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Tampa Electric Company
Polk Power Station Unit No. 1
Preliminary Public Design Report

Topical Report

June 1994

Work Performed Under Cooperative Agreement No.: DE-FC21-91MC27363

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Tampa Electric Company
Tampa, Florida

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INTRODUCTION

1.0 INTRODUCTION

This preliminary Public Design Report (PDR) provides design information about Tampa Electric Company's Polk Power Station Unit No. 1, which will demonstrate in a commercial 250 MW unit the benefits of the integration of oxygen-blown, entrained-flow coal gasification with advanced combined cycle technology.

This project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology (CCT) Program under the provisions of Cooperative Agreement DE-FC21-91MC27363 between DOE and Tampa Electric Company, novated on March 5, 1992. The project is highlighted by the inclusion of a new hot gas cleanup system. DOE's project management is based at its Morgantown Energy Technology Center (METC) in West Virginia.

This report is preliminary, and the information contained herein is subject to revision. Definitive information will be available in the final PDR, which will be published at the completion of detailed engineering.

PROJECT DESCRIPTION

2.0 PROJECT DESCRIPTION

Tampa Electric Company is developing a new major power generation station in Polk County, Florida. The initial generating facilities at the Polk Power Station site will be an Integrated Gasification Combined Cycle (IGCC) nominal net 250-MW demonstration project developed by Tampa Electric and supported in part through funding from the DOE. Additional generating units will be added according to a phased schedule designed to match the projected growth of Tampa Electric's customer power demands, subject to obtaining need for power certifications from the Florida Public Service Commission. The additional generating units are planned to include two 220-MW combined cycle (CC) generating units and six 75-MW simple cycle combustion turbines. Site capacity after full build-out is planned to be about 1,150 MW.

The scope of the project described in this report is the construction of the IGCC along with site development sufficient to meet full build-out requirements. The overall objectives of this demonstration project are two-fold. First, to meet the goals of the DOE CCT program, the project will demonstrate and evaluate the performance and benefits of an IGCC unit utilizing a new hot gas cleanup (HGCU) technology for sulfur removal from the syngas. Second, the project will meet the requirements of Tampa Electric's generation expansion plan and its obligation to provide reliable and economical electric power to its current and future customers.

The IGCC demonstration project will be located on a 4,348-acre site in southwest Polk County, Florida. This location is in the middle of the phosphate rock mining region of Florida, and much of the plant will be built on reclaimed mined-out lands.

Major participants in the project include Tampa Electric Company, TECO Power Services, Inc. (TPS), DOE, Air Products and Chemicals, Inc., Bechtel Power Corporation acting as engineer and construction manager, General Electric Company, G.E. Environmental Services, Inc., Monsanto Enviro-Chem, MAN GHH, Raytheon Engineers and Constructors, L & C Steinmüller, and Texaco.

TPS is a subsidiary of TECO Energy, Inc. and an affiliate of Tampa Electric Company (TEC). TPS is responsible for overall project management for the DOE co-funded portion of the Polk IGCC Project. TPS will also concentrate on commercialization of this IGCC technology, as part of the Cooperative Agreement between TEC and DOE, novated on March 5, 1992.

The IGCC facilities will consist of an oxygen-blown entrained flow coal gasification system to produce syngas for the combustion turbine (CT). The planned coal gasification system is based on Texaco's commercially available coal gasification technology. L & C Steinmüller and MAN GHH are the suppliers of the convective and radiant syngas coolers, respectively.

TECHNOLOGY OVERVIEW

3.0 TECHNOLOGY OVERVIEW

Polk Power Station Unit No. 1 consists of a highly integrated, nominal 250 MW (net) oxygen-blown, entrained-flow gasification/combined cycle power generation facility. Polk Power Station includes an air separation unit from which virtually all oxygen and nitrogen produced is efficiently and effectively used. The 95 percent pure oxygen from the ASU is the oxidant for the gasification of coal, slurried in water. The majority of the nitrogen, at 98 percent purity, is injected at the combustion section of the combustion turbine (CT). The addition of nitrogen in the CT combustion chamber has dual benefits. First, the addition of nitrogen increases the mass flow through and power output from the CT. Second, the nitrogen acts to control potential NO_x air emissions by reducing the combustor flame temperature which, in turn, reduces the formation of NO_x in the fuel combustion process. The process of using nitrogen to control the flame temperature and NO_x formation is similar to that achieved by steam or water injection NO_x control methods; however, the use of nitrogen does not require the use and consumption of water as with the water/steam injection methods.

The combined cycle (CC) technology is of a proven design with the exception of the combustion system for the GE 7F combustion turbine. The hardware and control philosophy are under development to prepare for the use of combined flows of hot and cold syngas to the CT, in concert with the injection of nitrogen at the head end of the combustors.

Also included for Polk Power Station is a new hot gas cleanup system (HGCU) capable of treating 45,000 lb/hr of the syngas, and a cold gas cleanup system (CGCU) sized to accept 100 percent of the gasifier output. Use of the HGCU will provide additional system efficiencies by demonstrating the technical improvements realized from cleaning syngas at a temperature of 900°F. The HGCU incorporates cyclone technology at the inlet to the unit and a barrier filter at the outlet to the CT.

Another important example of integration technology is embodied in the project's distributed control system (DCS), which will bring the complex network of system data together in a way that enhances plant reliability and provides state-of-the-art control and diagnostic capability.

DESIGN BASIS DESCRIPTION

4.0 DESIGN BASIS DESCRIPTION

4.1 PROJECT PERFORMANCE DESIGN BASIS

4.1.1 Capacity

The gasification section will be designed to fully load GE's 7F combustion turbine at 90°F ambient, 60 percent relative humidity and 14.63 psia. The design capacity of each section is determined on the basis of the information shown in Table 4.1.

4.1.2 Availability/Reliability

Availability. In this context availability will mean the Equivalent Availability Factor (EAF) which represents the unit's total composite availability over a specified amount of period hours versus the units potential availability (100 percent) over the same period hours. All full outages (planned, unplanned, maintenance, etc.) as well as deratings are considered reductions to the unit's availability to produce at full load capacity. The plant has a design equivalent availability of 85%.

The equivalent availability factor as summarized above is as defined by the North American Electric Reliability Council. An example calculation is included in Table 4.2.

Reliability. In this context, reliability is defined as the ability of a unit to produce electricity upon demand. Downtimes are expected to result from 10 percent forced downtimes and 5 percent planned downtimes. The number of trains selected to provide acceptable availability and reliability is shown in Table 4.3.

Table 4.1

DESIGN CAPACITY BASIS

Section	Capacity Basis
Air Separation Unit (ASU)	Coal throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Coal Handling	Coal throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Slurry Preparation	Coal throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Gasification	Gas throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Convect. Cooling, Scrubbing	Gas throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Low Temperature Gas Cooling	Gas throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Slag Handling	Slag throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Black Water Handling	Fines throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Acid Gas Removal (AGR)	Gas throughput of Pittsburgh #8 with a sulfur content of 3.5 wt% dry basis.
Sulfuric Acid Plant	Pittsburgh #8 with 3.5% sulfur content
Brine Concentration	0.1 wt% Chlorine in the coal, dry basis
Power Block	Fuel gas, steam and nitrogen for Pittsburgh #8
Fresh Water Systems	NO_x control when firing No. 2 fuel oil
Industrial Wastewater Treatment	150% of 25-year, 24-hour rainfall with the capability of handling a second 9-inch rain storm after a 72-hour period.
Sanitary Wastewater Treatment	50 GPD per person for maximum staffing of 210 at future full build-out
Boiler Feed Water	Greater of CT fuel oil or syngas operation

Table 4.2

EQUIVALENT AVAILABILITY CALCULATION EXAMPLE

Condition	First Year Hours	Second Year Hours
Calendar Year	8760	8760
Scheduled Maintenance	0	438
Scheduled Operations	8760	8322
Unscheduled Downtime	1752	876
Expected Operations	7008	7446

1st Year Equivalent Availability = (7008/8760)*100 = 80%
2nd Year Equivalent Availability = (7446/8760)*100 = 85%

NOTE: These calculations are for example only and are not intended to reflect actual operations.

Table 4.3

NO. OF TRAINS AND CAPACITY INFORMATION

Section	No. of Trains
Air Separation Unit (ASU)	1 - 100%
Coal Handling System	1 - 100%
Gasification System	1 - 100%
Low Temperature Gas Cooling	1 - 100%
Slag Handling	1 - 100%
Black Water Handling	1 - 100%
Acid Gas Removal (AGR)	1 - 100%
Sulfuric Acid Plant	1 - 100%
Brine Concentration	1 - 100%
Power Block	1 - 100%
Fresh Water System	1 - 100%
Potable Water Treating	1 - 100%
Demineralizer	2 - 60%
Sanitary Water Treating	1 - 100%
Industrial Water Treating	1 - 100%

4.1.3 Design Basis Feed Composition

The design coal (the coal on which the design and sizing of equipment will be based) for the Tampa Electric IGCC Project is a modified Pittsburgh #8 with 3.5 wt% (dry basis) sulfur. The normal operating coal is Pittsburgh #8 with 2.57 wt % (dry basis) sulfur. The expected coal analysis for Pittsburgh #8 is shown in Table 4.4. The design and normal operating case (NOC) coal analyses are shown in Table 4.5.

The maximum sulfur content of any coal specified for use at Polk Power Station Unit #1 will be 3.5 wt% (dry basis). The design chlorine content will be 0.1 wt% dry basis. The design coal trace element data is shown in Table 4.6. The specifications for the No. 2 fuel oil that will be used as a startup fuel and as a backup fuel for the combustion turbine are shown in Table 4.7. The design and normal operating case coal rates are approximately 2000 STPD and 1900 STPD, dry basis, respectively.

4.1.4 Coal Handling Systems

The design of the coal handling system for this project will be based on receipt of coal by truck. The conveyor from the unloading hopper will be designed to operate at approximately 3000 TPH. The system will also include a coal storage day bin with a capacity of approximately 20 hours of coal.

4.1.5 Preheat Fuel

Liquid propane will be vaporized and used to preheat the gasifier and the sulfuric acid plant. The fuel will be supplied from portable facilities on an as needed basis. The design propane composition is as follows:

Propane	99 Mol%
Butane	1 Mol%
Water	0 Mol%
Sulfur Compounds	0 Mol %
Total	100%

Table 4.4

COAL ANALYSIS DATA
(Pittsburgh #8)

Ultimate Analysis (wt %)	As Received	Dry Basis
Moisture	4.74	0
Carbon	73.76	77.43
Hydrogen	4.72	4.95
Nitrogen	1.39	1.46
Chlorine	0.10	0.10
Sulfur	2.45	2.57
Ash	7.88	8.27
Oxygen	4.96	5.22
Total	100.00	100.00
HHV (Btu/lb)	13290	13841 (Calc.)
Properties		
Ash (wt %)		
K_2O	1.32	
Na_2O	0.86	
Ash Fusion Temperature: (Reducing Atmosphere)		
Init (°F)	2100	
Soft (°F)	2150	
Hemi (°F)	2230	
Fluid (°F)	2340	
As Received Coal - Top Size	3/4" x 0 Normal 2" x 0 Maximum	
Hargrove Grindability Index	53	

Table 4.5

DESIGN AND NORMAL OPERATING COAL ANALYSES

Coal Analysis (Wt %, Dry Basis):

	Design	**Normal**
Carbon	77.43	77.43
Hydrogen	4.95	4.95
Nitrogen	1.46	1.46
Sulfur	3.50	2.57
Oxygen	5.22	5.22
Ash	7.44	8.37
	100.00	100.00

Table 4.6

DESIGN COAL TRACE ELEMENT DATA

	Maximum Content (wppm)
Aluminum	11300
Antimony	4.0
Arsenic	13
Barium	84
Beryllium	4.7
Boron	140
Cadmium	1.9
Calcium	3600
Chromium	28
Cobalt	9.3
Copper	26
Iron	10300
Lead	4.7
Magnesium	750
Manganese	45
Mercury	0.28
Molybdenum	10
Nickel	14
Potassium	1600
Selenium	8
Silicon	28500
Silver	0.04
Sodium	760
Strontium	280
Thallium	2.5
Tin	8
Titanium	1300
Vanadium	52
Zinc	54

Table 4.7

DESIGN NO. 2 FUEL OIL ANALYSIS

Parameter	Value
Specific gravity @60°F (maximum)	0.876
Viscosity, Saybolt (SUS) @ 100°F	
Minimum	40.2
Maximum	32.6
Flash Point, °F (minimum)	100
Pour Point, °F (minimum)	20
Minimum gross heating value, Btu/gal	
LHV	129,811
HHV	137,600
Water and sediment, percent by volume (maximum)	0.05
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015
Trace constituents, ppm (maximum)	
Lead	1.0
Sodium	1.0
Vanadium	0.5

4.1.6 Air Separation Unit Requirements

The ASU has been specified to produce approximately 2020 TPD of pure oxygen, 1985 TPD produced at 575 psig and 35 TPD produced at 50 psig. The purity requirement of the oxygen is 95 mol%. The design conditions for the unit are 90°F ambient dry bulb, 75°F ambient wet bulb and 14.63 psia.

The ASU has been designed for full nitrogen recovery, with a maximum total nitrogen production of approximately 6400 TPD. Approximately 6000 TPD of nitrogen will be produced at a nominal 255 psig for syngas diluent, approximately 400 TPD will be produced at high pressure for soot blowing. The minimum purity (N_2+Argon) required for the nitrogen is 98 mol% for diluent and 99.99 mol% for high pressure nitrogen.

4.1.7 Power Block Design Parameters and Product Specifications

The power block is designed to operate on both syngas and No. 2 fuel oil. During startup and other times when syngas is not available, the power block will generate power from a No. 2 oil fired, water injected, GE Frame 7F combustion turbine. When available, the primary fuel will be syngas made in the gasification section with nitrogen from the ASU for NO_x control. The syngas will come from either the CGCU process exclusively or from the CGCU and HGCU.

In addition to using the combustion turbine to generate electricity, the power block will utilize an HRSG, and a steam turbine and a condenser/hotwell in a combined cycle configuration to generate additional electricity. The HRSG is a three pressure level unit with superheater, reheater, evaporators, drums, economizers, boiler feed water preheaters and an integral deaerator. The steam turbine is a 1450 psig/1000°F reheat turbine with double flow condensing LP section.

High pressure saturated steam generated in the gasification section will be routed to and superheated in the HRSG.

Intermediate and low pressure steam and water systems will also interface with the gasification section.

The HRSG is designed to handle the full load CT exhaust flow.

The power block will generate three phase, 60 Hz electric power at 18 KV from the combustion turbine generator and at 13.8 KV from the steam turbine generator. The generator step-up transformers will transform the generator voltages to 230 KV.

4.1.8 Sulfuric Acid Plant

4.1.8.1 Feed Gas Conditions. The feed gas conditions are provided for the AGR acid gas, ammonia acid gas, HGCU offgas, HGCU air for drying, and oxygen.

The Normal Operating and Design Case 1 are for operation on 100% CGCU feed to the sulfuric acid plant. Design Case 2 is for operation on 90% CGCU feed and 10% HGCU feed to the sulfuric acid plant. The Normal Operating is for a gasifier feed of 2.5 wt% sulfur coal, the expected coal quality. Design Cases 1 and 2 are for a gasifier feed of 3.5 wt% sulfur coal. All of the cases are for a gasifier operating at a H_2S:COS ratio of 40:1. The sulfuric acid plant will be designed to operate under all these cases as well as at a turndown of 50%.

AGR Acid Gas	Normal Operating	Design Case 1	Design Case 2
Temperature, °F	110	110	110
Pressure, PSIG	10.0	10.0	10.0
Ammonia Acid Gas			
Temperature, °F	200	200	200
Pressure, PSIG	10.0	10.0	10.0

The plant will be capable of operating when there is no ammonia acid gas available.

HGCU Offgas	Normal Operating	Design Case 1	Design Case 2
Temperature, °F	---	---	600 min 650 max
Pressure, PSIG			85.0 min 105.0 max

The HGCU offgas is from a new developing technology and may be subject to unplanned outages. The plant design will incorporate features to handle a potentially rapid transition from having HGCU offgas (Design Case 2) to not having the gas (Design Case 1).

The HGCU offgas may contain impurities detrimental to proper operation of the sulfuric acid plant. Because of this and the initially uncertain nature of the feed from the HGCU, the HGCU offgas will be introduced into the sulfuric acid plant upstream of the waste heat boiler. In addition, a blinded alternate feed point will be provided down stream of the waste heat boiler for the HGCU offgas.

HGCU Air for Drying

	Normal Operating	Design Case 1	Design Case 2
Temperature, °F	---	---	734 Min 800 Max
Pressure, PSIG	---	---	150

The HGCU air for drying stream is an offsite stream that is used in the regeneration of the solid reactant used in the HGCU and is only available when the HGCU is operating. The air drying requirement shown above may be required prior to the availability of the HGCU offgas.

Oxygen

	Normal Operating	Design Case 1	Design Case 2
Temperature, °F	110	110	110
Pressure, PSIG	100	100	100
Maximum Available lbs/hr	5250	5250	5250

4.1.8.2 Product and Effluent Specifications. Product and effluent specifications are provided for sulfuric acid, dry HGCU air, vent gas (effluent gas), acid water (cooling system bleed), and flare header.

Sulfuric Acid

Concentration, Min Wt % H_2SO_4	98
Onsite Storage Capacity	5 days production

Dry HGCU Air

Dew Point,°F	-30
Acid Mist (H_2SO_4), Max PPMV	5
Temperature, °F	734
Min Temp., °F	650
Pressure, Min PSIG	115

Vent Gas (Effluent Gas)

Pressure, Minimum PSIG	1.0

The vent gas will meet the following Federal and State of Florida Air Quality Permit requirements:

- Max lbs SO_2/ton of 100% H_2SO_4 Product	4
- Max lbs Acid Mist/Ton of 100% H_2SO_4 Prod.	0.15

Acid Water (Cooling System Bleed)

SO_2 Content, Max PPMW	50
Pressure, Minimum PSIG	75

Flare Header

Offsite back pressure, Maximum PSIG (includes both static and developed)	10

To be used for relief valve and relief system design.

4.1.9 Design Life of Equipment

Equipment Type	**Design Life**
Vessels	30 years
Non-removable internals	30 years
Removable internals	10 years
Trays	10 years
Exchangers Shells	30 years
Exchangers Tubes	
Removable Bundles	10 years
Nonremovable Bundles	30 years
Piping	
Clean Non-corrosive	30 years
Corrosive/erosive	10 years

4.2 SITE CONDITIONS

4.2.1 Project Location

The Polk Power Station is located in Polk County, Florida between State Road (SR) 37 on the west, County Road (CR) 663 (Fort Green Road) on the east, and SR 630 on the north. The location includes all or portions of Sections 1-4 and 7-12 in T32S, R23E and Sections 34 and 35 in T31S, R23E.

4.2.2 Elevation

General elevation in the region is approximately 135 to 140 feet above mean sea level. The finish grade on the site in the vicinity of the major structures and equipment is anticipated to be approximately 140 to 145 feet.

4.2.3 Current Site Development

Most of the property was part of Agrico's Fort Green Mine and has been extensively mined for phosphate matrix. Most of the mining was performed by the strip mining process using draglines. The overburden remains on the site. Sand and clay separated from the phosphate matrix were not generally returned to this portion of the mine. Development of the site must be performed in accordance with Florida Department of Environmental Protection rules. The area of the site where the major structures will be located has not been mined.

4.2.4 Access

The site is accessible from SR 37 and from CR 663. In addition, the CSX Railroad runs adjacent to the site along the east side of CR 663. A spur from the CSX Railroad will be built, crossing Fort Green Road and entering the site from the east.

4.2.5 Soil and Groundwater Conditions

The site is generally level with an elevation variation of El. 136 to El. 139 ft., based on the surveyed elevations at borehole locations. The subsurface soils encountered at the site can be divided into three generalized strata as follows:

- Stratum I contains silty fine sand which is generally extended to a depth of about 20 to 30 feet. Most materials are in medium dense to dense conditions. Partially cemented very dense silty fine sand (Hardpan) is encountered at shallow depths of some borings. Loose materials are occasionally encountered at surficial topsoils and at random depths of a few borings.

- Stratum II predominantly composes of a green colored soil mixture containing clay, silt, and phosphate pellets and pebbles. Most materials encountered are in medium dense to very dense conditions or in very stiff to hard consistency. Very silty fine sands with occasional clayey seams are encountered at random depths of a few borings.

- Stratum III composes of hard mottled, mostly white dolosilt interbedded with thin limestone and dolomite lenses. The top of this stratum is generally located at El. 90 to El. 95 feet.

For these soil conditions shallow foundations (spread footing or mat) are technically feasible and cost-effective in construction and will be used. In general, provision of deep foundations including a piling system will not be necessary for the structure in terms of geotechnical considerations of bearing capacity and potential foundation settlement.

Design groundwater elevation is 136 feet.

4.2.6 Seismic Design Requirements

Facilities will be designed for earthquake seismic risk zone 0.

4.3 CLIMATIC DESIGN DATA

4.3.1 Summer Design Temperatures

Design temperature:	90°F dry bulb, 75°F wet bulb
Maximum temperature:	100°F dry bulb, 80°F wet bulb

4.3.2 Winter Design Temperatures

Design temperature:	40°F dry bulb, 38°F wet bulb
Minimum temperature:	18°F dry bulb, 15°F wet bulb

4.3.3 Snowfall

Design snow load:	0 psf

4.3.4 Rainfall

Mean annual rainfall:	53.4 inches
Design rainfall in 1 hour:	3.0 inches (10-year occurrence)
Design rainfall in 24 hours:	13.5 inches (1.5 x 25-year occurrence rate of 9 inches)

Data obtained from the Rainfall Frequency Atlas of the United States, Technical Paper 40, 1961.

4.3.5 Barometric Pressure

Design barometric pressure: 14.63 psia

4.3.6 Wind Load

The wind loads will be based on a design wind speed of 110 mph. Category III will be used to determine importance factor and exposure C will be used to determine velocity pressure coefficients.

4.4 UTILITY SPECIFICATIONS

4.4.1 Existing Utilities

The site is not served by any existing public or private water supply or wastewater collection and treatment systems. Water use permits have been obtained, as part of the site permitting efforts, to draw water from the Floridan Aquifer.

Wastewater treatment is part of the design of the IGCC plant with the restriction of zero discharge of process water.

A 69 KV, 60 Hz, 3-phase power line runs along the east side of SR 37 near the plant site. This will be the source for the construction power substation. This substation will step down the 69 KV to 13.8 KV and provide for two 600 amp distribution circuits.

A 230 KV, 60 Hz, 3-phase transmission line runs along Fort Green Road and connects TEC's Pebbledate substation to the Hardee Power Station. This line will be routed through the Polk Power Station switchyard.

A 230 KV, 60 Hz, 3-phase transmission line connects TEC's Pebbledale and Mines substations. This line will be routed through the Polk Power Station switchyard to each GSU.

4.4.2 Saturated Steam System

Saturated steam is produced and consumed at three general pressures; high pressure (1650 psig), intermediate pressure (400 psig), and low pressure (50 psig). The saturated steam system design pressures and temperatures are shown in Table 4.8.

Table 4.8

DESIGN PRESSURES OF SATURATED STEAM SYSTEMS

High Pressure System	Min.	Norm.	Max.
Saturated 1650 psig (2)			
Press. (psia)	415	1665	1665
Intermediate Pressure System			
Saturated 400 psig (2)			
Press. (psia)	415 (1)	415	415
Low Pressure System			
Saturated 50 psig (2)			
Press. (psia)	65	65	75

NOTES:

(1) Startup Operation
(2) All steam pressures are measured at the supply header for each piece of equipment.

4.4.3 Fresh Water System

Fresh water will be supplied from onsite wells. This water will be degasified to remove H_2S, chlorinated, filtered, and pumped to a service water tank for feed to the service water, the demineralized water, and the potable water systems.

The design analysis for water from the Floridan Aquifer in the area is summarized in Table 4.9.

4.4.4 Potable Water

Potable water system provides for drinking water, sanitary facilities, safety showers, and eyewash stations. It will be degasified, chlorinated, and pumped from a storage tank to supply the system. A pressurized accumulator will be used to maintain system pressure during power outages.

Hypochlorite will be used to chlorinate the water upstream of the service water tank and upstream of the potable water tank.

Potable water specifications will be in accordance with State of Florida Drinking Water Standard FAC-17-550.

4.4.5 Demineralized Water

Filtered well water from the service water system will feed the demineralized water system. A reverse osmosis system will perform the primary demineralization. This treatment will be followed by decarbonation, additional demineralization, and then transfer to the power block for distribution.

Demineralized water specifications are as follows:

Sodium, ppm as Na	0.005 maximum
Silica, ppm as SiO_2	0.02 maximum
Total solids, ppm	0.05 maximum
Conductivity, μho/cm at 25°C	0.1 maximum
pH at 25°C	6 - 8

4.4.6 Boiler Feed Water

The principal source of boiler feedwater is condensate from the steam turbine, with makeup from the demineralized water system.

Table 4.9

WATER QUALITY ANALYSIS

Parameter	Units	Well Water
B0D20	mg/L	0
COD	mg/L	390
TSS	mg/L	33
TDS	mg/L	237
pH, units		7.66
Alkalinity	mg/L	110
Ammonia, nitrogen	mg/L	0
Antimony	mg/l	0
Arsenic	mg/L	0
Barium	mg/L	0.092
Benzene	mg/L	0
Beryllium	mg/L	0
Cadmium	mg/L	0
Calcium	mg/L	37.1
Carbon tetrachloride	mg/L	0
Chloride	mg/L	13.4
Chlorine	mg/L	
Chromium	mg/L	0
Chromium VI	mg/L	0
Color, pt-co (units)		20
Conductivity	umhos/cm	330
Copper	mg/L	0
Cyanide	mg/L	0
Fluoride	mg/L	0.44
Gross Alpha	pCi/L	0

Table 4.9 (Continued)

WATER QUALITY ANALYSIS

Parameter	Units	Well Water
Total iron	mg/L	0.2
Lead	mg/L	0
Magnesium	mg/L	13.1
Total Manganese	mg/L	0
Mercury	mg/L	0
Nickel	mg/L	0
Nitrate	mg/L	0.26
Nitrite	mg/L	0
Phosphorus	mg/L	0.071
Potassium	mg/L	4.28
Radioactivity, Ra 226	pCi/L	1.4
Radioactivity, Ra 228	pCi/L	0
Selenium	mg/L	0
Silver	mg/L	0
Sodium	mg/L	15.7
Sulfate	mg/L	39.5
Sulfide	mg/L	1.88
Surfactants	mg/L	0.06
Total organic nitrogen	mg/L	0
Zinc	mg/L	0.014

4.4.7 Steam Condensate

Steam condensate from the gasification facilities is routed to an atmospheric flash drum. This condensate will be reused as boiler feedwater makeup.

Steam condensate from the steam turbine condenser is recycled within the power block to the boiler feedwater deaeration system.

4.4.8 Service Water

The service water system is supplied from the service water storage tank which is supplied will be filtered and chlorinated wellwater. Service water system specifications are as follows:

Mechanical Design Pressure:	150 psig
Normal Operating Pressure:	100 psig
Minimum Operating Pressure:	90 psig

4.4.9 Fire Water System

The fire protection system will be designed as a plant loop. Fire water will be supplied from the cooling water reservoir by four firewater pumps. A low flow capacity motor driven jockey pump runs continuously to maintain firewater system pressure when demand is low. When the flow requirement increases beyond the jockey pump's capacity, the three main firewater pumps are sequentially started: first the motor driven pump, followed by the two diesel driven pumps.

Fire water system specifications are as follows:

Mechanical Design Pressure:	150 psig
Normal Operating Pressure:	100 psig
Minimum Operating Pressure:	90 psig

4.4.10 Cooling Water

Cooling water will be supplied from a cooling reservoir with a capacity of approximately 10,185 acre-feet.

There are two types of cooling water systems:

- **Open Loop Circuits** - The Circulating Water System cools the steam turbine surface condenser. The Open Loop Cooling Water System supplies cooling water to the two closed loop heat exchangers, the ASU, the sulfuric acid plant, the condenser vacuum pumps, and some gasification area exchangers.

- **Closed Loop Circuits** - The Power Block Closed Loop Cooling Water System cools all exchangers in the power block and the air compressor area. This system exchanges heat with the open loop circuit through the Power Block Closed Loop Cooling Water Heat Exchangers.

  The Gasification Closed Loop System cools some exchangers in the Gasification, Acid Gas Removal, and Brine Concentration Areas. This system exchanges heat with the open loop circuit through the Closed Loop Exchanger.

The open loop cooling water is pumped from the cooling reservoir and returned to it. The closed loop systems are filled initially and sealed, never mixing with the open loop water.

The Circulating Water System is a low head high flow system. The water boxes on the condenser operate at a slight vacuum. The design maximum supply temperature is 85°F. The return temperature will be between 95°F and 100°F.

The design parameters for the Open Loop Cooling Water System are as follows:

	Temperature (°F)	Pressure (psig)
Design Supply	85	60
Design Return	110	5

The design parameters for the Power Block Closed Loop System are as follows:

	Temperature (°F)	Pressure (psig)
Design Supply	93	70
Design Return	103	30

The design parameters for the gasification Closed Loop System are as follows:

	Temperature (°F)	Pressure (psig)
Design Supply	95	70
Design Return	110	40

4.4.11 Plant and Instrument Air

Plant and instrument air will be supplied from lubed, rotary screw compressors.

Instrument air will be dried to a dew point of -40°F by a desiccant air dryer. Backup instrument air will be supplied by letdown from the main air compressor in the ASU.

Plant and Instrument air design pressures are as follows:

	Plant Air PSIG	Instrument Air PSIG
Mechanical Design:	150	150
Normal:	110	110
Maximum:	125	115
Minimum:	65	65

4.4.12 Nitrogen

Nitrogen will be supplied from the ASU and will be used in the following services with these design specifications:

Syngas Diluent:

Minimum Purity*, N_2 + Argon (mol %)	98
Supply Pressure (psig)	255
Temperature (°F)	350-720

Soot Blowing:

Minimum Purity*, N_2 + Argon (mol %)	99.99

Inert Gas Blanket & Purge:

Minimum Purity*, N_2 + Argon (mol %)	98
Supply Pressure (psig)	35
Supply Temperature (°F)	100

High Pressure Nitrogen

Minimum Purity*, N_2 + Argon (mol %)	99.99
Supply Pressure (psig)	885
Supply Temperature (°F)	420

*Contaminants are either water or oxygen.

4.4.13 Electrical Supply

Nominal electrical system voltages will be as follows:

13.8 KV, 3-phase, 60 Hz, WYE, resistance grounded

4160 Volt, 3-phase, 60 Hz, WYE, resistance grounded

480 Volt, 3-phase, 60 Hz, Delta, ungrounded

120/240 Volt, 1-phase, 60 Hz, solidly grounded

125 Volts, DC, ungrounded

PLANT DESCRIPTION

5.0 PLANT DESCRIPTION

5.1 SITE DESCRIPTION

The site layout plan for the entire 4,348-acre Polk Power Station site is presented in Figure 5.1-1. The IGCC is the first unit planned for this site, but the long-term plan calls for additional generating facilities to be on this site. This figure shows the locations of the proposed electric generating units and associated facilities on the site after full build-out (i.e., 1,150 MW capacity) as well as the land use/land cover classifications of the site areas which will be reclaimed by Tampa Electric Company. These reclaimed, undeveloped areas will provide a combination of buffer, water management, and wildlife habitat/corridor functions on the site.

As shown in Figure 5.1-1, the main power plant facilities will be located in the central area of the portion of the site to the east of SR 37. This plant site area was not mined for phosphate, but has been disturbed by the surrounding mining activities. The main power plant facilities (i.e., power block and fuel and by-product storage areas) will be located more than 2,500 feet from offsite properties, more than 1.5 miles from residential areas to the west along Bethlehem Road and 2.8 miles from residential areas to the southeast along Mills Road. Also, as shown in the figure, a vegetated buffer area will be provided along public roadways surrounding the eastern site tract (i.e., SR 37, CR 630, and CR 663 [Fort Green Road]).

The cooling reservoir will be constructed in mined-out areas located to the east and south of the main facility site. The other mined-out portions of the eastern site tract to the west and north of the main facilities will be reclaimed/developed into a series of wetlands and uplands which will be used for management of stormwater runoff from the plant site and to restore pre-mining drainage conditions for the Little Payne Creek system. The remaining areas of the eastern tract (i.e., the southwest corner, the 775-acre area north of the main plant site and cooling reservoir extending to CR 663, and the reclaimed lake to the east of the reservoir) will not be significantly altered by the project. The two transmission line corridors will run through the northern site area.

The 1,511-acre portion of the site to the west of SR 37 will be reclaimed to a wildlife habitat/corridor system consisting of an integrated series of forested and non-forested wetlands and uplands. No power plant facilities will be located on this tract and, after reclamation, the area will develop into a wildlife corridor between the headwater areas of the Little Manatee River and Payne Creek and the South Prong Alafia River system.

POST RECLAMATION VEGETATION WITHIN PROJECT BOUNDARY

		NON-MANDATORY ACRES	MANDATORY ACRES		TOTAL ACRES
			IMC	AGRICO	
140	TRANSPORTATION	0	0	3	3
148	GAS TRANSMISSION SUBSTATION	0	1	13	14
151	ELECTRICAL POWER FACILITY	0	0	261	261
210	PASTURE	211	98	467	776
230	CITRUS	0	0	18	18
320	SHRUBLAND	4	0	540	544
330	MIXED RANGELAND	6	0	0	6
420	UPLAND HARDWOOD FOREST	29	9	17	55
430	UPLAND MIXED FOREST	34	74	666	774
520	LAKES	165	36	63	264
530	RESEVOIRS	0	0	834	834
620	WETLAND HARDWOOD FOREST	40	4	17	61
630	WETLAND MIXED FOREST	11	4	295	310
640	HERBACEOUS WETLAND	23	26	379	428
		TOTAL 523	TOTAL 252	TOTAL 3573	TOTAL 4348

TWP. 31 S - RGE. 22 E

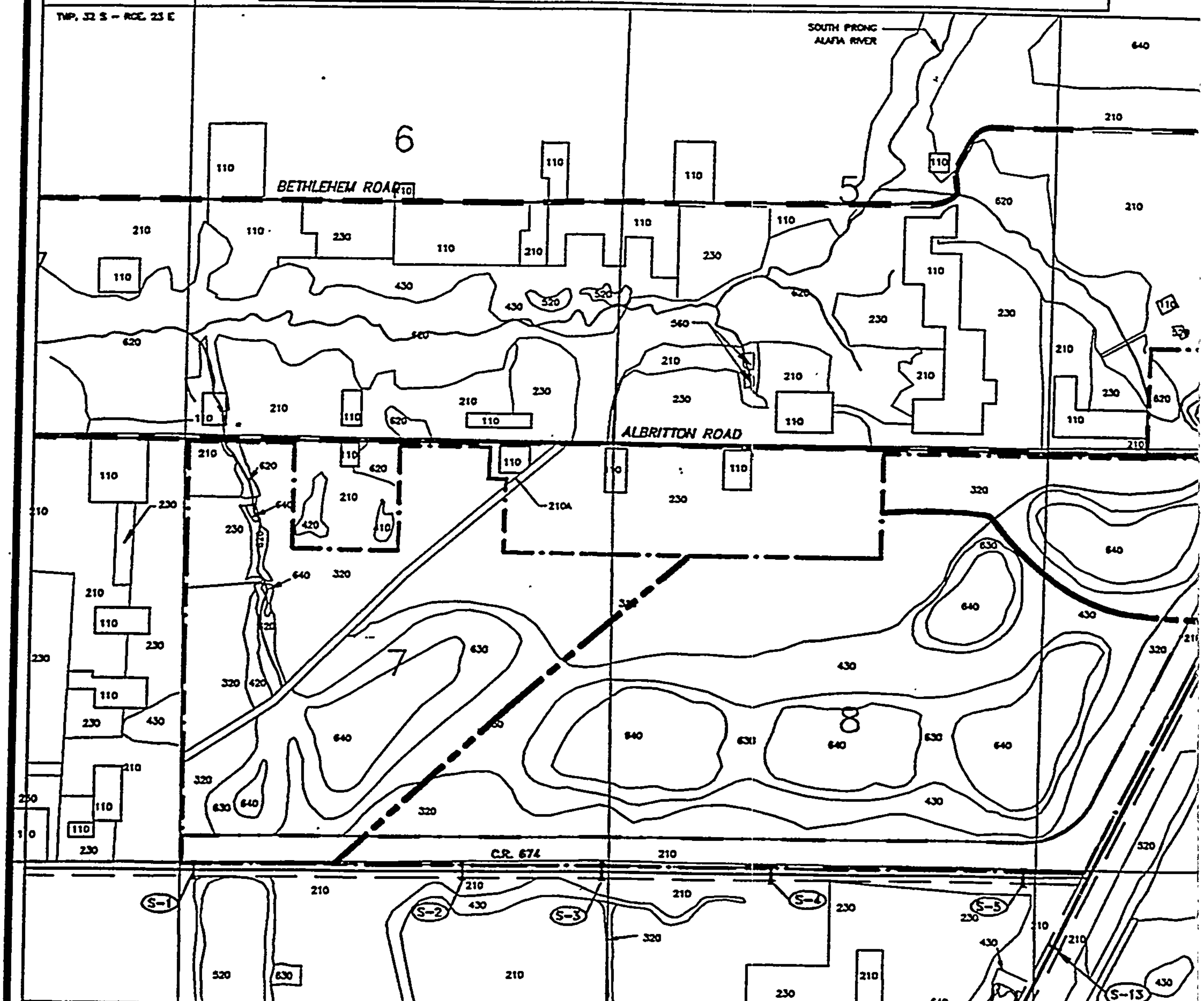
TWP. 31 S - RGE. 23 E

HILLSBOROUGH CO.

POLK COUNTY

31

33



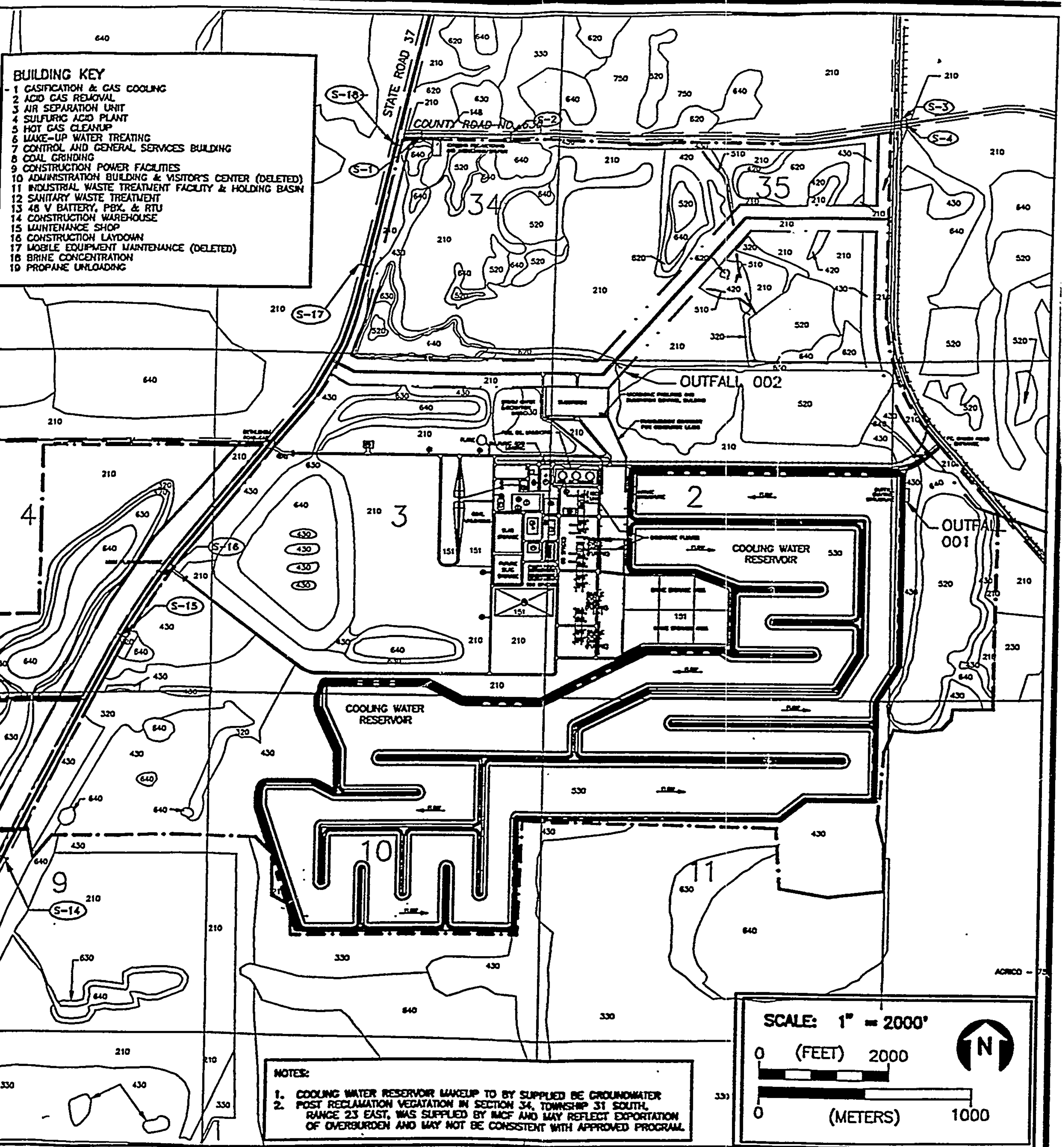


Figure 5.1-1

SITE LAYOUT PLAN

Approximately 261 acres (i.e., approximately 6 percent) of the entire site, excluding the cooling reservoir, will be classified for power plant facilities after full build-out of the proposed Polk Power Station. Of this 261 acres, approximately 140 acres will actually be used for the main power facilities and structures, including the coal, fuel oil, by-product, and brine storage areas, and industrial waste treatment (IWT) systems.

5.2 PLANT LAYOUT

The overall plant layout is presented in Figure 5.2-1. Several design features of the layout are noted below.

The location of the operating facilities in the center of the site provides a buffer between them and public areas.

The power block, the primary user of cooling water from the reservoir, is located as near to the cooling water intake structure as is permitted by the transmission corridor. With the large flow rates, cooling water lines are large, and it is important to minimize both length and pressure drop.

Space has been reserved for future expansion of power generation and slag storage facilities.

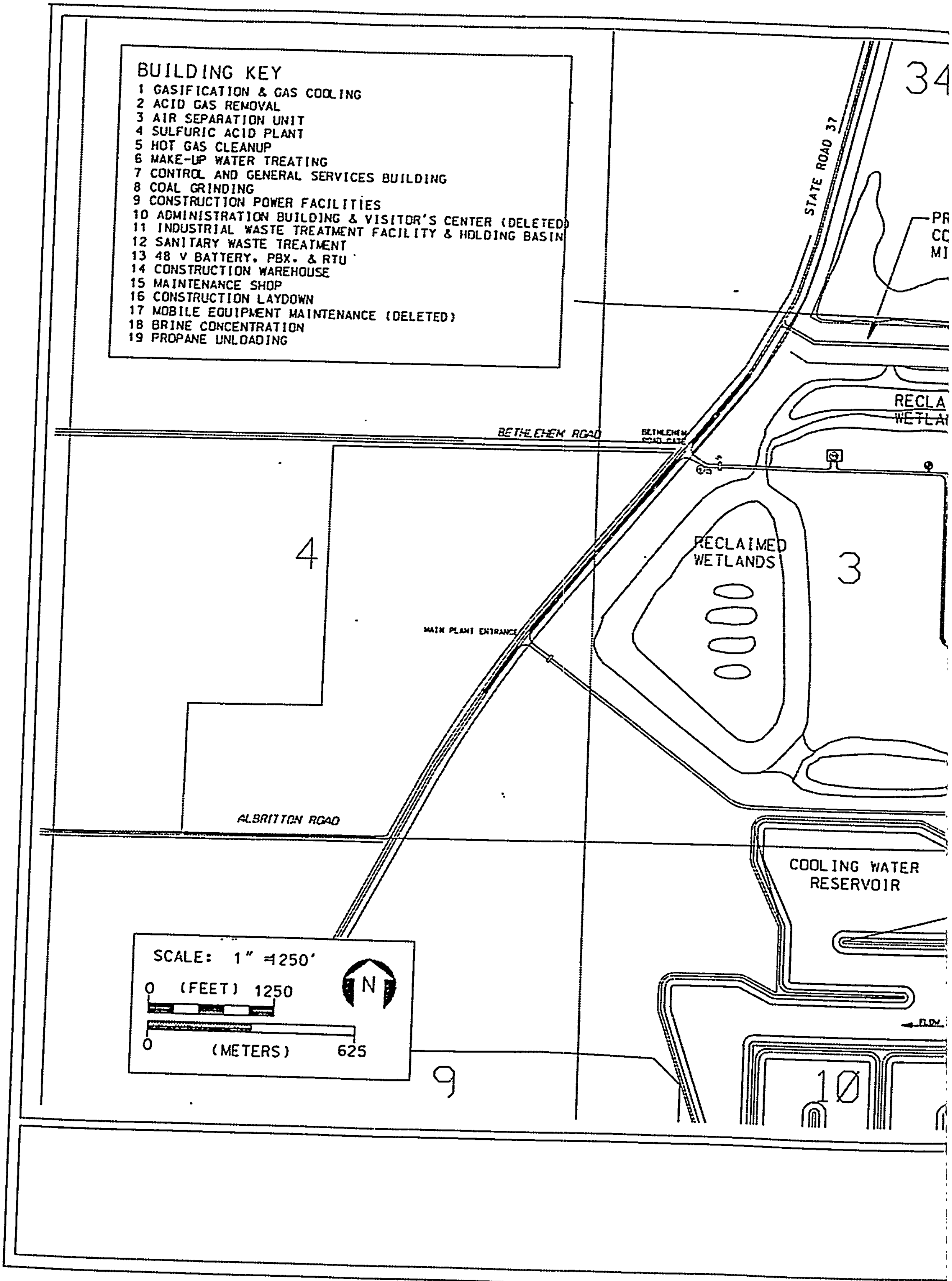
5.3 PROCESS DESCRIPTION

A general block flow diagram of the process is shown in Figure 5.3-1. The process begins with the delivery of fuels to the site. The startup and backup fuel for Polk Power Station is distillate oil which will be delivered by truck with sufficient onsite storage. The design fuel for the plant is Pittsburgh #8 which will be transported by river and ocean-going barges to TEC's Big Bend Station, then transloaded to trucks for delivery to the Polk site, where silo storage is provided.

The coal is ground in rod mills, then slurried with water and combined with oxygen from the air separation unit to produce a high temperature (2600+°F), medium pressure (400 psig) syngas within a Texaco-designed, pressurized, oxygen-blown, entrained-flow gasifier. Approximately 2000 tons per day of coal (dry basis) is thus converted into a medium-Btu syngas with a heat content of about 250 Btu/scf (LHV).

Molten coal ash flows from the bottom of the gasifier vessel into a water-filled quench tank where it solidifies into slag. The slag is subsequently removed, crushed and dewatered prior to its sale as a multi-use by-product.

Syngas produced in the gasifier flows through a series of heat recovery units to partially cool the gas prior to its diversion to two separate clean-up systems. In one of these systems, approximately 45,000 lb/hr of the syngas is treated at approximately 900°F in an HGCU using


BUILDING KEY
1 GASIFICATION & GAS COOLING
2 ACID GAS REMOVAL
3 AIR SEPARATION UNIT
4 SULFURIC ACID PLANT
5 HOT GAS CLEANUP
6 MAKE-UP WATER TREATING
7 CONTROL AND GENERAL SERVICES BUILDING
8 COAL GRINDING
9 CONSTRUCTION POWER FACILITIES
10 ADMINISTRATION BUILDING & VISITOR'S CENTER (DELETED)
11 INDUSTRIAL WASTE TREATMENT FACILITY & HOLDING BASIN
12 SANITARY WASTE TREATMENT
13 48 V BATTERY, PBX, & RTU
14 CONSTRUCTION WAREHOUSE
15 MAINTENANCE SHOP
16 CONSTRUCTION LAYDOWN
17 MOBILE EQUIPMENT MAINTENANCE (DELETED)
18 BRINE CONCENTRATION
19 PROPANE UNLOADING
STATE ROAD 37
34
BETHLEHEM ROAD
MAIN PLANT ENTRANCE
4
RECLAIMED WETLANDS
3
ALBRITTON ROAD
COOLING WATER RESERVOIR
SCALE: 1" =1250'
0 (FEET) 1250
0 (METERS) 625
N
9
10

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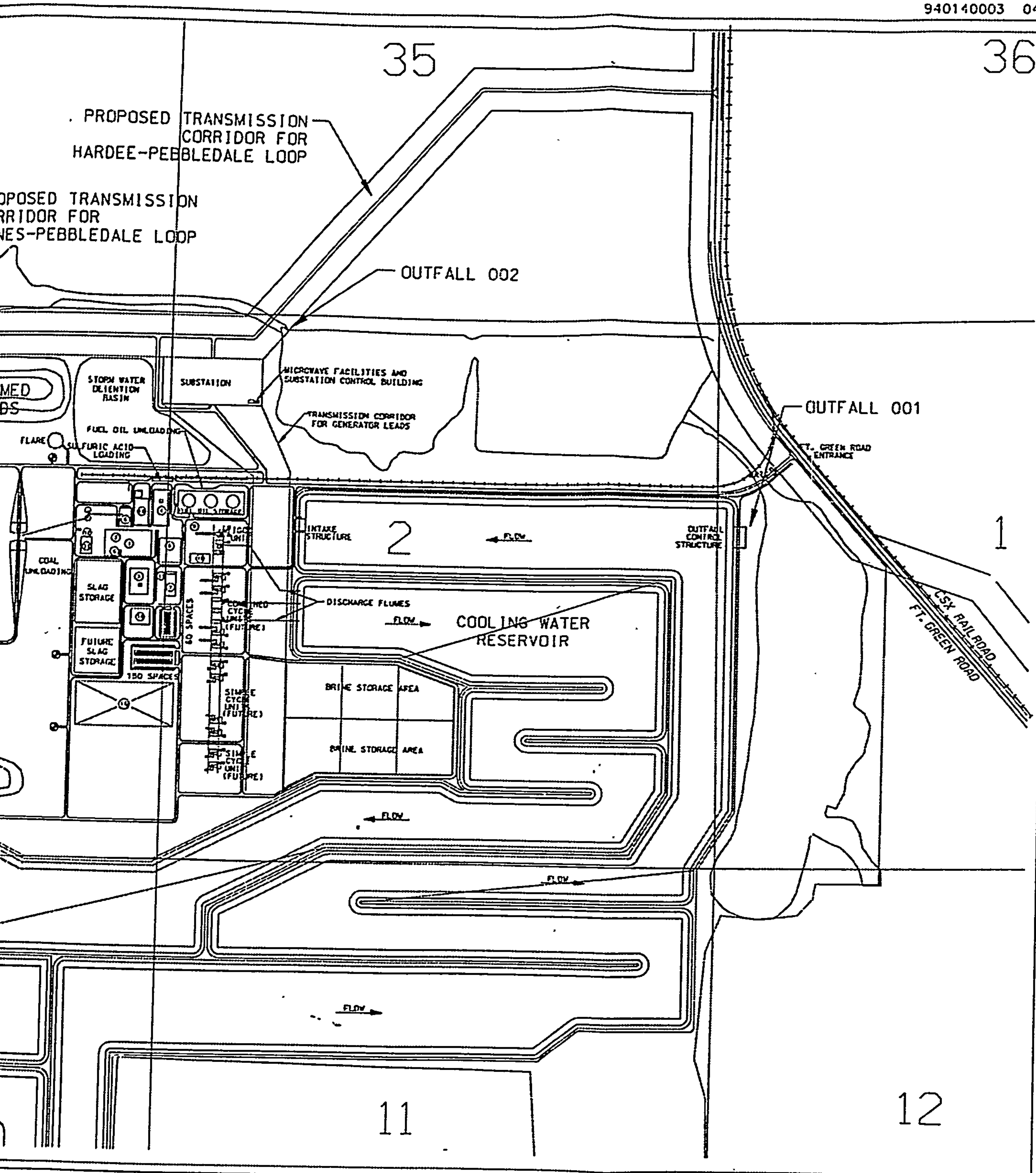


Figure 5.2-1

OVERALL PLANT LAYOUT PLAN

a metal oxide sorbent to capture sulfur-containing compounds. An associated regeneration system will produce a highly concentrated SO_2 stream which will in turn feed a sulfuric acid plant for production of a saleable acid by-product. Demonstration of this advanced metal oxide hot gas desulfurization technology at a commercial scale is a significant goal for the Polk IGCC Project and represents a first for the industry.

The remaining syngas continues to the CGCU system, where it is treated at 105°F in a conventional acid gas removal system, from which the resultant acid gas is sent to the sulfuric acid plant for conversion into saleable by-product. This portion of the plant is capable of processing 100% of the gasifier output of raw syngas.

From these syngas clean-up systems, the cleaned, medium-Btu syngas is routed to the combustion section of the advanced combustion turbine where it combines with compressor discharge air to be burned. At this point, nitrogen from the air separation unit is injected into the same combustion hardware to serve two purposes. The nitrogen acts as a diluent to control NO_x emissions, and adds substantial mass flow to combustion turbine throughput to increase power output. The mixture of syngas, air and nitrogen expands through the CT to produce about 192 MW from the combustion turbine generator.

As the exhaust gases exit the CT, heat is extracted in the heat recovery steam generator (HRSG) to produce high, medium and low pressure steam. This steam, along with high and medium pressure steam generated in the gasification process, expands through a double-flow reheat steam turbine to generate an additional 122 MW of power. Small streams of steam and condensate are also exchanged with the HGCU and sulfuric acid plant for overall process integration and optimization.

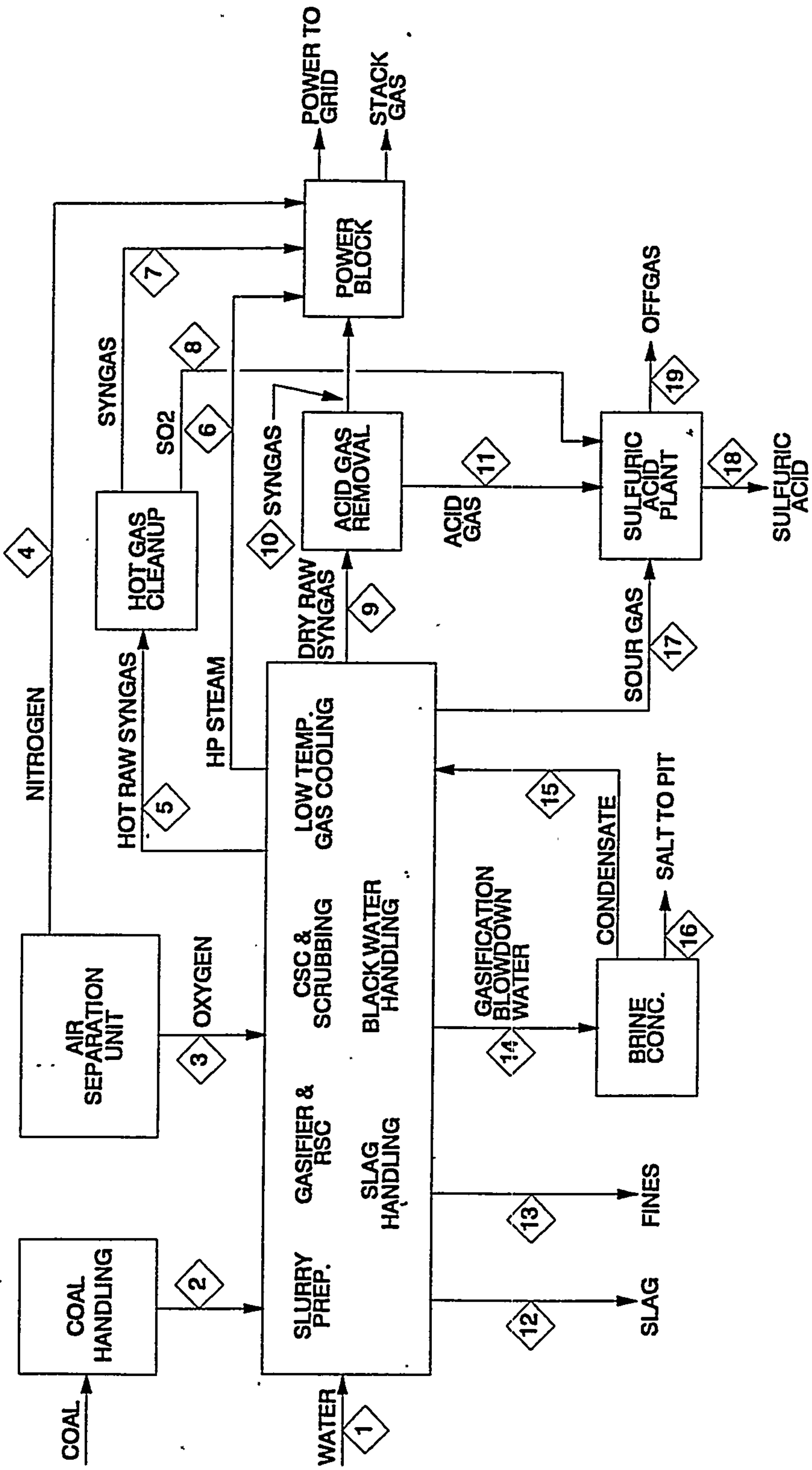
Auxiliary power consumption for the IGCC facility is approximately 64 MW, most of which is required for air separation. Nominal net power output from the IGCC demonstration plant will be 250 MW.

5.3.1 Gasification

5.3.1.1 Gasification and Cold Gas Cleanup. This unit will utilize commercially available gasification technology as provided by Texaco in their licensed oxygen-blown entrained-flow gasifier. In this arrangement, coal is ground to specification and slurried in water to the desired concentration (60-70% solids) in rod mills. The unit will be designed to utilize about 2,000 tons per day of coal (dry basis). This coal slurry and an oxidant (95% pure oxygen) are then mixed in the gasifier burner where the coal partially combusts in an oxygen deficient environment, at a temperature in excess of 2600°F. This produces syngas with a heat content of about 250 Btu/SCF (LHV). The oxygen will be produced from an air separation unit (ASU). The gasifier is expected to achieve greater than 95% carbon conversion in a single pass.

Figure 5.3-1

GENERAL BLOCK FLOW DIAGRAM



The raw syngas flows from the gasifier through the syngas cooling system where the temperature will be reduced from about 2,600°F to about 900°F. A syngas stream of approximately 45,000 lb/hr is sent to the HGCU system and the remainder of the syngas, up to 100% of design flow, continues to the CGCU system, a traditional amine type scrubber. This flow arrangement was selected to provide assurance to TEC that the IGCC capacity would not be restricted due to the demonstration of the HGCU system.

Sulfur removed in both the HGCU and CGCU systems will be recovered in the form of sulfuric acid, which has a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of about 77,000 tons of sulfuric acid will have minimal impact on the price and availability of these products in the phosphate industry.

Most of the ungasified coal exits the bottom of the radiant syngas cooler into the slag lockhopper where it is quenched with water. These solids generally consist of slag and uncombusted coal products. As they exit the slag lockhopper, these non-leachable products are readily saleable for blasting grit, roofing tiles, and construction building products.

The water in the slag lockhoppers requires treatment before it can be reused. All of the water from the gasification process will be cleaned and reused, thereby giving the gasification system zero process discharge. The treatment consists of filtration, followed by concentration in several stages of evaporation. The remaining salt solids are crystallized and stored in an onsite landfill. The condensed water from evaporation is recycled to slurry coal.

5.3.1.2 Air Separation Unit. The ASU will use ambient air to produce oxygen for use in the gasification system and sulfuric acid plant, and nitrogen which will be sent to the advanced CT and to gasification for soot blowing. The addition of nitrogen in the CT combustion chamber has dual benefits. First, since syngas has a substantially lower heating value than natural gas, a higher fuel mass flow is needed to maintain heat input. This additional mass flow has the advantage of producing higher CT power output. Second, the nitrogen acts to control potential NO_x emissions by reducing the combustor flame temperature which, in turn, reduces the formation of thermal NO_x in the fuel combustion process.

The ASU is sized to produce 2,020 tons per day of 95% pure oxygen and 6,013 tons per day of 98% pure nitrogen for CT diluent, 401 tons per day of 99.99% pure nitrogen for gasification plant soot blowing, and 24 tons per day of 98% pure dry nitrogen for blanketing.

5.3.1.3 Hot Gas Cleanup. The HGCU system is being developed by General Electric Environmental Services, Inc. (GEESI). This process is undergoing pilot plant testing at GE's facilities in Schenectady, NY. The advantage of the HGCU over the CGCU is the ability to use the syngas directly from the gasification system. Instead of having to cool the gas prior to sulfur removal, the HGCU will accept gas at 900-1000°F. The successful demonstration of this technology will enable future IGCC systems to achieve higher efficiency.

An absorption/regeneration system will produce a highly concentrated (about 13%) SO_2 stream. This will feed a sulfuric acid plant for production of a saleable acid by-product.

Two other support processes will be demonstrated for potential improvements to this process. In addition to the high efficiency primary and secondary cyclones being provided upstream of the sulfur removal system, a high temperature barrier filter will be installed downstream of sulfur removal to protect the combustion turbine.

Sodium bicarbonate, $NaHCO_3$, will be injected upstream of the secondary cyclone for removal of chloride and fluoride species.

5.3.1.4 Sulfuric Acid Plant. The sulfuric acid plant will take the sulfur-containing gases from both the HGCU and the CGCU and will recover the sulfur in the form of sulfuric acid.

The sulfur in the CGCU gas is in the form of H_2S. The first processing step in the sulfuric acid plant is the oxidation of H_2S to SO_2 with air in the decomposition furnace. The gases leaving the furnace are combined with the HGCU feed gas, in which the sulfur is already in the form of SO_2. Oxygen is added to the gas before compression for flow through multiple catalyst beds where the SO_2 is converted to SO_3. The SO_3 is contacted with a circulating solution of sulfuric acid in a two-stage absorption process to form the product sulfuric acid.

5.3.2 Power Generation

The key components of the combined cycle are the advanced CT, HRSG, steam turbine (ST), and generators.

The HRSG is installed in the combustion turbine exhaust to complete the traditional combined cycle arrangement and provide steam to the 124 MW steam turbine.

No auxiliary firing is provided within the HRSG system. Hot exhaust from the CT will be channeled through the HRSG to recover the CT exhaust heat energy. The HRSG high and medium pressure steam production will be augmented by steam production in the coal gasification plant. All high pressure steam will be superheated in the HRSG before delivery to the high pressure section of the ST.

The ST will be designed as a double flow reheat turbine with low pressure crossover extraction. The ST generator will be designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1,400 psig and 990°F with 1,000°F reheat inlet temperature.

The operation of the combined cycle power plant will be coordinated and integrated with the operation of the gasification plant. The initial startup of the power block will be carried out on low-sulfur No. 2 fuel oil. Transfer to syngas will occur upon establishment of fuel production from the gasification plant.

Under normal operation, syngas from the gasification process and nitrogen from the ASU will be provided to the CT. The syngas/nitrogen mix at the CT combustion chamber will be regulated by the CT control system to control the NO_x emission levels from the unit.

Cold reheat steam from the high pressure turbine exhaust and HRSG intermediate pressure steam will be combined before reheating in the HRSG and subsequent admission to the intermediate pressure section of the ST. Some intermediate pressure steam will also be supplied to the HRSG from the sulfuric acid plant and the syngas cooling section of gasification.

PLANT SYSTEMS

6.0 PLANT SYSTEMS

The generalized flow diagram of IGCC systems and process has been given in Figure 5.3-1.

6.1 GASIFICATION

6.1.1 Gasifier System

The IGCC unit will use the Texaco proprietary oxygen-blown, entrained-flow, single-train gasification system to produce syngas for combustion in the advanced CT. Design processing rate is 2,000 tpd of coal, dry basis. While the gasification train will be the largest Texaco train in operation to date, the system involves commercially proven technologies, processes, and equipment.

Figure 6.1-1 presents the process flow schematic for the gasification system. As shown in this figure, coal slurry from the slurry feed tank and oxygen from the air separation unit will be fed to the gasifier and sent to the process burner. The gasifier will be a refractory lined vessel capable of withstanding high temperatures and pressures. The coal slurry and oxygen will react in the gasifier at high temperatures to produce syngas. The syngas will consist primarily of hydrogen, CO, water vapor, and CO_2, with small amounts of H_2S, COS, methane, argon, and nitrogen. Coal ash and unconverted carbon in the gasifier will form a liquid melt called slag.

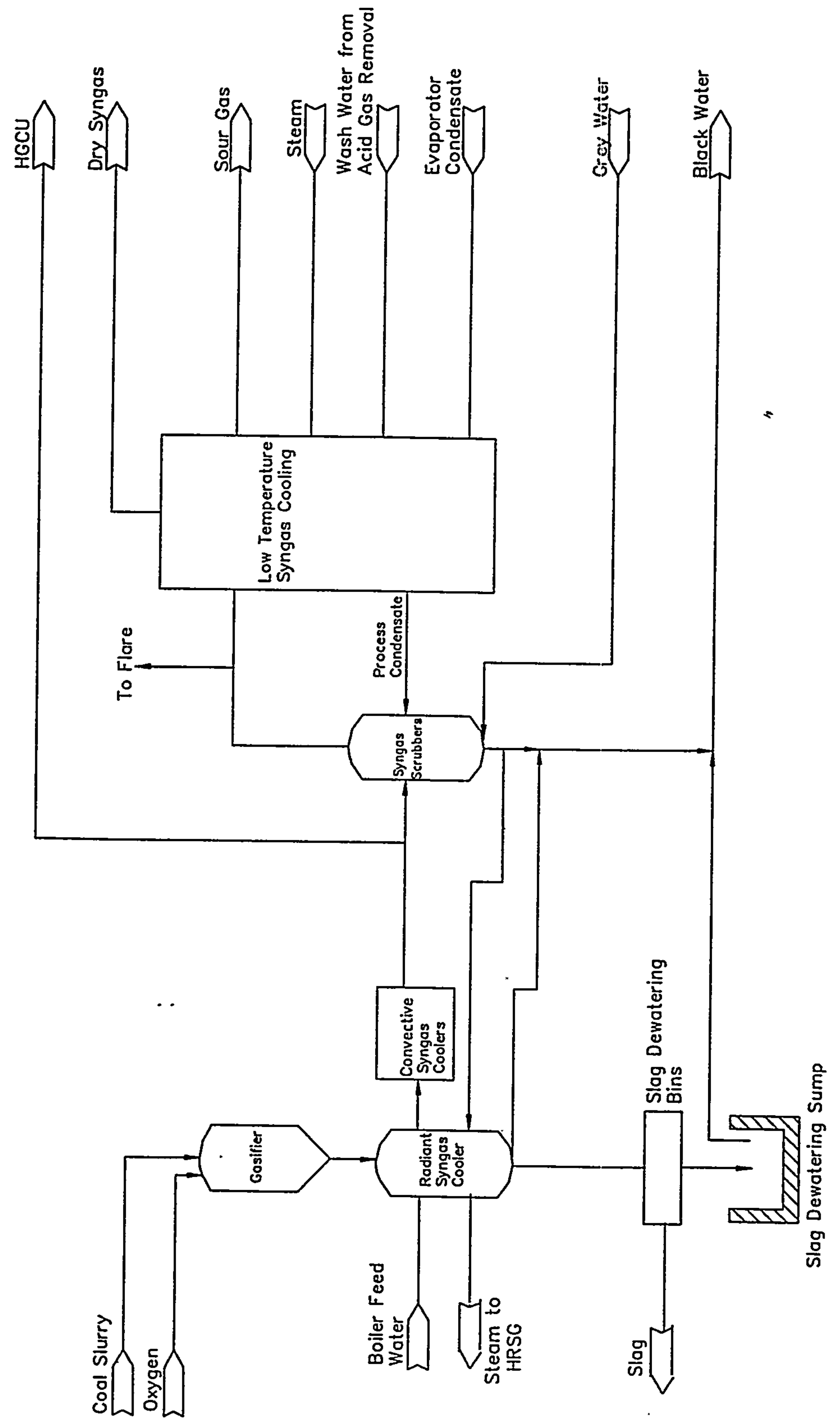
Hot syngas and slag from the gasifier will flow downward into a radiant syngas cooler, which is a high pressure steam generator equipped with a water wall to protect the vessel shell. Heat will be transferred primarily by radiation from the hot syngas to the boiler feed water circulating in the water wall. High pressure steam produced in this boiler will be routed to the HRSG in the power block area which will supplement the heat input from the CT to the HRSG and increase the efficiency of the generating unit.

The syngas will pass over the surface of a pool of water at the bottom of the radiant syngas cooler and exit the vessel. The raw syngas will then be sent to the convective coolers and then to the low temperature syngas cooling system in the CGCU system for further heat recovery and to the demonstration HGCU system. The slag will drop into the water pool and will be fed to the slag dewatering bins.

Gasification process water called black water will also collect with the slag in the bottom of the radiant syngas cooler and flow with the slag into the slag dewatering bins for separation of slag and water. The slag will be transferred to storage, while the water will be processed and reused.

Figure 6.1-1

GASIFICATION, SLAG HANDLING, AND SYNGAS COOLING SYSTEM SCHEMATIC



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6.1.2 Coal Handling, Grinding, and Slurry Preparation

The coal handling, grinding, and slurry preparation system for the IGCC unit will receive and prepare the coal for input to the gasifier. Figure 6.1-2 presents a schematic of this system.

Coal will be delivered to the site from a coal transloading facility at Tampa Electric Company's Big Bend Station. The coal will be delivered in covered, bottom-dump trucks with a 28-ton payload. A total of 80 to 100 trucks per day will be required at design rate. On the site, the trucks will off-load in an enclosed unloading structure into an above-grade unloading hopper. Dust suppression sprays will be provided at the top of the hopper to control dust emissions. Belt feeders will transfer coal from the hopper outlets onto an enclosed unloading conveyor.

The unloading conveyor will transport coal from the unloading structure up and into one of the two storage silos. A diverter gate and a silo feed conveyor will feed coal to the second, adjacent silo. A dust collection system will be provided at the top of the silos to collect dust at the conveyor/feeder/silo transfer points.

As shown in Figure 6.1-2 coal will be conveyed from the coal silos and fed to the grinding mill with recycled process water and makeup water from the water supply system. The grinding mill may also be fed fine coal recovered by the dust collecting system. Ammonia may be added to the mill for pH adjustment, if necessary. The pH of the slurry will be maintained between 6 and 8 to minimize corrosion in the carbon steel equipment. A slurry additive for reducing viscosity will also be pumped continuously to the grinding mill.

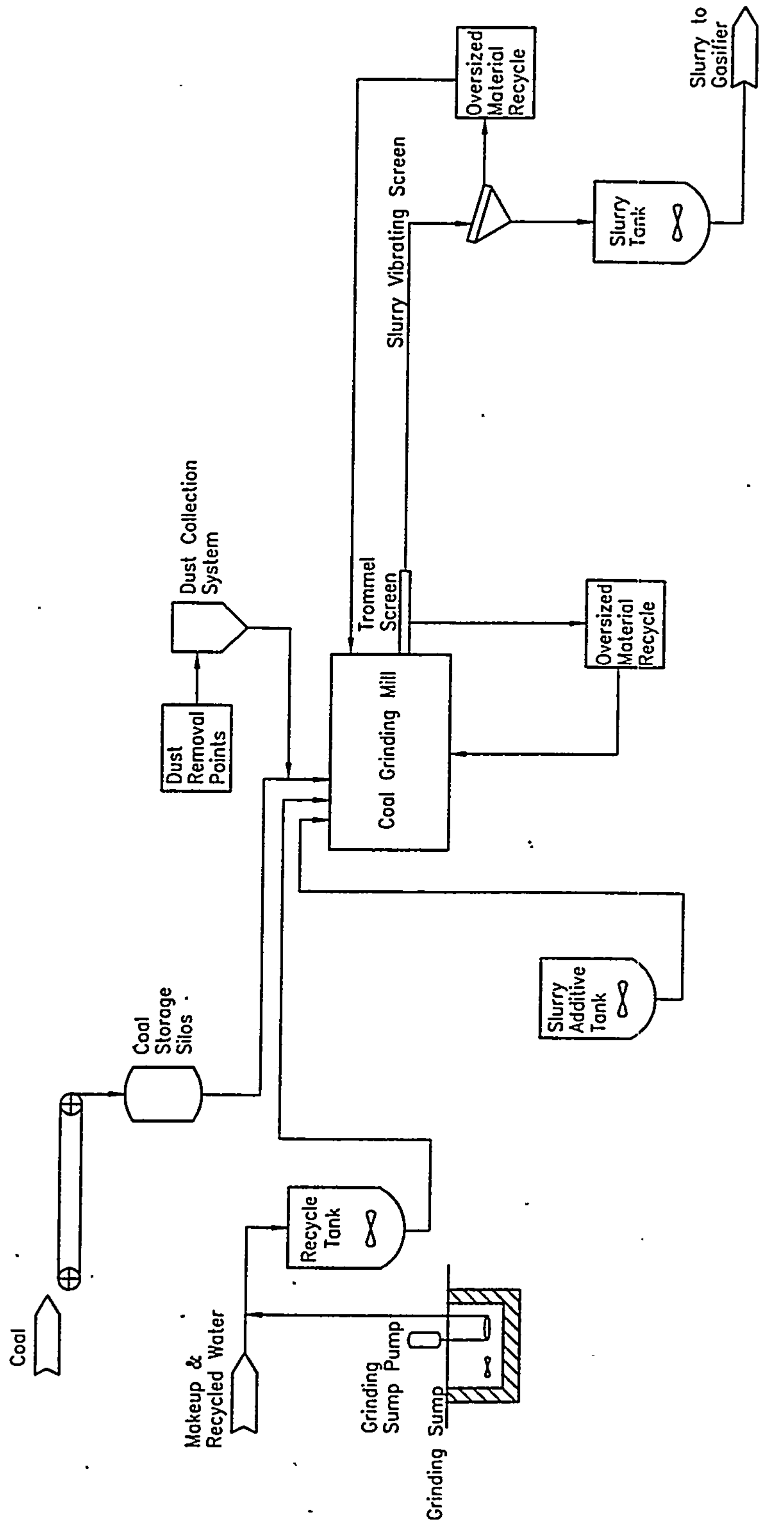
The grinding mill will reduce the feed coal to the design particle size distribution. The mill will be a conventional rod-type system with an overflow discharge of the slurry. Slurry discharged from the grinding mill will pass through a trommel screen and over a vibrating screen to remove any oversized particles before entering the slurry tank. Oversized particles will be recycled to the grinding mill.

A below-grade grinding sump will be located centrally within the coal grinding and slurry preparation area to handle and collect any slurry drains or spills in the area. Materials collected in the sump will be routed to the recycle tank for reuse in the process.

In order to minimize groundwater withdrawals and use, water for the slurry preparation system will be provided from several sources. Water for the system will be provided primarily by moisture contained in the coal feed, and by recycled feed and grinding sump water. Additional makeup water to the slurry system will be provided from the overall plant service water system. Through the collection and recycling process, there will be no water discharges from the coal grinding and slurry preparation system. All water from the system is fed to the gasifier in the coal slurry.

Figure 6.1-2

COAL GRINDING AND SLURRY PREPARATION SCHEMATIC



Potential particulate matter air emissions from the coal storage bin, grinding mill, and rod mill overflow discharge will primarily be controlled by the wet nature of these subsystems and by the use of enclosures for the subsystems with vents through fabric filters or baghouses. The slurry tank vents will be equipped with carbon canisters for absorption of potential H_2S or ammonia (NH_3) emissions.

6.2 COLD GAS CLEANUP (CGCU)

The raw, hot syngas from the gasifier will be routed to the separate conventional CGCU and demonstration HGCU systems for appropriate treatment. The CGCU system will be designed to treat 100 percent of the syngas flows for the unit, while the HGCU system will be capable of treating approximately 45,000 lb/hr of the syngas when the unit is operating at full capacity. The CGCU system is described in the following paragraphs, and descriptions of the HGCU system are provided in subsection 6.3.

The initial treatment process for the raw syngas within the CGCU system involves the syngas scrubbing and cooling systems.

The raw, hot syngas from the gasifier will contain entrained solids or fine slag particles which must be removed to produce the clean syngas fuel. Also, the raw hot syngas needs to be cooled in order to be effectively cleaned in the acid gas removal unit or CGCU system. The flow schematic for these syngas scrubbing and cooling processes is presented in Figure 6.1-1.

As shown, the raw hot syngas from the gasifier will be fed through the high temperature syngas cooling system to the syngas scrubbers where entrained solids are removed. The syngas will then be routed to the low temperature gas cooling section, where the syngas is cooled by recovering its useful heat by generating steam and preheating boiler feedwater. The syngas is further cooled with cooling water, which will extract much of the water from the syngas prior to its routing to the acid gas removal system.

The syngas scrubber bottoms streams will contain all the solids which were not removed in the radiant syngas cooler sump. The solids in the bottoms streams will be routed to the black water handling system.

In the gasification and slag handling systems, water removed from the slag contains fine particles of slag and ungasified solids. This process water is referred to as black water due to its coloration from the suspended particles. As discussed previously, the syngas scrubbers also generate black water, which contains the fine particles entrained in the syngas existing the gasifier and removed in the scrubbing process.

All black water from the gasification and syngas cleanup processes will be collected, processed, recycled to the extent possible, and contained within the processes. There will be no liquid discharges of these process waters to other systems or to the cooling reservoir. The effluent remaining after processing of this black water will be concentrated and crystallized into a solid consisting primarily of salt called brine which will be stored in a lined landfill on the site with an appropriately designed leachate collection system. The water separated from the salts will be recycled for slurrying coal feed.

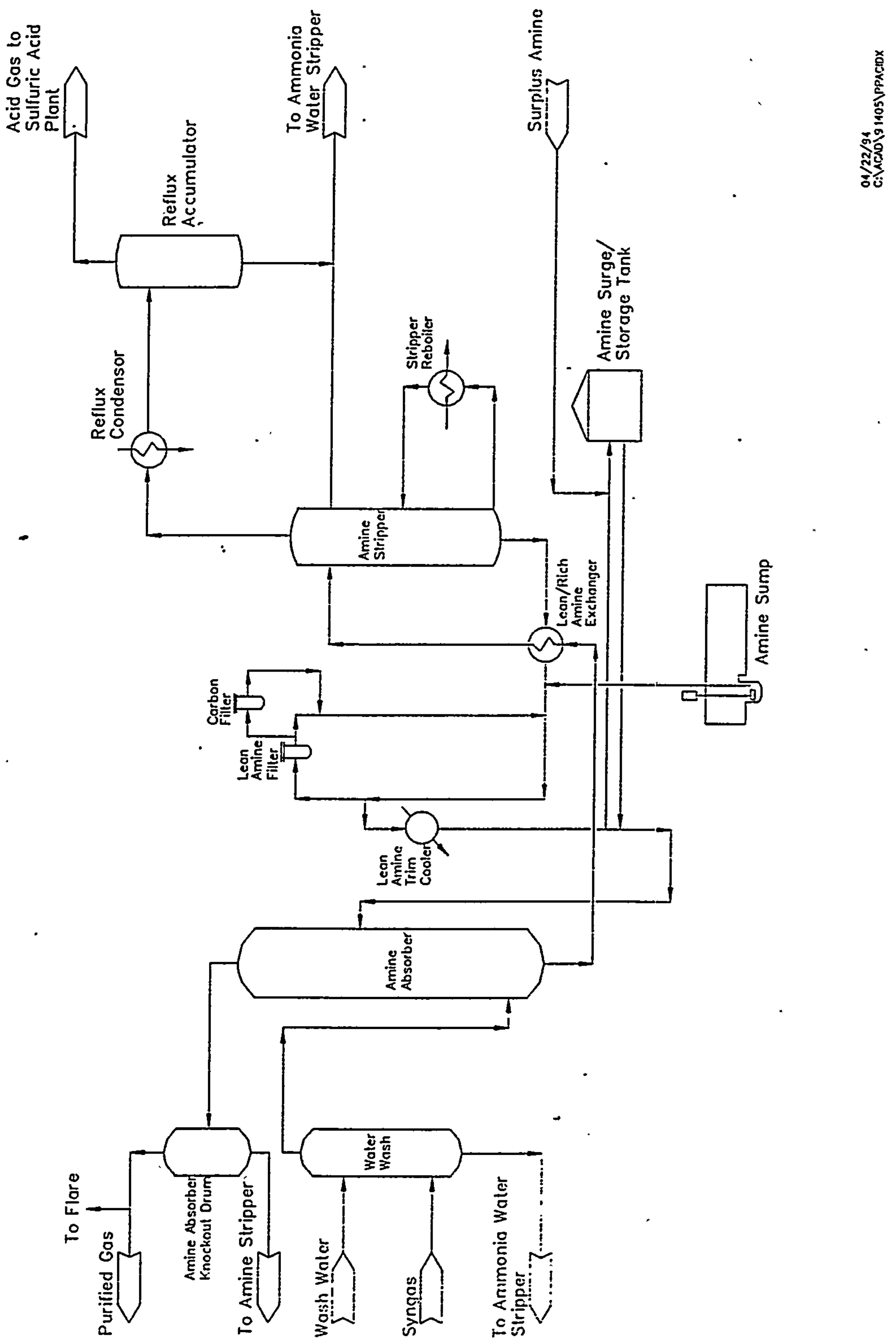
After removal of the entrained solids, the syngas will still contain sulfur compounds (H_2S and COS) which will be removed prior to firing the syngas in the advanced CT unit to control potential SO_2 air emissions. The acid gas removal unit will remove the acid gases from the syngas. The process flow schematic for this unit is provided in Figure 6.2-1.

In the acid gas removal unit, the cooled syngas will first be water-washed in the water wash column. Wash water will be pumped to the column to remove contaminants which would potentially degrade the amine from the syngas. The wash water from the column will be sent to the NH_3 water stripper. The washed syngas will then flow to the amine absorber.

The syngas will be contacted with amine in the amine absorber. Acting as a weak base, the amine will absorb acid gases such as H_2S by chemical reaction. The purified syngas will flow through a knockout drum to remove entrained amine. The recovered liquid will be returned to the amine stripper.

The rich amine will be stripped of the acid gas in the amine stripper by steam generated in the stripper reboiler. The acid gas overhead will be partially condensed by the reflux condenser and collected in the reflux accumulator. The acid gas, primarily H_2S and CO_2, from the reflux accumulator will go to the sulfuric acid plant and the condensed liquid reflux will be returned to the amine stripper.

Figure 6.2-1
ACID GAS REMOVAL UNIT SCHEMATIC



6.3 HOT GAS CLEANUP (HGCU)

A schematic of the HGCU system is presented in Figure 6.3-1. For the system demonstration, approximately 45,000 lb/hr of the hot raw syngas will be routed from the gasifier to the HGCU system for cleanup prior to firing in the combustion turbine.

6.3.1 Particulate Removal

Entrained fine particles in the hot syngas will be removed in the primary high efficiency cyclone as shown in Figure 6.3-1 and recycled to the black water handling system. Following this cyclone is a secondary cyclone whose function is to remove the sodium bicarbonate which is introduced upstream for halogen removal. The collected solids from the secondary cyclone will be sent to the onsite brine storage area. A large fraction of the remaining particulate matter (PM) entering the absorber will be captured by the sorbent bed, reducing particle concentration to below 30 ppm. A small amount of sorbent fines will be entrained from the absorber and collected in a high efficiency barrier filter. The barrier filter will effectively capture all of the high-density sorbent dust and will practically eliminate all fines larger than 5 microns. The high temperature barrier filter, employing pulse cleaning, will remove greater than 99.5 percent of the residual PM prior to the CT. The solids from the barrier filter are nonhazardous and will be sent offsite for disposal. Larger fines will be sieved on screens at the regenerator sorbent outlet. Fugitive fines from the screens will be collected in a small, low temperature bag filter. The sorbent fines from both collection points will be recycled to the catalyst supplier.

6.3.2 Desulfurization

The absorber is the intermittently moving bed reactor shown schematically in Figure 6.3-1. The sulfur-laden syngas from the primary cyclone will enter the absorber through a gas manifold at its bottom and flow upward countercurrent to the moving bed of sorbent pellets.

The sulfur compounds, mainly H_2S, in the syngas react with the sorbent according to:

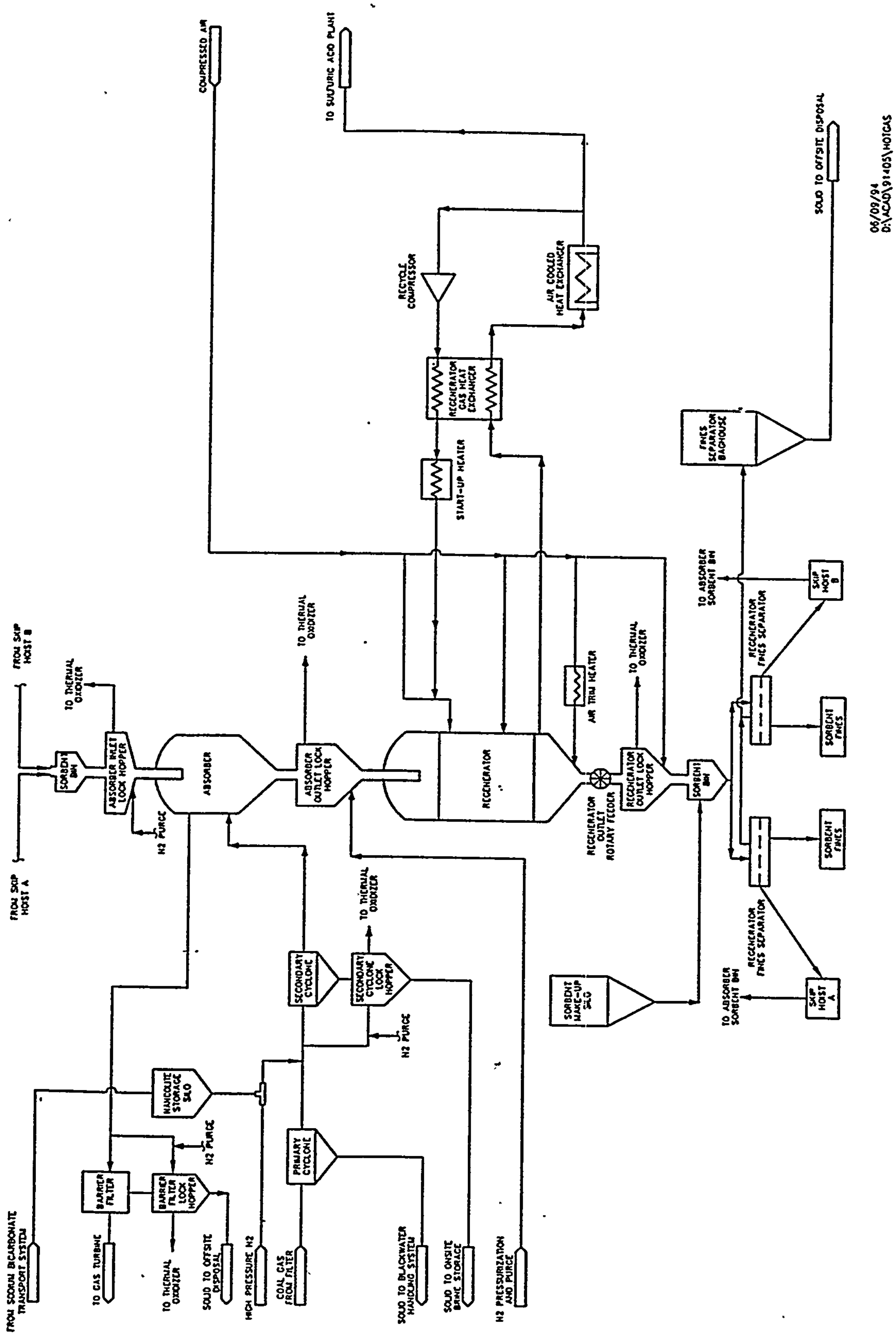
$$ZnO + H_2S \rightarrow ZnS + H_2O$$

The syngas leaving the absorber is expected to contain less than 30 ppmv of H_2S and COS.

The absorber bed will be stationary at low H_2S outlet concentrations and will be moved upon H_2S breakthrough. The H_2S breakthrough control signal will activate solids flow from the bottom of the absorber into the absorber's outlet lockhopper, causing the bed and the reaction zone to move downward by gravity. The displaced sulfided sorbent will be replaced by regenerated sorbent from the absorber's inlet lockhopper.

Figure 6.3-1

HOT GAS CLEANUP SYSTEM SCHEMATIC



6.3.3 Regeneration

The ability to regenerate and recycle the sorbent is essential for economically viable hot syngas desulfurization. The regeneration step is a highly exothermic oxidation process requiring careful temperature control. Too high a temperature will sinter and destroy the sorbent structure and reduce its ability to react with sulfur in consecutive absorption steps. Low temperature will result in sulfate formation and a loss of reactive sorbent to the desulfurization process.

The reactor will be divided into two stages: an upper stage and a lower stage. As the sorbent moves down the reactor, the reaction proceeds in a controlled atmosphere. Nearly continuous sorbent movement in the regenerator will be controlled by the rotary feeder at its bottom. The chemical reactions in the regenerator are:

$$ZnS + 1.5O_2 \rightarrow ZnO + SO_2$$

$$ZnO + SO_2 + 0.5O_2 \longleftrightarrow ZnSO_4$$

The sulfation reaction is reversible and favors the formation of sulfate at low temperatures in the presence of oxygen at the lower oxidation stage.

Sulfided sorbent will be fed from the absorber's outlet lockhopper to the top of the regenerator where oxidation of the sulfided sorbent occurs. The sorbent will move down the regenerator in cocurrent flow with the regeneration gas. Oxygen concentration will be controlled to limit the gas temperature.

The oxygen concentration will be controlled by the ratio of air to recycle gas to limit the temperature in the bed. The recycle flow rate will be controlled to maintain oxygen concentration in the upper stage.

The final polishing phase of regeneration will be accomplished at the lower stage of the regenerator where dry air flows countercurrent to the sorbent. This stream will cool the sorbent to a temperature acceptable for downstream equipment, purge the SO_2 - rich gas, and ensure complete regeneration. The gas streams from the cocurrent and countercurrent flows will mix to form the recycle gas stream.

6.3.4 Regeneration Gas Recycle Subsystem

The regeneration gas recycle is shown in Figure 6.3-1 and operates in a closed loop with dry air as an input and an SO_2 - rich gas as a product output. The regeneration gas recycle loop will be designed as an internal diluent that will reduce the oxygen concentration in the air to the desired levels without the use of externally provided diluents such as steam or nitrogen.. Using recycle rather than external inert diluent will also enrich the SO_2 concentration of the product stream.

The heat exchangers in the recycle loop will be designed to control the temperature of the regenerator inlet streams. The steam generator will remove the heat generated during the regeneration reaction by cooling the recycle gas stream. The recycle compressor will operate at a sufficient suction temperature to avoid H_2SO_4 condensation and a regenerative gas heat exchanger will reheat the compressed gas for recycle to the regeneration process. The heat of combustion of the sulfur will be transferred to the CC power block through the steam generated prior to recycle compression of the recycle gas stream.

6.3.5 Halogen Removal

Commercial grade sodium bicarbonate will be injected with a small quantity of high pressure nitrogen, upstream of the secondary cyclone as shown in Figure 6.3-1. Chloride and fluoride species will be removed by a direct contact reaction with sodium bicarbonate, forming stable salts, and removed by the secondary cyclone. These salts will be routed to the secondary cyclone hopper for disposal in the onsite brine disposal area.

6.4 COMBINED CYCLE POWER GENERATION

Key components of the combined cycle power generation area are the CT generator, HRSG, and ST generator.

6.4.1 Combustion Turbine-Generator

The CT is a GE 7F, designed for low-NO_x emissions firing syngas, with low sulfur fuel oil for startup and backup. Rated output from the hydrogen-cooled generator when the CT is firing syngas is 192 MW.

The syngas is delivered to the combustion turbine via control valves on the syngas fuel control skid. Nitrogen is used as the diluent to reduce the formation of NO_x in the exhaust gas. The flow of nitrogen to the combustor is regulated by valves on the nitrogen control skid.

When operating on the fuel oil backup, demineralized water is used as a diluent to reduce the formation of NO_x in the exhaust gas. The flow of fuel oil and demineralized water is controlled by a separate skid, the fuel forwarding skid.

6.4.2 Heat Recovery Steam Generator

The heat recovery steam generator recovers the combustion turbine exhaust heat to produce steam for the generation of additional power in the steam turbine. The HRSG will be of three-pressure level, reheat, natural circulation design. The HRSG generates high pressure (HP) superheated steam to supply the steam turbine and reheats the HP turbine exhaust steam for feed to the intermediate pressure (IP). The HRSG also generates IP steam which is combined with the HP turbine exhaust steam. Low pressure (LP) is generated for plant use in the latter sections of the HRSG, and boiler feed water (BFW) is preheated for additional heat recovery.

The HRSG consists of HP, reheat (RH), IP, and LP sections. The HP section heats BFW and generates superheated steam for feed to the HP steam turbine. It also provides HP economized BFW to the gasification area and receives HP saturated steam from gasification. The RH section combines HP turbine exhaust with IP superheated steam and adds superheat to the mixture for feed to the IP steam turbine. The IP section heats BFW and generates superheated steam to be mixed with cold reheat steam for feed to the RH section. The IP section also provides BFW and saturated steam to the fuel plant. The LP section heats and deaerates BFW for the HP and IP systems and provides saturated steam and deaerated LP feedwater for export to the gasification plant.

6.4.3 Steam Turbine Generator

The steam turbine generator is a double flow reheat unit with low pressure crossover extraction and a hydrogen-cooled generator. The steam turbine generator is designed specifically for highly efficient combined cycle operation with nominal turbine inlet conditions of approximately 1450 psig and 1000°F with 1000°F reheat inlet temperature. Rated capacity is 124.2 MW; rated speed is 3600 rpm. Expected output during normal operation is 122 MW.

The outlet from the last stage of the turbine is condensed by heat exchange with circulating water from the plant cooling water reservoir. Condensate from the steam turbine condenser will be returned to the HRSG/integral deaerator by way of the coal gasification facilities, where some condensate preheating occurs.

6.4.4 Condensate System

The condensate system operates in this combined cycle power plant to:

- Return condensed steam to the cycle by pumping condensate from the condenser hotwell to the deaerator.
- Condense the steam from the steam turbine gland seals and return the condensate to the cycle.

- Provide sources of condensate to various miscellaneous systems.

- Provide a dump to condensate storage tank on a high hotwell level, and to provide condensate makeup to the condenser hotwell.

Condensate pump operation is required during combined cycle operation. One of the two 100 percent capacity condensate pumps is always in service during normal plant operation, while the other condensate pump is in the "auto" standby mode.

The auto standby condensate pump is started when the condensate system header pressure drops below the setpoint, as sensed by a pressure switch.

The condensate pump transfers condensate from the condenser hotwell through the gland seal condenser to the LP economizer by way of a heating loop in the gasification plant.

A minimum flow recirculation to the condenser is controlled by a recirculation flow control valve which protects the condensate pumps by keeping the flow rate above minimum requirements, when the system demand is low.

A hotwell dump line is connected from the condensate discharge line to the condensate storage tank for returning condensate in the event of a high level in the hotwell. Condensate supply to the hotwell is by way of vacuum drag under normal operation, and by the condensate make-up pump otherwise.

The condensate pumps also supply water to the:

- Steam Turbine Exhaust Hood Spray System

- Vacuum Pump Seals

- Condensate Receiver

- Condensate Return Unit

- Gland Seal Emergency Spray

- HRSG Chemical Injection Equipment

- Closed Cooling Water Head Tank

- Feedwater Pump Seals

6.4.5 Electrical Power Distribution System

For plant startup and periods when the plant is down, power is received at 230 KV and is backfed through the generator step-up transformers with the generator breakers in the open position. This provides power to the station 13.8 KV auxiliary transformers. The station 13.8 KV switchgear distributes power at 13.8 KV to the various plant loads including the power block 4160V and 480V auxiliary transformers. The 4160V switchgear provides power to the combustion turbine static starting system and to the 4160V motors.

During startup, power is back-fed through the CT generator step-up transformer or the steam turbine generator step-up transformer to power up the static starting unit. Once the combustion turbine is up to speed and self sustaining, the static starter is deenergized, and the generator can be synchronized to the 230 KV system by closing the 18 KV generator breaker. Similarly, when the steam turbine generator is up to speed, it can be synchronized to the 230 KV system by closing the appropriate 230 KV switchyard breakers first and then the steam turbine generator breaker.

Once the combustion turbine is started up and synchronized to the system, the combustion turbine can provide power to all of the station loads through the station 13.8 KV power distribution systems.

The 480V switchgear distributes power to the various 480V motors and motor control centers associated with the operation of the power generation system.

The power block 125VDC requirements are provided from two batteries. One battery is dedicated to the combustion turbine and is contained in the packaged electrical and electronic control cab. Other 125 VDC loads associated with the power generation are served from the station battery system.

Power will be generated at 18 KV by the combustion turbine generator and at 13.8 KV by the steam turbine generator.

Each generator is connected via iso-phase bus duct to its respective generator step-up transformer through an SF6 generator breaker and disconnect switch. Bus duct taps are provided for connection to the station auxiliary transformers.

6.5 AIR SEPARATION UNIT

The air separation unit will use ambient air to produce oxygen for use in the gasification system and sulfuric acid plant, and nitrogen which will be sent to the advanced CT.

Figure 6.5-1 presents process flow schematics of the air separation unit. As shown in the figure, ambient air will be filtered in a two-stage air filter designed to remove particulate material. The first filter stage will consist of a fixed panel filter; the second filter stage will consist of removable elements, which are periodically replaced. The air will then be compressed in a multistage centrifugal air compressor equipped with inter-cooling between stages and a condensate removal system.

The compressed air will be cooled in an aftercooler. Chilled air from the aftercooler will be fed to the molecular sieve contaminant adsorbers. The molecular sieves will remove impurities, such as water vapor, CO_2, and some hydrocarbons from the air. The air will then be filtered in the dust filter to remove any entrained molecular sieve particles. Adsorbent regeneration gas will then be recovered and reused as CT diluent.

The air from the adsorbers will be fed to the cold box where it is cooled against returning gaseous product streams in a primary heat exchanger (PHX). A small fraction of the air will be extracted from the PHX and expanded to provide refrigeration for the cryogenic process. The expanded air will then be fed to the low pressure distillation column for separation.

The remaining air will exit the cold end of the PHX a few degrees above its dewpoint. The air will be fed to the high pressure distillation column where it will be separated into a gaseous nitrogen vapor and an oxygen-enriched liquid stream. The nitrogen vapor will be condensed in the high pressure distillation column condenser against boiling liquid oxygen. The liquid nitrogen will be used as reflux in the high and low pressure distillation columns.

Oxygen and nitrogen will be produced in the low pressure distillation column. Heat from the condensing nitrogen vapor will provide reboiler action in the liquid oxygen pool at the bottom of the low pressure distillation column. The oxygen vapor will be warmed to near-ambient temperature in the PHX and fed to the oxygen compressor, where it will be compressed to the pressure required by the gasification unit.

Nitrogen vapor from the low pressure distillation column will be warmed to near-ambient temperature in the PHX, and sent to the advanced CT.

As backup to the air separation unit, a liquid nitrogen storage system will be provided for system purging and maintaining low temperature in the cold box. The backup liquid nitrogen system will be maintained in a cold, ready-to-start state.

Figure 6.5-1

AIR SEPARATION UNIT SCHEMATIC
(Page 1 of 2)

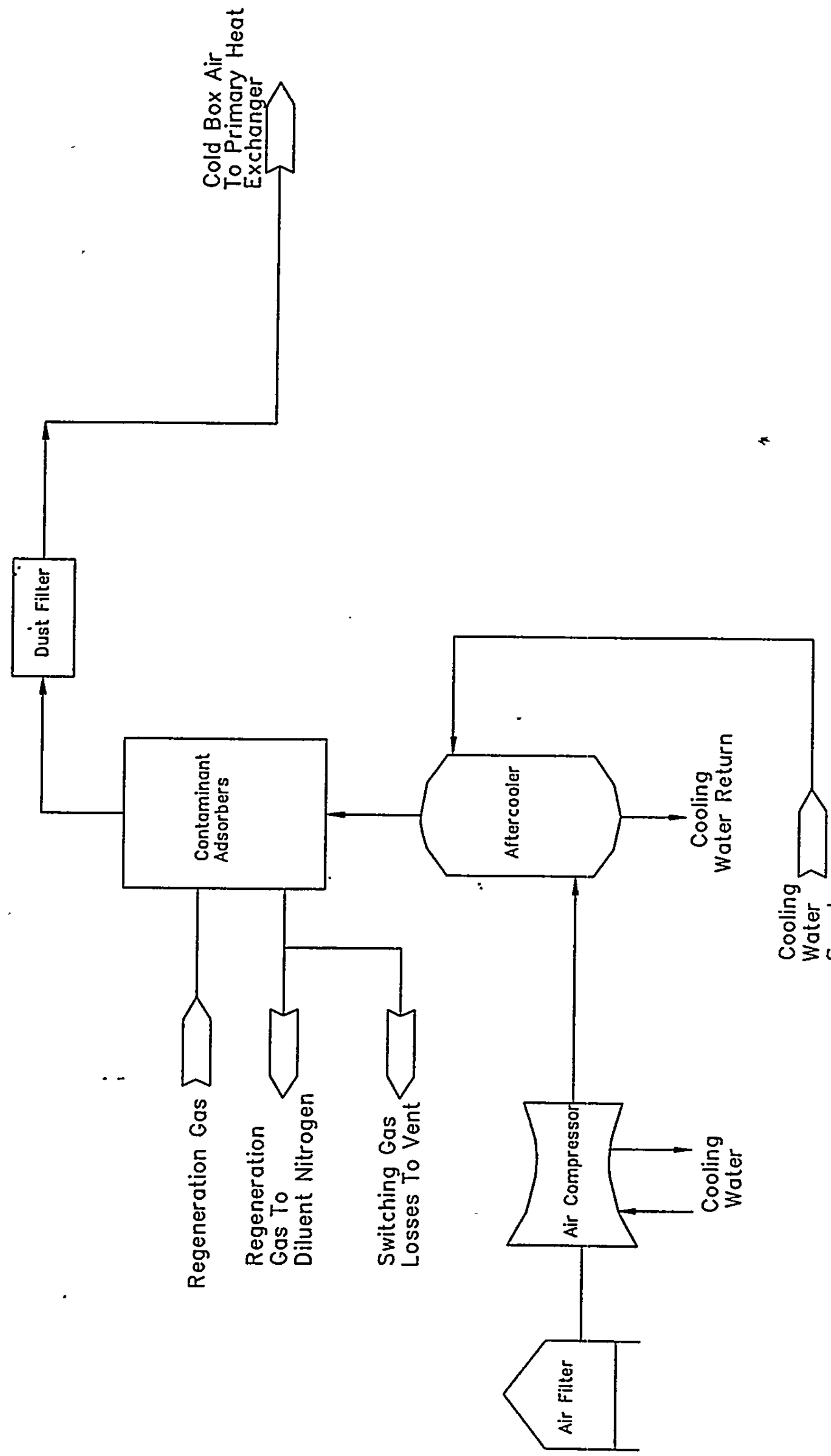
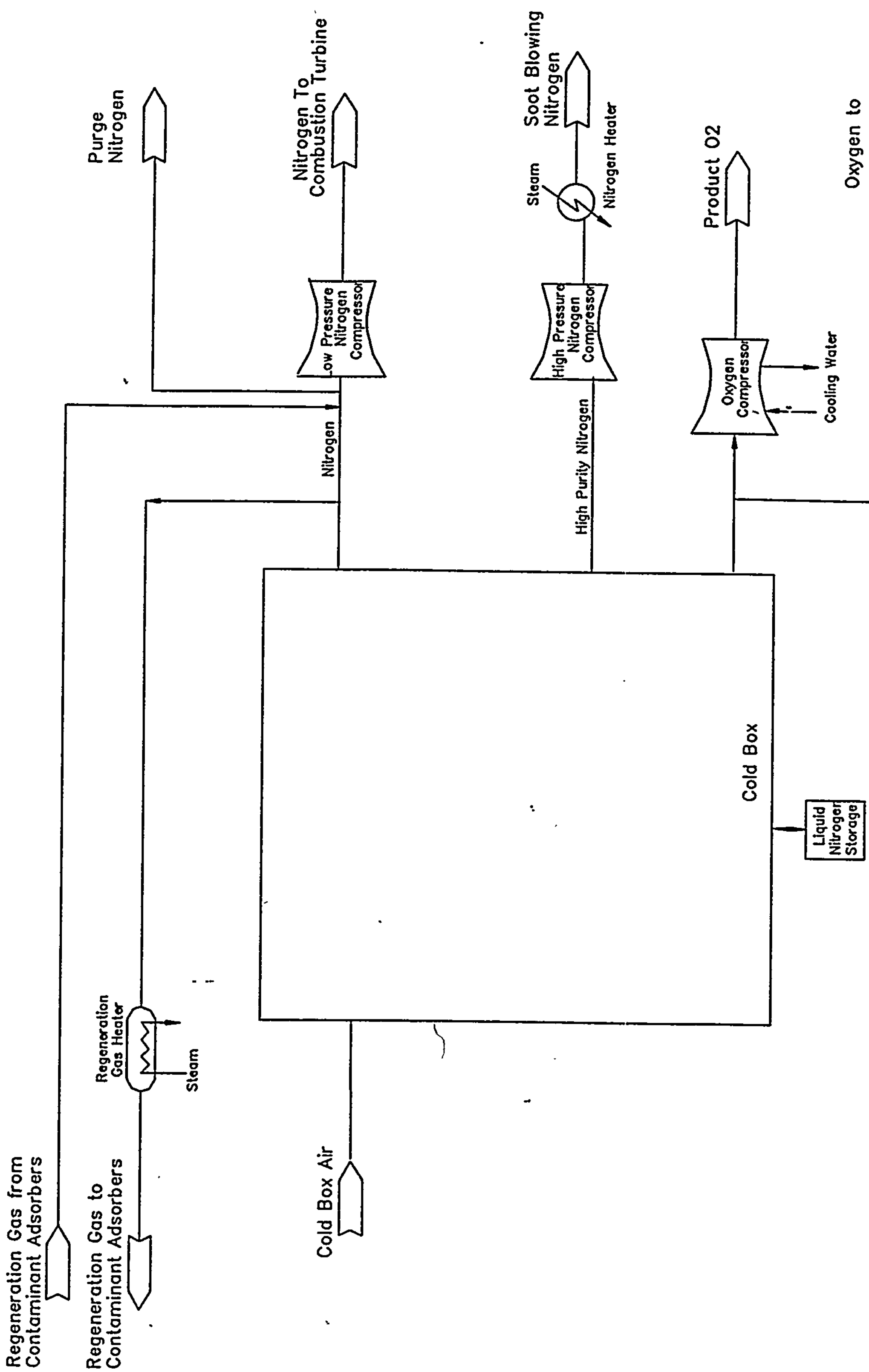


Figure 6.5-1
AIR SEPARATION UNIT SCHEMATIC
(Page 2 of 2)



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The air separation unit process will not consume water and will produce only minor amounts of water from condensation in the main air compressor aftercooler. This water will be sent to IWT. The unit will require water only for noncontact cooling purposes which will be provided from the makeup water system and/or the cooling reservoir.

6.6 BY-PRODUCT HANDLING

6.6.1 Slag

The slag handling system will remove ungasified solids from the gasification process equipment. These solids consist of the coal ash and unconverted coal components (primarily carbon) that exit the gasifier in the solid phase. The schematic presented in Figure 6.1-1 also shows the slag handling process flow.

In the gasification system, coarse solids and some of the fine solids will be flushed from the radiant cooler into the slag dewatering bin. Solids flushed to the slag dewatering bin will be piled and be dewatered by gravity into the slag dewatering sump. The concrete dewatering bin will be bunkered to prevent runoff from the area. From the dewatering bin, the slag will either be loaded into trucks for transport and use offsite or transported to the temporary, onsite slag storage area which is described in subsection 6.6.2. The water removed from the slag and bins will be pumped to the gasification process black water handling and processing system.

Again, all waters produced in this slag handling system will be collected and routed to the black water handling system for processing reuse. Also, potential particulate matter air emissions from the system will be minimal due to the wet nature of the slag and processes.

This system will generate the coarse slag material at a maximum rate of approximately 210 short-tons per day (stpd) on a dry basis and the material will contain approximately 25 percent moisture. The slag is classified as nonhazardous and nonleachable and will be marketed and sold for various offsite commercial uses such as abrasives, roof material, industrial filler, concrete aggregate, or road base material.

6.6.2 Slag Storage Area

During periods when the slag by-product cannot be sold in a timely manner, a temporary storage area will be developed on the site. Initially, an area will be developed to be capable of storing slag generated by approximately 2-1/2 years of operation of the IGCC unit at full capacity. An additional 2-1/2 year storage area will be developed as needed in the unexpected event that sales of the slag for offsite uses are less than the slag production rates. The temporary slag storage area shown on the site layouts in Figures 5.1-1 and 5.2-1 would provide sufficient capacity for developing storage cells for up to five years of slag production from the IGCC unit operating at 100-percent capacity. The slag storage area will include a stormwater runoff collection basin and surrounding berm to prevent runoff from reentering the area. Both the slag storage area and the runoff collection basin will be lined with a synthetic material or other materials with similar low permeability characteristics. The runoff basin will be designed to contain runoff water volumes equivalent to 1.5 times the 25-year, 24-hour storm event. Water collected in the runoff basin will be routed to the industrial wastewater treatment (IWT) system for filtration.

6.6.3 Sulfuric Acid

The sulfuric acid plant converts gaseous sulfur compounds from the hot and cold gas cleanup systems to sulfuric acid by-product for sale to the local Florida fertilizer industry. The conversion of these gases involves a multi-step catalytic process based on proven technology in widespread commercial use.

In the HGCU process, an acid gas is produced which has a high SO_2 concentration. In the CGCU process, hydrogen sulfide (H_2S) containing gases from the acid gas removal unit and the NH_3 stripping unit will be routed through knockout drums to remove any entrained water. The CGCU gases will then be introduced into the decomposition furnace, along with combustion air. Supplemental fuel may be added to maintain the proper operating temperature. The air may be preheated to reduce the volume of fuel and thereby combustion products. Hot gases from the HGCU unit will be introduced into the system downstream of the decomposition furnace and mix with the combusted acid gas from the CGCU unit.

The mixed gases from the CGCU and HGCU systems will be cooled in a waste heat boiler, recovering as much usable energy as possible. The boiler steam side will operate at 400 psig to avoid condensing acid in the tubes. The gases from the waste heat boiler will be cooled in a quench tower with a circulating stream of weak acid, i.e., a conventional open spray tower. The gas then flows through the gas cooling tower, a packed column, for further cooling and water condensation.

Reaction air in the form of low-pressure 95% purity oxygen will be added to the process stream to provide the required amount of oxygen for the SO_2 to SO_3 reaction.

The gases leaving the cleaning and cooling system and the reaction air will flow to a drying tower, where the remaining water is removed. The gases from the drying tower will go to the main blower, which provides the necessary pressure for flow through the reactor beds and absorber towers.

The gases from the blower will then be heated in the reactor feed/effluent exchangers to achieve the proper reaction temperature and sent through catalytic reactor beds. There will be additional heat removal and recovery equipment in the reactor section between the reactor beds. An indirect propane-fired heater will be used to supplement the reaction heat for startup. The gases from the reactor will be cooled and sent to the absorber towers, where 98-percent acid absorbs the SO_3 from the process gas stream. The high concentration H_2SO_4 will be circulated from the absorber towers bottoms, through the acid coolers, and then returned to the top of the absorber towers. The gases from the absorber towers will pass through mist eliminators to remove acid mist, and the gas from the final absorber tower will then be vented to atmosphere.

The H_2SO_4 unit will be constructed adjacent to the gasification facilities on the site. The facilities will include an aboveground tank to provide for temporary storage of the H_2SO_4 by-product and appropriate handling and loading equipment. The H_2SO_4 will be transported offsite in specially designed rail cars or trucks for commercial use. The unit would produce approximately 77,000 tons per year (tpy) of liquid H_2SO_4 by-product.

6.6.4 Sulfuric Acid Storage Facilities

Both the CGCU acid gas treatment system and the demonstration HGCU system produce offgases containing sulfur compounds which will require treatment. These offgases will be treated by converting the sulfur compounds in the gas to H_2SO_4 which is a marketable by-product especially with the central Florida chemical fertilizer industry.

The H_2SO_4 by-product will be produced in a H_2SO_4 plant. As necessary, the H_2SO_4 will be temporarily stored onsite in a tank or in specially designed railcars prior to shipment offsite. The fixed storage tank will provide for 5 days of storage on the site.

Stormwater runoff from the H_2SO_4 storage, handling, and loading area will be directed to the IWT system for appropriate treatment prior to being routed to the cooling reservoir for reuse.

6.7 BALANCE OF PLANT SYSTEMS

6.7.1 Cooling Water

The steam electric generating components of the IGCC unit require water to cool or condense the exhaust steam from the ST. Cooling water is also required for gasification, ASU, sulfuric acid, and other miscellaneous users. The waste heat transferred to the cooling water must then be rejected to the atmosphere. The cooling/heat rejection system for the Polk Power Station will be a cooling reservoir.

The cooling reservoir will be constructed in areas which have been mined for phosphate and currently consist of water-filled mine cuts between rows of overburden spoil piles. The reservoir will occupy an area of approximately 860 acres, including the areas of the surrounding and internal earthen berms. The reservoir will be a primarily below-grade facility after final contouring and development of the site. The maximum elevation of the bottom of the reservoir will be approximately 123 feet with an average elevation of 120 feet, and the top of the surrounding berms will be 145 feet. The internal berms will have a top elevation of approximately 141 feet. The finish grade on the main power plant facility area will be between 140 and 145 feet. Under normal operating conditions, water levels in the reservoir will be approximately 136 feet, and the total water surface area will be approximately 727 acres. Reference point for the elevations given is mean sea level.

The top of the surrounding and internal earthen berms will be approximately 25 and 17 feet wide, respectively, to provide access for inspection and maintenance purposes. The berms will be constructed with gentle slopes (4 feet horizontal to 1 foot vertical) to minimize potential erosion and visual quality effects. The berms will also be re-vegetated after construction and the vegetation will be appropriately controlled and maintained to prevent future erosion.

Intake and discharge structures to provide and subsequently discharge the cooling water will be constructed within the cooling reservoir. The estimated circulating cooling water flow requirements are approximately 130,000 gpm for the steam turbine condenser and 40,000 gpm for the remainder of the plant including the air separation unit. One set of two 50 percent pumps will supply water for the condenser, and another set of two 50 percent pumps will supply water for the other users. This warmed return water will be routed throughout the reservoir area by the internal berm system and cooled through evaporation prior to intake and reuse in the system.

For users that require higher quality water than that provided by the cooling reservoir, two closed loop cooling water systems are provided: one for the power generation area and one for the gasification area. Heat is rejected from these loops to the reservoir cooling water.

6.7.2 Fuel Oil Storage

The plant has storage for 3,000,000 gallons of No. 2 fuel oil, which is used to fire the auxiliary boiler and the combustion turbine when gasification is down.

Fuel oil is unloaded from the tank trucks and pumped by the fuel oil truck unloading pumps to the fuel oil storage tank. From the fuel oil storage tank, the fuel oil is pumped to either the combustion turbine fuel forwarding skid or to the auxiliary boiler.

The unloading area is curbed and the storage tank area is diked. All rainfall and spills in these areas are collected and sent to an oily-water separation system.

6.7.3 Utility Summary

Major plant utility requirements are power, steam, cooling water, well water, propane, and No. 2 fuel oil. The consumptions of these units are summarized in Table 6.1.

Table 6.1

SUMMARY OF ESTIMATED UTILITY CONSUMPTION

Area	Motor HP	Electricity (KW)	Steam (1000) Lb/hr			Water (GPM)		Fuel (Lb/Hr)	
			LP	IP	HP	Well	Cooling	Propane	Fuel Oil
Gasification Area	2,176	1,299	18.0	(8.8)	(496.1)	0	4,598	884*	0
Acid Gas Removal	403	241	38.9	0.0	0.0	0	5,989	0	0
Sulfuric Acid Plant	1,137	679	0.0	(25.7)	0.0	0	4,600		926
Air Separation Plant	78,700	54,300	7.0	0.0	0.0	0	17,340	0	0
Hot Gas Cleanup	1,137	679	0.0	0.0	0.0	0	210	0	0
Brine Concentration Area	789	471	8.1	0.0	0.0	0	1,482	0	0
Coal Handling/Slurry Prep	2,158	1,288	2.0	0.0	0.0	0	0	0	0
Power Block	4,928	2,941	0.0	0.0	0.0	0	134,295	0	81,500*
Utility	3,661	2,185	(3.5)	0.0	0.0	1,300	415	46	2,766*
Total	95,089	64,081	70.5	(34.5)	(496.1)	1,300	168,719	46	926

* Indicates intermittent consumption, not included in totals
() Indicates normal utility production

6.8 DISTRIBUTED CONTROL SYSTEM

The Distributed Control System (DCS) planned for Polk Power Station Unit 1 is a highly modular, microprocessor based system which will provide both continuous and sequential control for most of the equipment at the station. Approximately 5000 inputs and outputs will be connected to the DCS. Typical input signals include pump and motor vibrations, pressure and level transmitters, process analyzers, and relay contacts. The operator interface will be through color CRT and operator consoles located in the main control room. With the operator interface the operator may adjust unit loads, start and stop motors, monitor and trend all plant operations. All plant alarming will be directed through the DCS and indicated on CRT screens and printers.

Control graphics are the key to controlling plant processes. Since the overall plant logic has been designed so that most equipment can be started or stopped from the control room graphics, local control panels will be kept to a minimum.

The DCS will be used in integrating the different plant areas. For example, a decrease in the output of the air separation unit would effect equipment in other areas. The DCS will automatically adjust the gasifier output or power block generation to compensate for air plant changes.

Process Control Units contain the plant operating configuration. These units are distributed throughout the plant. Communication between the Process Control Units, Operators Consoles and the VAX historian computer is accomplished through redundant fiber optic cables creating a plantwide communication network. This network has also been designed to include communication with other plant control units such as the Mark V turbine control systems and the Gasification Emergency Shutdown System.

The historian will have two major functions. First, the historian will contain steam and gas property libraries for use in a variety of calculations. These calculations include efficiency for a particular piece or stage of equipment, overall area, and unit efficiencies. Secondly, the historian will provide long term storage of all important data plantwide. Sequence of events will be stored and displayed for identifying the cause of plant shutdowns. Long term storage of critical data is used to identify the degradation in equipment performance. Maintenance schedulers rely on this information. Alarm histories and operator event logs are used to improve or correct operating practices.

6.9 EMERGENCY SHUTDOWN SYSTEM

The Emergency Shutdown System (ESD) planned for the Polk Power Station is a Triple Modular Redundant (TMR) Architecture, Fault tolerant, microprocessor based system which will provide for equipment and personnel protection in the Gasifier and Coal Slurry areas.

Approximately 250 inputs and outputs will be connected to the ESD System. Many of the inputs to the system will be triplicate measurements of the same process parameter, and many of the outputs are to dual in-line solenoid valves in the field. ESD System solenoids are connected to control valve pneumatic signal lines, and, when deenergized due to a trip condition detected by the ESD program, vent the control valves to their fail-safe positions.

The ESD system will include an engineering workstation for program development. The primary operator interface to the system will be through a one-way serial communication link from the ESD system to the Distributed Control System (DCS). Any required communication from the DCS to the ESD System will be hard-wired. Communications from the ESD system to the DCS will include transmitter readings, process alarms, first-out alarms, trip alarms, and system diagnostic alarms.

The TMR architecture of the ESD system with all functions of the system triplicated into three separate operational legs, provides the fault tolerance required for this safety application. No single point of failure will cause the system to fail. Extensive diagnostic capabilities will help maintenance personnel pinpoint any faults in any one of the three legs of the system. TMR input/output boards can be replaced online without affecting the process and without the need for shutting down the system. The calculated system reliability is greater than 99.99%