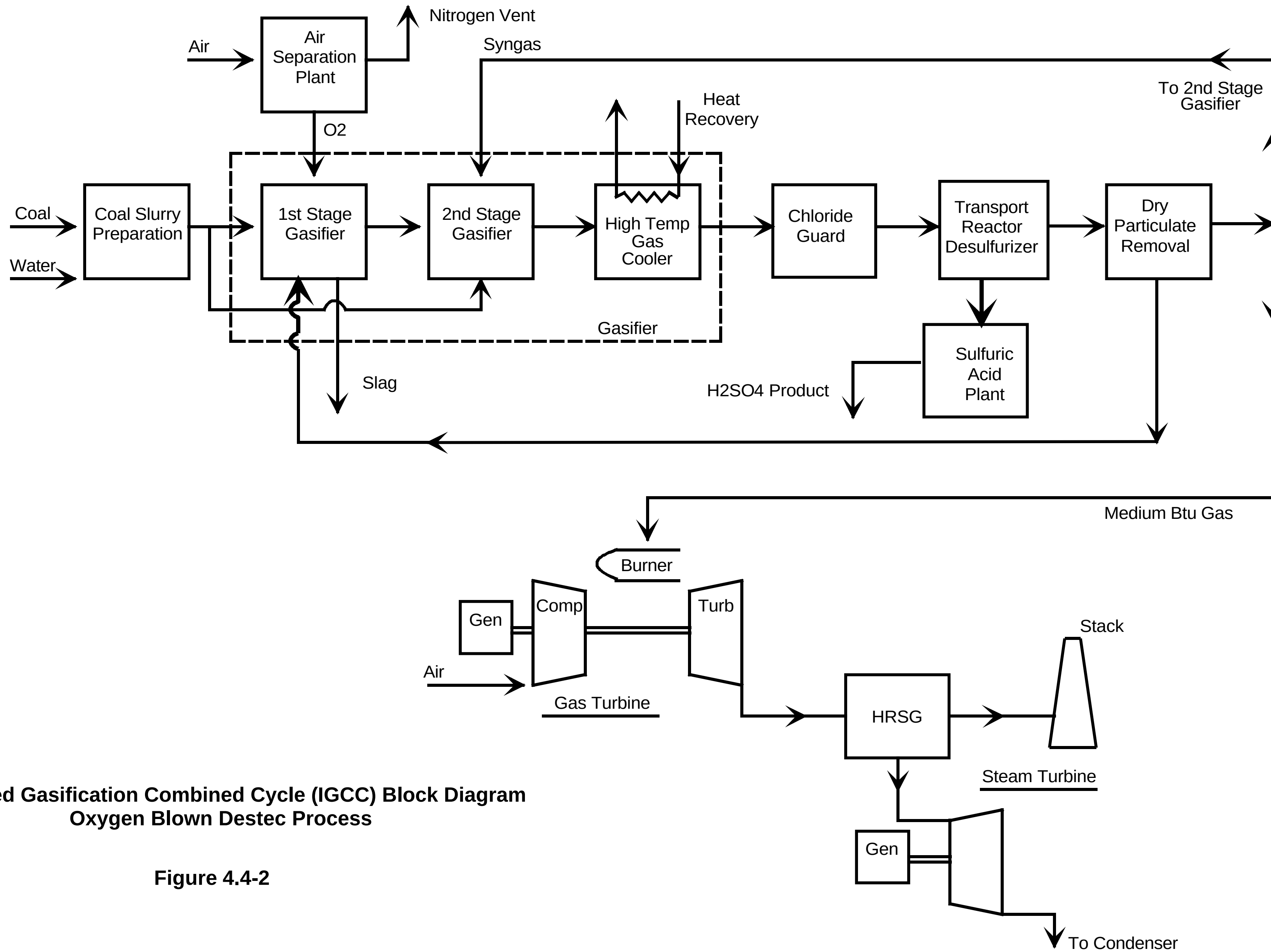
The following is a summary description of the overall gasification process and its integration with the power generation cycles used in this reference design. (Refer to Figure 4.4-2.)

Illinois No. 6 coal is ground to 200 mesh and mixed with water to be fed to the pressurized Destec gasifier as a slurry. The slurry is fired with oxygen to produce medium-Btu gas, which is largely comprised of CO, H_2, and CO_2, and is discharged from the gasifier at 1900°F and cooled in a gas cooler to 1110°F.

The cooled gas passes through the chloride guard containing a fixed-bed reactor, exposing the gas to nahcolite to reduce the chloride level to less than 1 ppm, thus protecting the sorbent and the combustion turbine downstream. The gas then enters the THGD, where sufficient sulfur is removed to result in a final sulfur level of less than 10 ppm. The gas is then cleaned in the dry particulate removal system containing a final ceramic candle type barrier filter, resulting in very low levels of particulates. Fly ash from the filter is transferred to the fines combustor where it is oxidized. The regeneration gas from the THGD is a mixture of air and SO_2, which is a suitable feedstock for the sulfuric acid plant.

The gas exiting the THGD is conveyed to the combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The exhaust gas from the turbine and HRSG is released to the atmosphere via a conventional stack.

Based on the selection of a machine derived from General Electric "H" class combustion turbine, a fuel gas pressure of 400 psig was established to provide a margin above the compressor discharge pressure (275 psig for this reference case), allowing for necessary system and valve pressure drop.



Integrated Gasification Combined Cycle (IGCC) Block Diagram
Oxygen Blown Destec Process

Figure 4.4-2

Based on the above, a nominal gasifier pressure of 500 psig is required. At this pressure, a single gasifier is required. The gasifier is similar in size to the commercial-sized island utilized in the Wabash River Coal Gasification Repowering Project, which operates at a nominal pressure of 450 psig. The wall thickness of the gasifiers and other vessels and piping comprising the gasifier islands is increased by approximately 11 percent to compensate for the higher pressure (500 psig vs. 450 psig).

4.4.4.1 Coal Grinding and Slurry Preparation

Coal is fed onto conveyor No. 1 by vibratory feeders located below each coal silo. Conveyor No. 1 feeds the coal to an inclined conveyor (No. 2) that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. The rod mill grinds the coal and wets it with treated slurry water from a slurry water tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

4.4.4.2 Gasifier

Note: The following description is taken from the Coal Gasification Guidebook: Status, Applications, and Technologies, prepared by SFA Pacific, Inc. for the Electric Power Research Institute.

The Destec coal gasifier is a slurry feed, pressurized, upflow, entrained slagging gasifier whose two-stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. The slurry water consists of recycle water from the raw gas cooling together with makeup water. About 80 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 20 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1900°F.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 20 percent of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is easily gasified. The gasifier is refractory lined and uncooled. The hotter first-stage section of the gasifier also includes a special slag-resistant refractory. The 1900°F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 1100°F, generating saturated steam for the steam power cycle in the process.

4.4.4.3 Gas Desulfurization

The THGD section of the IGCC island serves to remove most of the sulfur from the gas produced by the gasifier. The gas delivered from the gasifier to the THGD system is at 1100°F and 425 psig. The sulfur compounds in the gas (predominantly H_2S) react with the sorbent to form zinc sulfides, yielding a clean gas containing less than 10 ppmv of sulfur compounds. The sorbent for this process is Z-sorb, a zinc-based material also containing nickel oxide.

The uncleaned gas enters the bottom of an absorber column, where it mixes with powdered sorbent, and then rises in the column. The gas/powder mixture exiting the column passes through a cyclone where the sorbent is stripped out for recycle. The clean gas discharged from the absorber flows to a high-efficiency barrier-type filter to remove any remaining particulates.

A regeneration column is used to regenerate the sorbent material from sulfide form to oxide form. Regeneration gas, laden with SO_2, is conveyed to the sulfator for capture of the sulfur and conversion to a disposable form.

4.4.4.4 Particulate Removal

The particulate removal stage in this gasification process is dependent upon a high-efficiency barrier filter comprised of an array of ceramic candle elements in a pressure vessel. The filter is cleaned by periodically back pulsing it with gas to remove the fines, which are collected and conveyed to the gasifier.

4.4.4.5 Chloride Guard

The chloride guard functions to remove HCl from the hot gas, prior to delivery to the combustion turbine.

The chloride guard is comprised of two 100 percent capacity pressure vessels packed with a pebble bed of nahcolite, a natural form of sodium bicarbonate. One vessel is normally in service, with a nominal service period of two months. The second vessel is purged, cooled, drained of spent bed material, and recharged while the other vessel is in service. The chloride guard vessels are approximately 13 feet in diameter, 25 feet high, and fabricated of carbon steel.

4.4.4.6 Sulfuric Acid Plant

The regeneration of the sorbent in the THGD subsystem produces an offgas from the regeneration process, which contains an SO_2 concentration of 13 percent. This is adequate for feed to a contact process sulfuric acid plant. Key to the process is the four-pass converter developed by Monsanto. The reaction from SO_2 to SO_3 is an exothermic reversible reaction. Equilibrium conversion data show that conversion of SO_2 decreases with an increase in temperature. Using a vanadium catalyst, a contact plant takes advantage of both rate and equilibrium considerations by first allowing the gases to enter over a part of the catalyst at about 800 to 825°F, and then allowing the temperature to increase adiabatically as the reaction proceeds. The reaction essentially stops when about 60 to 70 percent of the SO_2 has been converted, at a temperature in the vicinity of 1100°F. The gas is cooled in a waste heat boiler and passed through subsequent stages, until the temperature of the gases passing over the last portion of catalyst does not exceed 805°F.

The gases leaving the converter, having passed through two or three layers of catalyst, are cooled and passed through an intermediate absorber tower where some of the SO_3 is removed with 98 percent H_2SO_4. The gases leaving this tower are then reheated, and they flow through the remaining layers of catalyst in the converter. The gases are then cooled and pass through the final absorber tower before discharge to the atmosphere. In this manner, more than 99.7 percent of the SO_2 is converted into SO_3 and subsequently into product sulfuric acid.

4.4.4.7 Gas Turbine Generator

The combustion turbine used for the second case is a General Electric Model "H." This machine is an axial flow, single spool, constant speed unit with variable inlet guide vanes and four stages of variable stator vans. A summary of the features of the machine is presented below:

- Inlet and Filter — Two-stage, renewable pad filters, preceded by a rain louver and screen
- Compressor — Axial flow, 18-stage, 23:1 pressure ratio
- Combustors — Can-annular, 12 cans, dry low-NOx type
- Turbine — Steam cooling - two stages, air cooling - one stage, no cooling - one stage
- Generator — Hydrogen-cooled, 20 kV, 60 Hz static exciter

4.4.4.8 Steam Generation

<u>Heat Recovery Steam Generator</u>

The HRSG is a drum-type, triple-pressure design with an integral deaerator. The HRSG is matched to the characteristics of the General Electric "H" turbine exhaust gas when firing medium-Btu gas. The HP drum produces steam at main steam pressure while the IP drum produces steam that is combined with the reheat. The LP drum produces steam that is used for feedwater deaeration. The LP drum also serves as storage for feedwater, and suction of the boiler feed pump is taken from this drum.

Gas Cooler

The gas cooler contains a steam drum and heating surface for the production of saturated steam. This steam is conveyed to the HRSG where it is superheated.

4.4.4.9 Air Separation Plant

The elevated pressure air separation plant is designed to produce a nominal output of 2,200 tons/day of 95 percent pure O_2. The plant is designed with one 100 percent capacity production train. Liquefaction and liquid oxygen storage provide an 8-hour backup supply of oxygen. Nitrogen for fuel gas dilution is also produced.

In this air separation process, air is compressed to 196 psig and then cooled. The cooled air enters a reversing heat exchanger, where it is cooled to the liquefaction point prior to entering a double column (high/low pressure) separator. Refrigeration for cooling is provided by expansion of high-pressure gas from the lower part of the high-pressure column.

4.4.5 IGCC Support Systems (Balance of Plant)

4.4.5.1 Coal Handling System

The function of the balance-of-plant coal handling 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 unloader and coal receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous 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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) 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 crushers. The coal then enters the second crusher, which reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the stationary tripper, which loads the coal into one of the two silos.

<u>Technical Requirements and Design Basis</u>

- Coal burn rate:
  - Maximum coal burn rate = 255,500 lb/h = 128 tph plus 10% margin = 140 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 217,000 lb/h = 108 tph (based on MCR rate multiplied by an assumed 85% capacity factor)
- Coal delivered to the plant by unit trains:
  - Two and one quarter unit trains per week at maximum burn rate
  - One and three-quarters unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 400 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 10,000 tons (72 hours at maximum burn rate)

– Dead storage = 85,000 tons (30 days at average burn rate)

4.4.5.2 Slag Ash Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. The ash is removed from the process as slag. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary, through a proprietary pressure letdown device, to a series of dewatering bins. The separated liquid is recycled to the slag quench water bath.

The cooled, solidified slag is stored in a storage vessel. The hopper is sized for a nominal holdup capacity of approximately 72 hours of full-load operation. At periodic intervals, a convoy of slag hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately 12 truck loads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power.

4.4.6 <u>Steam Cycle Balance of Plant</u>

The following section provides a description of the steam turbines and their auxiliaries.

4.4.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, IP section, and one double-flow LP section, all connected to the generator by a common shaft. 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 last-stage bucket length of 30 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig/1000°F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the HP turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 395 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Extraction steam from the cold reheat is used for the “H” machine to provide cooling the stationary and rotating parts of the turbine, mainly the first- and second-stage stationary nozzle and buckets plus the stage one shroud. The steam is returned to the hot reheat for performance augmentation.

Turbine bearings are lubricated by a closed-loop water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

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.

4.4.6.2 Condensate and Feedwater Systems

Condensate

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

Feedwater

The function of the feedwater system is to pump the various feedwater streams from the LP drum with deaerator storage capabilities located in the HRSG to the respective steam drums. Two motor-driven, HP and IP, 50 percent capacity boiler feed pumps are provided. Each pump is provided with a variable speed drive to support startup, shutdown, and part-load operation. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the LP drum. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

4.4.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 1800 psig/1000°F exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 440 psig/650°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 395 psig/1000°F exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

4.4.6.4 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.

4.4.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 4.4-3.

Table 4.4-3
INTEGRATED GASIFICATION COMBINED CYCLE

Major Steam Cycle Piping Required

Pipeline	Flow, lb/h	Press., psia	Temp., °F	Material	OD, in.	Twall, in.
Condensate	1,100,000	135	100	A106 Gr. B	8	Sch. 40
HP Feedwater, Pump to HRSG	810,000	2316	325	A106 Gr. C	8	Sch. 160
IP Feedwater, Pump to HRSG	63,000	600	320	A106 Gr. B	3	Sch. 40
LP Econ. Water to Gasifier	34,400	90	320	A106 Gr. C	3	Sch. 40
LP Econ. Steam to HRSG	34,400	90	320	A106 Gr. C	6	Sch. 40
HP Econ. Water to Gasifier	385,000	2016	627	A106 Gr. C	8	Sch. 160
HP Econ. Steam to HRSG	385,000	2016	637	A335 Gr. P91	6	Sch. 160
Main Steam/HRSG to Steam Turbine	805,000	1815	1000	A335 Gr. P91	10	1.375
Cold Reheat/ST to HRSG	372,500	450	650	A106 Gr. B	14	Sch. 40
Hot Reheat/HRSG to ST	776,000	405	1000	A335 Gr. P91	18	Sch. 40
Cold Reheat to GT	337,300	450	650	A106 Gr. B	12	Sch. 40
Hot Reheat from GT	337,300	405	1000	A335 Gr. P91	14	Sch. 40
Fuel Gas/Gasifier Island to Gas Turbine	500,800	400	1105	A335 Gr. P91	16	Sch. 40
O_2 Piping to Gasifier	186,000	620	250	A106 Gr B	6	Sch. 40

4.4.7 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.

4.4.8 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.

4.4.9 Site, Structures, and Systems Integration

4.4.9.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

4.4.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate structures required for this technology is based on the assumption of a flat site. The IGCC gasifier and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the south, as shown in the conceptual arrangement presented in Section 4.2. Figure 4.2-3 presents the basic plant arrangement.

The gasifier and its associated process blocks are located west of the coal storage pile. The gas turbine and its ancillary equipment are sited west of the gasifier island, in a turbine building designed expressly for this purpose. A HRSG and stack are east of the gas turbine, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the west side of the steam turbine building.

The cooling tower heat sink for the steam turbine is located to the east of the steam turbine building. The air separation plant is further to the east, with storage tanks for liquid O_2 located near the gasifier and its related process blocks. Sulfur recovery and wastewater treatment areas are located east and south of the air separation plant.

The arrangement described above provides good alignment and positioning for major interfaces; relatively short steam, feedwater, and fuel gas pipelines; and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located north of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through a triple-pressure HRSG and then to a new 213-foot stack. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.

4.4.10 Equipment List - Major

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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		1
14	Conveyor No. 4	48" belt	400 tph	1
15	Transfer Tower	N/A	400 tph	1
16	Tripper	N/A	400 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	1,500 ton	2

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Not Applicable

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		80 tph	2
2	Conveyor No. 1	Belt	160 tph	1
3	Conveyor No. 2	Belt	160 tph	1
4	Rod Mill Feed Hopper	Vertical, double hopper	200 ton	1
5	Vibratory Feeder		80 tph	2
6	Weight Feeder	Belt	80 tph	2
7	Rod Mill	Rotary	80 tph	2
8	Slurry Water Storage Tank	Field-erected	100,000 gal	1
9	Slurry Water Pumps	Horizontal, centrifugal	625 gpm	2
10	Rod Mill Product Tank	Field-erected	170,000	1
11	Rod Mill Product Pumps	Horizontal, centrifugal	850 gpm	2
12	Slurry Storage Tank	Field-erected	300,000	1
13	Centrifugal Slurry Pumps	Horizontal, centrifugal	1,700 gpm	2
14	PD Slurry Pumps	Progressing cavity	300 gpm	2
15	Slurry Blending Tank	Field-erected	100,000 gal	1
16	Slurry Blending Tank Pumps	Horizontal, centrifugal	325 gpm	2

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	50,000 gal	1
2	Condensate Pumps	Vert. canned	1,100 gpm @ 310 ft	2
3	Deaerator	Horiz. spray type	1,130,000 lb/h 215°F	1
4	IP Feed Pumps	Interstage bleed from HP feed pump	66 gpm/1,200 ft	2
5	HP Feed Pumps	Barrel type, multi-staged, centr.	850 gpm / 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fab. water tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	20,000 gal No. 2 oil	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, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exch	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 horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, 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

ACCOUNT 4A GASIFICATION

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized entrained bed	2860 tpd/500 psig	1
2	Gas Cooler	Firetube	167 x 10^6 Btu/h	1
3	Flare Stack	Shielded	465,000 lb/h medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	80,000 acfm, 70 psig discharge pressure	1
2	Cold Box		2,200 ton/day O_2	1
3	Oxygen Compressor	Centrifugal, multi-stage	33,200 scfm, 620 psig discharge pressure	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Qty
1	Sorbent Storage Hopper	*		1
2	Sorbent Feed Hopper	*		1
3	Transport Desulfurizer	*		1
4	Desulfurizer Cyclone	*		1
5	Transport Regenerator	*		1
6	Regenerator Cyclone	*		1
7	Sorbent Regeneration Air Heater	*		1
8	Regenerator Effluent Gas Cooler	*		1

* This information is proprietary and is not presented.

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	340 MWe Gas Turbine Generator	Axial flow single spool based on "H"	1510 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1510 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

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 sections and integral deaerator	HP-2300 psig/325°F 805,000 lb/h superheat to 1000°F IP-600 psig/320°F 63,000 lb/h	1
2	Raw Gas Cooler Steam Generator	Drum and heater	2300 psig/sat. steam 384,000 lb/h	1
3	Stack	Carbon steel plate lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	160 MW Turbine Generator	TC2F30	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	875,000 lb/h steam @ 2.0 in. Hga with 78°F water, 19°F temp rise	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2700/25 scfm (hogging/holding)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	40,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell counter-flow, film type fill	56°F WB/78°F CWT/ 97° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

ACCOUNT 10A SLAG DEWATERING & REMOVAL

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath		1
2	Slag Precrusher		12 tph solids	1
3	Slag Crusher	Roll	12 tph solids	1
4	Slag Depressurizing Unit	Proprietary	12 tph solids	1
5	Slag Dewatering Unit	Horizontal, weir	4 tph solids	3
5	Slag Conveyor	Drag chain	4 tph	3
6	Slag Conveyor	Drag chain	8 tph	*1
6	Slag Storage Vessel	Reinf. concrete vert. cylindrical	1,200 ton	*1
7	Slide Gate Valve			*1
8	Telescoping Unloader		25 tph	*1

*Total for plant.

4.4.11 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the market-based intermediate O_2-blown Destec 400 MW plant is shown in Table 4.4-4. The estimate summarizes the detail estimate values that were developed consistent with Section 9, “Capital and Production Cost and Economic Analysis.” The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 4.4-4

Client: DEPARTMENT OF ENERGY
Report Date: 14-Aug-98 11:02 AM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Destec (2010-"H")
Plant Size: 427.7 MW,net
Estimate Type: Conceptual
Cost Base (Jan) 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	5,752	1,154	5,023	352		**$12,281**	982		2,653	**$15,916**	37
2	COAL & SORBENT PREP & FEED	6,977	1,605	7,535	527		**$16,644**	1,332	559	2,444	**$20,978**	49
3	FEEDWATER & MISC. BOP SYSTEMS	5,803	2,825	4,504	315		**$13,447**	1,076		3,505	**$18,028**	42
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	9,257		9,429	660		**$19,346**	1,548	1,935	2,283	**$25,111**	59
4.2	High Temperature Cooling	15,118		15,405	1,078		**$31,602**	2,528	3,160	3,729	**$41,019**	96
4.3	ASU/Oxidant Compression	57,300		w/equip.			**$57,300**	4,584		6,188	**$68,072**	159
4.4-4.9	Other Gasification Equipment		3,924	2,194	154		**$6,271**	502		1,793	**$8,566**	20
	SUBTOTAL 4	*81,675*	*3,924*	*27,027*	*1,892*		***$114,519***	*9,161*	*5,095*	*13,993*	***$142,768***	*334*
5	HOT GAS CLEANUP & PIPING	26,369	2,264	9,371	656		**$38,659**	3,093	4,547	9,438	**$55,737**	130
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	43,435		3,306	231		**$46,973**	3,758	3,523	5,425	**$59,680**	140
6.2-6.9	Combustion Turbine Accessories		148	170	12		**$330**	26		107	**$463**	1
	SUBTOTAL 6	*43,435*	*148*	*3,477*	*243*		***$47,303***	*3,784*	*3,523*	*5,532*	***$60,143***	*141*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,255		1,905	133		**$15,294**	1,224		1,652	**$18,169**	42
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,997	743	1,410	99		**$4,249**	340		637	**$5,226**	12
	SUBTOTAL 7	*15,252*	*743*	*3,316*	*232*		***$19,543***	*1,563*		*2,288*	***$23,395***	*55*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	11,689		2,140	150		**$13,978**	1,118		1,510	**$16,606**	39
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	5,646	172	3,097	217		**$9,132**	731		1,698	**$11,561**	27
	SUBTOTAL 8	*17,335*	*172*	*5,236*	*367*		***$23,110***	*1,849*		*3,208*	***$28,167***	*66*
9	COOLING WATER SYSTEM	3,997	2,227	3,766	264		**$10,253**	820		1,991	**$13,064**	31
10	ASH/SPENT SORBENT HANDLING SYS	3,726	686	3,177	222		**$7,811**	625	534	1,039	**$10,009**	23
11	ACCESSORY ELECTRIC PLANT	12,384	4,091	10,067	705		**$27,247**	2,180		4,858	**$34,285**	80
12	INSTRUMENTATION & CONTROL	6,517	1,548	5,752	403		**$14,220**	1,138		2,327	**$17,685**	41
13	IMPROVEMENTS TO SITE	2,006	1,153	4,017	281		**$7,458**	597		2,416	**$10,471**	24
14	BUILDINGS & STRUCTURES		4,505	5,812	407		**$10,724**	858		2,895	**$14,477**	34
	TOTAL COST	**$231,228**	**$27,045**	**$98,081**	**$6,866**		**$363,220**	**$29,058**	**$14,258**	**$58,589**	**$465,125**	**1087**

5. <u>CIRCULATING PFBC, SECOND GENERATION, BOOSTED</u>

5.1 INTRODUCTION

This circulating pressurized fluid bed combustor (CPFBC) concept utilizes a carbonizer to produce a syngas from volatiles in the coal. The syngas is combusted in the topping combustor of a state-of-the-art combustion turbine, derived from the Westinghouse 501G technology class.

The CPFBC portion of the plant is comprised of a single train of process vessels, including one each of a carbonizer, pressurized fluid bed combustor, and fluid bed heat exchanger. Multiple vessels are used for cyclones and ceramic candle filter vessels, which remove particulates from the gas path.

The resulting plant produces a net output of 379 MWe at a net efficiency of 47 percent, on an HHV basis.

5.2 HEAT AND MASS BALANCE

This CPFBC power plant utilizes a combined cycle for conversion of thermal energy from the fluid bed to electric power. An open Brayton cycle using air and combustion products as working fluid is used in conjunction with the existing conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the fluidized bed heat exchanger (FBHE) and in the heat recovery steam generator (HRSG), and by heating feedwater in the HRSG.

The gas turbine operates in an open cycle mode, with alterations to the cycle originally established for the W501G class machine. The inlet air is compressed in a single spool compressor to the design basis discharge pressure. Instead of passing directly on to the burner assembly as in a standard "G" machine, most of the air is removed from the machine and conveyed to the CPFBC island, where it is divided into several streams. A small portion of the air (5 percent) is boosted to a higher pressure (385 psig) for use in the lock hopper injection system for fuel and sorbent. Another small stream (9.5 percent) is boosted to 335 psig for induction into the carbonizer, where it facilitates the coal devolatilization and pyrolysis process. An additional stream (approximately 24 percent) is retained at the machine and used internally for turbine cooling air, and for cooling of the multi-annular swirl burner (MASB) assemblies. The remaining air removed from the machine is sent to the CPFB combustor area.

The main air stream removed from the machine is compressed in a motor-driven boost compressor by a nominal 32 psi or 12 percent increase. The boosted air then is sent to the CPFBC vessel and the accompanying FBHE to provide O_2 for combustion reactions and fluid momentum for material transport. The carbonizer and lock hopper air streams are boosted by separate compressors.

The cleaned hot gas from the CPFBC is returned to the gas turbine, along with low-Btu fuel/gas from the carbonizer. These two streams are mixed and combusted in an MASB topping combustor, which is comprised of a number of combustion chambers that are mounted external to the original gas turbine machine envelope. The gas turbine used in this application requires significant structural and flow path modifications and is thus considered a derivative of the 501G machine, and not an actual production model.

The hot combustion gases are conveyed to the inlet of the turbine section of the machine, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are discharged through a HRSG to recover the large quantities of available thermal energy. The HRSG exhausts to the plant stack.

The Rankine steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram, Figure 5-1. Overall performance for the entire plant, including Brayton and Rankine cycles, is summarized in Table 5-1, which includes auxiliary power requirements. The net plant output, after plant auxiliary power requirements are deducted, is 379 MWe. The overall net plant efficiency is 47 percent, based on HHV of the fuel.

The steam generation in the FBHE and in the HRSG is matched to the steam conditions established for this design. The Rankine cycle used herein is based on a 2400 psig/1050°F/1050°F single reheat configuration. The HP turbine uses 1,037,486 lb/hour steam at 2400 psig and 1050°F. The cold reheat flow from the HP turbine to the reheater in the FBHE is 991,293 lb/hour of steam at 510 psig and 657°F, which is reheated to 1050°F before entering the IP turbine section.

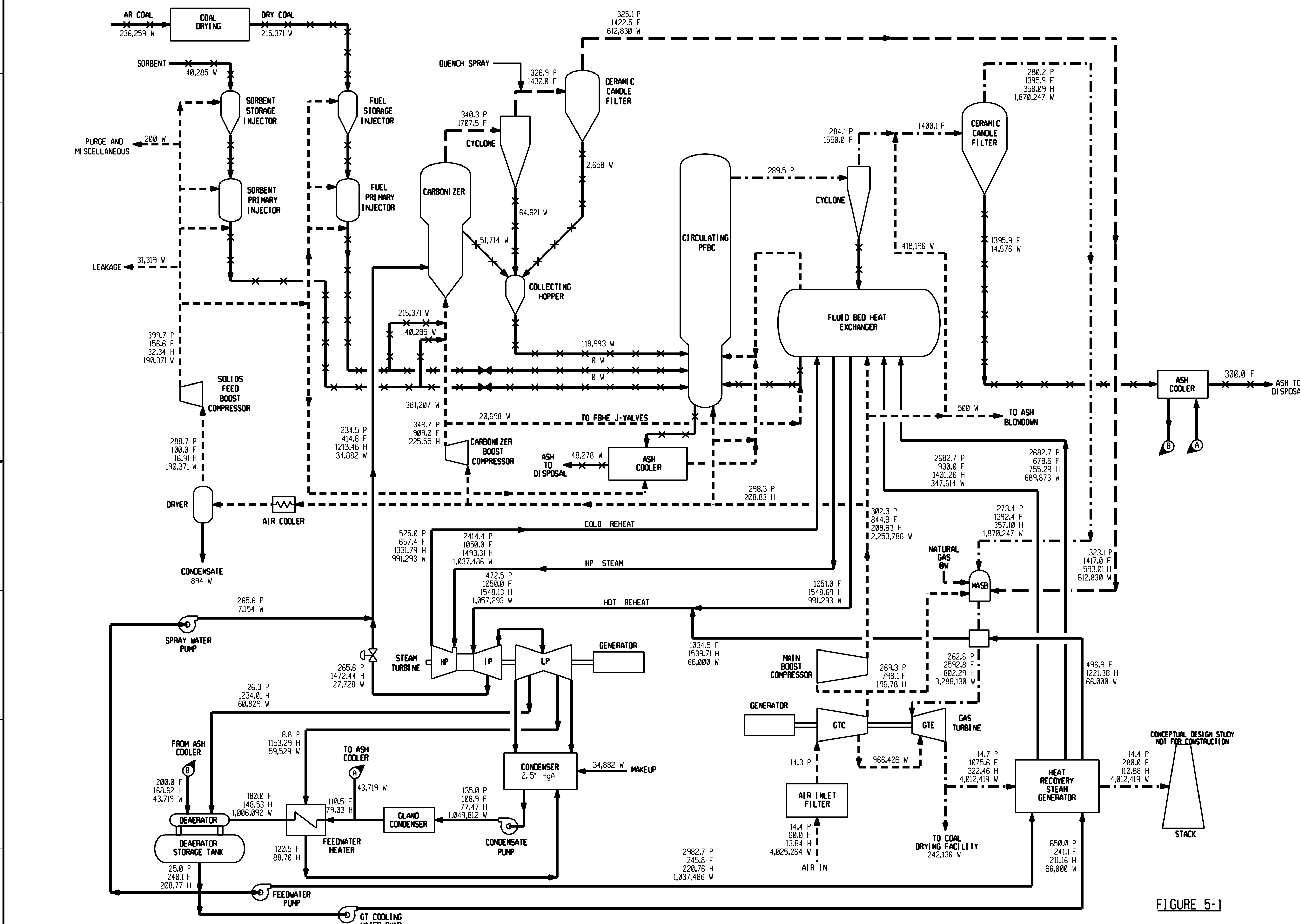


FIGURE 5-1

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018°F AND 0.08865 PSIA.
2. BOOST COMPRESSORS ARE MOTOR DRIVEN.
3. STEAM LEAKAGE AND BLOWDOWN MODELED BUT NOT SHOWN.

DD

LEGEND

- - - - -	AIR
— — —	FUEL GAS
— · — · —	COMBUSTION PRODUCTS/VITIATED AIR
—×——×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GAS TURBINE POWER :	210.894 MWe
STEAM TURBINE POWER :	198.915 MWe
GENERATOR LOSS :	8.035 MWe
AUXILIARY POWER (TOTAL) :	22.590 MWe
NET PLANT POWER :	379.184 MWe
NET PLANT EFFICIENCY :	47.0 % HHV
NET PLANT HEAT RATE :	7,269 Btu/kWh HHV

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DISCP ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION	CONSTRUCTION STATUS
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.	

DRAWN BY CLR 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 POWER GROUP INC.

READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE

CLEAN COAL TECHNOLOGY PROGRAM

CPFBC REFERENCE PLANT

DEPARTMENT OF ENERGY

HEAT AND MASS BALANCE DIAGRAM

MAXIMUM EFFICIENCY CASE TASK 22

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-006

REV A

ARCH	HVAC	I & C	ELECT	MECH	CIVIL	STRUC	ARCH	HVAC	I & C	ELECT	MECH	CIVIL	STRUC	ARCH	HVAC	I & C	ELECT	MECH	CIVIL	STRUC	ARCH	HVAC	I & C	ELECT	MECH	CIVIL	STRUC	ARCH	HVAC	I & C	ELECT	MECH	CIVIL	STRUC

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193APFBC/193APFBT J.S.WHITE/P.M.WITMAN

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Table 5-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

(Loads are presented for one CPFB package, one gas turbine, and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine	206,759
Steam Turbine	<u>195,015</u>
Total	401,774
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	150
Coal Drying and Crushing	1,400
Limestone Handling & Preparation	450
Transport Booster Compressor	880
Carbonizer Booster Compressor	2,010
Main Boost Compressor	8,130
Condensate Pumps	160
Main Feed Pump	3,720
Boiler Forced Circulation Pump	100
Miscellaneous Balance of Plant (Note 1)	900
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	300
Circulating Water Pumps	1,620
Cooling Tower Fans	900
Ash Handling	80
Soot Blowers (Note 2)	0
Transformer Loss	1,390
TOTAL AUXILIARIES, kWe	22,590
Net Power, kWe	379,184
Net Efficiency, % HHV	47
Net Heat Rate, Btu/kWh (HHV)	7,269
CONDENSER COOLING DUTY, 10^6 Btu/h	1,000
CONSUMABLES	
As-Received Coal Feed, lb/h	236,260
Sorbent, lb/h	40,285

Note 1 - Includes plant control systems, lighting, HVAC, etc.

Note 2 - Soot blowing medium is steam. Electric power consumption is negligible.

The steam turbine selected to match this cycle is a two-casing, reheat, double-flow exhaust machine. The HP and IP turbine sections are contained in one casing, with the LP section in another casing. The turbine runs at 3,600 rpm, and drives a hydrogen-cooled generator. The LP turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga at the nominal 100 percent load design point. For each LP turbine, the last-stage bucket length is 30.0 inches, the pitch diameter is 85 inches, and the annulus area per end is 55.6 square feet.

The condensate and feedwater heating is accomplished by heat recovery from the gas turbine exhaust, in the HRSG. A deaerating heater is provided, with heating accomplished by steam generated in the HRSG.

In summary, the major features of the steam turbine cycle for this PFBC plant include the following:

- Subcritical steam conditions and single reheat (2400 psig/1050°F/1050°F).
- Motor-driven boiler feed pumps.
- Turbine configuration based on one 3,600 rpm tandem compound, two-flow exhaust machine.
- Condensate and feedwater heating principally accomplished in the HRSG, recovering heat from the gas turbine exhaust.

5.3 EMISSIONS PERFORMANCE

The operation of the circulating second-generation CPFBC is projected to result in low levels of emission for NOx, SO_2, and particulate (fly ash). At the same time, the discharge of solid wastes to a landfill or recycle process is expected to be comparable to that for a PC plant with a wet FGD system. The emissions levels are presented in Table 5-2.

The low level of SO_2 is achieved by capture of the sulfur in the bed by calcium in the limestone sorbent. The nominal design basis SO_2 removal rate is set at 95 percent with a Ca/S ratio of 1.75 for the CPFBC used in this study.

Table 5-2
AIRBORNE EMISSIONS - CPFBC, CIRCULATING BED, SECOND GENERATION

	Values at Design Condition (at 433 MWe)			
	lb/10^6 Btu	**Tons/year 65%**	**Tons/year 85%**	**Tons/MWh**
SO_2	0.23	1,804	2,360	1.67
NOx	0.1	785	1,026	0.725
Particulates	0.002	< 16	<209	0.006
CO_2	205.7	1,614,700	2,111,500	1,496

The low levels of NOx are achieved by the zoning and staging of combustion in the gas turbine MASB combustors. In addition, the limitation of bed gas exit temperature to 1600°F or less is a significant contributor to reducing the formation of NOx in the CPFBC vessel and the carbonizer, since the kinetics of NOx formation are significantly retarded at these relatively low combustion temperatures. The techniques of SCR or SNCR can reduce NOx emissions further, but are not applied to the subject plant in accordance with the ground rules stated in Section 3.

Particulate discharge to the atmosphere is limited by the use of the ceramic candle filters, which provide a collection efficiency of greater than 99.9 percent.

CO_2 emissions, on an intensive basis (lb/MMBtu), are comparable to other coal-fired technologies in this study since the same fuel is used (Illinois No. 6 coal).

5.4 DESCRIPTION OF CPFBC, SECOND GENERATION, ISLAND SYSTEMS

In this version of the circulating pressurized fluid-bed technology, crushed coal is injected, along with a sorbent such as limestone, into a carbonizer vessel. The coal is subjected to a mild gasification process, with the volatile matter driven off as overheads. This gaseous product passes through a single stage of cyclones to remove most of the particulates, followed by a ceramic candle filter. The hot gas from the CPFBC vessel also passes through a stage of cyclones, followed by a bank of candle filters. This gas and the low-Btu gas from the carbonizer are ducted to an MASB assembly, where the gas is combusted, and then expanded through the turbine section of the gas turbine.

The char from the carbonizer, along with the solids removed by the cyclone and filter, are passed to the CPFBC vessel where the char is combusted. The solids removed from the CPFBC overhead gases are collected in a hopper and passed into the FBHE, where they release sensible heat for steam generation. Additional steam generation, along with feedwater heating, occurs in the HRSG that is located in the gas turbine exhaust stream.

As noted in Section 5.4.2, the abundance of heat recovery opportunities in the CPFBC gas path results in a large reduction in steam flow normally extracted from the steam turbine for the purpose of feedwater heating. Therefore, the selection of the LP turbine configuration and last-stage bucket length will be indicative of a larger exhaust annulus area than might be expected for a steam turbine of comparable power output in a PC plant.

For this study, a combustion turbine based on the Westinghouse 501G technology class type has been selected. The actual machine would require some significant modifications to the standard production 501G unit. These are described in Section 5.4.3. This class of machine represents a good match to the overall cycle requirements, based on a total power output of a nominal 380 MWe. Operating in the boosted second-generation CPFBC cycle, the gas turbine is expected to generate approximately 207 MWe.

Based on the selection of a derivative of the 501G, the various components of this CPFBC plant may be sized, rated, etc. The text below describes each of the major components in a summary manner.

5.4.1 <u>Carbonizer Subsystem</u>

A single carbonizer subsystem is provided for the CPFBC package. The subsystem is comprised of a single carbonizer vessel, with two cyclones, two ceramic candle filter vessels, two collecting hoppers, and N-valves. Coal, limestone sorbent, and compressed air enter the carbonizer vessel from below via a manifold with multiple nozzles, one for each constituent. The coal is devolatilized and pyrolized in the carbonizer, with the low-Btu gas leaving as overheads and the char draining by gravity from a standpipe bed drain to a collecting hopper below. The overhead gases pass through the cyclones and ceramic candle filters with the collected solids drained to the collecting hoppers. The cleaned gases are conveyed to the gas turbine for combustion.

The carbonizer and its companion vessels are fabricated of SA-516 Gr. 70 steel plate, and are ASME Section VIII stamped vessels. The vessels are lined with refractory material 8 inches thick. Table 5-3 presents nominal dimensions and metal wall thicknesses for each vessel.

Table 5-3
CARBONIZER VESSEL SIZE

Vessel	OD, ft-in.	Overall Height, ft	Twall, in.*
Carbonizer	16-6	50	1.875
Cyclone	9-0	30	1.25
Collecting Hopper	14-0	20	1.625
Ceramic Candle Filter	11-0	50	1.25

*Nominal wall thickness at thickest section

The N-valve is a non-mechanical valve that uses nitrogen to fluidize and transfer solids from the carbonizer subsystem to the CPFBC. The valve is fabricated from carbon steel pipe segments, with nominal diameters of 30 inches.

5.4.2 Circulating Pressurized Fluid-Bed Combustor (CPFBC) Subsystem

The CPFBC subsystem is comprised of the CPFBC vessel, four cyclones, six ceramic candle filters, an FBHE, a pressure vessel containing the FBHE, and a J-valve.

The solids received from the carbonizer subsystem enter the CPFBC near the bottom of the vessel. Compressed air enters the vessel at two principal locations: primary air enters at the bottom of the vessel, with secondary air entering via an array of nozzles approximately 20 feet above a grid plate located near the bottom of the vessel. The grid plate functions as an air distributor and as a floor for the bed.

Flue gases and entrained solids leave the CPFBC vessel via two refractory-lined nozzles at the top of the vessel and pass through the cyclones and candle filters. The entrained solids removed by the cyclones flow by gravity down to the FBHE. The cleaned gas leaving the filters flows to the gas turbine where it is mixed with the low-Btu fuel gas from the carbonizer to support combustion in the topping combustor of the turbine.

The FBHE is contained inside a large horizontal cylindrical pressure vessel. The FBHE is divided into three major cells: a center cell that receives solids from the cyclones, and two end cells that contain tube bundles for superheating and reheating steam from the steam turbine cycle. The solids circulate between the CPFBC, cyclones, and FBHE; they return to the CPFBC in a continuous cycle. The J-valve modulates the transfer of solids, consisting of ash, unburned carbon, and sorbent material, from the bottom of the FBHE to the CPFBC vessel.

The ceramic candle filters are vertical, cylindrical vessels, with conical bottom sections, containing a number of ceramic candle elements. These candle elements are arranged into arrays, each containing a number of candle elements. The arrays are supported inside the vessel by a plenum and tubesheet arrangement, reinforced with channels. The vessel interior is lined with 8 inches of refractory. The filters are designed to provide a collection efficiency greater than 99.9 percent.

The CPFBC and its companion vessels are fabricated from SA-516 Gr. 70 steel plate material, and are ASME Section VIII stamped vessels. The vessels are lined with refractory material 8 inches thick. Table 5-4 presents approximate dimensional data for these vessels.

5.4.3 Gas Turbine Generator

The gas turbine generator selected for this repowering application is based on the Westinghouse Electric Corp. Type 501G. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes. The standard production version of this machine, fired with natural gas, will develop a compressor pressure ratio of 19.2:1 and a turbine inlet temperature of almost 2600°F.

Table 5-4
CPFBC VESSEL SIZES

Vessel	OD, ft-in.	Overall Height, ft	Twall, in.*
PFBC	22-0	115	2.375
Cyclone	11-0	41	1.375
Filter	11-0	50	1.25
Hopper	8-0	13	1.125
FBHE Vessel	36-0	55 (length)	3.50

*Nominal wall thickness at thickest section

In second-generation CPFBC service, the machine must be modified to collect the compressor discharge air for discharge to the external CPFB circuit. The modifications to the machine include the incorporation of an MASB assembly to replace the original can-annular design. The MASB combustors burn the low-Btu gas with high efficiency while minimizing NOx production. The turbine nozzle area must be increased by approximately 2 percent to accommodate the increased mass flow of hot gas in this case. In addition, the rotor inlet temperature is reduced to 2470°F for this conceptual design case, to accommodate liner cooling considerations for the MASB assembly. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements. The generator is a standard hydrogen-cooled machine with static exciter.

5.4.4 Boost Subsystem

The boost subsystem is comprised of a single full-size boost compressor. A 12,000 hp 7,200V induction motor drives the fan through a hydroviscous type variable speed drive (VSD). The boost subsystem provides a boost in air pressure at the combustion turbine compressor discharge, which compensates for the additional unrecoverable pressure drop encountered in a CPFBC cycle. The pressure boost is instrumental in enabling the combustion turbine power output to meet or exceed its design basis power output potential, and to avoid significant changes to turbine design parameters.

The boost compressor is a centrifugal fan type unit placed in a heavy gauge housing with a stuffing box to minimize shaft seal leakage. The fan and housing are fabricated of carbon steel (A36 for the housing and A514 for the wheel). The VSD provides the capability to reduce compressor flow (by reducing speed) to match the airflow requirements of the combustion turbine compressor, which will vary at part load. Variable inlet guide vane control for the fans is possible, but potential air leakage problems around the guide vane shaft seals render the VSD the design of choice for this conceptual study.

5.4.5 Heat Recovery Steam Generator

The HRSG is a drum-type, double-pressure design matched to the characteristics of the gas turbine exhaust gas when firing low-Btu gas, and to the steam conditions selected for the steam cycle. The HP drum produces steam at 2670 psig, which is superheated in the HRSG superheater to 930°F. The mid-pressure drum produces steam at 600 psia, which is superheated in the HRSG to 500°F. This mid-pressure steam is used for burner transition cooling in the gas turbine. Additional heat recovery from the gas turbine exhaust gas is accomplished by heating feedwater and condensate in economizer surface in the HRSG.

5.4.6 Fuel Preparation and Injection System

The fuel preparation and injection system receives crushed coal, sized at 3/4" x 0, from the coal handling system. The system interface is at the slide gate valves at the discharge of the new silos.

The fuel preparation and injection system is comprised of two complete crushing/drying subsystems, each rated at 140 tph. At this capacity, one subsystem operates about 20 hours per day, or both subsystems operate approximately 10 hours per day to crush and dry the quantity of coal required to sustain continuous plant operation. The crusher/dryer arrangement provides operational flexibility for the plant with respect to crushing and drying operations, and provides redundancy so that a single failure will not cause a plant shutdown.

Each subsystem is comprised of a roller mill type crusher, an iso-kinetic type separator, a main mill fan, a cyclone collector, an exhaust fan, and a baghouse type filter. The rough-sized (3/4" x 0) coal is fed from the discharge of the coal silo through a rotary feeder to the inlet of the mill. The coal is crushed to nominal 1/8-inch size. The crushed coal is exhausted from the mill through the iso-kinetic separator, conveyed by entrainment in a circulating flow of air, to the cyclone collector. The crushed coal is disentrained from the air stream in the cyclone collector, and discharged through a rotary valve to a crushed coal day bin. Each day bin discharges through slide gate valves to gravimetric type feeders. The feeders meter the crushed coal into a lock hopper system. Each lock hopper train is comprised of a storage injector and a primary injector; these lock hoppers are pressurized by compressed air from the solids feed boost compressor. The storage injectors discharge into the primary injectors, which discharge the coal into the pressurized carbonizer and CPFBC vessels.

A supply of hot gas at approximately 1100°F is taken from the discharge of the combustion turbine, and supplied to each crushing/drying subsystem. The temperature for the circulating airstream transporting the coal around the drying loop is maintained above the dew point of the gas, or approximately 250°F. The exhaust fan for each subsystem removes a fraction of the circulating stream on a continuous basis to maintain moisture levels nearly constant. The exhaust flow is passed through a baghouse filter to remove particulates, which are discharged to the crushed coal day bin. Filtered exhaust gas is discharged through local short stacks.

5.4.7 Sorbent Injection System

The sorbent injection system receives limestone sorbent that is ground to the correct size distribution by the sorbent handling and preparation system. The sorbent is crushed to nominal 1/8-inch size. The sorbent day bins discharge through slide gate valves into two parallel trains of lock hopper systems. Each lock hopper train is comprised of a storage injector and a primary injector; the lock hoppers are pressurized by compressed air from the solids feed boost compressor. The storage injectors discharge into the primary injectors, which discharge the limestone into the carbonizer.

5.4.8 Flare Stack

A flare stack is provided to dispose of combustible gases from the carbonizer during upset transients such as unit trip. The stack is self-supporting, carbon steel with refractory lining and pilot ignition.

5.5 PFBC SUPPORT SYSTEMS (BALANCE OF PLANT)

5.5.1 Coal Handling System

The function of the coal handling 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 and including the slide gate valves on the outlet of the coal storage silos.

Operation Description

The bituminous 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 (No. 1). The coal is then transferred to a conveyor (No. 2) 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 (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0. The coal then enters a second crusher that reduces the coal size to 1" x 0. The coal is then transferred by conveyor No. 4 to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the two silos.

Technical Requirements and Design Basis

- Coal burn rate:
  - Maximum coal burn rate = 236,260 lb/h = 118.1 tph plus 10% margin = 130 tph (based on the 100% MCR rating for the plant, plus 10% design margin)
  - Average coal burn rate = 200,000 lb/h = 100 tph (based on MCR rate multiplied by an 85% capacity factor)

- Coal delivered to the plant by unit trains:
  - Two and one-half unit trains per week at maximum burn rate
  - Two unit trains per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 9 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 900 tph (maximum, both conveyors in operation)
  - Reclaim rate = 300 tph
- Storage piles with liners, run-off collection, and treatment systems:
  - Active storage = 9,400 tons (72 hours at maximum burn rate)
  - Dead storage = 68,000 tons (30 days at average burn rate)

5.5.2 Limestone Handling and Preparation System

The function of the balance-of-plant limestone handling and preparation system is to receive, store, convey, and crush the limestone delivered to the plant for feeding to the CPFBC island sorbent injection system. The scope of the system is from the storage pile up to the sorbent injection system lock hopper inlets.

Operation Description

Limestone will be delivered to the plant by 25-ton trucks.

The limestone is unloaded onto a storage pile located adjacent to a reclaim hopper, beneath which are a pair of vibrating feeders, rated at 150 tons/hour each. A bulldozer pushes the limestone into the reclaim hopper, where a pair of feeders loads limestone onto a belt conveyor for transport to two 100 percent capacity equipment trains for crushing. Each train is comprised of a 120-ton capacity surge bin supplying one rod mill of 35 tons/hour capacity each. The rod mills discharge to the suction side of a positive displacement solids pump, which transport the pulverized material to two day bins of 265 tons capacity each. The day bins discharge the material to the sorbent injection system described in Section 5.4.7.

<u>Technical Requirements and Design Basis</u>

- Limestone usage rate:
  - Maximum limestone usage rate = 40,285 lb/h = 20.1 tph plus 10% margin = 22.2 tph (based on the 100% MCR rating for the plant)
  - Average limestone usage rate = 34,300 lb/h = 17 tph (based on the MCR limestone usage rate multiplied by an 85% capacity factor)
- Limestone delivered to the plant by 25-ton dump trucks
- Total number of trucks per day = 21 (based on maximum usage rate)
- Total truck unloading time per day = 4 hours
- Unloading time per truck = 10 minutes
- Receiving hopper capacity = 35 tons
- Limestone received = 1" x 0
- Limestone storage capacity = 16,000 tons (30 days supply at maximum burn rate)
- Storage pile size = 185 ft x 90 ft x 40 ft high
- Conveying rate to surge bin = 150 tph
- Vibratory feeder/limestone rod mill capacity, 35 tph for each mill (based on two mills operating one shift per day or one mill operating two shifts per day)
- Day bin storage = 500 tons (24-hour supply at maximum burn rate, total for two bins)

5.5.3 <u>Ash Handling</u>

The ash handling system conveys, stores, and disposes of ash removed from the fluidized bed (spent bed material, or bottom ash), and from the ceramic candle filters (fly ash).

Spent bed material drains from the FBHE bed into a restricted pipe discharge (RPD) hopper. The hopper operates at atmospheric pressure; the pressure drop from the FBHE vessel to atmospheric pressure occurs across the packed bed material in the restricted inside diameter (nominally 6 inches) of the refractory-lined pipe. The pipe extends downward approximately 8'-6" into the hopper.

A slide gate valve at the bottom outlet of the hopper regulates the flow of material from the hopper to a screw cooler, which cools and transports the ash out and onto a system of drag chain conveyors. The conveyors transport the ash to a pair of storage silos for temporary holdup. Ash from the candle filters is transported from the RPD hoppers located at the base of the filters. A slide gate at the bottom outlet of the hopper regulates the flow of material from the hopper to a screw cooler, which cools and transports the ash to a system of drag conveyors.

The silos are sized for a nominal holdup capacity of 36 hours of full-load operation (1,140 tons capacity) per each. At periodic intervals, a convoy of ash hauling trucks will transit the unloading station underneath the silos and remove a quantity of ash for disposal. Approximately 30 truck loads per day are required to remove the total quantity of ash produced by the repowered plant operating at nominal rated power.

5.6 STEAM CYCLE BALANCE OF PLANT

The following section provides a description of the steam turbines and their auxiliaries.

5.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine consists of a high-pressure (HP) section, intermediate-pressure (IP) section, and one double-flow low-pressure (LP) section, all connected to the generator by a common shaft. 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 last-stage bucket length of 30 inches.

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 2400 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 FBHE for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 460 psig/1050°F. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided.

The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

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, datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

5.6.2 Condensate and Feedwater Systems

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the feedwater heater. The system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser, and a low-temperature feedwater heater. 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.

Feedwater

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank to the respective steam drums. Two motor-driven, half-sized boiler feed pumps are provided. At least one of the two pumps is provided with a variable speed drive to support startup, shutdown, and part-load operation. 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.

5.6.3 Main and Reheat Steam Systems

Main and Reheat Steam

The function of the main steam system is to convey main steam from the FBHE superheater outlet to the high-pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the FBHE reheater, and to the turbine reheat stop valves.

Main steam at approximately 2500 psig/1050°F exits the FBHE superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam at approximately 510 psig/660°F exits the HP turbine, flows through a motor-operated isolation gate valve, to the FBHE reheater. Hot reheat steam at approximately 460 psig/1050°F exits the FBHE reheater through a motor-operated gate valve and is routed to the IP turbines.

5.6.4 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.

5.6.5 Major Gas Path and Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the gas path and steam cycle. A summary of the required piping is presented in Table 5-5 and Table 5-6.

5.7 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.

Table 5-5
CPFBC - STEAM CYCLE PIPING REQUIRED

Pipeline	Flow, lb/h	Press., psig	Temp., °F	Material	OD, in.	Twall, in.
Condensate	1,049,800	125	110	A106 Gr. B	12	Sch. 40
Feed Pump to HRSG	1,037,500	2980	260	A106 Gr. C	10	Sch. 160
Feedwater/HRSG to FBHE	689,800	2700	680	A106 Gr. C	8	Sch. 160
Main Steam/HRSG to FBHE	347,614	2600	930	A335 Gr. P22	10	1.50
Main Steam/FBHE to Steam Turbine	1,037,500	2500	1050	A335 Gr. P22	14	2.0
Cold Reheat	991,300	510	620	A106 Gr. B	28	0.50
Hot Reheat	1,057,300	460	1050	A691 Gr. 22	28	0.75

Table 5-6
CPFBC - GAS PATH PIPING REQUIRED

Pipeline	Flow, lb/h	Press., psig	Temp., °F	Material	OD, in.	Twall, in.
Gas Turbine Compressor to Boost Compressor	2,253,786	300	800	A691 Gr. P22	42	0.50
Boost Compressor to CPFBC	2,253,786	300	830	A691 Gr. P22	42	0.50
CPFBC Island to Gas Turbine (Vitiated Air)	1,870,247	260	1400	A672 Gr. B70 Refractory-lined	78	0.75
Low-Btu Gas to Gas Turbine (from Carbonizer)	612,830	310	1400	A672 Gr. B70 Refractory-lined	36	0.375
Carbonizer Compressed Air	381,207	320	890	A106 Gr. B	16	Sch. 40
Transport Compressed Air	198,371	350	150	A106 Gr. B	8	Sch. 40

5.8 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.

5.9 SITE, STRUCTURES, AND SYSTEMS INTEGRATION

5.9.1 Plant Site and Ambient Design Conditions

Refer to Section 2 for a description of the plant site and ambient design conditions.

5.9.2 New Structures and Systems Integration

The development of the reference plant site to incorporate the structures required for this technology is based on the assumption of a flat site. The general layout is shown in Figure 5-2. The CPFBC island and related structures are arranged in a cluster, with the coal and slurry preparation facilities adjacent to the east.

The gas turbine and its ancillary equipment are sited directly to the north of the CPFBC island in a turbine building. The HRSG and stack are north of the gas turbine, with the steam turbine and its generator in a separate building located to the west. Service and administration building are located at the west side of the steam turbine building.

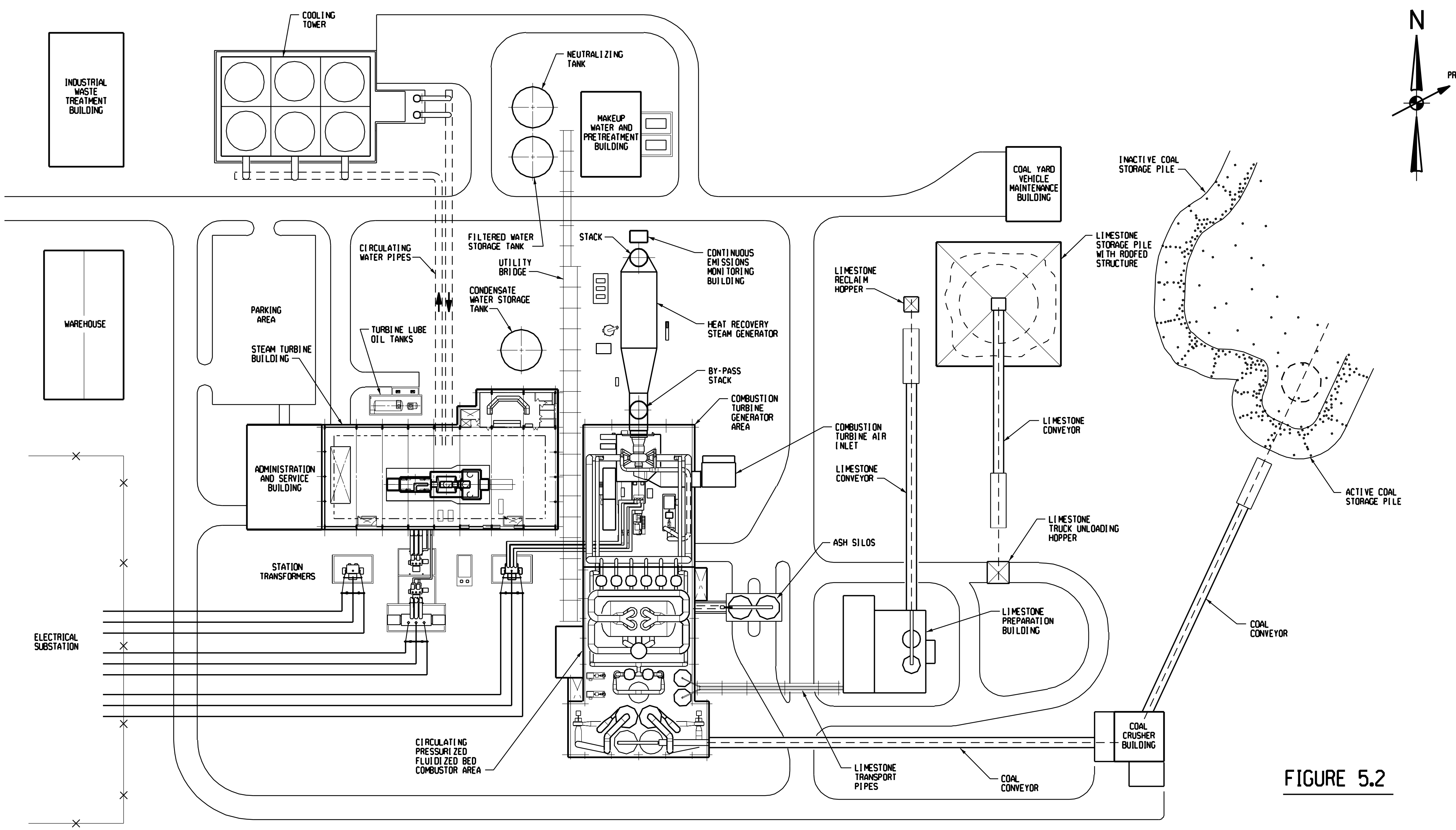

FIGURE 5.2

PLAN VIEW

0 50 100 150 200
GRAPHIC SCALE IN FEET

NOTES:

DD

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	LEAD ENGINEER	LEAD DISCP ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION	CONSTRUCTION STATUS
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.	

LDE ___ DATE ___

DRAWN BY CLR DATE 12/21/98

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
CLEAN COAL TECHNOLOGY PROGRAM
CIRC PRESSUREIZED FLUIDIZED BED COMB
DEPARTMENT OF ENERGY TASK 22

PLANT GENERAL ARRANGEMENT
PLANT LAYOUT

SCALE 1"=50'

PARSON'S DWG. NO. 8436-1-200-002-701

REV A

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The cooling tower heat sink for the steam turbine is located to the north of the steam turbine building. The electrical transformer area, containing the main step-up transformers for the gas turbine and steam turbine, as well as the unit auxiliary transformer, is south of the steam turbine building. The plant electrical switchyard is west of the transformers.

The arrangement described above provides good alignment and positioning for major interfaces, relatively short steam, feedwater, and circulating water gas pipelines, and allows good access for vehicular traffic. Transmission line access from the gas turbine and steam turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located east of the gas turbine. The clean, hot, medium-Btu gas is conveyed to the turbine combustors for mixing with the air that remained on-board the machine. Turbine exhaust is ducted directly through a triple-pressure HRSG and then to a new 213-foot stack. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

Access and construction laydown space are freely available on the periphery of the plant, with several roads, 26 feet wide plus shoulders, running from north to south between the various portions of the plant.

5.10 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 No. 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor No. 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	40 ton	2
7	Feeder	Vibratory	200 tph	2
8	Conveyor No. 3	48" belt	400 tph	1
9	Crusher Tower	N/A	400 tph	1
10	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
11	Crusher	Granulator reduction	6"x0 - 3"x0	1
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	1
13	As-Fired Coal Sampling System	Swing hammer		2
14	Conveyor No. 4	48" belt	300 tph	1
15	Transfer Tower	N/A	300 tph	1
16	Tripper	N/A	300 tph	1
17	Coal Silo w/Vent Filter and Slide Gates	N/A	1,300 ton	2

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Truck Unloading Hopper	N/A	35 ton	2
2	Feeder	Vibratory	150 tph	2
3	Conveyor No. 1	30" belt	150 tph	1
4	Conveyor No. 2	30" belt	150 tph	1
5	Limestone Surge Bin		120 ton	2
6	Bin Activator		35 tph	2
7	Feeder	Gravimetric	35 tph	2
8	Limestone Rod Mill	Rotary	35 tph	2
9	Pump	Screw type, pneumatic; Fuller-Kovako	35 tph	2
10	Blower	Positive displacement	15 psig	2
11	Dust Collector	Bag filter		2
12	Exhaust Fan	Centrifugal		2
13	Limestone Day Bin		24 hours/265 tons	2
14	Slide Gate Valve			2

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

ACCOUNT 2A FUEL PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Feeder	Rotary	140 tph	2
2	Grinding Mill	Roller	140 tph	2
3	Separator	Iso-kinetic	140 tph	2
4	Cyclone Collector	Cone bottom	140 tph	2
5	Cyclone Rotary Valve		120 tph	2
6	Dust Collector	High efficiency fabric	30,000 cfm	2
7	Dust Collector Rotary Valve		10 tph	2
8	Exhaust Fan	Centrifugal	30,000 cfm	2
9	Main Mill Fan	Centrifugal	120,000 cfm	2
10	Crushed Coal Bin	Vertical, cylindrical	640 ton	2
11	Slide Gate Valve		100 tph	2
12	Feeders	Gravimetric	100 tph	2
13	Coal Storage Injector	Vertical, cylindrical	11'-0" ID x 27'-0"	2
14	Coal Primary Injector	Vertical, cylindrical	12'-0" ID x 61'-6"	2

ACCOUNT 2B SORBENT INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Limestone Storage Injector	Vertical, cylindrical		2
2	Limestone Primary Injector	Vertical, cylindrical		2
3	Feed Valve	Rotary		2

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	100,000 gal	1
2	Condensate Pumps	Vert. canned	1,050 gpm @ 400 ft	2
3	LP Feedwater Heater 1	Horiz. U tube	2,010 gpm 110°F to 180°F	1
4	Deaerator	Horiz. spray type	1,006,100 lb/h 180°F to 240°F	1
5	Deaearator Storage Tank	Horiz. pressure vessel	60,000 gal 80 psig	1
6	Boiler Feed Pumps	Barrel type, multi-staged, centr.	1,040 gpm @ 6,800 ft	2
7	GT Cooling Water Pump	Barrel type, multi-staged, centr.	70 gpm @ 1,500 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler (Heating)	Shop fab. water tube design	125 psig, sat, 80,000 lb/h	1
2	Fuel Oil Storage Tank	Vertical, cylindrical	60,000 gal	1
3	Fuel Oil Unloading Pump	Gear	50 psig, 100 gpm	1
4	Fuel Oil Supply Pump	Gear	150 psig, 50 gpm	2
5	Service Air Compressors	Recip., single stage, double acting, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. centrifugal, double suction	200 ft, 700 gpm	2
8	Closed Cycle Cooling Heat Exchanger	Shell and tube	50% cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 700 gpm	2
11	Fire Service Booster Pump	Two-stage horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1,000 gpm	1
13	Raw Water	SS, single suction	60 ft, 1,500 gpm	2
14	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
15	Filtered Water Tank	Vertical, cylindrical	100,000 gal	1
16	Makeup Demineralizer	Anion, cation, and mixed bed	200 gpm	2
17	Liquid Waste Treatment System		10 years, 25-hour storm	1
18	Condensate Demineralizer	Mixed bed	1,200 gpm	2

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty
1	Carbonizer Vessel	Vertical, cyl., refractory lined, steel, ASME VIII	300 psig	1
2	Carbonizer Cyclone		306,000 lb/h gas flow ea.	2
3	Carbonizer Cyclone Collecting Hopper			2
4	Carbonizer Filter	Ceramic candle	306,000 lb/h gas flow ea.	2
5	Carbonizer Boost Compressor	Centrifugal, high press./high temp. housing	9,000 acfm housing design: 400 psig/1000°F	2
6	CPFBC Vessel	Vertical, cyl., refractory lined, steel	300 psig	1
7	CPFBC Cyclone	Centrifugal	467,560 lb/h ea.	4
8	CPFBC Filter	Ceramic candle	311,700 lb/h gas flow ea.	6
9	Fluid-Bed Heat Exchanger Pressure Vessel	Horizontal cylindrical pressure vessel, steel, ASME VIII	300 psig	1
10	Fluid-Bed Heat Exchanger	Fin-tube, waterwall, multi-cell fabrication contains steam generation bed and drum; super-heater, and reheater sections	Main steam: 2500 psig/1050°F Reheat steam 525 psig/1050°F	1
11	Refractory-Lined Pipe	Carbon steel, B31.1 Code, 6-inch refractory lining	300 psig/1600°F gas	
12	Circulation Pumps	Canned, vertical	10,000 gpm/60 ft TDH Design pressure 2200 psig	1
13	Flare Stack	Vertical stack, refractory lined	84 in. OD, 55 ft high	1
14	Solids Feed Booster Compressor	Centrifugal high press./high temp. housing	1800 acfm housing design: 300 psig/100°F	2
15	Filter Backpulse Compressor	Positive displacement gas compressor, multi-stage, intercooled	Inlet 210 psig/100°F Outlet 1500 psig/150°F	2

ACCOUNT 5 FLUE GAS CLEANUP

(Not required, cleanup accomplished in ceramic filters, Account No. 4)

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

ACCOUNT 6A COMBUSTION TURBINE AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Qty
1	210 MWe Gas Turbine Generator	Axial flow single spool based on W501G	1120 lb/sec airflow 2580°F firing temp. 19.2:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1120 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque Converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Air to Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1
11	Fire Protection Package	Halon		1

ACCOUNT 6B BOOST SUBSYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Main Booster Compressor	Centrifugal, high press./high temp. housing, variable speed drive	60,000 acfm, housing design: 300 psig/240°F	1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Qty
1	Heat Recovery Steam Generator	Drum, double pressure, includes economizer section	2700 psig/930°F/675°F 1,037,500 lb/h 600 psig/500°F, 66,000 lb/h	1
2	Stack	Carbon steel plate type 409 stainless steel lined	60 ft/sec exit velocity 213 ft high by 21 ft inside dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	200 MW Turbine Generator	TC2F30	2400 psig 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	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	1,049,800 lb/h steam @ 2.5 in. Hga with 75°F water, 20°F temp. rise	1
8	Condenser Air Ejector	Twin element, two-stage, condensing ejector, motivated by steam	240 lb/h air and non-condensibles @ 2.0 in. Hga	1
9	Hogging Ejector	Single element, single-stage ejector, air motivated	425 cfm @ 10 in. Hga	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	50,000 gpm @ 60 ft	2
2	Cooling Tower	Evaporative, mechanical draft	54°F WB 20°F approach 20°F range 100,000 gpm	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Fluidized Bed Heat Exchanger RPD Hoppers	Restricted pipe discharge, refractory lined	300 psig	2
2	Ceramic Candle Filter RPD Hoppers	Restricted pipe discharge, refractory lined	300 psig	2
3	Ash Screw Coolers (Spent Bed)	Water cooled	50,000 lb/h	1
4	Ash Screw Coolers (Candle Filter)	Water cooled	15,000 lb/h	1
5	Drag Chain Conveyor		65,000 lb/h	1
6	Drag Chain Conveyor		65,000 lb/h	1
7	Drag Chain Conveyor		71,000 lb/h	1
8	Ash Storage Silo	Vertical, cylindrical, concrete	1,140 ton	2
9	Fluidizing Blower			2
10	Telescoping Chute			2

5.11 CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY

The summary of the conceptual capital cost estimate for the CPFBC plant is shown in Table 5-7. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 5-7

Client: DEPARTMENT OF ENERGY

Report Date: 14-Aug-98 10:52 AM

Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: 2gPFBCw/Boost

Plant Size: 379.2 MW,net

Estimate Type: Conceptual

Cost Base (Jan) 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	7,538	1,270	3,245	227		**$12,280**	982		2,794	**$16,056**	42
2	COAL & SORBENT PREP & FEED	12,633	1,254	2,838	199		**$16,924**	1,354	609	2,596	**$21,483**	57
3	FEEDWATER & MISC. BOP SYSTEMS	6,107	3,212	4,799	336		**$14,453**	1,156		3,709	**$19,319**	51
4	CARBONIZER, PFBC & PFB HTX											
4.1	PFB PRESSURE VESSEL	3,031		448	31		**$3,510**	281	526	432	**$4,749**	13
4.2	PFBC Boiler	1,672		357	25		**$2,055**	164	308	253	**$2,780**	7
4.3	PFBC Economizer	24,307		4,599	322		**$29,227**	2,338	4,384	3,595	**$39,544**	104
4.4-4.9	Other PFBC Equipment	1,092	6,241	4,082	286		**$11,701**	936	68	2,566	**$15,272**	40
	SUBTOTAL 4	*30,102*	*6,241*	*9,486*	*664*		***$46,493***	*3,719*	*5,287*	*6,845*	***$62,345***	*164*
5	HOT GAS CLEANUP & PIPING	15,015	4,968	4,582	321		**$24,886**	1,991	4,270	6,259	**$37,405**	99
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	50,976		2,820	197		**$53,994**	4,319	8,099	6,641	**$73,053**	193
6.2-6.9	C.T. Booster Air System & BOA	785	1,018	1,141	69		**$3,013**	241		707	**$3,961**	10
	SUBTOTAL 6	*51,762*	*1,018*	*3,960*	*267*		***$57,006***	*4,561*	*8,099*	*7,348*	***$77,014***	*203*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	7,241		927	65		**$8,233**	659		889	**$9,781**	26
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,528	611	1,136	80		**$3,355**	268		513	**$4,136**	11
	SUBTOTAL 7	*8,769*	*611*	*2,063*	*144*		***$11,588***	*927*		*1,402*	***$13,917***	*37*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	17,120		2,666	187		**$19,972**	1,598		2,157	**$23,727**	63
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	2,687	4,169	3,254	228		**$10,339**	827		1,874	**$13,039**	34
	SUBTOTAL 8	*19,807*	*4,169*	*5,920*	*414*		***$30,311***	*2,425*		*4,031*	***$36,767***	*97*
9	COOLING WATER SYSTEM	4,286	2,498	4,325	303		**$11,411**	913		2,237	**$14,561**	38
10	ASH/SPENT SORBENT HANDLING SYS	6,504	1,192	1,531	107		**$9,334**	747	486	1,580	**$12,147**	32
11	ACCESSORY ELECTRIC PLANT	9,721	2,715	6,934	485		**$19,855**	1,588		3,503	**$24,946**	66
12	INSTRUMENTATION & CONTROL	5,319	1,439	5,507	385		**$12,650**	1,012		2,121	**$15,783**	42
13	IMPROVEMENTS TO SITE		3,349	5,430	380		**$9,159**	733		2,967	**$12,859**	34
14	BUILDINGS & STRUCTURES		4,635	6,006	420		**$11,061**	885		2,986	**$14,932**	39
	TOTAL COST	**$177,562**	**$38,572**	**$66,624**	**$4,653**		**$287,411**	**$22,993**	**$18,752**	**$50,379**	**$379,535**	**1001**

6. NATURAL GAS COMBINED CYCLE (NGCC)

6.1 MARKET-BASED NGCC

6.1.1 Introduction

Two market-based designs are presented and are based on the use of a natural gas-fired combustion turbine (CT) coupled with a heat recovery steam generator (HRSG) to generate steam for a steam turbine generator. The plant configuration reflects current information and design preferences, the availability of newer combustion and steam turbines, and the relative latitude of a greenfield site.

The first rendition of CT/HRSG technology is based on selection of a gas turbine exemplified by the Westinghouse 501G 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 cycle plant to produce a total net output of 326 MWe, at an efficiency of 50.6 percent (HHV). For this study, a single gas turbine is used in conjunction with one 1650 psig/1000°F/1000°F steam turbine.

The second rendition of a CT/HRSG technology is based on selection of a gas turbine represented by the General Electric “H” machine. This machine also provides values of power output, airflow, and compressor pressure ratio that provide a good match with the HRSG to generate steam for the companion steam cycle plant to produce a total net output of 395 MWe at an efficiency of 53.4 percent HHV. One gas turbine is combined with an 1800 psig/1050°F/1050°F steam turbine.

6.1.2 Heat and Mass Balance

The first market-based plant described in this section is based on use of one Westinghouse 501G gas turbine generator coupled with a triple-pressure HRSG supplying steam to one steam turbine generator. The second market-based plant is based on the use of one General Electric “H” gas turbine generator coupled with a triple-pressure HRSG supplying steam to one steam turbine generator. The resulting power plants utilize a combined cycle for conversion of thermal energy to electric power.

Overall performance for the plants, including Brayton and Rankine cycles, is summarized in Table 6.1-1 and Table 6.1-2, which include auxiliary power requirements. Table 6.1-1 summarizes the plant based on the Westinghouse gas turbine, and Table 6.1-2 summarizes the plant based on the General Electric turbine. An open Brayton cycle using air and combustion products as working fluid is used in conjunction with the conventional subcritical steam Rankine cycle. The two cycles are coupled by generation of steam in the HRSG, and by feedwater heating in the HRSG. The overall air and steam power cycles are shown schematically in the 100 percent load Heat and Mass Balance diagrams, Figure 6.1-1 and Figure 6.1-2.

The inlet air for both plants is compressed in a single spool compressor to the design basis discharge pressure, and then passes directly on to the burner assembly. The hot combustion gases exit the burners and pass to the inlet of the turbine section of the machine, where they enter and expand through the turbine to produce power to drive the compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG to recover the large quantities of thermal energy that remain. The HRSG exhausts to the plant stack.

The W501G machine uses steam to provide cooling for transition ducts between the burner assembly and the turbine inlet. In this study, the steam used for cooling is obtained by removing the steam from the HP steam drum in the HRSG, adding approximately 85°F of superheat in the superheat coil (to assure that the steam remains dry), and then throttling the steam to the appropriate pressure (590 psig). The steam is heated in the transitions to above 1100°F, and then mixed with hot reheat steam leaving the HRSG. The steam conditions were selected to match tentative generic requirements established by the gas turbine manufacturer for the steam used to cool the transitions.

The “H” turbine utilizes cold reheat from the steam turbine for cooling the stationary and rotating parts of the turbine, mainly the first- and second-stage stationary nozzle and buckets plus the stage one shroud. Cold reheat is routed to the turbine where it is heated to 1050°F and then mixed with the hot reheat steam leaving the HRSG.

Table 6.1-1
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD
WESTINGHOUSE 501G

(Loads are presented for one gas turbine and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,650
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine	225,090
Steam Turbine	108,881
Total	333,971
AUXILIARY LOAD SUMMARY, kWe	
Fuel Gas Booster Compressor (Note 1)	1,600
Condensate Pumps (Note 2)	305
HP Feed Pump (Note 3)	1,430
Miscellaneous Balance of Plant (Note 4)	900
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	150
Circulating Water Pumps	1,190
Cooling Tower Fans	1,100
Transformer Loss	755
TOTAL AUXILIARIES, kWe	7,830
Net Power, kWe	326,141
Net Efficiency, % HHV	50.6
Net Heat Rate, Btu/kWh (HHV)	6,743
CONDENSER COOLING DUTY, 10^6 Btu/h	680
CONSUMABLES	
Natural Gas, lb/h @ 21,837 Btu/lb, HHV	100,700

Note 1 - Natural gas pressure boosted from 300 psig to 625 psig

Note 2 - Includes LP feedwater

Note 3 - Includes IP feedwater

Note 4 - Includes plant control systems, lighting, HVAC, etc.

Table 6.1-2
PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD
GENERAL ELECTRIC "H"

(Loads are presented for one gas turbine and one steam turbine)

STEAM CYCLE	
Throttle Pressure, psig	1,800
Throttle Temperature, °F	1,050
Reheat Outlet Temperature, °F	1,050
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine	275,800
Steam Turbine	127,537
Total	403,337
AUXILIARY LOAD SUMMARY, kWe	
Fuel Gas Booster Compressor (Note 1)	1,680
Condensate Pumps (Note 2)	120
HP Feed Pump (Note 3)	1,630
Miscellaneous Balance of Plant (Note 4)	900
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	150
Circulating Water Pumps	1,240
Cooling Tower Fans	700
Transformer Loss	1,370
TOTAL AUXILIARIES, kWe	8,310
Net Power, kWe	395,027
Net Efficiency, % HHV	53.4
Net Heat Rate, Btu/kWh (HHV)	6,396
CONDENSER COOLING DUTY, 10^6 Btu/h	830
CONSUMABLES	
Natural Gas, lb/h @ 21,837 Btu/lb, HHV	115,700

Note 1 - Natural gas pressure boosted from 300 psig to 625 psig

Note 2 - Includes LP feedwater

Note 3 - Includes IP feedwater

Note 4 - Includes plant control systems, lighting, HVAC, etc.

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA

DD

LEGEND

- - - - -	AIR
— — —	FUEL GAS
—·—·—	COMBUSTION PRODUCTS
—x—x—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	229.430 MWe
STEAM T-G POWER :	110.979 MWe
GENERATOR LOSS (TOTAL):	6.438 MWe
AUXILIARY POWER (TOTAL):	7.830 MWe
NET PLANT POWER :	326.141 MWe
NET PLANT EFFICIENCY :	50.6 %
NET PLANT HEAT RATE :	6,743 Btu/kwh

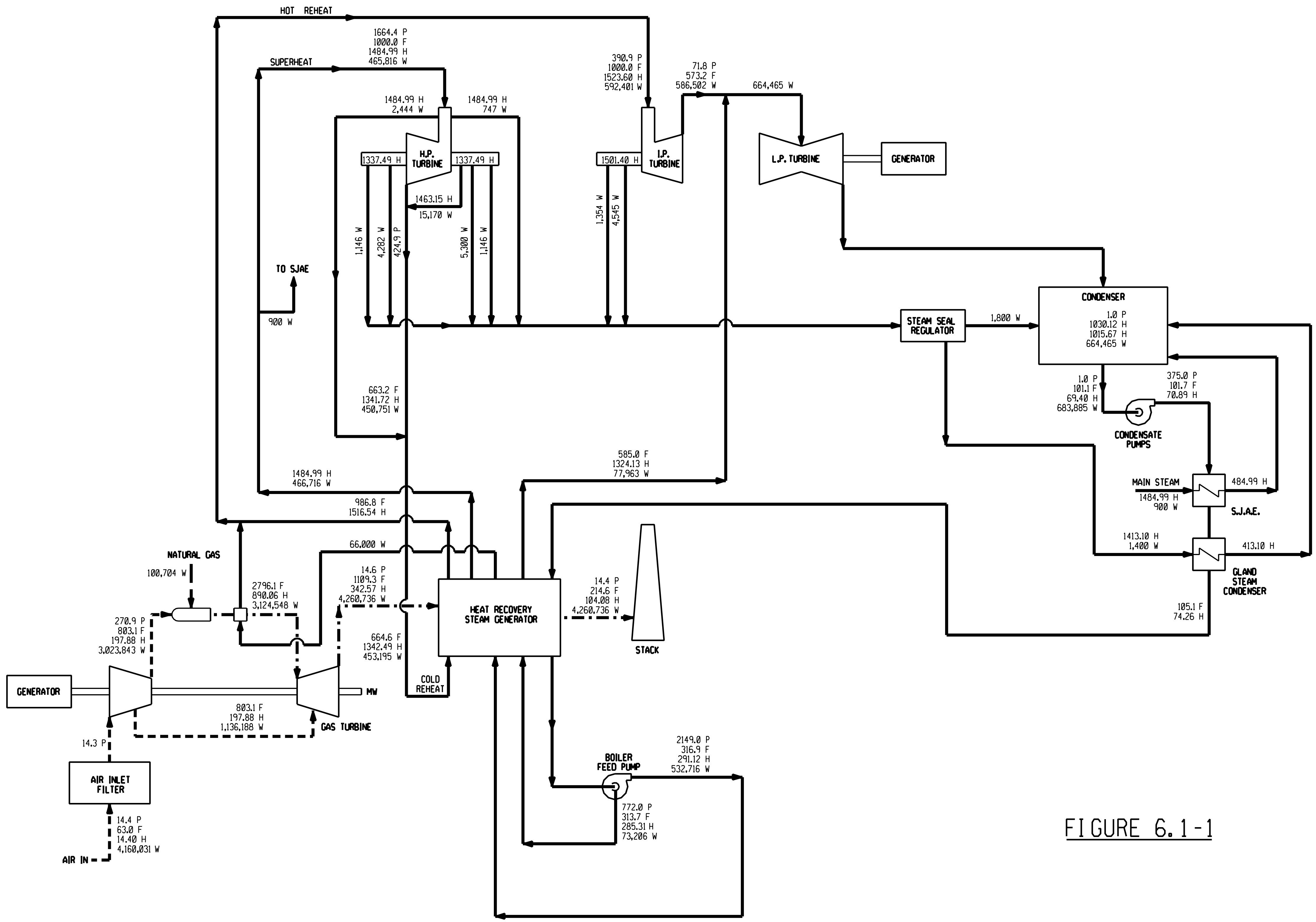

FIGURE 6.1-1

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER	LEAD DISCP ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER

STATUS OF DRAWING	DEFINITION	CONSTRUCTION STATUS
PRELIMINARY	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.	

DRAWN BY CDK 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 POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
NGCC PERFORMANCE
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-007 REV A

PPGI-FILE:
PPGI-DATE:

432006:40031407.GRA
432006:40031407.NOD

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NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32.018° F AND 0.08865 PSIA
2. IP BOILER IN HRSG GENERATES ADDITIONAL COLD REHEAT STEAM.

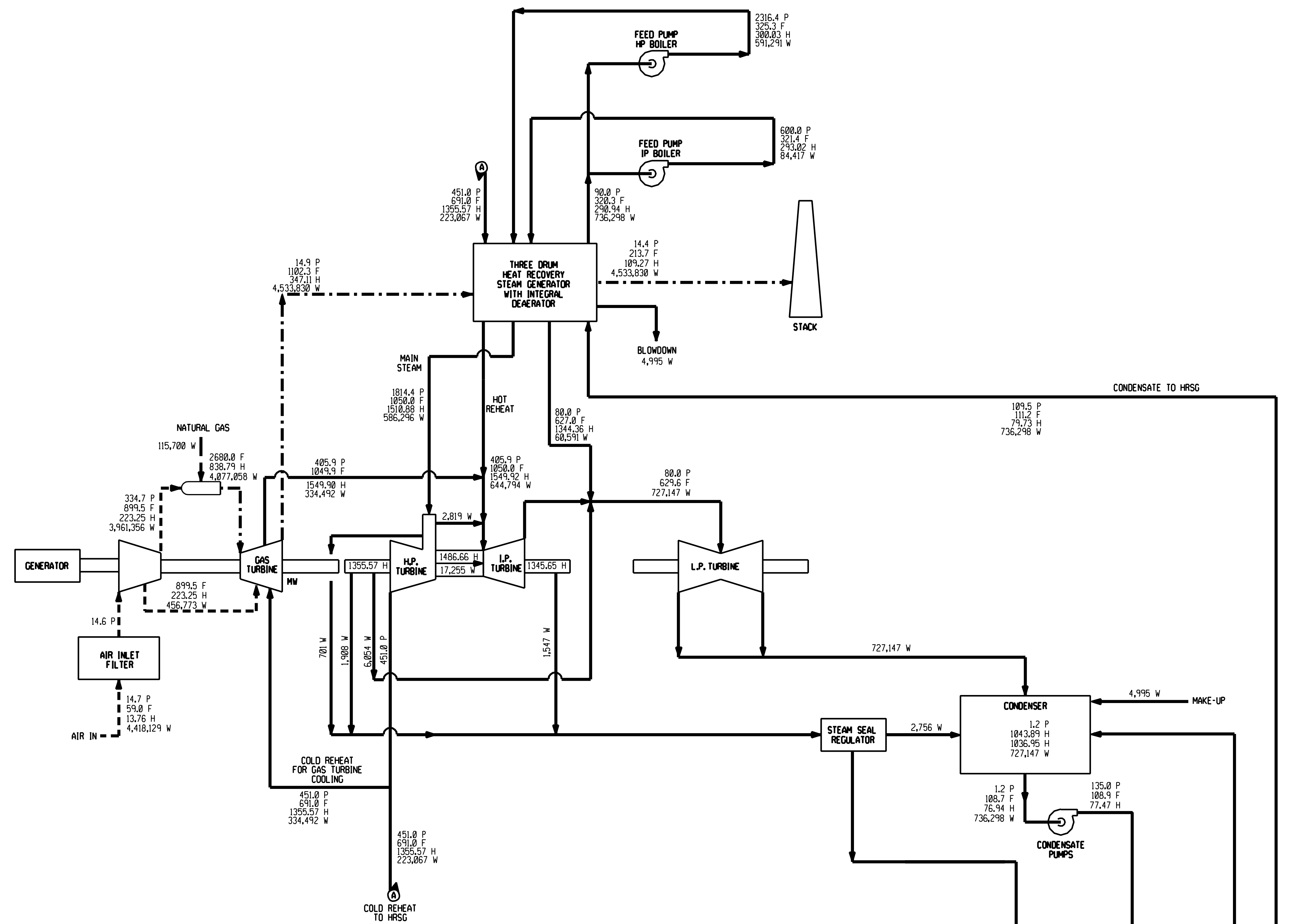

FIGURE 6.2-1

LEGEND

- - - -	AIR / OXIDANT
— — —	FUEL GAS
— · — ·	COMBUSTION PRODUCTS
—×—×—	SOLIDS
———	WATER / STEAM
P	ABSOLUTE PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, Btu/LB
W	TOTAL PLANT FLOW, LB/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY
(ONE GAS AND ONE STEAM TUBINE)

GAS T-G POWER :	280.000	MWe
STEAM T-G POWER :	129.479	MWe
GENERATOR LOSS (TOTAL):	6.142	MWe
TRANSFORMER LOSS (TOTAL):	1.370	MWe
AUXILIARY POWER (TOTAL):	6.940	MWe
NET PLANT POWER :	395.027	MWe
NET PLANT EFFICIENCY :	53.4	%
NET PLANT HEAT RATE :	6,396	Btu/kwh

J.S.WHITE 107HCC18 3/23/1998

REV | DATE | DESCRIPTION | DRAWN | CHECKED | LEAD DESIGNER | ENGINEER | LEAD DISCP ENGINEER | PROJ ENGR MANAGER | PROJECT MANAGER

STATUS OF DRAWING: PRELIMINARY — DEFINITION: REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUPTIONS. REVIEWED NOT CHECKED.

CONSTRUCTION STATUS: CONCEPTUAL DESIGN STUDY NOT FOR CONSTRUCTION

DRAWN BY: CLB DATE: 3/22/98

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 POWER GROUP INC.
READING / BOSTON / CHARLOTTE / CHATTANOOGA

CLIENT/PROJECT TITLE
CLEAN COAL TECHNOLOGY PROGRAM
NATURAL GAS COMBINED CYCLE
DEPARTMENT OF ENERGY TASK 22

PLANT HEAT AND MATERIAL BALANCE
100% RATED POWER
GENERAL ELECTRIC "H" ATS

SCALE NONE

PARSON'S DWG. NO. MBAC-1-400-314-009 REV A

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416006.31898.GRA
416006.31898.DGN

PPGI-FILE:
PPGI-DATE:

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The Rankine cycle for the plant utilizing the 501G machine is based on a 1650 psig/1000°F/1000°F single reheat configuration. The HP turbine receives 465,816 lb/h steam at 1665 psia and 1000°F from the HRSG. The cold reheat flow from the HP turbine to the reheater in the HRSG is 450,751 lb/h of steam at 425 psia and 663°F. The steam is combined with an additional 75,650 lb/h of steam generated in the IP drum of the HRSG; both streams combine and return to the HRSG to be reheated to 987°F. The steam returning from the transitions is mixed with the hot reheat steam for admission to the IP turbine section. The LP drum and superheater of the HRSG generate 77,963 lb/h of steam at 80 psia and 585°F for admission to the LP turbine at the cross-over.

The steam turbine is a single machine comprised of tandem HP, IP, and two-flow LP turbines driving one 3600 rpm hydrogen-cooled generator. The turbine is equipped with three sets of admission valves, one for each of the HP, IP, and LP turbines. The turbine exhausts to a single-pressure condenser operating at 2.0 inches Hga at the nominal 100 percent load design point. For the LP turbine, the last-stage bucket length is 23.0 inches, the pitch diameter is 65.5 inches, and the annulus area per end is 32.9 square feet.

The Rankine cycle for the plant utilizing the “H” machine is based on an 1800 psig/1050°F/1050°F single reheat configuration. The HP turbine receives 586,300 lb/h steam at 1815 psia and 1050°F from the HRSG. The cold reheat flow from the HP turbine to the reheater in the HRSG is 223,100 lb/h of steam at 450 psia and 691°F. An additional 334,500 lb/h of cold reheat is sent to the gas turbine for cooling the gas turbine. The hot reheat steam at 406 psia and 1050°F flows from the HRSG, joins with the steam from the gas turbine, and enters the IP section of the steam turbine. The LP drum and superheater of the HRSG generate 60,600 lb/h of steam at 80 psia and 627°F for admission to the LP turbine at the cross-over.

The steam turbine is a single machine comprised of tandem HP, IP, and two-flow LP turbines driving one 3600 rpm hydrogen-cooled generator. The turbine is equipped with three sets of admission valves, one for each of the HP, IP, and LP turbines. The turbine exhausts to a single-pressure condenser operating at 2.5 inches Hga at the nominal 100 percent load design point. For the LP turbine, the last-stage bucket length is 23.0 inches, the pitch diameter is 65.5 inches, and the annulus area per end is 32.9 square feet.

Condensate and feedwater heating is accomplished by heat recovery from the gas turbine exhaust in the HRSG. Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the HRSG inlets.

In summary, the major features of the steam turbine cycles for these CT/HRSG plants include the following:

- Subcritical steam conditions and single reheat (1650 psig/1000°F/1000°F) / (1800 psig/ 1050°F/1050°F).
- Steam generated at three pressures in the HRSG, corresponding to main steam, reheat steam, and LP turbine (cross-over).
- Motor-driven boiler feed pumps.
- Turbine configuration based on one 3600 rpm tandem-compound, two-flow exhaust machine.
- A single deaerating heater, integral to the HRSG.
- Condensate and feedwater heating principally accomplished in the HRSG, recovering heat from the gas turbine exhaust.

6.1.3 Emissions Performance

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 and NOx emissions. CO_2 emissions are reduced relative to those produced by burning coal, given the same power output and efficiency. Solid waste emissions are negligible.

Summaries of the plant emissions utilizing the 501G and “H” machines are presented in Table 6.1-3 and Table 6.1-4, respectively.

Table 6.1-3
AIRBORNE EMISSIONS - WESTINGHOUSE 501G COMBUSTION TURBINE/HRSG

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	Neg.	Neg.	Neg.	
NOx	< 0.028	188	246	0.202
Particulates	Neg.	Neg.	Neg.	
CO_2	118	738,502	965,734	796

Table 6.1-4
AIRBORNE EMISSIONS - GENERAL ELECTRIC "H" COMBUSTION TURBINE/HRSG

	Values at Design Condition (65% and 85% Capacity Factor)			
	1b/10^6 Btu	Tons/year 65%	Tons/year 85%	lb/MWh
SO_2	Neg.	Neg.	Neg.	
NOx	< 0.028	216	282	0.192
Particulates	Neg.	Neg.	Neg.	
CO_2	118	848,474	1,109,543	754

The elimination of SO_2 and particulate discharge is a consequence of using natural gas as the only fuel in this plant.

The low level of NOx production (<10 ppm) is achieved by the zoning and staging of combustion in the gas turbine combustors.

CO_2 emissions are low on an intensive basis (1b/10^6 Btu), and on a total basis (tons/year), due to the firing of natural gas.

6.1.4 Combustion Turbine and Heat Recovery Steam Generator

6.1.4.1 Combustion Turbine

The combustion turbine used for the first case is a Westinghouse Model 501G. This machine is an axial flow, single spool, constant speed unit with variable inlet guide vanes. A summary of the salient features of the machine is presented below:

- Inlet and Filter — Two-stage, renewable pad filters, preceded by a rain louver and screen
- Compressor — Axial flow, 17-stage, 19.2:1 pressure ratio
- Combustors — Can-annular, 16 cans, dry low-NOx type
- Turbine — Four stages (three cooled)
- Generator — Hydrogen-cooled, 20 kV, 60 Hz static exciter

The combustion turbine used for the second case is a General Electric Model "H." This machine is an axial flow, single spool, constant speed unit with variable inlet guide vanes and four stages of variable stator vanes. A summary of the features of the machine is presented below:

- Inlet and Filter — Two-stage, renewable pad filters, preceded by a rain louver and screen
- Compressor — Axial flow, 18-stage, 23:1 pressure ratio
- Combustors — Can-annular, 12 cans, dry low-NOx type
- Turbine — Steam cooling - two stages; air cooling - one stage; no cooling - one stage
- Generator — Hydrogen-cooled, 20 kV, 60 Hz static exciter

6.1.4.2 Heat Recovery Steam Generator

The HRSG for both power plants is configured with HP, IP, and LP steam drums, and superheater, reheater, and economizer sections. The HP drum is supplied with feedwater by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 1000°F for the 501G plant and 1050°F for the H plant. The IP drum for the 501G plant is supplied with feedwater from an interstage bleed on the HP boiler feed pump. The IP drum for the "H" plant is supplied with feedwater from a separate boiler feed pump. The IP steam from the drum is mixed with cold reheat steam from the HP turbine exhaust; the combined flows pass to the reheat section for heating to 1000°F for the 510G plant and 1050°F for the "H" plant (final temperature after mixing with transition steam returning from the combustion turbine), for induction in the IP turbine. The LP drum provides steam to the integral deaerator, and also to the LP turbine.

Finally, the economizer sections heat condensate and feedwater (in separate tube bundles). 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.

The HRSG exhausts directly to the new stack, which is fabricated from carbon steel plate materials and lined with Type 409 stainless steel.

6.1.5 <u>CT/HRSG Support Systems (Balance of Plant)</u>

6.1.5.1 Gas Lines

In this design, it is assumed that a natural gas main with adequate capacity is at the fenceline of the site and that a suitable right of way is available to install a branch line to the site. The gas pressure available in the main is assumed to be 350 psig for the purpose of this study. 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.

6.1.5.2 Gas Metering

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.

6.1.5.3 Gas Booster Compressor

The 501G gas turbine requires a fuel gas pressure of 600 psig at the fuel inlet flange to the machine. The pressure delivered to the site, less losses in the branch main and in the metering station, is assumed to be about 300 psig. (This assumes an allowance of 50 psig for the pressure drop in the gas line to the site and in the metering station). Therefore, a fuel gas compressor is provided to boost the gas pressure to the required value. For the purposes of this study, a motor-driven screw type unit is provided, with the ability to deliver a nearly constant delivery pressure over a wide range of flow rates.

6.1.6 Steam Cycle Balance of Plant

6.1.6.1 Steam Turbine Generator and Auxiliaries

The steam turbine for both plants consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. 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 last-stage bucket length of 23 inches.

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 1650 psig/1000°F for the 501G plant and 1800 psig/1050°F for the “H” plant. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 375 psig/1000°F for the 501G plant and 395 psig/1050°F for the “H” plant. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches

95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 23 kV. A static, transformer type exciter is provided.

The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of a storage tank, pumps, filters, and pressure controls, all skid-mounted.

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.

6.1.6.2 Condensate and Feedwater Systems

Condensate

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.

Feedwater

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 service, and two 50 percent capacity motor-driven pumps are provided for IP service for the "H" plant. The HP pumps for the 501G plant are provided with an interstage takeoff to provide IP feedwater. 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.

6.1.6.3 Steam Systems

Main, Reheat, and Low-Pressure Steam

The function of the main steam system is to convey main steam from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater and from the HRSG reheater outlet to the turbine reheat stop valves.

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

6.1.6.4 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.

6.1.6.5 Major Steam Cycle Piping Required

A significant amount of high-temperature/high-pressure piping is required to connect the various components comprising the steam cycle. A summary of the required piping is presented in Table 6.1-5 for the 501G plant and Table 6.1-6 for the “H” plant.

6.1.7 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.

6.1.8 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.

Table 6.1-5
COMBUSTION TURBINE/HEAT RECOVERY STEAM GENERATOR ("G")

Steam Cycle Piping Required

	Flow, lb/h	Press., psia	Temp., °F	Mat'l	OD, in.	Twall, in.
Condensate	685,000	375	100	A106 Gr. B	8	Sch. 40
IP Feedwater to HRSG	73,206	772	315	A106 Gr. B	4	Sch. 40
HP Feedwater to HRSG	532,700	2149	317	A106 Gr. B	8	Sch. 160
Main Steam to ST	466,000	1664	1000	A335 Gr. P22	8	1.25
Cold Reheat to HRSG	451,000	410	665	A106 Gr. B	16	Sch. 40
Hot Reheat to ST	595,000	390	1000	A335 Gr. P22	18	Sch. 40
LP Steam from HRSG to ST	78,000	72	585	A106 Gr. B	12	Sch. 40
Transition Cooling Steam to GT	66,000	600	570	A106 Gr. B	6	Sch. 40
Transition Cooling Steam from GT	66,000	390	1110	A 335 Gr. P22	8	Sch. 120

Table 6.1-6
COMBUSTION TURBINE/HEAT RECOVERY STEAM GENERATOR ("H")

Steam Cycle Piping Required

	Flow, lb/h	Press., psia	Temp., °F	Mat'l	OD, in.	Twall, in.
Condensate	736,300	135	110	A106 Gr. B	8	Sch. 40
IP Feedwater to HRSG	84,400	600	320	A106 Gr. B	4	Sch. 40
HP Feedwater to HRSG	591,300	2320	325	A106 Gr. B	8	Sch. 160
Main Steam to ST	586,300	1815	1050	A335 Gr. P22	10	1.25
Cold Reheat to HRSG	223,100	451	690	A106 Gr. B	10	Sch. 40
Hot Reheat to ST	644,790	400	1050	A335 Gr. P22	18	Sch. 40
LP Steam to ST	61,000	80	630	A106 Gr. B	12	Sch. 40
Cold Reheat Cooling Steam to GT	334,490	451	690	A106 Gr. B	12	Sch. 40
Transition Cooling Steam from GT	334,492	405	1050	A 335 Gr. P22	14	Sch. 120

Note: Flow conditions in the above tables are nominal, rounded values.

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.

6.1.9 Site, Structures, and Systems Integration

The development of the reference plant site to incorporate the new structures required for this technology is based on the assumption of a flat site. The gas turbine and its ancillary equipment are located in a turbine building. A HRSG and stack are north of the gas turbine, with the steam turbine and its generator in a separate building continuing the development to the north. Service and administration buildings are located at the north end of the steam turbine building.

The arrangement described above provides good alignment and positioning for major interfaces, as well as relatively short steam, feedwater, and fuel gas pipelines, and allows good access for vehicular traffic. Transmission line access from the gas turbine step-up transformer to the switchyard is also maintained at short distances.

The air and gas path is developed in a short and direct manner, with ambient air entering an inlet filter/silencer located east of the gas turbine. Air from the compressor discharge flows through the can-annular combustor where it supports combustion of the natural gas. The hot combustion product gases are expanded through the turbine section, and pass through a triple-pressure HRSG and then to a 213-foot stack. The height of the stack is established by application of a good engineering practice rule from 40 CFR 51.00.

6.1.10 Equipment List 301G Machine Plant - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Not Applicable

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

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	36,800 scfm, 350 psig 16 in. OD, Sch. 40	10 miles
2	Gas Metering Station		36,800 scfm	1
3	Gas Booster Compressor	Screw type, motor driven	36,800 scfm, inlet P: 300 psig disch P: 625 psig	2

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	50,000 gal	2
2	Condensate Pumps	Vert. canned	700 gpm @ 900 ft	2
3	HP Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	530 gpm @ 5,540 ft, 80 gpm @ 1,950 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

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, horiz.	100 psig, 450 cfm	2
6	Inst. Air Dryers	Duplex, regenerative	450 cfm	1
7	Service Water Pumps	Horiz. 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 horiz. cent.	250 ft, 700 gpm	1
12	Engine-Driven Fire Pump	Vert. turbine, diesel engine	350 ft, 1000 gpm	1
13	Raw Water	SS, single suction	60 ft, 100 gpm	2
14	Filtered Water Pumps	SS, 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 PFBC BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

Not Required

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	230 MWe Gas Turbine Generator	Axial flow single spool based on W501G	1200 lb/sec airflow 2580°F rotor inlet temp. 19.2:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1200 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Air to Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1
11	Fire Protection Package	Halon		1

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-2100 psig/315°F 467,000 lb/h, superheat to 1000°F IP-770 psig/313°F 75,650 lb/h, superheat to 987°F LP-65 psig/312°F 78,000 lb/h, superheat to 585°F	1
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	110 MW Turbine Generator	TC2F23, triple admissions	1650 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	680,000 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)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	34,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	52°F WB/74°F CWT/ 94° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

6.1.11 Equipment List "H" Machine Plant - Major

ACCOUNT 1 COAL AND SORBENT HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Not Applicable

ACCOUNT 1B LIMESTONE HANDLING AND PREPARATION SYSTEM

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	105,829 lb/h, 350 psig 18 in. OD, Sch. 40	10 miles
2	Gas Metering Station		105,829 lb/h	1
3	Gas Booster Compressor	Screw type, motor driven	105,829 scfm, inlet P: 300 psig disch P: 625 psig	2

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	50,000 gal	2
2	Condensate Pumps	Vert. canned	750 gpm @ 310 ft	2
3	IP Feed Pumps	Horizontal split case Multi-staged, centr. with interstage bleed for IP feedwater	84 gpm @ 1,177 ft	2
4	HP Feed Pumps	Horizontal split case Multi-staged	600 gpm @ 5,100 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Same as 501G plant

ACCOUNT 4 PFBC BOILER AND ACCESSORIES

Not Required

ACCOUNT 5 FLUE GAS CLEANUP

Not Required

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	280 MWe Gas Turbine Generator	Axial flow single spool based on "H"	1510 lb/sec airflow 2600°F rotor inlet temp. 23:1 pressure ratio	1
2	Enclosure	Sound attenuating	85 db at 3 ft outside the enclosure	1
3	Air Inlet Filter/Silencer	Two-stage	1510 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,500 hp, time from turning gear to full load ~30 minutes	1
5	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
6	Oil Cooler	Air-cooled, fin fan		1
7	Electrical Control Package	Distributed control system	1 sec. update time/ 8 MHz clock speed	1
8	Generator Glycol Cooler	Air-cooled, fin fan		1
9	Compressor Wash Skid			1
10	Fire Protection Package	Halon		1

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-2300 psig/325°F 591,300 lb/h, superheat to 1050°F IP-585 psig/321°F 84,400 lb/h, superheat to 927°F	1
2	Stack	Carbon steel plate, lined with type 409 stainless steel	213 ft high x 28 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	130 MW Turbine Generator	TC2F23, 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	727,000 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)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. W. Pumps	Vert. wet pit	37,000 gpm @ 80 ft	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	52°F WB/74°F CWT/ 94° HWT	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Not Applicable

6.1.12 Conceptual Capital Cost Estimate Summary

The summary of the conceptual capital cost estimate for the NGCC plant is shown in Table 6.1-7 and Table 6.1-8. The estimate summarizes the detail estimate values that were developed consistent with Section 9, "Capital and Production Cost and Economic Analysis." The detail estimate results are contained in Appendix E.

Examination of the values in the table reveal several relationships that are subsequently addressed. The relationship of the equipment cost to the direct labor cost varies for each account. This variation is due to many factors including the level of fabrication performed prior to delivery to the site, the amount of bulk materials represented in the equipment or material cost column, and the cost basis for the specific equipment (degree of field fabrication required for items too large to ship to the site in one or several major pieces). Also note that the total plant cost ($/kW) values are all determined on the basis of the total plant net output. This will be more evident as other technologies are compared. One significant change compared to the PC technologies is that the power is generated by multiple sources. As a result, the steam turbine portions have a good economy of scale, but the combustion turbine and technology do not.

Table 6.1-7

Client: DEPARTMENT OF ENERGY - Task 36
Project: Market Based Advanced Coal Power Systems

Report Date: 16-Dec-98
05:28 PM

TOTAL PLANT COST SUMMARY

Case: Natural Gas Combined Cycle-"G"
Plant Size: 326.1 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
2	COAL & SORBENT PREP & FEED											
3	FEEDWATER & MISC. BOP SYSTEMS	4,835	2,213	3,785	265		**$11,097**	888		2,905	**$14,891**	46
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries											
4.2	High Temperature Cooling											
4.3	Recycle Gas System											
4.4-4.9	Other Gasification Equipment											
	SUBTOTAL 4											
5	HOT GAS CLEANUP & PIPING											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	39,817		2,820	197		**$42,834**	3,427		4,626	**$50,887**	156
6.2-6.9	Combustion Turbine Accessories		136	157	11		**$305**	24		99	**$428**	1
	SUBTOTAL 6	*39,817*	*136*	*2,977*	*208*		***$43,139***	*3,451*		*4,725*	***$51,315***	*157*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	12,541		1,803	126		**$14,470**	1,158		1,563	**$17,190**	53
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,750	651	1,236	87		**$3,724**	298		558	**$4,580**	14
	SUBTOTAL 7	*14,291*	*651*	*3,039*	*213*		***$18,194***	*1,456*		*2,121*	***$21,770***	*67*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	9,644		1,589	111		**$11,345**	908		1,225	**$13,477**	41
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	4,365	133	2,394	168		**$7,060**	565		1,313	**$8,937**	27
	SUBTOTAL 8	*14,010*	*133*	*3,983*	*279*		***$18,404***	*1,472*		*2,538*	***$22,415***	*69*
9	COOLING WATER SYSTEM	3,113	1,728	2,934	205		**$7,980**	638		1,549	**$10,168**	31
10	ASH/SPENT SORBENT HANDLING SYS											
11	ACCESSORY ELECTRIC PLANT	7,525	1,799	4,793	336		**$14,454**	1,156		2,530	**$18,140**	56
12	INSTRUMENTATION & CONTROL	2,668	1,367	4,760	333		**$9,128**	730		1,644	**$11,501**	35
13	IMPROVEMENTS TO SITE	1,674	962	3,352	235		**$6,224**	498		2,016	**$8,738**	27
14	BUILDINGS & STRUCTURES		3,731	4,841	339		**$8,911**	713		2,406	**$12,030**	37
	TOTAL COST	**$87,934**	**$12,721**	**$34,464**	**$2,412**		**$137,531**	**$11,002**		**$22,434**	**$170,968**	**524**

Table 6.1-8

Client: DEPARTMENT OF ENERGY - Task 36 **Report Date:** 17-Dec-98 05:44 PM
Project: Market Based Advanced Coal Power Systems

TOTAL PLANT COST SUMMARY

Case: Natural Gas Combined Cycle-"H"
Plant Size: 395.0 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1998 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies		TOTAL PLANT COST	
				Direct	Indirect				Process	Project	$	$/kW
1	COAL & SORBENT HANDLING											
2	COAL & SORBENT PREP & FEED											
3	FEEDWATER & MISC. BOP SYSTEMS	5,172	2,381	4,027	282		**$11,862**	949		3,110	**$15,922**	40
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries											
4.2	High Temperature Cooling											
4.3	Recycle Gas System											
4.4-4.9	Other Gasification Equipment											
	SUBTOTAL 4											
5	HOT GAS CLEANUP & PIPING											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	41,448		3,306	231		**$44,986**	3,599		4,859	**$53,444**	135
6.2-6.9	Combustion Turbine Accessories		148	170	12		**$330**	26		107	**$463**	1
	SUBTOTAL 6	*41,448*	*148*	*3,477*	*243*		***$45,316***	*3,625*		*4,965*	***$53,907***	*136*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,414		1,928	135		**$15,477**	1,238		1,672	**$18,387**	47
7.2-7.9	HRSG Accessories, Ductwork and Stack	1,758	654	1,241	87		**$3,740**	299		560	**$4,600**	12
	SUBTOTAL 7	*15,172*	*654*	*3,169*	*222*		***$19,217***	*1,537*		*2,232*	***$22,986***	*58*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	9,984		1,828	128		**$11,940**	955		1,289	**$14,184**	36
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	4,883	149	2,678	187		**$7,897**	632		1,469	**$9,997**	25
	SUBTOTAL 8	*14,867*	*149*	*4,506*	*315*		***$19,837***	*1,587*		*2,758*	***$24,182***	*61*
9	COOLING WATER SYSTEM	3,476	1,935	3,275	229		**$8,916**	713		1,731	**$11,360**	29
10	ASH/SPENT SORBENT HANDLING SYS											
11	ACCESSORY ELECTRIC PLANT	8,105	1,811	4,912	344		**$15,171**	1,214		2,649	**$19,034**	48
12	INSTRUMENTATION & CONTROL	2,867	1,469	5,115	358		**$9,810**	785		1,766	**$12,361**	31
13	IMPROVEMENTS TO SITE	1,831	1,053	3,667	257		**$6,807**	545		2,206	**$9,557**	24
14	BUILDINGS & STRUCTURES		4,001	5,204	364		**$9,569**	766		2,584	**$12,918**	33
	TOTAL COST	**$92,938**	**$13,601**	**$37,352**	**$2,615**		**$146,506**	**$11,720**		**$24,001**	**$182,227**	**461**

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7. INSTRUMENTATION AND CONTROLS

Instrumentation and control technology has undergone significant advances in the last 20 years. The control technology has evolved from the analog control with pen recorders, manual/auto station, and alarm panels prevalent 20 years ago to modern distributed control systems (DCS) with CRT-based operator interfaces and new control algorithms based on modern microprocessor technology. DCS control has the capability either to monitor system operation and guide control room operators through adjustments that will optimize the process, or to automate the process, thereby optimizing it. In addition, through sophisticated algorithms, the DCS can correct for off-design conditions. Advances in computing capabilities have allowed designers to model processes closely; thus the computing system is able to determine the most appropriate means of optimizing the system.

Utility owners have begun to replace their current analog control systems for several reasons. Replacement parts are becoming scarce, the benefits of the DCS systems have been proven, and implementation costs have been minimized. However, while utility-designed control systems are very similar to control systems that would be found in market-based facilities, utility control systems tend to contain more instrumentation, as well as more maintenance and diagnostic equipment. Utilities are generally concerned with optimization and efficiency. The utilities will use the abundance of instrumentation for confirmation of operating parameters and maintenance and performance of advanced monitoring during partial load conditions. Utilities will also design DCS systems with redundancy of main components.

The control system of the market-based facility, however, is designed to operate at one specific point, and enough instrumentation is provided to allow the facility to safely and effectively operate at that point. Very little planning is provided to facilitate operation at other loads. Redundancy in the DCS is not provided. The plant is instrumented as little as possible to maintain a safe working facility. Tanks will be provided with a low level alarm and switch that will shut down the forwarding pump, rather than the utility design of a low level alarm and a low-low level switch to shut down the pump. In a market-based design, tanks that are filled from a truck (sodium hypochlorite, sodium bisulfite used in water treatment) are provided with site glass level indicators; high level alarms are not provided. In a utility-based design, this same tank would have a high level indicator, a high-high level indicator, and an automatic shutoff point.

Generally, utility owners are interested in “expert” systems, while owners of market-based plants are not interested in investing in these advanced systems.

The future of control system technology is quickly developing through technological advancements and the changing microprocessor industry. Costs are decreasing due to the improvement in microchip technology and advancements in the manufacturing techniques of microprocessor boards.

The foreseeable future of the control system technology brings with it geographic distribution of intelligence. DCS equipment will become more rugged, or environmentally hardened. The equipment will no longer need a temperature-controlled, clean environment. It will become acceptable to have multiple DCS cabinets located directly inside the plant without requiring special enclosures. The equipment will be capable of operating in atmospheres up to 120°F, and will not give off high levels of heat. The processor boards will be hermetically sealed and located in a separate section of the cabinet from the access door where maintenance and altering set points would occur.

In the next generation of power systems, the majority of equipment, systems, and processes will be automated and controlled through the DCS. With the quantity of equipment and instrumentation that will be controlled through the DCS, dedicated point-to-point connections will equate to an immense wiring system. Work is presently being done to determine the feasibility of replacing the current wiring scheme with a network or field bus. The field bus will communicate digitally with a controller highway, which will communicate with the Operator Interface System. This will eliminate the long runs of cable required by dedicated point-to-point connections. The major concern with this scenario is the ability of various vendor-supplied controls to communicate with the plant control system. In the future, the industry may standardize on one line of products for the Operator Interface System (i.e., Microsoft). This will enable equipment suppliers to standardize a specific control system to interface with a known system.

Also in the future, historical data will be stored in a separate area of the DCS. The operating system will be capable of exporting historical data to a personal computer, where the operator can manipulate the data in a multitude of fashions. In addition, the DCS will be able to compare the current data to historical data to determine loss of efficiency or changes in operating parameters. The DCS will then notify the operator of such changes, and suggest modification to correct the operation. In addition, it will alert the operator that the performance of the piece of equipment is dropping off, and there is a need for maintenance to the equipment to prevent catastrophic failure. The historical data will provide information of what maintenance has been done to that piece of equipment, along with the operating parameters before and after the maintenance was performed.

Another area of improvement in the future of the control system is the instrumentation. Pressure and temperature instrumentation has basically remained the same over the past ten years. With the development of fiber optics, it is feasible that this technology will be incorporated in the instruments, thus improving the accuracy and precision of temperature and/or pressure measurements.

It is feasible that control systems will become so sophisticated that startup could be accomplished by a single pushbutton. This would entail a complicated sequence of controls, expert systems to verify operations before proceeding with the next operation. This philosophy stems from the unmanned combustion turbines. To accomplished unmanned startups, all drain and vent valves would need to be motor-operated. Motor-operated drain and vent valves will add significant cost to the capital plant cost. Therefore, this scenario would apply only to facilities located where it is harmful or expensive to employ human operators.

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8. ANALYSIS OF ENVIRONMENTAL UNCERTAINTIES

8.1 ENVIRONMENTAL ISSUES

In the process of power generation technology selection, the decision-maker is evaluating systems that will enable utilities to meet stringent environmental requirements while providing competitive electricity prices. The technologies must produce significantly lower emissions of acid rain gases, greenhouse gases, and air toxics species than the present generation of coal-fueled power plants. Additionally, the project must be environmentally sound such that a permit can be obtained before the project is considered for financing. The financial community looks at the satisfaction of regulatory and permit issues as a pre-requisite to any commitment. The permit must exist or be obtainable before the financial community will commit funds. Specifically, the financial community will not accept any permitting or environmental risk. This means that the need to develop and obtain the environmental permits is the responsibility of the ultimate owner or the developer. In addition, from the lender's perspective, there is no "extra credit" given for developing a design that goes beyond the environmental and regulatory requirements.

At a time when the utility business is becoming more deregulated, the technology required to produce electric power has to satisfy more environmental regulatory requirements. New or modified facilities must be developed to comply with a full range of environmental regulations. The significant regulations and environmental issues include:

- National Environmental Policy Act of 1969 (NEPA)
- Clean Air Act Amendments of 1990 (CAAA)
- New Source Performance Standards (NSPS)
- National Ambient Air Quality Standards (NAAQS)
- Prevention of Significant Deterioration (PSD)
- Greenhouse Gases Reduction
- Emissions Allowances and Trading

- Hazardous Air Pollutants
- Water Discharge
- Solid Waste Disposal
- Externalities

The CAAA requirements are the most extensive, and the technology needed to address these requirements offers an opportunity for CCTs to achieve a competitive advantage. The advantage to an existing generator is that the emission reductions required of existing plants would be achieved by repowering with a CCT rather than installing additional emission controls to the source. This assumption is realistic in that the CCT will meet the most stringent emission limitation expected.

A review of both existing environmental regulations and potential future environmental concerns, which may or may not impact the selection of technology, is valuable to the decision-making process. The following highlights some of the key issues.

The National Environmental Policy Act (NEPA) - NEPA of 1969 was approved into law on January 1, 1970. This Act established a national policy to promote efforts that will prevent or eliminate damage to the environment. The law required, as a part of a proposal for activities that could have a significant impact on the quality of the human environment, the submission of an Environmental Impact Statement (EIS). The EIS identifies environmental impacts that can result from a project and then provides an approach and alternatives that may be used to mitigate the impacts. The specific requirements for the EIS have evolved and will continue to evolve. However, for CCT projects, the most significant requirements include emission streams, effluent streams, and waste streams associated with air, water, and solid waste. The EIS will identify the quantity, composition, and frequency of discharges. The evaluation of discharges is essential to ensure the project meets discharge limitations.

Clean Air Act Amendments of 1990 (CAAA) - CAAA was signed into law in November of 1990 with a goal to reduce pollution from gaseous emissions by 56 billion pounds a year. The control of pollutants that can contribute to acid rain is subject to Title IV of the CAAA. These regulations include a two-phase, market-based approach to reduce SO_2 emissions from power plants and provides for the requirement to have an allowance trading system. Reductions of oxides of nitrogen will also be achieved, but through performance standards set by the Environmental Protection Agency (EPA). Title III of the CAAA identifies a "major polluter" as a source that will emit more than 10 tons per year of any one of 189 listed hazardous pollutants or more than 25 tons per year of any combination of hazardous air pollutants. Other requirements of the CAAA cover non-attainment areas, permitting, motor vehicles, and stratospheric ozone depletion.

The Energy Policy Act of 1992 (EPAct) - EPAct was signed into law in October of 1992. Under Title XVI, Global Climate Change is addressed. Among the provisions, Title XVI calls for DOE to establish a voluntary reporting system for participants to submit information on their greenhouse gas emissions. On October 19, 1993, the Climate Change Action Plan, which described the actions that would be taken to reduce greenhouse gas emissions, was released by the President and Vice President. The Plan describes nearly 50 new and expanded initiatives that would reduce emissions. Included in those initiatives were the use of CCTs.

New Source Performance Standards (NSPS) - The EPA has issued a series of standards that address a number of basic industrial categories. NSPS reflect the maximum degree of emission control that can be achieved by an industry through direct emission control, operation, and other available methods. NSPS are available for the various fuel sources and are used as a part of the permitting process. NSPS are applicable to the following combustion sources:

- Fossil fuel fired steam generators
- Electricity utility steam generating units
- Industrial - commercial - institutional steam generating units
- Incinerators
- Municipal waste combustors
- Sewage treatment plants

- Gas turbines

National Ambient Air Quality Standards (NAAQS) - The Clean Air Act directs EPA to identify and set national ambient air quality standards for pollutants that cause adverse effects to public health and the environment. EPA has set national air quality standards for six common air pollutants: particulate matter (measured as PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ground-level ozone (O_3) [smog], and lead (Pb). For each of these pollutants, EPA has set health-based or "primary" standards to protect public health, and welfare-based or "secondary" standards to protect the environment (crops, vegetation, wildlife, buildings and national monuments, visibility, etc.). Additional requirements will be placed on facilities based on whether the facility will be located in an area that is meeting the ambient air quality standards. If the NAAQS are being met in an area of a proposed facility, the facility will be subject to the requirements of the attainment area (i.e., prevention of significant deterioration of air quality). If requirements are not being met, non-attainment area requirements will be applicable. In non-attainment areas, the control equipment should be designed to achieve the lowest achievable emission rate (LAER), which is the most stringent of either any State's Implementation Plan emission rate or any demonstrated technology but in no case less stringent than NSPS. The non-attainment area requirements also specify that the emissions from the new source be more than offset by a reduction in emissions from existing sources in the area.

Prevention of Significant Deterioration (PSD) - The PSD requirements are applicable to major modifications or new major stationary sources being located in areas that are meeting NAAQS. The PSD requirements are developed around the concept of installing the best available control technology (BACT). By definition, the CCTs should qualify as BACT, which is the maximum degree for emission reduction determined on a case-by-case basis for new sources in clean air areas with cost, energy, and technical feasibility taken into account, but in no case is BACT less stringent than NSPS. The PSD requirements also include air quality dispersion modeling to estimate compliance with PSD increments and NAAQS. Preconstruction monitoring (both ambient air pollutants and meteorology) may be required for comparing existing ambient air quality to NAAQS and for dispersion modeling. An analysis of impairment to visibility, soils, and vegetation that would occur as a result of the source, and the air quality impacts of projected general commercial, residential, industrial, and other growth associated with the source is also required.

Environmental Externalities - The costs to society because of increased health care, depleted resources, and a general reduction in quality of life are environmental externalities. However, the consideration of environmental externalities has not yet been a major influence in the selection of technology for electrical power generation. The categories of environmental externalities range from measured impacts on crops, fish, recreational opportunities, and visual aesthetics. The trend away from reflecting environmental costs in utility decisions is occurring due to the ratepayer and competitive pressure to reduce the cost of power.

8.1.1 Future Environmental Concerns

At the present time, the uncertainties of future pollution control plans discussed below cause concerns that will have to be addressed if they become an EPA standard. In fact, the more stringent standards will likely affect existing sources as well as future sources. The future sources will have to use the emission offsets from the existing sources against new sources. There has not been any indication of the direction that EPA is heading, and it is not possible to anticipate what the future requirements may be, or the effect. Nevertheless, the future emissions from a new or repowered plant with a CCT will be less than the emissions from the existing plant.

Table 8-1 provides a brief implementation schedule for some of the CAAA Titles.

Ozone Non-Attainment - Title I of the CAAA addresses the issue of non-attainment, that is, those areas that are not meeting ambient air quality standards. The area of concern in this regard is the ozone non-attainment area. Within ozone non-attainment areas, the concern is that NOx emissions are being considered as precursors to ozone generation, and further control of NOx emissions may be forthcoming. In the Northeast Ozone Transport Region, a potential future requirement limiting NOx emission rates to 0.2 lb/MMBtu, or lower, may be imposed in order to meet ozone standards in the region.

Table 8-1
CAAA of 1990 SUMMARY SCHEDULE

Title	Phase	Poll	Description	Sources Affected	Regs Due	Implement Date
I			OZONE NON-ATTAINMENT (NOx) (OTR (4) sources only)			
	1	NOx	RACT	All Major Sources (1)	1993	5/31/95
	2	NOx	Meet ambient air quality standards (2)	>250 MMBtu/h heat input & >15 MW	1997	5/1/99
	3	NOx	Meet ambient air quality standards (2)	>250 MMBtu/h heat input & >15 MW	2001	5/1/03
III			HAZARDOUS AIR POLLUTANTS (HAPs)			
		HAPs	Draft Report to Congress on Utilities HAP emissions due 4/96. Final Report to Congress due 12/96.	Utility Boilers, if EPA decides that HAP emissions pose a risk. Proposed Air Toxic Regulations	11/15/98	
		HAPs	Maximum Achievable Control Technology (MACT)	Utility Boilers, if EPA decides that HAP emissions pose a risk. Final Air Toxic Regulations	11/15/2000	2003
IV			ACID DEPOSITION			
	1	NOx	Low-NOx Burner Technology (3)	Group 1 175 tangential fired and dry bottom/ wall-fired boilers (3)		1/1/96
	1	SO_2	Allocation System	Units >100 MW and emitting >2.5 lb/MMBtu		1/1/95
	2	NOx	Best system in cost comparable to Phase 1 Low-NOx Burner (3)	Group 2 boilers >25 tons NOx/year, 2000 Units (3)	1/1/97	1/1/00
	2	SO_2	Allocation System	Units >25 MW		1/1/00
V			PERMITS	Operating Permits for All Sources		11/95

Notes:

(1) In Pennsylvania facilities emitting 100 tons or more of NOx/year and in New Jersey facilities emitting 25 tons or more of NOx/year.

(2) Applicable in the 5-month period (May-Sept) with RACT year around.

(3) Affects utilities outside the Ozone Transport Region (OTR) as Title I is more stringent than Title IV for OTR affected utilities.

(4) Northeast OTR comprises northern Virginia through Maine including Washington, D.C. In order for the OTR to meet ambient air quality standards, the Ozone Transport Assessment Group is considering expanding the area covered to those upwind states bordering the Mississippi River eastward and Texas.

Ozone NAAQS - EPA is phasing out and replacing the previous 1-hour primary ozone standard with a new 8-hour standard to protect against longer exposure periods. EPA is setting the standard at 0.08 parts per million (ppm). EPA will designate areas as non-attainment for ozone by the year 2000 (using the most recently available three years of air quality data at that time). Areas will have up to three years (or until 2003) to develop and submit state implementation plans (SIPs) to provide for attainment of the new standard. The new standards will not require local emission controls until 2004, with no compliance determinations until 2007. The Clean Air Act allows up to 10 years from the date of designation for areas to attain the revised standards with the possibility of two one-year extensions.

Ozone Transport Assessment Group (OTAG) - Because ozone is a pollutant that travels great distances, it is increasingly clear that it must be addressed as a regional problem. For the past two years the EPA has been working with the 37 most eastern states through the OTAG in the belief that reducing interstate pollution will help all areas in the OTAG region attain the NAAQS. A regional approach can reduce compliance costs and allow many areas to avoid most traditional non-attainment planning requirements. The OTAG completed its work in June 1997 and forwarded recommendations to the EPA. Based on these recommendations, the EPA will propose a rule requiring states in the OTAG region that are significantly contributing to non-attainment or interfering with maintenance of attainment in downwind states to submit SIPs to reduce their interstate pollution. The EPA plans to issue the final rule by September 1998.

$PM_{2.5}$ NAAQS - EPA is making more stringent the current particulate standard from PM_{10} down to $PM_{2.5}$ and smaller. EPA revised the PM standards by adding a new annual $PM_{2.5}$ standard set at 15 micrograms per cubic meter ($\mu g/m^3$) and a new 24-hour $PM_{2.5}$ standard set at 65 $\mu g/m^3$. The EPA will make designation determinations (i.e., attainment, non-attainment, or unclassifiable) within two to three years of revising a standard. A comprehensive monitoring network will be required to determine ambient $PM_{2.5}$ particle concentrations across the country. Monitoring data will be available from the earliest monitors by the spring of 2001, and three years of data will be available from all monitors in 2004. EPA will make the first determinations about which areas should be designated non-attainment status by 2002. States will have three years from the date of being designated non-attainment (or until between 2005 and 2008) to develop pollution control plans and submit them to EPA showing how they will meet the new standards. Areas will then have up to 10 years from their designation as non-attainment to attain the $PM_{2.5}$ standards, with the possibility of two one-year extensions.

SO_2 NAAQS - In January 1997, EPA proposed a new program to address the potential health risks posed to asthmatics by short-term peak levels of sulfur dioxide in localized situations. If implemented, this standard could affect sources with a potential to produce high concentrations of short-term bursts of SO_2 emissions.

Haze - The EPA proposed regional haze regulations to address visibility impairment. The proposed regulations will protect specific areas of concern, known as "Class I" areas. The Clean Air Act defines mandatory Class I Federal areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks. There are 156 of these areas protected under the existing visibility protection program. The proposed regional haze regulations apply to all states, including those states that do not have any Class I areas. State and local air quality agencies will implement the proposed regional haze program through revisions to their SIPs. The states will make decisions about specific emission management strategies.

Hazardous Air Pollutants - Title III of the CAAA covers the emissions of hazardous air pollutants (HAPs) from stationary sources. This has the potential of requiring power plants to control emissions of HAPs and to perform risk assessments of the most exposed individual if required by EPA. There is a study by the Electric Power Research Institute (EPRI) that indicates the emissions of HAPs from power plants are quite small -- in fact, just over half the values previously estimated by EPA. The EPA is required under the CAAA to perform two studies on power plant HAP emissions; one regarding the emissions of mercury from power plants, and the other on all other HAP emissions from utility sources. The interim report on HAPs, including mercury, was sent to Congress in October 1996; the final report was issued in early 1998. The final report recommended further study on HAPs.

Acid Deposition - Title IV relates to acid deposition. Phase I SO_2 emission requirements are being met primarily by fuel switching and/or blending, with some utilities opting for flue gas desulfurization (FGD) systems to take advantage of bonus allowances for early compliance with the Phase II requirements. The indications are that Phase II requirements for the utilities will be a test of the use of the allowance system. Utilities are expected to be purchasing excess allowances during Phase I and saving them for use in Phase II. Many utilities will be able to postpone making a decision on the method to be used to comply with the allowance program, whether it is the further use of fuel switching, or the installation of FGD scrubbers (which are also being demonstrated in the CCT program), or repowering existing sources with a CCT system with its inherently low SO_2 emission rate. The benefits of CCT are seen in the emission projections that are lower than emission rates projected by competitive technologies. Phase II NOx emission regulations are established for the various boiler types with the emission limits based on combustion controls, coal or natural gas reburning, or selective catalytic reduction.

NOx NSPS - The EPA proposed revisions to the Standards of Performance for Nitrogen Oxide emissions from new fossil-fuel fired steam generating units. The proposed emission limit is that after July 9, 1997 no affected unit shall be constructed, modified, or reconstructed such that the discharge of any gases contain nitrogen oxides in excess of 170 nanograms per joule (1.35 pounds per megawatt-hour) net energy output. < Definitions: Net output means the net useful work performed by the steam generated, taking into account the energy requirements for auxiliaries and emission controls. For units generating only electricity, the net useful work performed is the net electrical output (i.e., net busbar power leaving the plant) from the turbine generator set. >

Greenhouse Gases - International agreements have targeted CO_2 for reduction to pre-1990 levels. The overall effect of these international agreements is that the use of fossil fuels must be made more efficient than the existing operations. The U.S. policy on climate change calls for signing a legally binding treaty to reduce greenhouse gas emissions. A Senate resolution (S.Res. 98) states that the Senate will not approve a treaty that does not set identical emissions levels and compliance timetables for all parties. The resolution endorses the scientific consensus on climate change, and, while it throws a spotlight on the issue of developing countries, it still allows the United States negotiating flexibility.

Water - Water-related requirements such as water usage may be a significant issue that impacts the environmental permitting. For example, the concept of zero discharge may impact the handling of the process water. The trend in this country and North America in general is toward the reduction of water usage.

Waste - A final area of concern relates to the requirements to reduce the quantity of the waste that is being discharged. The trend is toward developing a process that is capable of zero discharge. New projects need to look at the beneficial uses of the solid waste, such as concrete production road construction or use of sulfur as the feed stock for process plant operation. The challenge will be to encourage use of byproducts in these markets and to develop additional markets.

8.2 REGULATORY ISSUES

The electric utility industry of today has evolved out of a series of changes in the Public Utilities Holding Company Act (PUHCA). This model was predicated on the management of a number of monopoly generating and distribution utilities that were charged with the requirement to serve, in exchange for the exclusive right to a service territory. This started to change with the passage of the Public Utilities Regulatory Policy Act of 1978. This change has accelerated since the latest enabling legislation, the Energy Policy Act of 1992.

The utility industry has responded to the changing legislative agenda with mixed reactions. In some cases, there is aggressive restructuring of the business designed to anticipate the direction the industry will take. In other cases, utility companies are taking more of a “wait and see” attitude. Today, the utility industry is made up of investor-owned, government-owned, and independent power producers. The final direction to be taken by the industry will not be clear for a number of years pending the interpretation of the new regulations by the industry, the legislatures, the regulators at the federal and state levels, and the courts.

8.2.1 Role of Federal Policies

The Federal Power Act supported self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered a limited service area. This structure of separate systems developed primarily because of the cost and technological limitations on the distance over which electricity could be transmitted. Through much of the 1960s, utilities were able to avoid price increases, but still achieve increased profits because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices.

The Public Utilities Regulatory Policy Act (PURPA) of 1978 started a wave of change throughout the electric utility industry. This legislation opened the electrical generating market to independent generators. The most significant was the emergence of the independent power producer (IPP), a non-utility producer of electric power. The wave of non-utility generators has been responsible for a significant number of the new generating assets built since 1985.

In enacting PURPA, Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates to consumers. In particular, Congress sanctioned the development of alternative generation sources designated as "qualifying facilities" (QFs) as a means of reducing the demand for traditional fossil fuels. PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.

Legislation continuing this fundamental change in the utility industry was the Energy Policy Act of 1992 (EPAct). EPAct introduced a number of changes to the Federal Power Act, PUHCA, and PURPA. These changes address wholesale wheeling and integrated resource planning, and promote energy efficiency. In addition, the EPAct established a new category of non-utility generators, exempt from PUHCA, the Exempt Wholesale Generators (EWGs). The EPAct also expanded the Federal Energy Regulatory Commission's (FERC's) authority to order utilities to provide wheeling service to companies that generate energy for resale.

Regulation changes intended to increase the amount of free-market competition in the electric power industry are beginning. To date, the broadest action is FERC's Order No. 888 Final Rule, issued April 24, 1996, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities." This rule requires all public utilities that own, control, or operate transmission for interstate commerce to have open access non-discriminatory transmission tariffs that contain minimum terms and conditions of service. The rule also permits the recovery of legitimate, prudent, and verifiable stranded costs associated with providing open access and transmission service. The object of this action is to promote competition in the wholesale bulk power market and provide consumers with more efficient, lower cost power. Under this rule competition in the electric utility market has been established. Public utilities have already responded by filing wholesale open access tariffs. It has been estimated by FERC that the potential benefits from this rule will be approximately $3.8 to $5.4 billion per year in cost savings.

8.2.2 State Regulatory Issues

The role of the state in the regulatory area is also changing. Changes in the federal law are prompting the states to look at their role as regulators. Some states are already moving to deregulate. Wheeling of power and free access to the distribution grid for EWGs is beginning. Many electric utilities are restructuring in anticipation of changes in their operation. States are addressing issues of integrated resource planning (IRP), wholesale wheeling, rate setting and cost disallowances, and stranded capital.

Essentially, IRP provisions establish ratemaking standards that encourage utilities to use demand side management and efficiency measures to meet their customers' needs. The approach treats supply and demand side resources on an equal basis. IRP will provide utility companies with an incentive to look at efficiency improvements.

Wheeling and free access to the utility distribution grid is at the core of the deregulation issue. The EPAct provides the owners of facilities generating electricity for sale or resale with the means to request FERC to grant transmission access. As a part of the deregulation process, the Act requires that the owners first negotiate for 60 days before a complaint is filed with FERC. In addition to wholesale wheeling, EPAct encourages the states to look at retail wheeling. It should be noted, the Act prohibits FERC from ordering retail wheeling. The outcome of the wheeling issue as provided by FERC Order No. 888 will significantly set the form of the utility industry.

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9. CAPITAL AND PRODUCTION COST AND ECONOMIC ANALYSIS

Capital cost, production cost, and cost-of-electricity estimates were developed for each plant based on adjusted vendor-furnished and actual cost data, and resulting in determination of a revenue requirement cost-of-electricity based on the power plant costs and assumed financing structure.

9.1 CAPITAL COSTS

The capital costs at the Total Plant Cost level include equipment, materials, labor, indirect construction costs, engineering, and contingencies. Operation and maintenance cost values were determined on a first-year basis and subsequently levelized over the 20-year plant book life to form a part of the economic analysis. Quantities for major consumables such as fuel and sorbent were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data. Operation cost was determined on the basis of the number of operators. 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 $/kW-year or ¢/kWh.

Each major component was based on a reference bottoms-up estimate, establishing a basis for subsequent comparisons and easy modification as the technology is further developed.

- Total Plant Cost, or “Overnight Construction Costs” values are expressed in January 1998 year dollars.
- Total Plant Investment values are expressed in mixed year dollars for a January 2005 commercial operation.
- The estimates represent commercial technology plants, or nth plants for the PC and NGCC and initial commercial offerings for the IGCC.
- The estimates represent a complete power plant facility, with the exception of the exclusions listed below.

- The estimate boundary limit is defined as the total plant facility within the "fence line," including coal receiving and water supply system but terminating at the high voltage side of the main power transformers.
- Site is characterized to be located in Middletown, USA. Although not specifically sited within any region, it is based on a relative equipment/material/labor factor of 1.0 and is considered to be located on a major navigable waterway.
- Costs are grouped according to a process/system oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.
- The operating and maintenance expenses and consumable costs were developed on a quantitative basis.
- Operating labor cost was determined on the basis of the number of operators required.
- Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost.
- Cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.
- Byproduct credits for commodities such as gypsum and emissions are not considered due to the variable marketability. However, credit for sulfuric acid is recognized in the economic evaluations.

Each of these expenses and costs is determined on a reference year basis and escalated to a first-year basis, and subsequently levelized over the life of the plant and reported on the 10^{th} year basis through application of a levelizing factor to determine the value that forms a part of the economic evaluation. This amount, when combined with fuel cost and capital charges, results in the figure-of-merit, COE.

The capital cost, specifically referred to as Total Plant Cost (TPC) for each power plant, was estimated for the categories consisting of bare erected cost, engineering and home office overheads, and fee plus contingencies. The TPC level of capital cost is the "overnight construction" estimate. The capital cost was determined through the process of estimating the cost of every significant piece of equipment, component, and bulk quantity.

The capital cost is defined not only in terms of the TPC but also the categories Total Plant Investment (TPI), and Total Capital Requirement (TCR). Table 9-1 identifies the various cost elements that are included in each level of the capital cost.

Table 9-1
LEVELS OF CAPITAL COST

Bare Erected Cost (Process Capital and Facilities)
Equipment Cost
Material Cost
Direct Labor Cost
Indirect Labor Cost
Total Plant Cost (TPC)
Engineering
Contingencies
Process
Project
Total Plant Investment (TPI)
Cash Expended (Escalation)
AFDC
Total Capital Requirement (TCR)
Royalty
Preproduction Cost
Inventory Capital
Initial Catalyst and Chemicals
Land Cost

The reference labor cost to install the equipment and materials was estimated on the basis of labor man-hours. Labor costing was determined on a multiple contract labor basis with the labor cost including direct and indirect labor costs plus fringe benefits and allocations for contractor expenses and markup. This was supplemented in limited cases, as required, with equipment labor relationship data to determine the labor cost.

The indirect labor cost was estimated at 7 percent of direct labor to provide the cost of construction services and facilities not provided by the individual contractors. The indirect cost represents the estimate for miscellaneous temporary facilities such as construction road and parking area construction and maintenance, installation of construction power; installation of construction water supply and general sanitary facilities, and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items.

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 8 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.

The TPC estimate summary at the major account level is shown on Table 9-2.

Consistent with conventional power plant practices, the general project contingency was added to the TPC to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. This project contingency is intended to cover the uncertainty in the cost estimate itself. The contingencies represent costs that are expected to occur. Based on EPRI criterion 1, the cost estimate contains elements of Classes I, II, and III level estimates. As a result, on the basis of the EPRI guidelines, a variable rate was used to arrive at the plant nominal cost value. These values, at the stem account level, are included in Appendix E. This project contingency is intended to cover the uncertainty in the cost estimate itself. A similar approach was applied to recognize process contingency except only non-mature accounts have process contingency values. The contingencies represent costs that are expected to occur.

TABLE 9-2
CASE COMPARISON - COST DATA
Total Plant Cost (Jan., 1998 $)

Acct No.	Item/Description	Destec 2 "F" $x1,000	Destec 2 "F" $/kW	Destec-"G" $x1,000	Destec-"G" $/kW	Destec-"H" $x1,000	Destec-"H" $/kW	Transport Gasifier $x1,000	Transport Gasifier $/kW	2gPFBCw/Boost $x1,000	2gPFBCw/Boost $/kW
1	COAL & SORBENT HANDLING	21,038	39	14,796	42	15,916	37	15,416	39	16,056	42
2	COAL & SORBENT PREP.& FEED	34,519	64	19,410	56	20,978	49	13,596	34	21,483	57
3	FW,COND.& MISC.SYS.	25,354	47	17,049	49	18,028	42	16,736	42	19,319	51
4	GASIFIER / BOILER & ACCESSORIES	225,411	415	125,137	358	142,768	334	70,400	177	62,345	164
5	GAS (HOT) CLEANUP & PIPING	69,948	129	52,084	149	55,737	130	77,179	194	37,405	99
6	COMBUSTION TURBINE/ACCESSORIES	82,767	152	58,088	166	60,143	141	60,143	151	77,014	203
7	HRSG, DUCTING & STACK	40,790	75	22,864	65	23,395	55	22,272	56	13,917	37
8	STEAM TURBINE GENERATOR	43,657	80	27,608	79	28,167	66	26,112	66	36,767	97
9	COOLING WATER SYSTEM	18,935	35	12,121	35	13,064	31	12,123	30	14,561	38
10	ASH/SPENT SORBENT HANDLING SYS	14,958	28	9,303	27	10,009	23	7,754	19	12,147	32
11	ACCESSORY ELECTRIC PLANT	49,660	91	32,323	93	34,285	80	21,892	55	24,946	66
12	INSTRUMENTATION & CONTROL	17,630	32	15,287	44	17,685	41	15,599	39	15,783	42
13	IMPROVEMENTS TO SITE	11,976	22	9,557	27	10,471	24	9,648	24	12,859	34
14	BUILDINGS & STRUCTURES	17,631	32	13,629	39	14,477	34	13,691	34	14,932	39
	TOTAL PLANT COST	**$674,276**	**1,241**	**$429,256**	**1,229**	**$465,125**	**1,087**	**$382,559**	**961**	**$379,535**	**1,001**

TABLE 9-2 (Cont'd)
CASE COMPARISON - COST DATA
Total Plant Cost (Jan., 1998 $)

Acct No.	Item/Description	Subcritical PC $x1,000	Subcritical PC $/kW	Supercritical PC $x1,000	Supercritical PC $/kW	Ultracritical PC $x1,000	Ultracritical PC $/kW	NGCC-"G" $x1,000	NGCC-"G" $/kW	NGCC-"H" $x1,000	NGCC-"H" $/kW
1	COAL & SORBENT HANDLING	19,134	48	18,560	46	18,095	45				
2	COAL & SORBENT PREP.& FEED	15,201	38	14,613	36	14,326	36				
3	FW,COND.& MISC.SYS.	31,276	79	32,304	80	33,059	83	14,891	46	15,922	40
4	GASIFIER / BOILER & ACCESSORIES	85,639	215	106,879	266	104,861	262				
5	GAS (HOT) CLEANUP & PIPING	64,146	161	63,314	158	61,621	154				
6	COMBUSTION TURBINE/ACCESSORIES							51,315	157	53,907	136
7	HRSG, DUCTING & STACK	22,293	56	21,583	54	20,925	52	21,770	67	22,986	58
8	STEAM TURBINE GENERATOR	66,916	168	70,906	176	73,062	183	22,415	69	24,182	61
9	COOLING WATER SYSTEM	24,563	62	24,761	62	24,676	62	10,168	31	11,360	29
10	ASH/SPENT SORBENT HANDLING SYS	22,254	56	21,643	54	21,132	53				
11	ACCESSORY ELECTRIC PLANT	25,373	64	25,614	64	25,600	64	18,140	56	19,034	48
12	INSTRUMENTATION & CONTROL	14,222	36	14,401	36	14,459	36	11,501	35	12,361	31
13	IMPROVEMENTS TO SITE	9,767	25	9,821	24	9,798	25	8,738	27	9,557	24
14	BUILDINGS & STRUCTURES	48,055	121	47,090	117	46,161	115	12,030	37	12,918	33
	TOTAL PLANT COST	**$448,840**	**1,129**	**$471,489**	**1,173**	**$467,774**	**1,170**	**$170,968**	**524**	**$182,227**	**461**

In addition to the TPC cost level, the TPI and TCR were determined. TPI at date of startup includes escalation of construction costs and allowance for funds used during construction (AFDC), formerly called "interest during construction," over the construction period. TPI is computed from the TPC, which is expressed on an "overnight" or instantaneous construction basis. For the design and construction cash flow, a variable expenditure rate was assumed, with all expenditures taking place at the end of the year.

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, preproduction (or startup) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Preproduction costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant startup. They are estimated as follows:
  - One month fixed operating costs -- operating and maintenance labor, administrative and support labor, and maintenance materials.
  - One month of variable operating costs at full capacity (excluding fuel) -- includes chemicals, water, and other consumable and waste disposal charges.
  - 25 percent of full capacity fuel cost for one month -- covers inefficient operation that occurs during the startup period.
  - Two percent of TPI -- covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.

- Inventory capital is the value of inventories of fuel, other consumables, and byproducts, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows: solid fuel inventory is based on full-capacity operation for 30 days, but natural gas is excluded from inventory capital.

- Inventory of other consumables (excluding water) is normally based on full-capacity operation at the same number of days as specified for the fuel. In addition, an allowance of 1/2 percent of the TPC equipment cost is included for spare parts.

- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not on storage, which is covered in inventory capital). No value is shown because costs are minimal and included directly in the component equipment capital cost.
- Land cost is based on $1,500 per acre.

The TPI and TCR values are included in the economic results table at the end of this section.

Although the estimate is intended to represent a complete power plant, there are several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).
- Onsite fuel transportation equipment (such as barge tug, barges, yard locomotive, bulldozers) is not included.
- Allowances for site-specific conditions (such as piling, extensive site access, excessive dewatering, extensive inclement weather) are not included.
- Switchyard (transmission plant) is not included. The scope of the cost estimate includes the high voltage terminal of the main power transformer.
- Ash disposal facility is excluded, other than the storage in the ash-storage silos. (The ash disposal cost is accounted for in the ash disposal charge as part of consumable costs.)
- Royalties are not included.

9.2 PRODUCTION COSTS AND EXPENSES

The production costs or operating costs and related maintenance expenses (O&M) described in this section pertain to those charges associated with operating and maintaining the power plants over their expected life.

The costs and expenses associated with operating and maintaining the plant include:

- Operating labor

- Maintenance
  - Material
  - Labor
- Administrative and support labor
- Consumable
- Fuel cost

These costs and expenses are estimated on a reference year (January 1998) basis and then escalated to a first-year basis, in January 2005 dollars. The first-year costs assume normal operation and do not include the initial startup costs. The operating labor, maintenance material and labor, and other labor-related costs are combined and then divided into two components: fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. The first-year O&M cost estimate allocation is based on the plant capacity factor.

The other operating costs, consumables and fuel, are determined on a daily 100 percent operating capacity basis and adjusted to an annual plant operation basis. The inputs for each category of operating costs and expenses are identified in the succeeding subsections, along with more specific discussion of the evaluation processes.

9.3 COST OF ELECTRICITY (COE)

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit is COE levelized (reported on a 10th year basis) coal pile-to-busbar cost of power expressed in ¢/kWh. The value includes the TCR, which is represented in the levelized carrying charge (sometimes referred to as the fixed charges), 10th year fixed and variable operating and maintenance costs, 10th year consumable operating costs, and the 10th year fuel cost.

The principal cost and economics output for this study, the Capital Investment and Revenue Requirement Summary, is included in Appendix E and summarized in Table 9-3. This table presents key TPC values and other significant capital costs, reference year operating costs, maintenance costs, consumables, fuel cost, and the levelized constant dollar busbar COE.

TABLE 9-3

CASE COMPARISONS - SELECTED COST & FINANCIAL DATA

TECHNOLOGY:	GASIFICATION COMBINED CYCLE (IGCC)								FLUIDIZED BED	
CASE:	Destec 2 "F"		Destec-"G"		Destec-"H"		Transport Gasifier		2gPFBCw/Boost	
	Base Year $		Base Year $		Base Year $		Base Year $		Base Year $	
Base (Reference Year), January:	1998		1998		1998		1998		1998	
MWe(net):	543.2		349.2		427.7		398.1		379.2	
Net Plant Heat Rate-100% Load (Btu/kWh-HHV):	8,522		7,513		6,968		6,870		7,269	
Capacity Factor (equivalent @ 100% Load):	85		85		85		85		85	
BARE ERECTED COST (BEC)-$x1000	$534,667		$334,677		$363,220		$281,703		$287,411	
BEC $/KW	984		958		849		708		758	
TOTAL PLANT COST (TPC)-$x1000	$674,276		$429,256		$465,125		$382,559		$379,535	
TPC $/KW	1,241		1,229		1,087		961		1,001	
TOTAL CAPITAL REQUIREMENT (TCR)-$x1000	$765,615		$470,670		$510,175		$426,694		$417,135	
TCR $/KW	1,409		1,348		1,193		1,072		1,100	
FIXED O & M (base year)-$/kW	31.29		35.60		32.78		31.42		29.64	
VARIABLE O & M (base year)-¢/kWh	0.07		0.08		0.08		0.07		0.07	
OPERATION & MAINTENANCE COSTS-¢/kWh	**Reference**	**Levelized**	**Reference**	**Levelized**	**Reference**	**Levelized**	**Reference**	**Levelized**	**Reference**	**Levelized**
Fixed O & M	0.42	0.42	0.48	0.48	0.44	0.44	0.42	0.42	0.40	0.40
Variable O & M	0.07	0.07	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07
Consumables	0.09	0.09	0.11	0.11	0.10	0.10	0.09	0.09	0.21	0.21
By-product Credit & Emission Credits/Costs	-0.19	-0.19	-0.17	-0.17	-0.16	-0.16	-0.15	-0.15		
Fuel	1.07	0.92	0.94	0.81	0.87	0.75	0.86	0.74	0.91	0.79
TOTAL PRODUCTION COST	1.47	1.32	1.45	1.32	1.33	1.21	1.30	1.18	1.59	1.46
LEVELIZED CARRYING CHARGES (Capital)		2.56		2.44		2.16		1.94		1.99
LEVELIZED BUSBAR COST OF POWER-¢/kWh Levelized (10th.Year $)		**3.88**		**3.76**		**3.38**		**3.12**		**3.46**

NOTES:

TPC costs in Jan.1998 $

TCR costs include escalation for 2005 initial operation

1st.year O&M (Production) Costs in 2005 dollars

10th.year O&M & COE based on years 2005 to 2025 operation

Credits (byproduct & emission) excluded from baseline analysis

Capital Structure (constant dollars)	% of Total	Cost (%)
Equity	20	16.5
Debt	80	5.8

Weighted Cost of Capital (after tax basis)=6.2%

Levelized Carrying Charge Factor=13.5%

Project Book Life=20 years

Fuel Cost Basis:	Coal	Nat.Gas
Coal = Illinois #6 @ 11,666 Btu/lb		
Jan.1998 base price, $/MMBtu	1.26	2.70
Annual Fuel escalation, real (1996-2005)	-1.36%	0.04%
Annual Fuel escalation, real (2005-2025)	-1.07%	1.21%
General Annual escalation	0.00%	0.00%

Fuel Price and escalation based on analysis of AEO 1998 data

TABLE 9-3 (Cont'd)

CASE COMPARISONS - SELECTED COST & FINANCIAL DATA

TECHNOLOGY:	PULVERIZED COAL (PC)						Nat.GasCombined Cycle			
CASE:	Subcritical PC		Supercritical PC		Ultracritical PC		NGCC-"G"		NGCC-"H"	
	Base Year $		Base Year $		Base Year $		Base Year $		Base Year $	
Base (Reference Year), January:	1998		1998		1998		1998		1998	
MWe(net):	397.5		401.8		399.7		326.1		395.0	
Net Plant Heat Rate-100% Load (Btu/kWh-HHV):	9,077		8,568		8,251		6,743		6,396	
Capacity Factor (equivalent @ 100% Load):	85		85		85		65		65	
BARE ERECTED COST (BEC)-$x1000	$360,255		$379,761		$376,805		$137,531		$146,506	
BEC $/KW	906		945		943		422		371	
TOTAL PLANT COST (TPC)-$x1000	$448,840		$471,489		$467,774		$170,968		$182,227	
TPC $/KW	1,129		1,173		1,170		524		461	
TOTAL CAPITAL REQUIREMENT (TCR)-$x1000	$487,586		$512,167		$507,588		$183,149		$195,344	
TCR $/KW	1,227		1,275		1,270		562		495	
FIXED O & M (base year)-$/kW	22.80		23.41		23.37		10.40		10.35	
VARIABLE O & M (base year)-¢/kWh	0.05		0.06		0.06		0.10		0.10	
OPERATION & MAINTENANCE COSTS-¢/kWh	**Reference**	**Levelized**	**Reference**	**Levelized**	**Reference**	**Levelized**	**Reference**	**Levelized**	**Reference**	**Levelized**
Fixed O & M	0.31	0.31	0.31	0.31	0.31	0.31	0.18	0.18	0.18	0.18
Variable O & M	0.05	0.05	0.06	0.06	0.06	0.06	0.10	0.10	0.10	0.10
Consumables	0.17	0.17	0.29	0.29	0.16	0.16	0.04	0.04	0.03	0.03
By-product Credit & Emission Credits/Costs										
Fuel	1.14	0.98	1.08	0.93	1.04	0.89	1.82	1.94	1.73	1.84
TOTAL PRODUCTION COST	1.67	1.52	1.74	1.59	1.56	1.42	2.14	2.26	2.04	2.15
LEVELIZED CARRYING CHARGES (Capital)		2.22		2.31		2.30		1.33		1.17
LEVELIZED BUSBAR COST OF POWER-¢/kWh Levelized (10th.Year $)		**3.74**		**3.90**		**3.72**		**3.59**		**3.32**

NOTES:

TPC costs in Jan.1998 $

TCR costs include escalation for 2005 initial operation

1st.year O&M (Production) Costs in 2005 dollars

10th.year O&M & COE based on years 2005 to 2025 operation

Credits (byproduct & emission) excluded from baseline analysis

Capital Structure (constant dollars)	% of Total	Cost (%)
Equity	20	16.5
Debt	80	5.8

Weighted Cost of Capital (after tax basis)=6.2%

Levelized Carrying Charge Factor=13.5%

Project Book Life=20 years

Fuel Cost Basis:	Coal	Nat.Gas
Coal = Illinois #6 @ 11,666 Btu/lb		
Jan.1998 base price, $/MMBtu	1.26	2.70
Annual Fuel escalation, real (1996-2005)	-1.36%	0.04%
Annual Fuel escalation, real (2005-2025)	-1.07%	1.21%
General Annual escalation	0.00%	0.00%

Fuel Price and escalation based on analysis of AEO 1998 data