APPLICANT INFORMATION

Applicant's Official Name: Tampa Electric Company

Address: Post Office Box 111, Tampa, Florida 33601-0111

Address of Official Headquarters: 702 North Franklin Street, Tampa, Florida 33602

Business Entity (corporation, partnership, cooperative): Corporation

Names, Owners, etc.: Tampa Electric Company

Name and Title of Chief Executive Officer: G.F. Anderson, President

Name, Address, and Phone Number of Official Representative Responsible for Obtaining Certification: A. Spencer Autry, Director, Environmental, Tampa Electric Company, P.O. Box 111, Tampa, Florida 33601-0111 813/228-4111

Site Location (County): Polk County, Florida

Nearest Incorporated City: Bowling Green

Latitude and Longitude: Latitude 27° 43' 43", Longitude 81° 59' 23"

UTMs Northerly: 3067.35

UTMs Easterly: 402.45

Section, Township, Range: All or portions of Sections 1 through 4 and 7 through 12, Township 32 South, Range 23 East and Sections 34 and 35, Township 31 South, Range 23 East

Location of Any Directly Associated Transmission Facilities (Counties): Polk County

Name Plate Generating Capacity: 1,150 megawatts (nominal net)

Capacity of Proposed Additions and Ultimate Site Capacity (where applicable): 1,150 megawatts (nominal net)

SITE CERTIFICATION APPLICATION
FOR
TAMPA ELECTRIC COMPANY
POLK POWER STATION PROJECT

Environmental Consulting &
Technology, Inc.
5200 Newberry Road, Suite E-1
Gainesville, Florida 32607

Thomas W. Davis
7/25/92
Thomas W. Davis, P.E.
Florida No. 36777

United Engineers & Constructors, Inc.
30 South 17th Street
Philadelphia, Pennsylvania 19101

Raymond A. Rizzi
7-24-92
Raymond A. Rizzi, P.E.
Florida No. 21834

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

Gregory M. Nelson
7/23/92
Gregory M. Nelson, P.E.
Florida No. 44078

1.4.3 GENERAL PROJECT DESCRIPTION

Tampa Electric Company is planning to construct and operate new electric generating units at the Polk Power Station site with units added according to a phased schedule designed to match the projected growth of Tampa Electric Company's Customer power demands, and subject to obtaining need for power certifications from the FPSC. The total nominal generating capacity of the units at the site will be approximately 1,150 MW. The first generating facilities at the Polk Power Station site will be an IGCC unit developed by Tampa Electric Company supported in part through funding from DOE under the Clean Coal Technology Demonstration program. The coal-fueled facilities will consist of a nominal net 150-MW advanced CT, initially fueled by low sulfur No. 2 fuel oil, with HRSG, ST, and CG facilities added 1 year later to complete the nominal net 260-MW IGCC unit. Tampa Electric Company's current long-range power resource planning efforts indicate that later facilities will consist of two nominal net 220-MW CC generating units and six stand-alone nominal net 75-MW CTs fueled primarily by natural gas with low sulfur No. 2 fuel oil as the backup fuel.

The IGCC facilities will consist of an oxygen-blown entrained flow gasification system to produce syngas fuel for the CT. The planned CG system is based on the Texaco, Inc. (Texaco) commercially available technology. The CC power block facilities are based on a General Electric Company (GE) advanced nominal net 150-MW 7F CT and nominal net 70-MW HRSG/ST configuration. The GE 7F CT is expected to be capable of a nominal net 190-MW capacity when operating with the coal gasifier and air separation unit. The other two CC units are based on a configuration of two nominal net 75-MW CTs with a nominal net 70-MW HRSG/ST facilities. The six stand-alone CTs are currently assumed to be nominal net 75-MW units.

The primary power plant facilities (i.e., power block and fuel storage) will be located on unmined land on the east side of SR 37. The surrounding mined-out land to the east and south of the plant facilities will be developed as a primarily below-grade cooling reservoir surrounded by a low-profile earthen berm with a top elevation of

145 feet National Geodetic Vertical Datum (ft-NGVD). Potable and process water will be provided by onsite wells. Stormwater runoff on the plant site will be collected, detained, recycled, and treated, as appropriate, in accordance with applicable regulations. The current designs for the plant systems are based on criteria to maximize plant water recycling and re-use, and to minimize groundwater withdrawals and offsite discharges. Discharges from the cooling reservoir will be routed to the Little Payne Creek drainage system.

Tampa Electric Company will be its own provider for most utilities at the Polk Power Station. Electricity, potable water, and sanitary sewerage treatment services will be provided by onsite facilities. Therefore, no interconnection to or demands on public utilities for these services will be created by the operation of the project. Domestic, construction, and certain industrial solid waste disposal services will be provided by licensed waste carriers/disposal contractors serving the region.

Four 230-kilovolt (kV) electric transmission circuits will be needed to connect the Polk Power Station with the Tampa Electric Company and Florida transmission grid. Two of the circuits will run northeast from the onsite Polk Power Station Substation to interconnect with Tampa Electric Company's existing Hardee Power Station-Pebbledale 230-kV transmission line adjacent to the Polk Power Station site along Fort Green Road. Thus, the corridor for these two circuits will be located within the site boundaries. The other two circuits will run west from the onsite substation to SR 37, then north along SR 37 approximately 5 miles to interconnect with Tampa Electric Company's existing Mines-Pebbledale 230-kV transmission line at a point to the west of the community of Bradley Junction. These two circuits will be located within a new transmission line corridor adjacent to SR 37.

As part of the development activities for the Polk Power Station, reclamation of lands disturbed by phosphate mining will occur in accordance with the requirements of Section 211, F.S., and Chapter 16C-16, F.A.C., and the Polk County Phosphate Mining Ordinance 88-19. The state reclamation requirements are administered by

FDNR. Tampa Electric Company will submit to FDNR and Polk County appropriate modifications to the currently-approved mine reclamation plans for the site which integrate the planned power plants and associated facilities while complying with FDNR and Polk County reclamation requirements. Chapter 9.0 of this SCA presents a summary of Tampa Electric Company's proposed plans to comply with the FDNR and Polk County mined land reclamation requirements. A separate document entitled Conceptual Reclamation Plan Application has also been submitted to FDNR and Polk County which includes more detailed information on the proposed reclamation plans and appropriate forms to modify existing, approved reclamation plans for the site under FDNR requirements.

1.4.4 CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

The DOE Clean Coal Technology Demonstration program is a government- and industry-cofunded technology development effort to demonstrate a new generation of innovative coal utilization processes in a series of large-scale *showcase* facilities built across the country. The program takes the most promising advanced coal-based technologies and moves them into the commercial marketplace through demonstration. These demonstrations are on a scale large enough to generate all the data, from design, construction and operation, that are necessary for the private sector to judge commercial potential and make informed, confident decisions on commercial readiness. The projects in the program are demonstrating technologies capable of being applied to the United States coal resource base and encompass advanced electric power generation systems, high-performance pollution control devices, and coal processing for clean fuels and industrial applications.

The innovative clean coal technologies being demonstrated offer tremendous potential as part of the solution to many complex problems that face the nation--and the world--in a rapidly changing arena dominated by energy, economic, and environmental issues. These issues include the following:

- Air quality,
- Acid rain,
- Global climate change,
- Power production,
- Energy security,
- Technology awareness, and
- International competitiveness.

The dependence of the electricity-producing industry on coal is especially strong, and the burning of coal to provide industrial heat and power is critical to the economy. In 1989, 86 percent of coal consumption went into the generation of electricity. By 2010, coal use in the electricity production industry will increase by at least

50 percent and double by 2030 even with optimistic estimates of contributions from conservation, renewable resources, and nuclear energy.

Currently available technologies will have difficulty in satisfying the rapidly changing environmental, economic, and technical performance requirements being imposed on power plants. The coal-fueled power plant of the future must be capable of meeting stringent siting and environmental demands while producing power efficiently and with a high level of reliability. Further, the ability to rapidly add generation capacity in modules which closely match load growth will be an important factor in keeping reasonable electricity costs to the consumer. Therefore, over the next 10 years, it will be critical to bring new technology options into the marketplace to satisfy not only the requirements of the traditional utility industry but also the requirements of independent power producers and cogenerators which are producing an increasing share of power in the United States. As a result of the Clean Coal Technology Demonstration program, new power production systems using technologies demonstrated in the program will have the potential to gain a major share of the market for replacement and new capacity through 2010, thereby providing a clean, efficient, reliable source of affordable energy.

The commercially-proven IGCC process basically has the following four steps:

1. A fuel gas is formed by reacting coal with air or oxygen;
2. The coal-derived syngas is cooled and purified;
3. The clean gas is burned, and the hot exhaust is routed through a CT to generate electricity; and
4. The residual heat in the exhaust is recovered in a HRSG to form steam for a conventional ST generator to produce additional electricity.

IGCC systems are among the cleanest and most efficient of the emerging clean coal technologies. Sulfur, nitrogen compounds, and particulates are removed before the fuel is burned in the CT.

Tampa Electric Company will demonstrate an oxygen-blown entrained-flow IGCC technology. Such a demonstration is expected to show that an oxygen-blown entrained-flow IGCC unit can achieve significant reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions when compared to existing and future coal-burning power plants using available, conventional pulverized coal technologies. The integrated performance to be demonstrated will include all major subsystems in the IGCC system entailing coal feeding; a pressurized, oxygen-blown entrained-flow gasifier capable of using caking coal; an air separation unit to provide oxygen to the gasifier as an oxidant and also to provide nitrogen to the CT for NO_x control and power augmentation; a commercially-proven cold gas cleanup (CGCU) system capable of treatment of 100 percent of the syngas flow in parallel with a demonstration hot gas cleanup (HGCU) system capable of a nominal 50-percent syngas flow treatment for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and CT fuel requirements; an advanced CT appropriately modified to use low-British-thermal-unit (Btu) syngas as fuel; the HRSG system; the system cycle; all control systems; and associated facilities.

In a coventional IGCC system, the syngas is cooled prior to sulfur removal and then reheated prior to firing in the CT. These cooling and reheating processes result in a less efficient power generation system. Part of the reason Tampa Electric Company was awarded this Clean Coal Technology Demonstration program project is due to the demonstration of a HGCU system. By using a bed of metal oxide particles, the syngas can be cleaned without first cooling it down. This will result in a more efficient system.

Under its agreement with DOE, Tampa Electric Company will demonstrate the HGCU system for a 2-year period. The demonstration period will involve significant testing and optimization to determine the cost and performance of the HGCU system as well as the overall integration of the CG and CC technologies. Successful operation will enable future IGCC systems to operate more efficiently, providing more opportunities to meet the goals of the Clean Coal Technology Demonstration program.

1.5 GENERAL DESCRIPTION OF GENERATING TECHNOLOGIES

The proposed Polk Power Station will consist of three types of electric generating technologies or units: CT units, CC units, and an IGCC unit. While many of the main electric generating components of these units are relatively similar, each type of unit has certain differences in its operational requirements and its emissions and wastes/by-products, which in turn may involve different potential environmental effects. To provide the reader of this SCA with an initial, basic understanding of the generating technologies, the following presents a general description of each type of the generating unit planned for the Polk Power Station. More detailed, technical descriptions of these units and their major systems, designs, and operations are provided in Chapter 3.0.

1.5.1 COMBUSTION TURBINE GENERATING TECHNOLOGY

The CT generating technology is the simplest of the three types of technologies planned for the Polk Power Station. When operated as a separate, distinct generating technology (i.e., not combined with HRSG/ST facilities as in a CC unit), CT units are often referred to as simple-cycle or stand-alone CTs. A basic CT electric generating unit consists of a compressor, a combustor, a turbine, and an electric generator in series and operating similar to a jet aircraft engine. In an aircraft engine, jet fuel is burned to produce hot gases which are used to spin a turbine, which in turn creates the thrust for the aircraft. For power generation, air is compressed in a compressor and delivered along with gaseous or liquid fuel to a high-pressure combustion chamber where the fuel is burned to produce hot gases. These high temperature, high pressure gases then pass and expand through a turbine causing the turbine to spin. The turbine drives a generator which produces electricity. Again, similar to jet aircraft engine operation, the hot combustion gases are released to the atmosphere after passing through the turbine. Figure 1.5.1-1 provides a simplified flow diagram of a CT power system.

Stand-alone CT units are generally used only as peaking units to supply electricity for those days of the year when demand is the highest or peaks. In this role, the

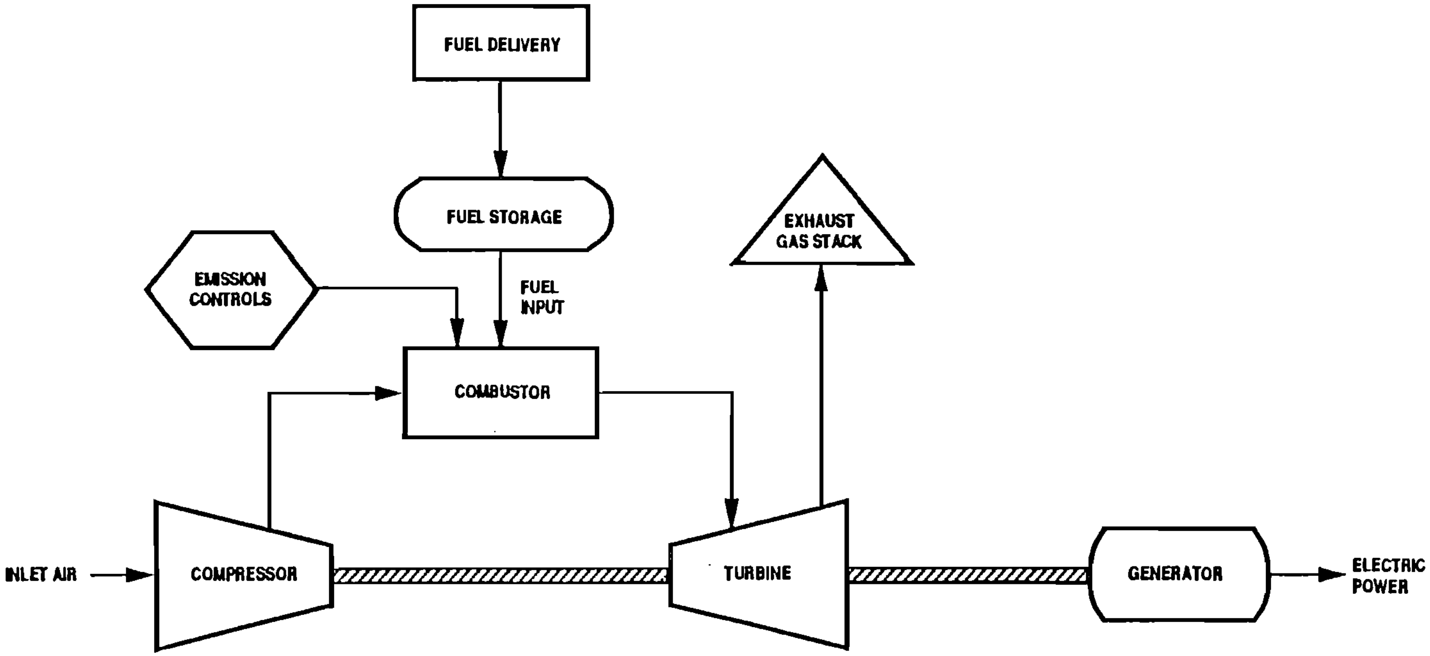

FIGURE 1.5.1-1.

SIMPLIFIED FLOW DIAGRAM OF COMBUSTION TURBINE POWER SYSTEM

Source: ECT, 1992.

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advantage of CTs is that a unit can start and stop generating electricity quickly. This rapid response makes the units effective in providing extra capacity during the periods of peak demand. Other advantages of CTs are that the units are relatively less expensive to build than other types of generating plants and require less time to build and be operational than other types of plants. Also, from an environmental standpoint, stand-alone CT units do not require water for cooling purposes and do not produce solid wastes or by-products.

The disadvantage of CT technology is that it is relatively less efficient in the conversion of energy created by the fuel combustion to electricity than many other available technologies. Thus, the cost of electricity generated by CT units is relatively more expensive than electricity generated by many other technologies. Also, until recently, CT units were generally limited in size with a maximum power-producing capacity of less than 100 MW. However, recent technological advances have allowed development of larger units (e.g., up to 150 MW). These larger CT units are often referred to as advanced CTs.

According to the ultimate site capacity plan shown in Table 1.3.3-1, a total of 11 CT units will be located on the Polk Power Station site; however, only six of the units are planned for long-term operation as stand-alone CTs. One of the units will be an advanced CT (i.e., GE 7F) with a nominal net capacity of 150 MW which will be operated in a stand-alone mode using No. 2 fuel oil only during the first year of operation. After the first year, this advanced CT will be integrated with HRSG, ST, and CG facilities to form the IGCC unit.

Currently, each of the remaining CTs are planned to have a nominal net capacity of 75 MW. Two of these CTs will be operated in a stand-alone mode for 1 to 2 years prior to being integrated to form a CC unit, while two other CTs will be only operated as a CC unit.

The remaining six CTs will be operated as stand-alone units to provide electric power during periods of peak demands. These CT units will use natural gas as primary fuel and No. 2 fuel oil as backup fuel.

Air pollution emission controls for the stand-alone CT units and CTs integrated for CC units will consist of a combination of measures. SO_2 emissions will be controlled by the use of fuels with low sulfur contents (i.e., natural gas with only trace sulfur content and fuel oil with a maximum sulfur content of 0.05 percent). NO_x emissions will be controlled by the use of efficiently designed and operated combustors called dry low-NO_x combustors when the units are fired by natural gas, and water injection when fired on the backup fuel oil. Other potential air pollutants [i.e., carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter less than or equal to 10 micrometers aerodynamic diameter (PM_{10}), and trace elements] will also be primarily controlled by the fuel characteristics and the efficient design and operation of the CT units.

1.5.2 COMBINED CYCLE GENERATING TECHNOLOGY

In general, a CC electric generating unit consists of one or two CT units configured with HRSG and ST facilities and a second electric generator. The efficiency of electric generation is improved when CT units are combined in a CC unit arrangement compared to CT units operated as stand-alone facilities. When CT units are used as stand-alone units, the hot combustion gases are released to the atmosphere after passing through the turbine. In a CC unit, the hot combustion gases from the CT are reused. The hot gases are ducted into an HRSG, where water in boiler tubes is heated to produce steam. The steam is then used to spin an ST which drives a second generator to produce electricity. Therefore, by reusing the waste heat from the CT units, additional electricity is efficiently produced by the ST and generator without additional fuel input.

Due to their improved efficiency, CC units are used to serve intermediate electricity demands or the portion of the utility load that varies daily. For example, intermediate plants may start up every morning and may stop every night when the demand diminishes.

Two CC generating units will be located at the Polk Power Station site. The IGCC generating unit also includes a CC unit, which will be configured slightly different than the two other units. Figure 1.5.2-1 presents a simplified flow diagram of a CC unit.

Each of the two CC units will have a nominal net generating capacity of 220 MW. As currently planned, each CC facility will be comprised of two 75-MW CT units, two HRSGs, and a 70-MW ST. The first CC unit will be developed under a phased schedule with one of the 75-MW CT units placed in service in early 1999, the second unit in service in early 2000, and the HRSG and ST facilities to complete the nominal net 220-MW CC unit scheduled for operation in early 2001. The phased CT units will be operated as stand-alone generating facilities until combined into the CC facility in order to meet Tampa Electric Company's projected peak power demands

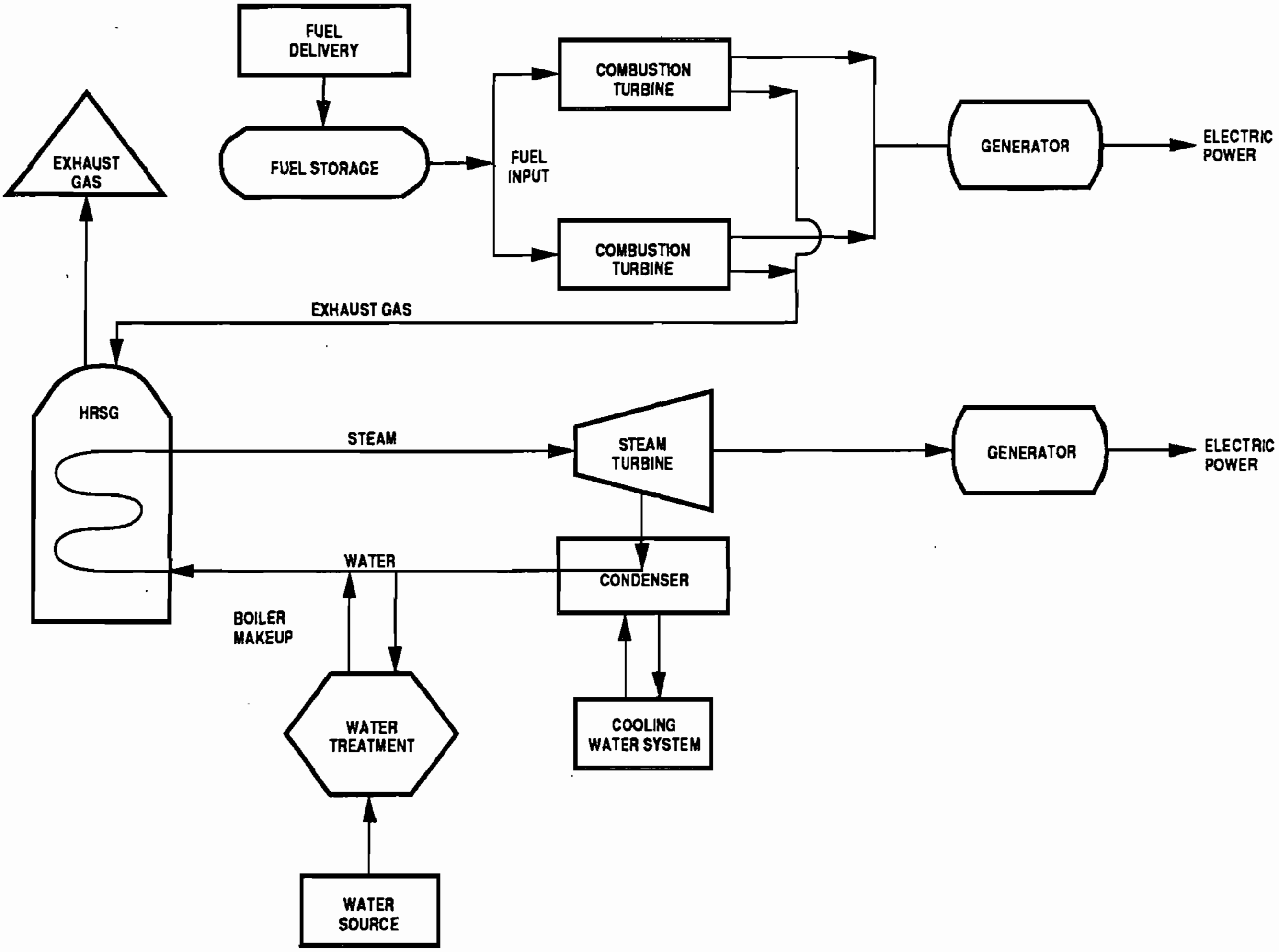

FIGURE 1.5.2-1.

SIMPLIFIED FLOW DIAGRAM OF COMBINED CYCLE POWER SYSTEM
Source: ECT, 1992.

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in the 1999 to 2001 timeframe. The components of the second CC unit are expected to be constructed concurrently beginning in early 2001 with the total nominal net 220-MW unit operational in early 2003.

Similar to the stand-alone CT units, the two CC units will use natural gas as primary fuel and No. 2 fuel oil as backup.

The proposed air pollutant emission controls for the CC units will also be similar to those for the stand-alone CT units (i.e., dry low-NO_x combustors when fired on natural gas and water injection when fired on the backup fuel oil).

Unlike the stand-alone CT units, the CC units will require water for the steam generating cycle as well as for air pollution control and other plant uses. Makeup water for the boiler steam cycle will be provided from the Floridan aquifer by wells on the site. Also, as discussed previously, an 860-acre cooling reservoir, including the area of the surrounding berm, will be constructed to provide circulating water for condenser cooling and system heat dissipation purposes.

1.5.3 INTEGRATED COAL GASIFICATION COMBINED CYCLE TECHNOLOGY

The IGCC generating technology involves the integration of CG facilities with a CC unit. As discussed previously, the initial electric generating facilities at the Polk Power Station site will be an IGCC unit with a nominal net generating capacity of 260 MW. The IGCC unit will be known as Polk Unit 1. The IGCC generating facilities will consist of a nominal net 150-MW advanced CT and nominal net 70-MW HRSG/ST and CG facilities. When the IGCC unit is operated on the syngas and with the associated air separation unit, the nominal net generating capacity of the advanced CT is expected to increase to 190 MW. The CC components (i.e., CT and HRSG/ST) of the unit produce electricity in a similar manner and have similar process and cooling water requirements as described previously for the two CC units at the site. However, instead of using two 75-MW CTs, the IGCC unit will use a single, larger advanced CT (i.e., GE 7F). Construction of the IGCC facilities will begin in early 1994 and the nominal net 150-MW advanced CT will be placed in service in mid-1995. The CT unit will be fueled initially by No. 2 fuel oil. The HRSG/ST and CG facilities will be placed in service 1 year later, or mid-1996, to complete the nominal net 260-MW IGCC unit. When completed, the unit will be fueled by coal gas or syngas produced from the CG facilities with No. 2 fuel oil as backup fuel.

CG involves a method of producing a clean, burnable gas from coal. Gasification is achieved by exposing coal to nearly pure oxygen in a pressurized vessel. Under these controlled conditions, the coal (i.e., the carbon in coal) is partially oxidized to form a combustible gas, consisting mainly of hydrogen and CO. When coal is burned conventionally, complete oxidation of carbon occurs with nearly all the chemical energy of the coal released as heat energy and the remaining gases will not burn. In the gasification process, by restricting the amount of oxygen available to the coal and controlling the temperature and duration of the reaction, only partial oxidation occurs and gases are formed that will burn.

The basic technology of CG has been in commercial use for many years. The first low-Btu gas gasifier for production of coal-derived gas began operation in England in 1832, and extensive use of gasifiers began in 1861. Medium-Btu gas production from coal began in 1875. By the 1920s, approximately 11,000 gasifiers were in use in the United States. The availability of low cost natural gas and oil in the mid-1900s resulted in a loss of interest in the CG process. Worldwide interest in CG renewed in 1973 because of the Arab oil embargo and ensuing drastic rise in the price of oil. The industrial need for more efficient, environmentally clean processes resulted in a number of extensive programs to develop *second generation* CG processes for the production of fuels and electric power.

The Dakota Gasification Company's Great Plains CG plant (Beulah, North Dakota) is an early example of these second generation plants. This facility used the Lurgi oxygen-blown fixed-bed CG technology.

The most prominent modern commercial-scale applications of CG in the United States are the Cool Water power plant in southern California and Tennessee Eastman plant in Kingsport, Tennessee, both of which use the Texaco gasification technology, the Dow Syngas project in Plaquemine, Louisiana, and the Shell CG Process in Deer Park, Texas. These facilities use an oxygen-blown entrained flow gasification process. The oxygen-blown CG system developed by Texaco will be used for the IGCC unit at the Polk Power Station.

As discussed previously, Tampa Electric Company will develop the IGCC unit in conjunction with a cooperative agreement with DOE under the Clean Coal Technology Demonstration program. Under this agreement, DOE will provide $120 million in funding for construction and operation of the unit to demonstrate the integration of CG and CC technologies and a new, more efficient technology for removing sulfur from the coal gas prior to its combustion. This innovative technology is called HGCU and has been developed by General Electric Environmental Systems, Inc. (GEESI). The demonstration aspects of the IGCC unit provide the opportunity to commercially demonstrate an economical and environmentally-acceptable means of generating electricity using coal which is the most abundant energy resource in the United States. Therefore, if successful, this demonstration could assist in reducing future reliance on and use of foreign energy resources (i.e., imported oil) for electricity generation in the United States.

The IGCC unit at the Polk Power Station will include both the proven CGCU system and the HGCU demonstration technology to assure the reliable production of clean syngas for the continued operation of the generating unit and compliance with applicable environmental regulations.

Figure 1.5.3-1 provides a simplified flow diagram of the IGCC unit planned for the Tampa Electric Company Polk Power Station. As shown in this figure, coal is fed to a conventional rod-type grinding mill to reduce the coal to the design particle size and mixed with water to create a coal slurry. The coal slurry is pumped to the gasifier which is a refractory-lined vessel capable of withstanding high temperatures and pressures. Pure oxygen is also provided to the gasifier from an air separation unit which separates the two major components of air, oxygen and nitrogen, through a process of cooling compressed air to liquid states, separating the oxygen and nitrogen streams, and re-warming the streams to gaseous states. In the gasifier, the coal slurry and oxygen react at high temperatures to produce syngas. The syngas consists primarily of hydrogen, CO, water vapor, and carbon dioxide (CO_2), with small amounts of hydrogen sulfide (H_2S), carbonyl sulfide (COS), methane, argon, and nitrogen. Heat created by the reaction in the gasifier is used to heat water in boiler tubes to steam which is provided to the HRSG/ST facilities.

Within the gasification process, ungasified components of the coal (primarily ash) are cooled in a pool of water at the bottom of the gasifier and form a solid by-product called slag. The slag material is a vitrified (i.e., glasslike) granular solid that is non-leachable and classified as non-hazardous. The slag has commercial applications such as sand-blasting material and as an aggregate in cement, road construction, and

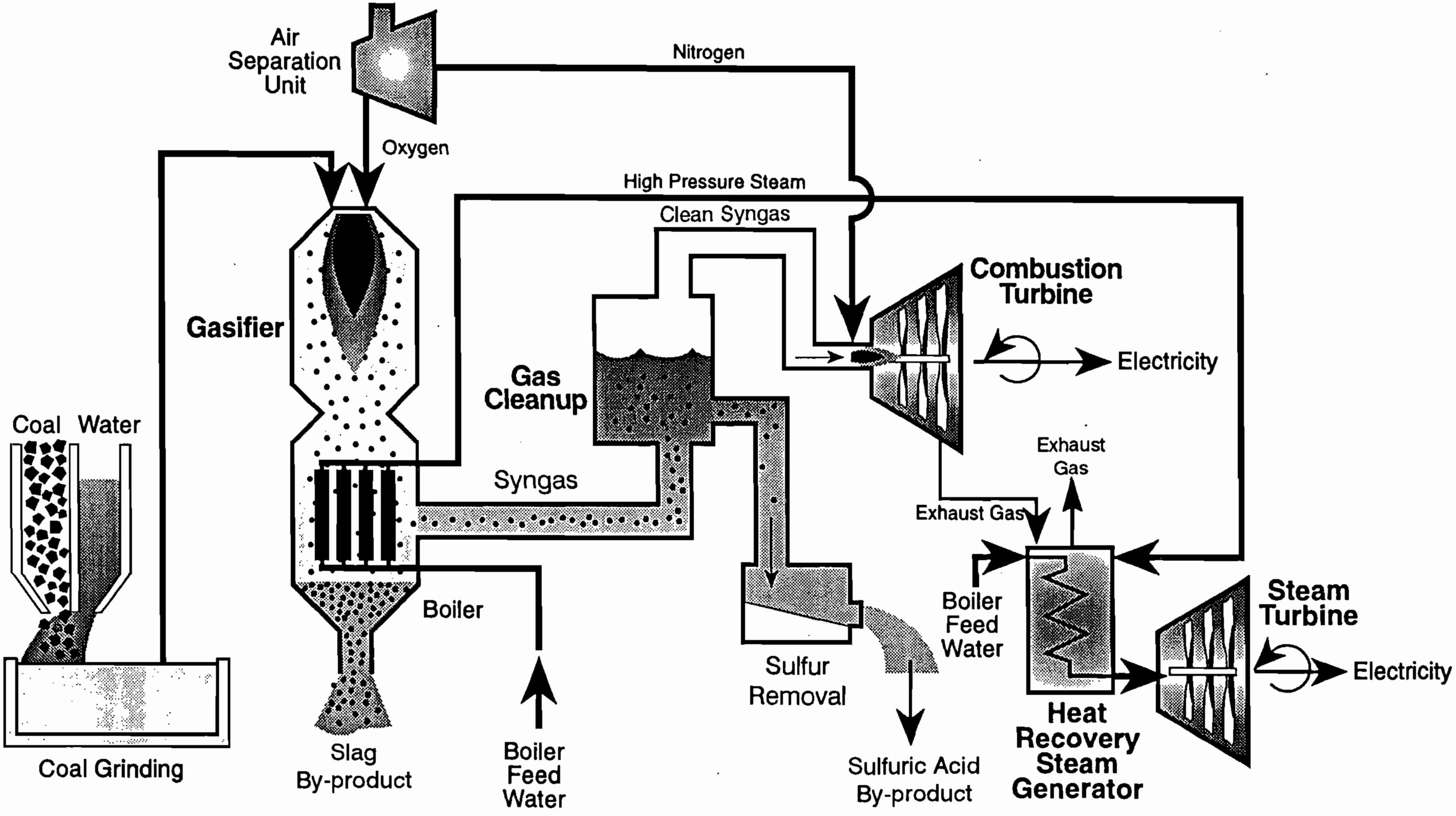

FIGURE 1.5.3-1.

SIMPLIFIED FLOW DIAGRAM OF INTEGRATED COAL GASIFICATION COMBINED CYCLE UNIT

Source: Texaco, 1992. Tampa Electric Company, 1992.

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other building materials. Although a temporary storage area for the slag will be developed onsite, the slag will be actively marketed and sold for offsite uses to minimize the onsite storage requirements. The temporary slag storage area will be lined with a synthetic material or other materials with similar low-permeability characteristics and have appropriate stormwater management control systems.

The syngas from the gasifier will be fed to the gas cleanup systems to remove entrained solids and acid gases such as CO_2 and H_2S. As discussed previously, the gas cleanup systems will include both the conventional CGCU and the demonstration HGCU methods. The CGCU system will be designed to treat 100 percent of the syngas flows for the IGCC unit, while the HGCU system will be capable of treating approximately 50 percent of the gas when the unit is operating at full capacity. ~~Within the CGCU system, the sulfur in the syngas is primarily converted to and recovered as molten, elemental sulfur using a combination of thermal and catalytic reactors. This sulfur recovery process is used extensively in the petroleum refining industry. Elemental sulfur is also a by-product with commercial uses, particularly for the chemical fertilizer industry in central Florida. Some temporary storage for the sulfur by-product in tanks or specially designed railcars will be provided on the site prior to shipment offsite.~~

For both the CGCU and demonstration HGCU systems, the sulfur in the syngas will be converted to sulfuric acid (H_2SO_4) in ~~a skid-mounted unit. Again,~~ an onsite H_2SO_4 plant. H_2SO_4 produced in this cleanup process has commercial uses and will be marketed and sold for these offsite uses.

As shown in Figure 1.5.3-1, the clean syngas is then fed to the advanced CT for firing to produce electricity and the exhaust gas is routed to the HRSG/ST facilities to produce additional electricity as a CC generating unit. Nitrogen from the air separation unit is also fed to the CT unit which increases the overall efficiency of the unit in generating electricity.

Again, the previous descriptions are intended to provide an initial overview of the electric generating technologies and units planned for the Polk Power Station. More detailed descriptions of the designs and operations of these facilities are provided in Chapter 3.0.

1.6 PROJECT TERMINOLOGY

In order to provide the reader of this SCA with a consistent understanding of the Polk Power Station project, Table 1.6.0-1 presents descriptions of certain project terms and components used throughout the SCA.

Table 1.6.0-1. Polk Power Station Project Terminology

Project Term/ Component	Description
Polk Power Station project	The overall Polk Power Station project includes the proposed power plant facilities with a nominal net 1,150-MW generating capacity; fuel delivery and storage facilities; by-product storage areas; cooling reservoir; water supply and wastewater treatment facilities; and associated transmission lines.
Polk Power Station site	The overall 4,348-acre site.
Main power plant facilities site	The approximately 150-acre area to the east of SR 37 on which the main power plant facilities and structures (i.e., power blocks, fuel and by-product storage) will be constructed.
Cooling reservoir	The approximately 860-acre area, including the area of the surrounding earthen berms, within which the cooling reservoir will be constructed. The reservoir will have an ~~maximum~~ average bottom elevation of 120 ft-NGVD and the top of the surrounding earthen berms will be at 145 ft-NGVD. The total water surface of the reservoir is approximately 727 acres at the normal operating water level of 136 ft-NGVD. Water discharges (i.e., blowdown) from the reservoir will be routed to the reclaimed lake at the eastern edge of the reservoir and flow into the Little Payne Creek system.
Wildlife corridor or wildlife/ water management area	The approximately 1,511-acre portion of the site to the west of SR 37; this area will be reclaimed in an integrated series of forested and non-forested wetlands and uplands, and will not contain power plant facilities or structures. After reclamation, the entire area will provide a wildlife corridor between the headwater areas of Payne Creek and the Little Manatee River and the South Prong Alafia River system.

Table 1.6.0-1. Polk Power Station Project Terminology (Continued, Page 2 of 3)

Project Term/ Component	Description
Eastern associated transmission line corridor	The 400-ft wide corridor area from the onsite substation to the existing Tampa Electric Company Hardee-Pebbledale 230-kV transmission line along the eastern edge of the site. This corridor is contained completely within the Polk Power Station site boundaries. Two 230-kV electric transmission circuits and structures will be constructed within the corridor.
Northern associated transmission line corridor	The corridor area from the onsite substation to to the existing Tampa Electric Company Mines-Pebbledale 230-kV transmission line at a point west of the community of Bradley Junction.. The corridor area is 400-ft wide as it runs west on the site from the substation to SR 37 and widens to 0.5 mile centered on SR 37 as it runs north along SR 37. The corridor width increases to 1 mile southwest of Bradley Junction as it turns northwest to interconnect to the existing line. Two 230-kV transmission line circuits and structures will be constructed within this corridor.
IGCC generating unit	The nominal net 260-MW IGCC unit consisting of an advanced CT and HRSG/ST facilities and integrated CG facilities including air separation unit, coal grinding facilities, gas cleanup systems, tail gas treating system, and CG process wastewater treatment facilities.
Stand-alone CC generating units	Two nominal net 220-MW CC units each consisting of two nominal net 75-MW CTs and nominal net 70-MW HRSG/ST facilities.
Stand-alone CT generating units	Six CT units each with a nominal net generating capacity of 75 MW.

Table 1.6.0-1. Polk Power Station Project Terminology (Continued, Page 2 of 3)

Project Term/ Component	Description
Syngas/coal gas	Syngas and coal gas are used interchangeably in this SCA to refer to the combustible coal-derived gas produced in the gasification process and, after appropriate cleanup, used as fuel in the advanced CT in the IGCC unit.

Source: ECT, 1992.

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Tampa Electric Company. 1992a. Volume of Environmental Information, Polk Power Station. Submitted to U.S. Department of Energy, Morgantown, WV.

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CHAPTER 3.0

THE PLANT AND DIRECTLY ASSOCIATED FACILITIES

This chapter provides descriptions of the proposed power plant facilities, the key components and systems of the plant and their operations, and the directly associated facilities which will comprise the Tampa Electric Company Polk Power Station. The descriptions include, to the extent possible, estimates of the expected character, quality, and quantity of discharges and emissions from the plant facilities and operations. Also, proposed measures and systems to control and, as necessary, treat the expected emissions and discharges are described in order to provide reasonable assurance that the plant operations comply with applicable regulatory requirements and standards. These descriptions are based on Tampa Electric Company's current plans and available engineering and design information for the proposed Polk Power Station project.

3.1 BACKGROUND

The proposed Polk Power Station project involves the phased construction and operation of electric generating units and associated facilities on a 4,348-acre site in southwest Polk County, Florida. The proposed generating units will include a nominal net 260-MW IGCC unit (i.e., Polk Unit 1), two nominal net 220-MW CC units, and six stand-alone nominal net 75-MW CT units. The construction and operation of these units will provide a total, ultimate generating capacity of approximately 1,150 MW (nominal net) at the Polk Power Station site.

Table 3.1.0-1 provides the phased schedule for construction and operation of the proposed generating units and overall site preparation and reclamation activities. As shown in this table, construction activities for the nominal net 260-MW IGCC unit will begin in January 1994 with the first component of the IGCC unit, a nominal net 150-MW advanced CT unit, scheduled to be in-service in July 1995. The schedule ends with the in-service date of the sixth and last stand-alone CT unit planned for the site in January 2010. The planned in-service dates for the generating units have

Table 3.1.0-1. Schedule for Construction and Operation of Generating Units at the Polk Power Station Site

Activity/Unit	Start Construction	Completion/ In-Service
Overall site preparation/reclamation, including cooling reservoir	January 1994*	July 1996††
150/190-MW advanced CT†	January 1994**	July 1995
CG and HRSG/ST for 260-MW IGCC unit	January 1994**	July 1996
75-MW CT	April 1998	January 1999
75-MW CT	April 1999	January 2000
HRSG/ST for conversion of two 75-MW CTs for 220-MW CC unit	April 2000	January 2001
75-MW CT	April 2001	January 2002
220-MW CC	April 2001	January 2003
75-MW CT	April 2005	January 2006
75-MW CT	April 2006	January 2007
75-MW CT	April 2007	January 2008
75-MW CT	April 2008	January 2009
75-MW CT	April 2009	January 2010

* Tampa Electric Company may request appropriate agency approvals to initiate certain site reclamation activities prior to this date.

† 150 MW when operated in simple-cycle CT or CC mode and fired on fuel oil. 190 MW when operated in IGCC mode with gasifier and air separation unit.

** Construction activities may be initiated prior to this date if all applicable regulatory approvals, licenses, and permits are obtained prior to December 1993.

†† Certain reclamation activities (e.g., vegetation planting) may extend beyond July 1996.

Source: Tampa Electric Company, 1992.

been phased to match Tampa Electric Company's power resource needs to meet its currently projected Customer demands in the 1995 through 2010 timeframe. The units have also been selected and sized to most reliably and cost-effectively meet these future Customer electricity demands. The schedule presented in Table 3.1.0-1 may be subject to some revisions in the future (i.e., the construction and in-service dates for certain units may be accelerated or delayed) based on the results of the company's ongoing Customer demand forecasting and power resource planning programs in the future as well as future orders determining the need for new generating capacity additions from the FPSC. At this time and by this SCA, Tampa Electric Company is requesting certification of the Polk Power Station site for an ultimate generating capacity of approximately 1,150 MW (nominal net).

Also, as shown in Table 3.1.0-1, overall preparation and reclamation of the Polk Power Station site are scheduled to begin in January 1994. Since the majority (i.e., more than 94 percent) of the site has been, is currently, or will be mined or disturbed by phosphate mining activities, overall site preparation involves not only activities to make the site suitable for development of the proposed generating units and associated facilities, but also required reclamation activities to comply with the mined land reclamation requirements of FDNR (Chapter 16C-16, F.A.C.) and Polk County Phosphate Mining Ordinance 88-19. Tampa Electric Company's proposed plans to comply with these requirements will require a modification of the currently-approved reclamation plans and programs for the site and are presented in Chapter 9.0 of this SCA and in a separate document submitted to FDNR and Polk County entitled Conceptual Reclamation Plan Application.

Tampa Electric Company's proposed project development plans have been selected and designed to take full advantage, environmentally and economically, of the site conditions existing after the mining activities have ceased and fulfill regulatory reclamation requirements. The main power plant facilities and structures will be developed on lands to the east of SR 37 which were not mined but disturbed by mining-related activities. Fill materials for this plant site area will be obtained from the development activities for the cooling reservoir. The use of existing mined-out areas on the site for the cooling reservoir allows the reservoir to be developed as a primarily below-grade facility which lessens groundwater withdrawals for cooling water makeup to and water discharges from the cooling reservoir as well as reduces construction and maintenance costs for the facility. The proposed development/reclamation plans for the 1,511-acre portion of the site to the west of SR 37 will result in an environmentally significant wildlife habitat and corridor resource area in southwest Polk County. Other mined-out areas on the site will be reclaimed to uplands and wetlands and integrated into the overall stormwater runoff management plans for the proposed project. These areas will also provide wildlife habitat resource areas on the site after development of the project.

As indicated in Table 3.1.0-1, the overall site preparation and reclamation activities are currently scheduled to begin in January 1994 after receipt of the final state site certification and federal agency approvals. However, during the review process of this SCA, Tampa Electric Company may request approvals from FDER and FDNR to initiate certain site reclamation activities prior to January 1994. The earlier initiation of these activities would be advantageous to the overall project in order to meet the statutory time limitations required by FDNR to initiate reclamation of mined lands and to provide as much time as possible for reclaimed, re-vegetated wetland and upland areas to become established and develop as wildlife habitat resources. Any reclamation activities conducted prior to the final site certification by the Siting Board will be conducted in accordance with the modified reclamation plans submitted to FDNR and Polk County in conjunction with this SCA and will not adversely affect any agency programs or future use of the site should the final site certification for the Polk Power Station not be approved.

The following sections provide overall descriptions of the proposed electric generating units, the operations of major processes and systems, and other associated facilities which will comprise the Tampa Electric Company Polk Power Station project. These descriptions will provide reviewers of this SCA with a detailed understanding of the proposed facilities and processes. Also, as appropriate, specific references are provided to other sections in this chapter and elsewhere in this SCA which present more detailed descriptions of the proposed facilities, systems, and processes.

3.1.1 INTEGRATED COAL GASIFICATION COMBINED CYCLE UNIT AND PROCESS DESCRIPTIONS

As discussed in Section 1.4.4, Tampa Electric Company will develop the proposed IGCC unit in conjunction with a cooperative agreement with DOE under the Clean Coal Technology Demonstration program. Under this agreement, DOE will provide $120 million in partial funding for construction of the unit and its operation for 2 years to demonstrate the integration of CG and CC technologies and a new, potentially more efficient technology (i.e., HGCU) for removing sulfur from syngas prior to combustion. These demonstration aspects of the IGCC unit provide Tampa Electric Company with the opportunity to commercially demonstrate an environmentally acceptable and economical means of generating electricity using coal which is the most abundant energy resource in the United States. Therefore, if successful, this demonstration could assist in reducing future reliance on the use of foreign energy oil resources for electricity generation in the United States.

As shown in Table 3.1.0-1, the first electric generating unit and initial component of the IGCC unit at the Polk Power Station site will be a nominal net 150-MW advanced CT unit which will be placed in service in July 1995. This unit will be a GE 7F CT. This advanced CT unit will be fired on low-sulfur No. 2 fuel oil during its first year of operation and will be used up to a maximum capacity factor of 10 percent to meet Tampa Electric Company's peak demands for electricity. Annual capacity factor is defined as the actual megawatt hours produced by a generating unit versus the maximum possible megawatt hours that could be produced, expressed on a percent basis.

After the first year of operation, this advanced CT unit will be integrated with HRSG and ST generator facilities to form a CC generating unit and CG facilities to comprise the proposed nominal net 260-MW IGCC generating unit. The CG facilities will be based on the Texaco oxygen-blown, entrained flow, gasification system. The proposed IGCC unit, known as Polk Unit 1, is scheduled to be operational in July 1996 in order to meet Tampa Electric Company's baseload power resource needs as approved by the FPSC. As a baseload generating unit, the proposed IGCC unit will be capable of operating at up to 100-percent capacity factor when fired on the syngas produced in the CG facilities. When fired on the syngas and operated with the addition of nitrogen gas from the proposed air separation unit to the CT, the advanced CT unit is expected to have a nominal net generating capacity of 190 MW.

After conversion of the advanced CT to the IGCC unit, the facilities will be designed to maintain the capability to fire No. 2 fuel oil as a backup fuel and operate in a CC mode, to provide required flexibility in meeting Customer demands in the event of unanticipated disruptions in the delivery of coal or unplanned unavailability of the CG facilities. Tampa Electric Company anticipates and is proposing to permit operations in this CC mode using the backup No. 2 fuel for a maximum annual capacity factor of 10 percent.

Air emission controls for the stand-alone advanced CT during the first year of operation and the CC module of the IGCC unit when fired on the backup No. 2 fuel oil will consist of a combination of measures. SO_2 emissions will be controlled by the use of fuel oil with a low sulfur content (i.e., maximum sulfur content of 0.05 percent). NO_x emissions will be controlled by water injection in the advanced CT which controls the combustion temperature to limit the formation of NO_x. Other potential air pollutants (e.g., CO, VOCs, PM_{10}, and trace elements) will be controlled primarily by the fuel oil characteristics (i.e., only trace contents of potential pollutants) and by the efficient design and operation of the CT unit. Section 3.4 of this SCA and the PSD Permit Application in Appendix 11.1.3 provide additional discussions on the selection and design of these proposed air emission control measures.

The IGCC unit will consist of the following major systems and processes:

- Coal grinding and slurry preparation;
- Air separation unit;
- Gasification system;
- Slag handling and storage;

- Syngas scrubbing and cooling systems;
- Gasification process black water handling and brine concentration system;
- Acid gas removal unit;
- ~~Sulfur by product recovery, handling, and storage;~~
- ~~Tail gas treating unit;~~
- HGCU system~~; and H_2SO_4 by-product handling and storage; and~~
- H_2SO_4 by-product handling and storage; and
- Power block.

Figure 3.1.1-1 provides an overall block flow diagram of these major systems and processes. Each of these major systems and processes is described in the following subsections. General descriptions of other facilities directly associated with the IGCC unit and, in some cases, with the other generating units proposed for the site (e.g., potable and process water supply and treatment, fuel delivery and storage, cooling reservoir, and by-product storage) are provided in Section 3.1.4.

3.1.1.1 Coal Grinding and Slurry Preparation

The coal grinding and slurry preparation system for the IGCC unit will prepare the coal for input to gasifier. Figure 3.1.1-2 presents a schematic of this system.

As shown in Figure 3.1.1-2, coal will be withdrawn from the coal storage area 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 collection 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

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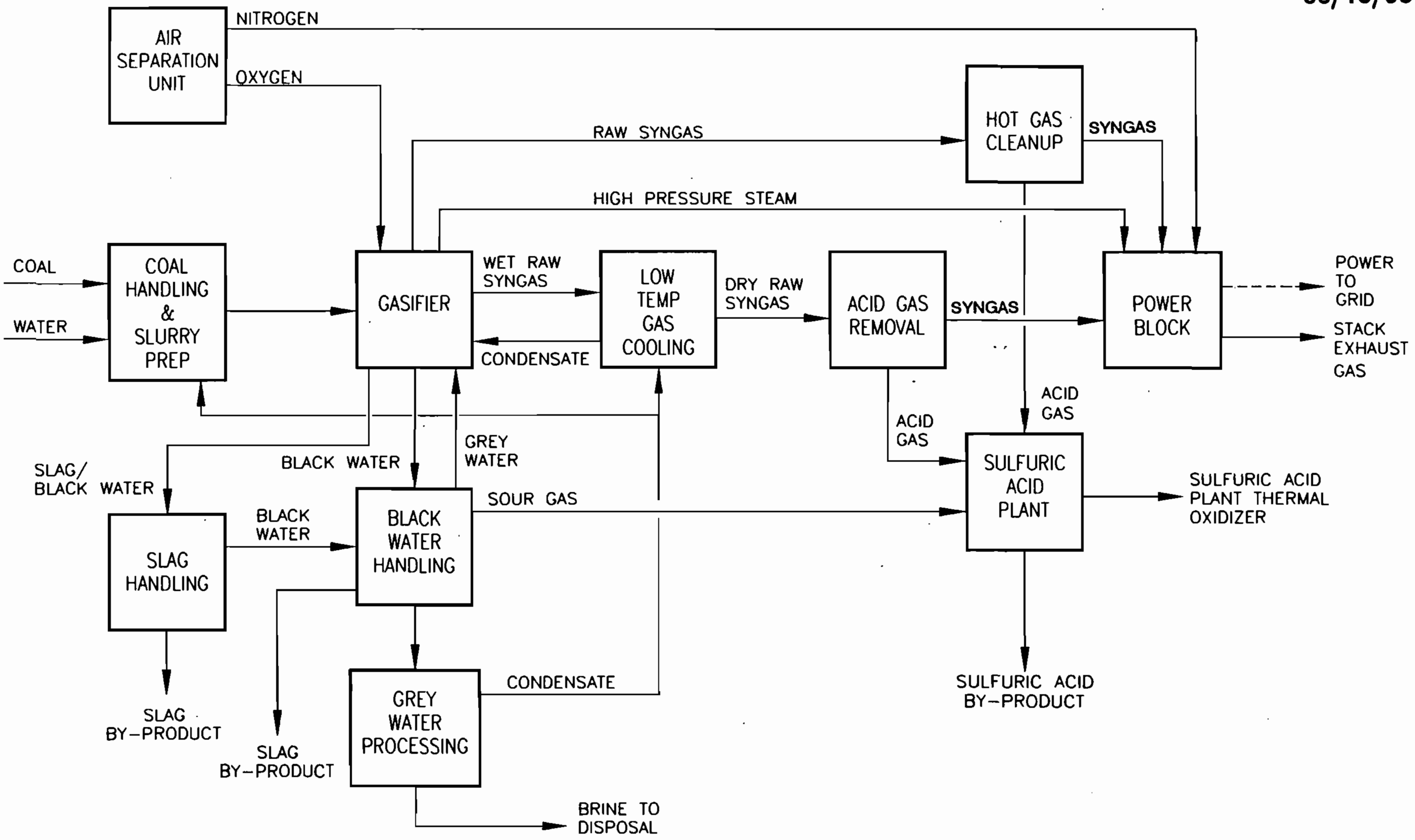

FIGURE 3.1.1-1.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1993.

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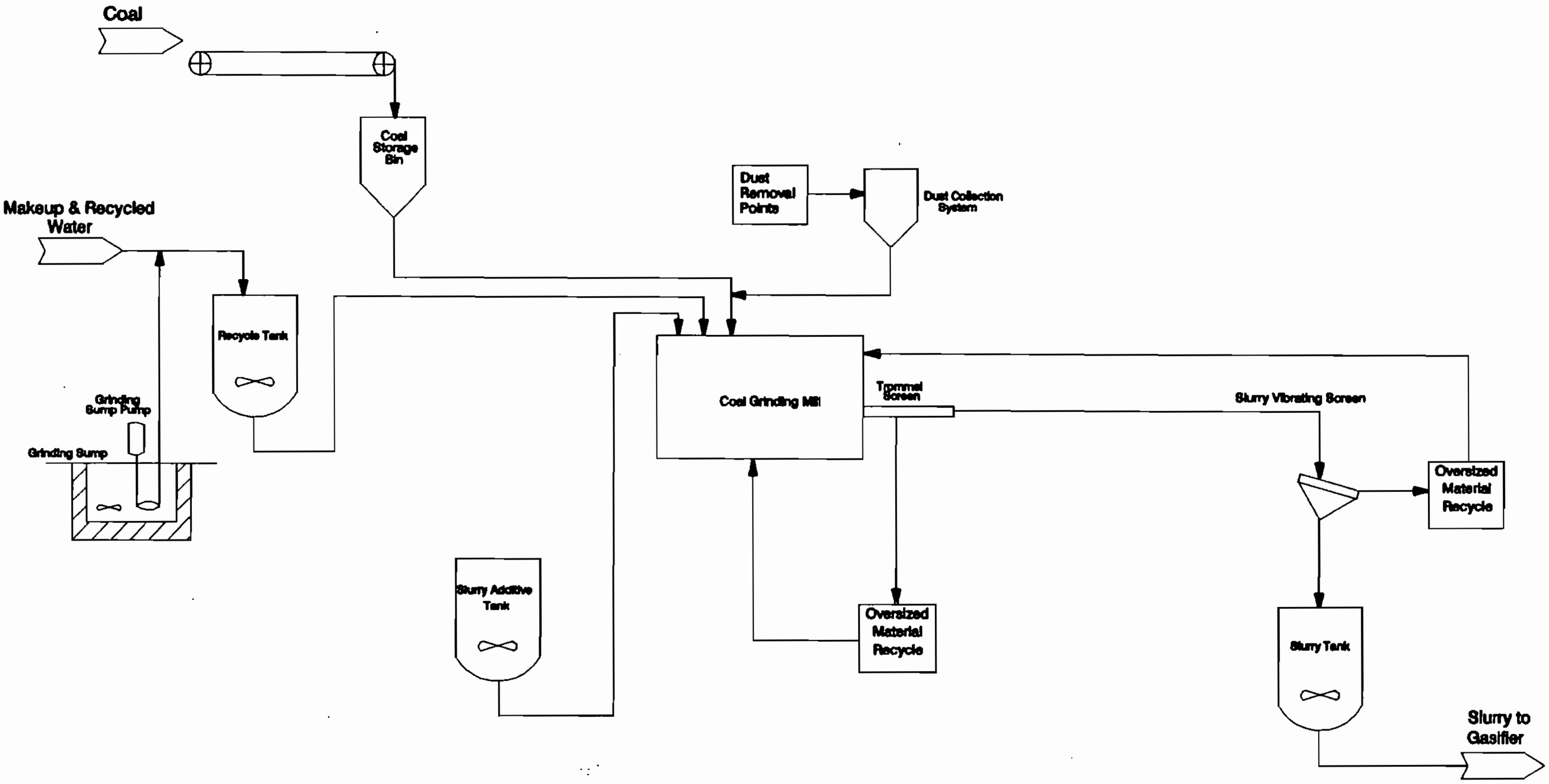

FIGURE 3.1.1-2.

COAL GRINDING AND SLURRY PREPARATION SCHEMATIC

Source: Texaco, 1992.

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and over a vibrating screen to remove any oversized particles before entering into 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 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.

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 grinding sump and slurry tank vents will each be equipped with carbon canisters for absorption of potential H_2S or ammonia (NH_3) emissions.

3.1.1.2 Air Separation Unit

The air separation unit will use ambient air to produce oxygen for use in the gasification system and sulfur recovery unit, and nitrogen which will be sent to the advanced CT. 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 which also results in higher CT unit output. Therefore, the addition of nitrogen increases the fuel mass flow and power output of the IGCC unit. 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.

Figure 3.1.1-3 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 blanket roll 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 and scrubbed in an aftercooler. Chilled air from the aftercooler will be fed to the molecular sieve contaminant absorbers. The molecular sieves will remove any remaining water vapor, CO_2, and unsaturated and saturated hydrocarbons from the air. The air will then be filtered in the dust filter to remove any entrained molecular sieve particles. Regeneration of the molecular sieve adsorbent will be accomplished by heating a nitrogen stream in the regeneration heater and passing it through the off-stream bed to drive off the adsorbed contaminants. The regeneration gas will then be vented to the atmosphere.

The purified air 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 at its midpoint and expanded through the compressed air turboexpander to provide refrigeration for the cryogenic process. The cooled, 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 dew point. The air will be fed to the high pressure distillation column and then to the

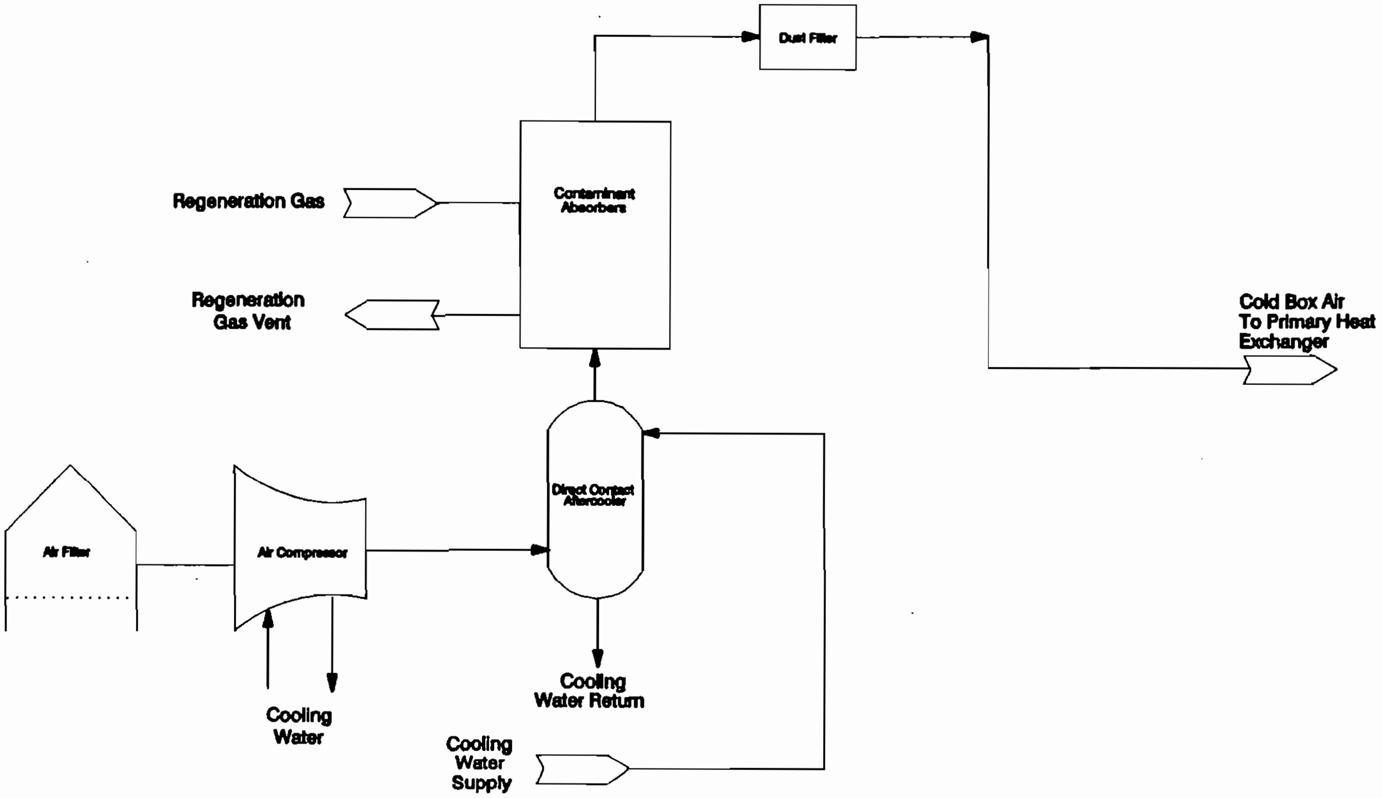

FIGURE 3.1.1-3.

AIR SEPARATION UNIT SCHEMATIC (PAGE 1 OF 2)

Source: Texaco, 1992.

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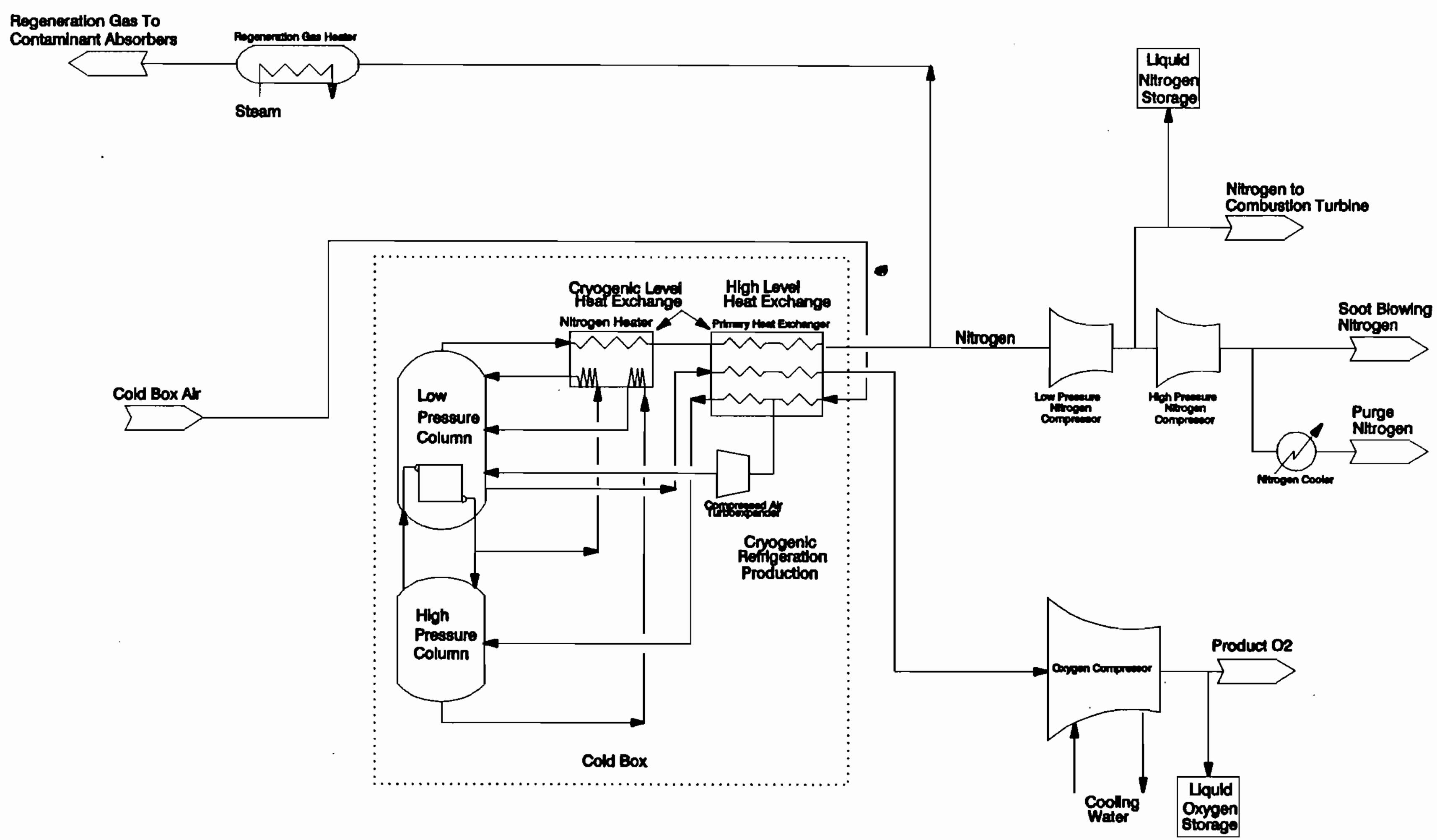

FIGURE 3.1.1-3.

AIR SEPARATION UNIT SCHEMATIC (PAGE 2 OF 2)

Source: Texaco, 1992.

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low 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.

The liquid nitrogen reflux, kettle liquid, and turbine discharge will be fed to the low pressure distillation column where they will be separated into oxygen and nitrogen. Heat from the condensing air 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 slightly in a superheater against subcooling nitrogen reflux liquid. The nitrogen will then be warmed to near-ambient temperature in the PHX. The nitrogen vapor will be compressed and sent to the advanced CT.

As potential backup systems to the air separation unit, liquid oxygen and nitrogen storage systems may be provided. If these systems are provided, the backup liquid oxygen and nitrogen systems will be maintained in a cold, ready-to-start state.

The air separation unit process will neither consume water nor produce or discharge wastewaters. The unit will require water only for non-contact cooling purposes which will be provided from the makeup water system and/or the cooling reservoir. Only minor, intermittent particulate matter air emissions may result from the venting of the regeneration gas.

3.1.1.3 Gasification System

The proposed IGCC unit will use the Texaco oxygen-blown, entrained flow, gasification system to produce syngas for the advanced CT. The proposed gasification system will involve a single-train gasifier which will be capable of converting approximately 2,325 tpd of coal, on a dry basis, to syngas. While the proposed gasification train will be the largest Texaco train in operation to date, the proposed system involves commercially proven technologies, processes, and equipment. Currently, licensed Texaco CG plants are being operated commercially by Tennessee Eastman in Kingsport, Tennessee; by Ube Ammonia in Ube City, Japan; and by SAR in Oberhausen, Germany. To date, these plants have gasified more than 5 million tons of coal and coke.

Also, although currently not in operation, the Texaco gasification system and a GE CT unit were successfully operated at the 120-MW Cool Water IGCC facility in Daggett, California. The Cool Water plant was developed jointly by Texaco, the Electric Power Research Institute (EPRI), Southern California Edison, Bechtel Power Corporation, GE, and a Japanese partnership.

The Cool Water facility was operated between June 1984 and June 1989 and is currently maintained in a long-term standby status. During its operation, the Cool Water IGCC plant was operated for more than 26,000 hours, generated more than 2.7 billion kilowatt hours (kwh) of electricity, and achieved a capacity factor of 87 percent in its final quarter of operation. The successful demonstration aspects of the Cool Water plant involved not only the commercial viability of the gasification technology for power generation, but also the environmental acceptability of the technology under stringent State of California and EPA regulations regarding air emissions, water quality, and solid wastes.

The Texaco gasification system has also been successfully operated in demonstration plants in Muscle Shoals, Alabama, and in Oberhausen, Germany, as well as in Texaco's gasification pilot plant and testing facilities in Montebello, California.

Figure 3.1.1-4 presents the process flow schematic for the proposed 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 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 high 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 sump tank.

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 sump tank. The proposed system for handling and processing the black water is described in Sections 3.5.4.5 and 3.5.4.6. Potential air emissions or leaks from the gasifier to the atmosphere will be negligible since it will be designed to maintain pressure and control syngas flows.

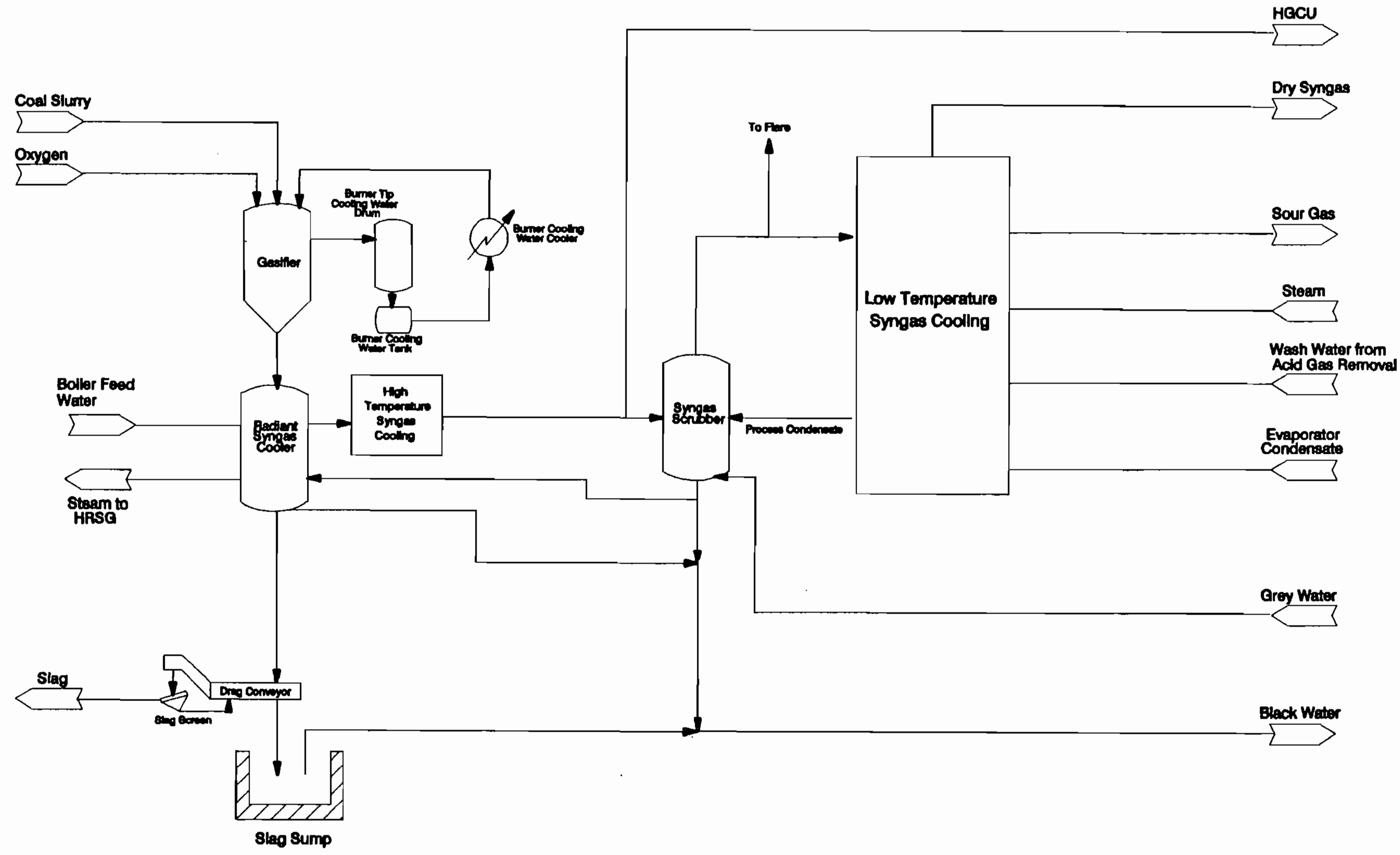

FIGURE 3.1.1-4.

GASIFICATION, SLAG HANDLING, AND SYNGAS COOLING SYSTEM SCHEMATIC

Source: Texaco, 1992.

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3.1.1.4 Slag Handling

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 3.1.1-4 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 sump tank. Solids flushed to the slag sump tank will settle onto the drag conveyor and will be carried out of the sump. Next, the solids will fall onto the slag screen where they are dewatered. The slag will then be transported by conveyors to a concrete dewatering pad. The concrete dewatering pad will be bunkered to prevent runoff from the area and have a sump to collect the dewatering water. From the dewatering pad, 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 Section 3.1.4. The water removed from the slag and sumps 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 and 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. As discussed in Section 3.7.1.5, the slag is classified as non-hazardous and non-leachable and will be marketed and sold for various offsite commercial uses.

3.1.1.5 Syngas Scrubbing and Cooling Systems

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 50 percent of the syngas when the unit is operating at full capacity. The CGCU system is described in the following subsections, and descriptions of the HGCU system are provided in Section 3.1.1.10.

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 3.1.1-4.

As shown in Figure 3.1.1-4, the raw hot syngas from the gasifier will be fed through the high temperature syngas cooling system to the syngas scrubber where entrained solids are removed. The syngas will then be routed to the low temperature gas cooling section. The low temperature gas cooling section will cool the syngas by recovering its useful heat and will condense out much of the water from the syngas prior to its routing to the acid gas removal system.

During startups, shutdowns, and upsets, syngas will be routed to the flare for short periods of time.

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

All water used in the syngas scrubbing and cooling processes will be provided by recycled water streams. Also, all process water streams will be sent to the black water handling system and/or reused within other CG plant systems. The syngas scrubbing and cooling processes will have no potential ambient air emissions.

3.1.1.6 Gasification Process Black Water Handling and Brine Concentration 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 in Section 3.1.1.5, the syngas scrubber also generates black water, which contains the fine particles entrained in the syngas exiting 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 condensed and crystallized into a solid consisting primarily of salt called brine which will be stored in lined landfill on the site with appropriately designed leachate and stormwater runoff collection and treatment systems. The black water handling, processing, and crystallization systems and processes are described in Section 3.5.4, and the brine storage area is described in Section 3.7.1.

3.1.1.7 Acid Gas Removal Unit

After removal of the entrained solids, the syngas will still contain acid gases such as CO_2 and H_2S 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 3.1.1-5.

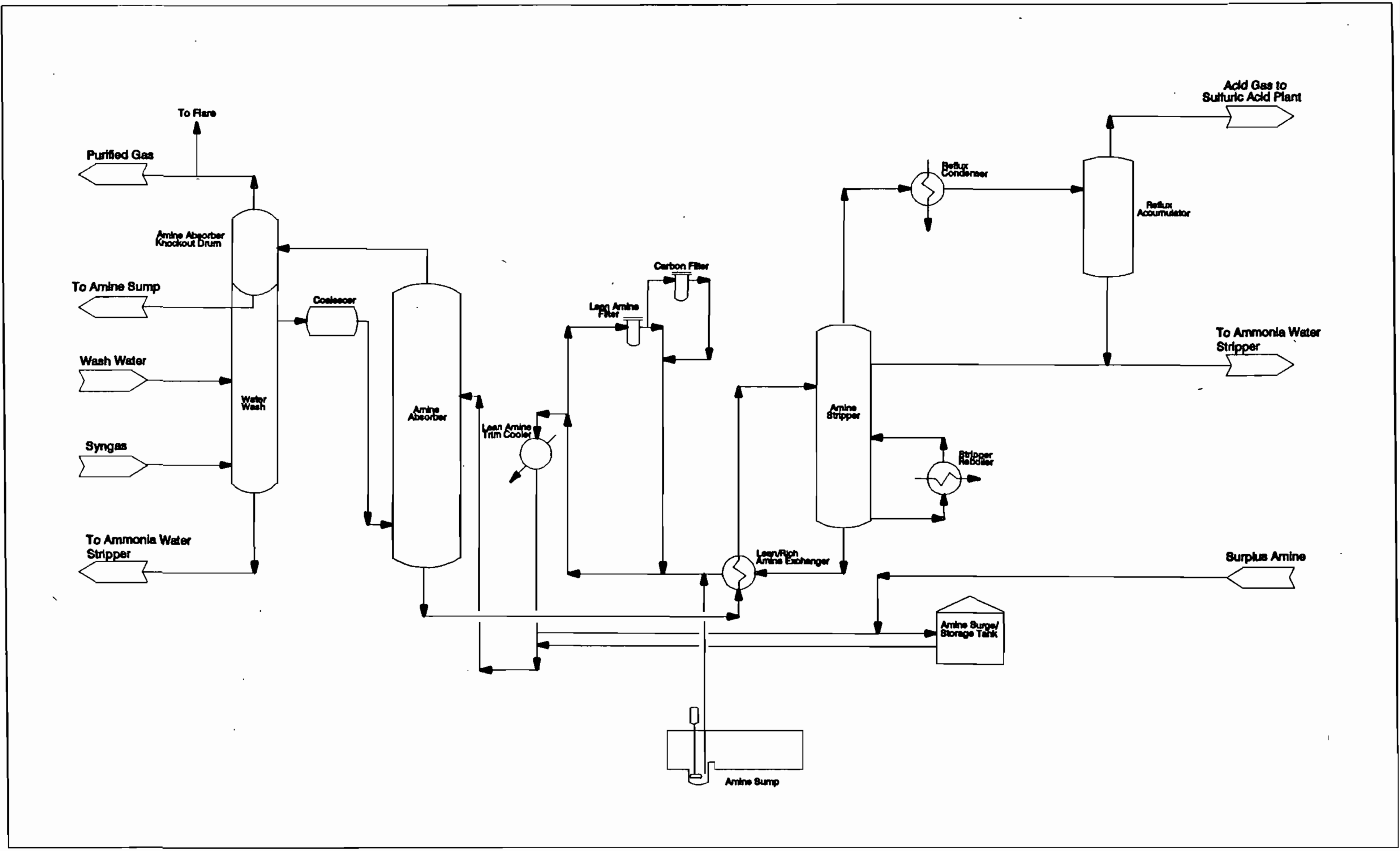

FIGURE 3.1.1-5.

ACID GAS REMOVAL UNIT SCHEMATIC

Sources: Texaco, 1992. Bechtel, 1993.

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In this 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 flow through a liquid coalescer to collect entrained water droplets and 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 CO_2 and H_2S by chemical reaction. The purified syngas will flow through a knock-out drum located on top of the water wash column to remove entrained amine. The recovered liquid will be returned to the amine sump.

During startups, shutdowns, and upsets, syngas will be routed to the flare for short periods of time.

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 ~~sulfur recovery unit~~ H_2SO_4 plant, and the condensed liquid reflux will be returned to the amine stripper.

~~3.1.1.8 Sulfur Recovery Unit~~

~~The sulfur recovery unit, shown schematically in Figure 3.1.1-6, will convert H_2S gas to a liquid molten sulfur by-product. Approximately one third of the feed H_2S will be oxidized in the thermal reactor to form SO_2. The SO_2 will then be reacted with the remaining H_2S to form elemental sulfur and water. NH_3 from the NH_3 stripper will also be oxidized to nitrogen and water. Any hydrocarbons in the acid gas feed will be oxidized in the thermal reactor to CO and water.~~

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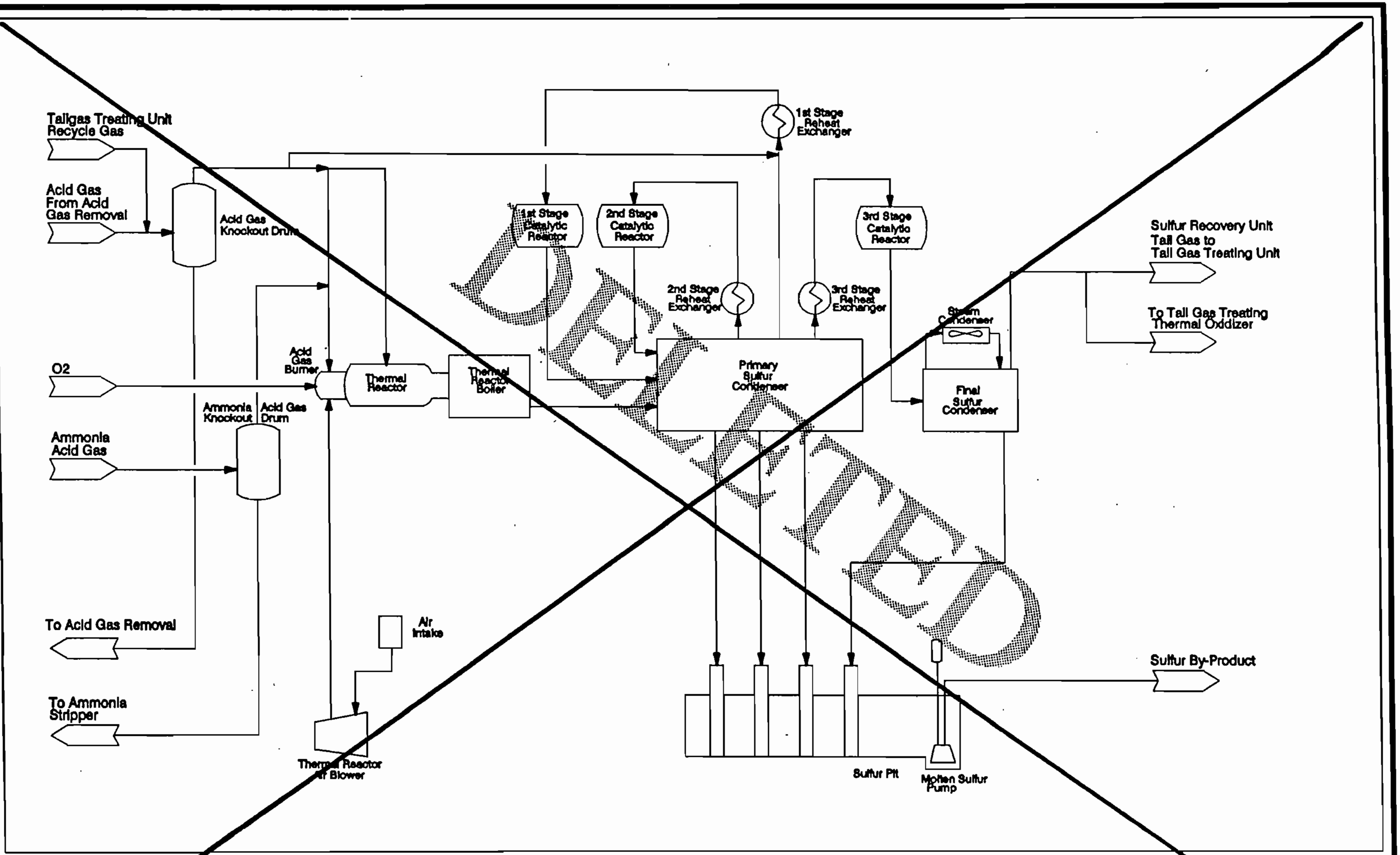

FIGURE 3.1.1-8.

SULFUR RECOVERY UNIT SCHEMATIC

Source: Texaco, 1992.

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~~The basic reactions are:~~

~~1. $H_2S + 1.5\ O_2 \rightarrow SO_2 + H_2O$, and~~

~~2. $2H_2S + SO_2 \rightarrow 1.5\ S_2 + 2H_2O$.~~

~~Depending on the concentration of H_2S in the acid gas feeds, as much as half of the unit's total sulfur by-product production will come from the non-catalytic reactions in the thermal reactor. This sulfur will be condensed and removed from the stream prior to feeding the first catalytic reactor. The balance of the sulfur by-product production will be formed in the three catalytic reactors.~~

~~The acid gas knock-out drum and the NH_3-water stripper gas knock-out drum will be designed to remove entrained water and condensed hydrocarbons from the amine acid gas and the NH_3-water stripper gas feeds from the acid gas removal unit upstream of the thermal reactor. The NH_3-water stripper gas stream will be fed entirely to the thermal reactor burner located in the front chamber of the thermal reactor. The amine acid gas from the acid gas removal unit may be split to assist the reaction. Pure oxygen will be added, if necessary, to maintain the front chamber temperature to ensure NH_3 combustion. If NH_3 is not present, then lower temperatures may be used. The remainder of the amine acid gas stream will be fed to the second chamber of the thermal reactor or by-passed to the inlet of the first stage reheat exchanger. Approximately one third of the H_2S in the feed gas will be converted to SO_2 and water in the thermal reactor. Air from the air blower and oxygen will be supplied to the thermal reactor to oxidize the H_2S in the NH_3 stripper gas to SO_2 and water, to oxidize the NH_3 to nitrogen and water, and to oxidize any hydrocarbons in the NH_3 stripper gas to CO_2 and water.~~

~~The hot combustion gas from the thermal reactor second chamber will enter the boiler where the gas is cooled. The effluent gas from the boiler will enter the primary sulfur condenser. Sulfur produced in the thermal reactor will be condensed in the primary sulfur condenser as the gas is cooled. Steam will be produced as the gas is cooled and the sulfur is condensed. The liquid sulfur will be separated from~~

~~the gas in a separator chamber at the outlet end of the primary sulfur condenser and will be drained to the sulfur seal pot. The liquid sulfur seal in the pot will prevent the process gas from escaping to the sulfur pit. The uncondensed gas from the first pass of the primary sulfur condenser will be routed to the first reheat exchanger where the gas is re-heated. The steam condensate produced from the reheat exchanger will flow to the primary sulfur condenser.~~

~~The gas from the first reheat exchanger will pass through the first catalytic reactor where the reaction of the remaining SO_2 with H_2S occurs over a fixed bed of activated alumina catalyst. The heat given off by the reaction in the first bed will be the greatest of all the catalytic reactor beds. The catalytic reactor product gas, containing the newly formed elemental sulfur, will exit the catalytic reactor and enter the second pass of the primary sulfur condenser. Sulfur formed in the first catalytic reactor will be condensed and will be drained to the sulfur seal pot.~~

~~The uncondensed gas will then be routed to the second reheat exchanger where it is heated prior to being fed to the second catalytic reactor. The second catalytic reactor will be similar in size and function to the first catalytic reactor. Since the concentration of the reactants will be lower in the second catalytic reactor feed than in the first, less reaction will take place. The second catalytic reactor effluent gas will again enter the primary sulfur condenser, where the bulk of the sulfur formed in the reactor will be condensed, and will be drained to the sulfur seal pot.~~

~~The uncondensed gas from the third pass of the primary sulfur condenser will be routed to the third catalytic reactor via the third reheat exchanger. Again, the steam condensate from this reheat exchanger will be sent to the primary sulfur condenser. Since the concentrations of H_2S and SO_2 will be low in the third catalytic reactor, only a relatively small amount of sulfur will be formed in this reactor. The sulfur formed in the third catalytic reactor will be condensed in the final sulfur condenser as the stream cools and drained to the sulfur seal pot.~~

~~The uncondensed gas (tail gas) will exit the final sulfur condenser via a mist eliminator pad and will be routed either to the tail gas treating unit or to the thermal oxidizer based on the tail gas sulfur content.~~

~~The thermal oxidizer will be designed to oxidize the tail gas from the sulfur recovery unit. Any unreacted H_2S, CS_2, COS, elemental sulfur, and any other combustible sulfur compounds in the gas will be oxidized almost entirely to SO_2 in the thermal oxidizer. The design thermal oxidizer combustion temperature will be maintained by burning a syngas stream or a low-sulfur fuel oil or natural gas in addition to the process effluent vapor. The oxidized products will be dispersed to the atmosphere via a 199 ft high stack.~~ ~~*Under normal operations, only the tail gas treating unit vent gas will be oxidized in the thermal oxidizer.*~~

~~The sulfur by-product will be of marketable-grade quality (i.e., greater than 90 percent purity). Approximately 90 tpd of sulfur by-product will be generated from the sulfur recovery unit when the IGCC unit is operating at full load and 100 percent of the syngas for the unit is treated in the CGCU system. The sulfur recovery unit will have a sulfur day tank within a concrete pit. The tank will have approximately a 10-day storage capacity. Heat will be provided by steam coils at the bottom of the pit. The tank will have pumps to transfer the molten sulfur to either the truck loading rack or the railcar loading rack for transport offsite. Additional storage capacity for the sulfur by-product may also be provided in specially designed rail cars.~~

~~*3.1.1.9* Tail Gas Treating Unit~~

~~The sulfur recovery unit will typically convert approximately 96 percent of its H_2S feed gas to molten liquid sulfur. However, the concentration of H_2S and SO_2 in the tail gas from the sulfur recovery unit may still be too high to release to the atmosphere under normal operating conditions. The tail gas treating unit will be designed to recover this remaining H_2S and SO_2 for recycle back to the sulfur recovery unit and meet applicable emission levels in the tail gas vented to the~~

~~atmosphere. Reaction and recovery sections of the tail gas treating unit are presented schematically in Figures 3.1.1-7 and 3.1.1-8, respectively.~~

~~As shown in Figure 3.1.1-7, the sulfur recovery unit tail gas will be fed to the feed heater, and hydrogen rich reducing gas will be added to the heated gas leaving the feed heater. The mixed gas stream will be fed to a catalytic reactor. The reactor feed gas will pass downward through the catalyst bed and virtually all of the~~ ~~SO_2~~, ~~sulfur, COS, and~~ ~~CS_2~~ ~~will be converted to~~ ~~H_2S~~. ~~In the reactor, the following basic reactions of~~ ~~SO_2~~ ~~and elemental sulfur will take place:~~

~~1.~~ ~~$SO_2 + 3H_2 \rightarrow H_2S + 2H_2O$~~, ~~and~~
~~2.~~ ~~$S + H_2 \rightarrow H_2S$~~.

~~The COS and~~ ~~CS_2~~ ~~will be hydrolyzed by the water vapor present in the sulfur recovery unit tail gas to~~ ~~H_2S~~ ~~and~~ ~~CO_2~~. ~~A small portion of the COS and~~ ~~CS_2~~ ~~may not be hydrolyzed by water vapor present and may be reduced by hydrogen directly to~~ ~~H_2S~~. ~~To assure complete reaction of the COS and~~ ~~CS_2~~ ~~to~~ ~~H_2S~~, ~~a minimum excess of approximately 50 percent of the stoichiometric requirement of hydrogen rich gas will be fed to the reactor. The CO in the sulfur recovery unit tail gas will also act like hydrogen as a reducing gas; i.e., it reacts with the water vapor in the reactor to form hydrogen and~~ ~~CO_2~~. ~~Therefore, minimal unreacted sulfur compounds will remain in the reactor outlet.~~

~~The hot gas leaving the reactor will be cooled in the waste heat boiler, which will generate steam. Water will be condensed out of the gas when it is further cooled by direct contact with the circulating quench water in the quench tower. The temperature of the quench water will increase as it cools the gas in the tower. The quench water bottoms will be pumped through the quench water cooler and quench water trim cooler before being returned to the top section of the quench tower. A slipstream of the quench water flow will be routed through the quench water filter to remove solids in the quench water.~~

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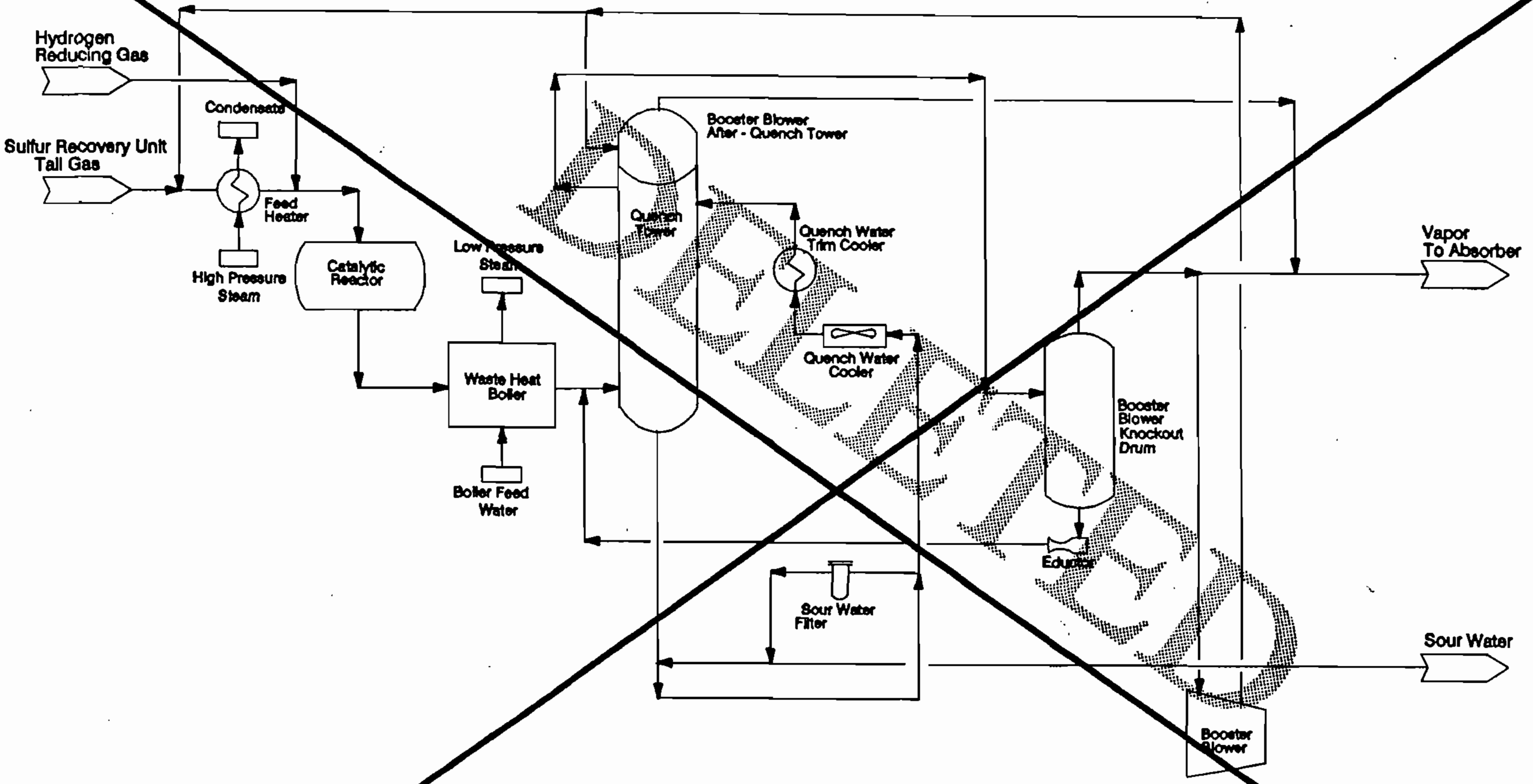

FIGURE 3.1.1-7.

TAIL GAS TREATING UNIT REACTION SECTION SCHEMATIC

Source: Texaco, 1992.

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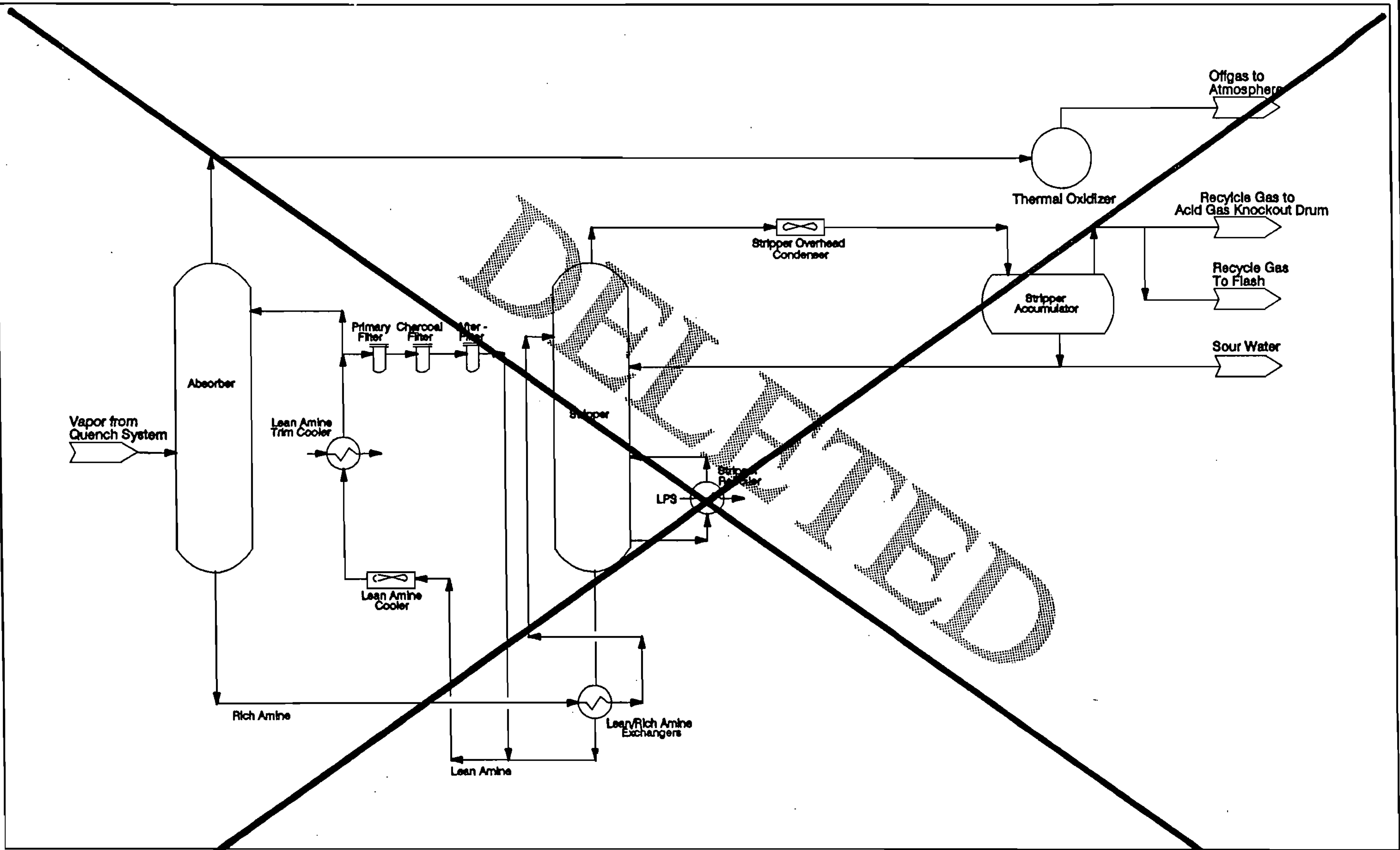

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FIGURE 3.1.1-8

TAIL GAS TREATING UNIT RECOVERY SECTION SCHEMATIC

Source: Texaco, 1992.

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~~The quench tower overhead gas stream will be fed to the booster blower knockout drum where any entrained liquid will be separated from the gas. The separated liquid will then be removed and returned to the quench tower bottoms above the normal liquid level. From the booster blower knockout drum, the gas normally will go to the absorber where it flows upward through the absorber through lean amine flowing downward in the absorber to remove the H_2S. The absorber overhead gas, which will have less than 260 parts per million volumetric (ppmv) of H_2S, will be fed to the thermal oxidizer. In the thermal oxidizer, H_2S and any other remaining sulfur compounds will be converted to SO_2 and vented to a stack.~~

3.1.1.10 Hot Gas Cleanup and Offgas Treating Systems

A schematic of the HGCU system is presented in Figure 3.1.1-9. For the system demonstration, a portion of the hot raw syngas will be routed from the gasifier to the HGCU system for cleanup prior to firing in the advanced CT.

Particulate Removal

Entrained fine particles in the syngas from the gasifier will be removed in the primary high efficiency cyclone as shown in Figure 3.1.1-9 and recycled to the black water handling system. Following this high efficiency cyclone is a second high efficiency cyclone whose function is to remove the ~~Nahcolite~~ sodium bicarbonate which is introduced upstream for halogen removal. The collected solids from the second high efficiency cyclone will be sent to the onsite brine ~~disposal~~ storage area. A large fraction of the remaining PM entering the absorber will be captured by the bed, reducing particle concentration to below 30 ppm. A small amount of zinc titanate fines will be entrained from the absorber and collected in a high efficiency barrier filter. The high efficiency barrier filter will effectively capture all of the high-density zinc titanate 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 ~~primary high efficiency cyclone and~~ barrier filter are non-hazardous 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

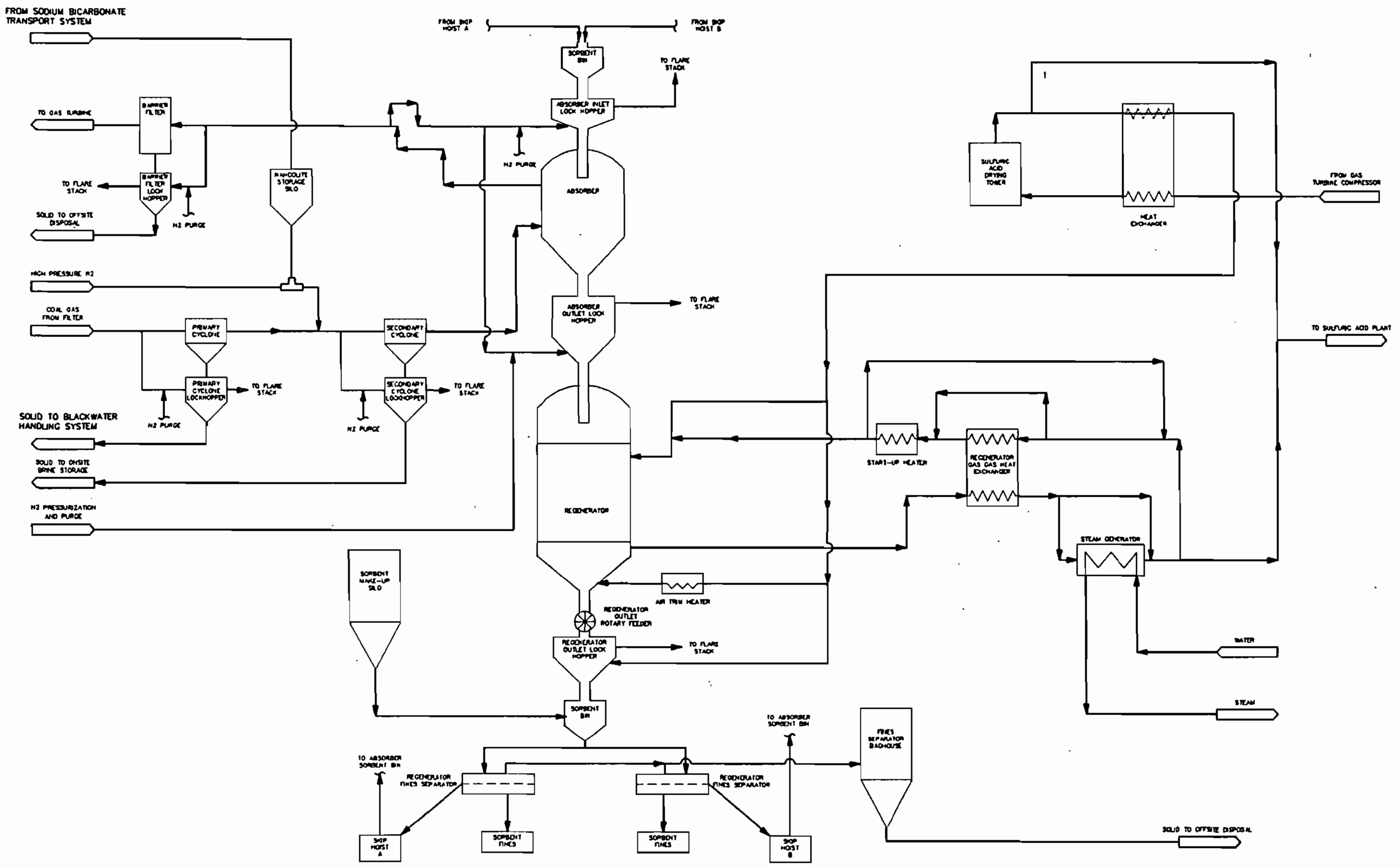

FIGURE 3.1.1-9.

HOT GAS CLEANUP SYSTEM

Source: GEESI, 1992.

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filter. The sorbent fines from both collection points will be recycled to the catalyst supplier.

Desulfurization

The absorber is the intermittently moving bed reactor shown schematically in Figure 3.1.1-9. The sulfur-laden coal gas from the primary cyclone will enter the absorber through a gas manifold at its bottom and flow upward countercurrent to the moving bed of zinc titanate 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 zinc titanate will be replaced by regenerated sorbent from the absorber's inlet lockhopper.

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 up to 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:

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

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

The sulfation reaction will be reversible and favor the formation of sulfate at low temperatures in the presence of oxygen at the lower oxidation stage.

Sulfided zinc titanate 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 reactor in cocurrent flow with the regeneration gas. Oxygen concentration will be controlled to limit the gas temperature. Under these conditions, no thermal damage will occur to the sorbent.

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 reactor 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.

Regeneration Gas Recycle Subsystem

The regeneration gas recycle is shown in Figure 3.1.1-9 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.

Halogen Removal

Commercial grade sodium bicarbonate~~, trade named Nahcolite,~~ will be injected with a small quantity of high pressure nitrogen, upstream of the secondary cyclone as shown in Figure 3.1.1-9. Chloride and fluoride species will be removed by a direct contact reaction with th~~e Nahcolite~~ 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.

3.1.1.11 Sulfuric Acid Plant

In the HGCU process, an ~~offgas~~ acid gas is produced which has a high SO_2 concentration. For the proposed project, this ~~offgas~~ acid gas will be treated by converting the SO_2 to H_2SO_4.

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 knock-out drums to remove any entrained water. These gases will then be introduced into a combustion chamber, along with combustion air or oxygen. 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 combustion chamber and mix with the combusted acid gas from the CGCU unit.

The conversion of these mixed gases involves a multi-step catalytic process based on proven technology in widespread commercial use, especially within the chemical fertilizer industry in central Florida. The liquid H_2SO_4 produced by this process is commercial grade and will be marketed and sold by Tampa Electric Company for offsite uses.

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 above 350 psig to avoid condensing acid in the tubes. The gases from the waste heat boiler will be quenched (cooled) in a scrubbing tower, with a circulating stream of water, i.e., a conventional open spray water tower.

Reaction air 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 tower. Depending on the available pressure of the acid gas (H_2S) feed stream(s), it may be possible to eliminate the blower.

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. The SO_2 concentration will determine the exact location of the various heat exchangers and heaters. An indirect fuel gas heater may be used to supplement the reaction heat for startup, turndown, or low SO_2 operations. The gases from the reactor will be cooled and sent to the absorber tower(s), where 93-percent acid absorbs the SO_3 from the process gas stream. The high concentration H_2SO_4 will be circulated from the absorber tower(s) bottom, through the acid cooler(s), and then returned to the top of the absorber tower(s). The gases from the absorber tower will pass through a mist eliminator to remove acid mist, and are then routed to the thermal oxidizer. The thermal oxidizer, which also operates during startup and shutdown, will burn distillate fuel. Gases and combustion products will be discharged to the atmosphere at approximately 1,400°F.

~~A skid-mounted~~ The H_2SO_4 unit will be constructed adjacent to the CG 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 for commercial use in specially-designed rail cars or trucks. Assuming the HGCU system is used to clean up approximately 50 percent of the syngas for the IGCC unit and the CGCU system is used to clean up the other 50 percent, or the CGCU system is used to clean 100 percent of the syngas at 100-percent generating capacity, the unit would produce approximately ~~45,000~~ 77,000 tons per year (tpy) of liquid H_2SO_4 by-product.

~~Tampa Electric Company is currently evaluating an integration concept that would allow some of the H_2S offgas from the CGCU sulfur recovery unit to be processed in the H_2SO_4 plant. The ability to treat the offgas from the CGCU system in the H_2SO_4 plant would enhance plant reliability if the CGCU system sulfur recovery and tail gas treating units were unavailable. Further, if the HGCU system is not successfully demonstrated, the integration would allow the H_2SO_4 plant to be productively used rather than left unused. This integration concept would retain the same overall sulfur removal efficiencies for the IGCC unit and would not change the proposed size of the H_2SO_4 plant or the amount of H_2SO_4 by-product produced.~~

3.1.1.~~11~~ 12 Power Production

The power production system for the IGCC unit is illustrated in Figures 3.1.1-10 and 3.1.1-11. The key components are the advanced CT, HRSG, and ST generator. The advanced CT will be a GE 7F. The unit will be designed for low-NO_x emissions firing syngas, with low sulfur fuel oil for startup and as backup fuel.

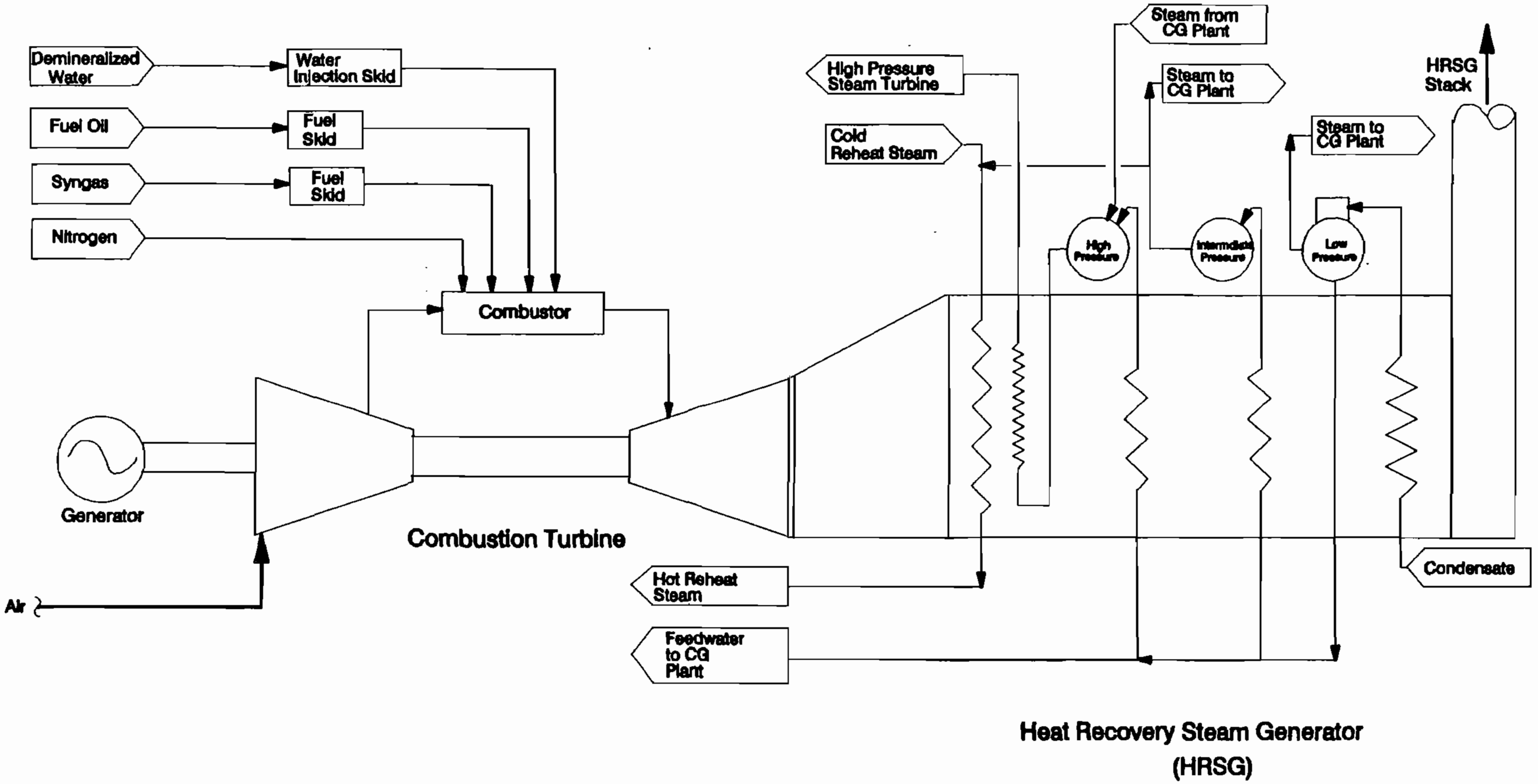

FIGURE 3.1.1-10.

COMBUSTION TURBINE PROCESS FLOW SCHEMATIC

Source: GE, 1992.

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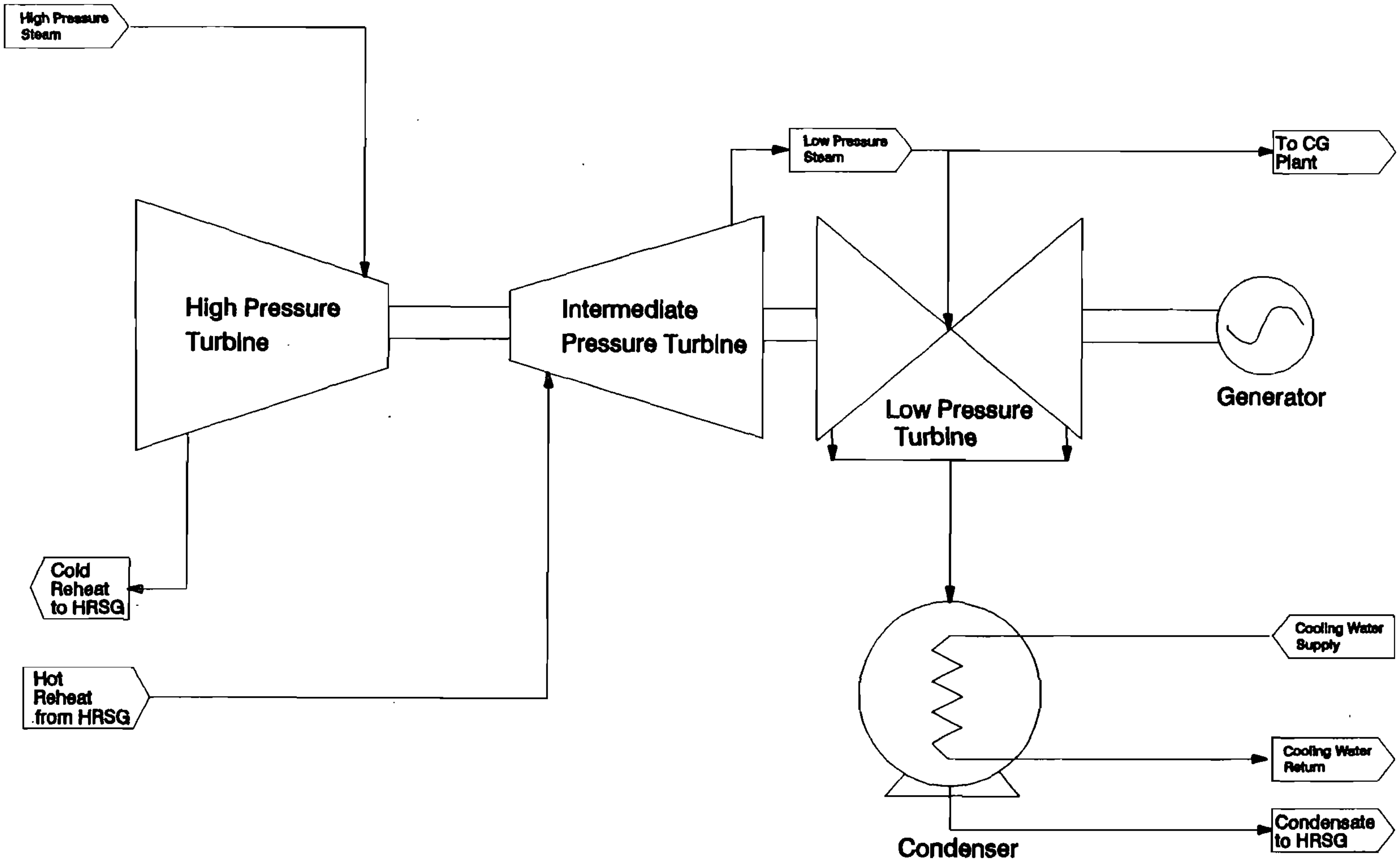

FIGURE 3.1.1-11.

STEAM TURBINE PROCESS FLOW SCHEMATIC

Source: GE, 1992.

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One HRSG will be employed to recover the CT exhaust heat and generate steam to power the ST. The HRSG will be a three-pressure level, reheat, natural circulation design. The HRSG will produce high pressure superheated steam for the high pressure ST, and will reheat the high pressure turbine exhaust steam for admission into the intermediate pressure ST. The HRSG will also produce intermediate pressure steam which is combined with high pressure turbine exhaust steam (cold reheat steam). Low pressure steam will be produced for supply to the CG facilities for process use. The HRSG will receive additional high pressure steam and heat energy from the CG facilities to supplement the steam cycle power output. No auxiliary firing is proposed within the HRSG system.

The ST will be designed as a double flow reheat with low pressure crossover extraction. The ST generator will be designed specifically for highly efficient CC operation with nominal turbine inlet throttle steam conditions of approximately 1,450 psig and 1,000°F with 1,000°F reheat inlet temperature.

The operation of the CC power plant will be coordinated with the startup and operation of the CG process plant. The initial startup of the power plant will be carried out on low-sulfur distillate fuel oil. Transfer to syngas will occur upon establishment of fuel production from the CG plant.

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

Hot exhaust from the CT will be channeled through the HRSG to recover the CT exhaust heat energy. The HRSG high pressure steam production will be augmented by high pressure steam production from the CG plant. All high pressure steam will be superheated in the HRSG before delivery to the high pressure ST.

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 ST. Some intermediate pressure steam will also be supplied from the HRSG to the sulfur recovery unit.

Additional low level energy integration will occur between the HRSG and the CG plant. Low pressure steam will be provided by the HRSG to the CG facilities for process use, and some low level waste heat in the CG facilities will be used for condensate heating for the HRSG. Extraction steam from the low pressure crossover will be available to supplement the HRSG low pressure steam production for the CG facilities when necessary. The low pressure turbine will exhaust to a water cooled condenser which will receive.cooling water from the cooling reservoir. Condensate from the ST condenser will be returned to the HRSG/integral deaerator by way of the CG facilities, where some condensate preheating occurs.

Emissions from power production will result from the combustion of fuels in the advanced 7F CT. During the first year of operation (i.e., prior to conversion to IGCC), the CT emissions will exit via a temporary CT stack. After conversion, the temporary CT stack will be removed, and emissions will exhaust via the HRSG stack.

3.1.2 COMBINED CYCLE UNIT DESCRIPTIONS

General descriptions of the CC and CT unit electric generating technologies were provided in Section 1.5.

As shown in Table 3.1.0-1, the proposed Polk Power Station will include two nominal net 220-MW CC units. Each of the CC units is expected to be comprised of two 75-MW CTs, two HRSGs, and one ST generator. The CTs will be designed with dry low-NO_x combustors to control NO_x air emissions when firing natural gas which will be the primary fuel for the units. NO_x emission control will be by water injection when the units are fired on the backup low-sulfur distillate fuel oil. SO_2 air emissions from the units will be controlled by the use of fuels with low sulfur contents (i.e., natural gas with trace sulfur content and fuel oil with a maximum sulfur content of 0.05 percent). The CTs will also be designed with by-pass exhaust stacks to be capable of operating in both CC and simple-cycle modes.

For each CC unit, two HRSGs (one per CT) will be employed to recover exhaust heat from the CTs and produce steam to power the ST generator. The HRSG/ST generator facilities will have a nominal net 70 MW generating capacity.

The two CC units will be capable of operation of up to a 100-percent capacity factor annually when fired on natural gas and up to a 25-percent annual capacity factor when fired on the backup, low-sulfur distillate fuel oil.

The CC units will require water for the steam generating cycle (i.e., boiler makeup and condenser cooling) and other plant uses as well as air emissions control when fired on backup fuel oil (see Section 3.5.4.1). Makeup water for the HRSG boiler, emission control, and other plant process water will be provided by treated waters from onsite wells in the Floridan aquifer. When fired on backup fuel oil, water injected into the CTs for NO_x emission control is evaporated and creates no wastewater. All process wastewaters from the facilities will be treated, as appropriate, in the onsite industrial wastewater treatment system and routed to the cooling reservoir for reuse. A description of the industrial wastewater treatment system is provided in Section 3.5.4.3.

Water for condenser cooling will be provided from and returned to the cooling reservoir. Descriptions of the cooling reservoir and its operations are provided in Section 3.5.1.

3.1.3 COMBUSTION TURBINE UNIT DESCRIPTIONS

The proposed Polk Power Station will also include six stand-alone, simple-cycle CT units. Each of the CTs will have a nominal net generating capacity of 75 MW, similar to the CTs comprising the CC units. Also, like the CTs in CC mode, the stand-alone CTs will be designed with dry low-NO_x combustors to control NO_x air emissions when firing natural gas, the proposed primary fuel for the units. NO_x emission control will again be accomplished by water injection when the units are fired on the backup distillate fuel oil. SO_2 air emissions from the CTs will be controlled by the use of low sulfur fuels (i.e., natural gas with only trace sulfur content and distillate fuel oil with a maximum sulfur content of 0.05 percent).

The CT units will be capable of operating up to a 50-percent annual capacity factor when fired on natural gas and 10 percent when fired on the backup fuel oil.

When fired on fuel oil, the CTs will require demineralized water for NO_x emission control by water injection. The injected water is evaporated in this emission control process and creates no wastewater. The CTs will require water for periodic and low volume uses such as non-chemical cleaning, washdowns, pump and equipment gland seals, and flushes. Wastewaters from these uses will be collected and appropriately treated in the industrial wastewater treatment system.

3.1.4 ASSOCIATED FACILITIES DESCRIPTIONS

To support the overall operations of the proposed electric generating units for the Polk Power Station project, various associated facilities and reclaimed areas will be constructed and operated on the site and certain associated facilities will be developed offsite. In addition to the facilities previously described in this section, the proposed directly associated facilities and areas will include the following:

- Access roadways and rail spur;
- Coal delivery, handling, and storage facilities;
- Natural gas and fuel oil delivery and storage facilities;
- Process, service, and potable water supply facilities;
- Domestic and industrial wastewater treatment systems;
- Cooling reservoir and discharge facilities;
- By-product slag~~, sulfur,~~ and H_2SO_4 handling, temporary storage, and shipping facilities;
- Stormwater collection and management systems;
- Substation and associated electric transmission line facilities; and
- Wildlife management/corridor area.

These associated facilities are described in the following subsections or references are provided to appropriate sections of this SCA which contain descriptions of these facilities and their processes and operations.

3.1.4.1 Access Roadways and Rail Spur

Roadway access to the main power plant facilities will be provided by two entrances on SR 37 and an entrance from Fort Green Road. All entrance roads will include appropriate geometric improvements at the intersections with the existing roadways in order to maintain acceptable LOS standards on the existing roadway network. Also, all entrance roads will have security gates to control access to the site. The southernmost entrance from SR 37 will be the main and employee entrance to the facilities. The northern entrance from SR 37, opposite Bethlehem Road, and the entrance from Fort Green Road will be used primarily for deliveries and for construction and operational contractor access to the site.

A railroad spur will be constructed from the existing CSX Railroad line which runs along the east side of Fort Green Road on the eastern boundary of the Polk Power Station site to the main power plant facilities area. Except for an approximately 200-ft segment to cross Fort Green Road, the rail spur will be located within the boundaries of the site. On the site, the rail spur will be approximately 1.5 miles with a rail loop at the end to provide for turning and storage of trains. The rail spur access to the site will be used for the delivery of coal and other materials and equipment to the site during construction and operation and for transport offsite of by-products (i.e., slag~~, sulfur,~~ and H_2SO_4) from the IGCC facilities.

3.1.4.2 Fuel Delivery, Handling, and Storage Facilities

The coal handling system will receive, store, reclaim, and transport coal from unit railroad cars and/or trucks to the coal preparation system serving the IGCC unit. The coal will be stored in an approximately 10-acre area on the site, including the surrounding berm and runoff basin. The coal storage area will be lined with a synthetic material or other material with similar low-permeability characteristics and include leachate and stormwater collection systems. The onsite coal handling and storage facilities are described in detail in Section 3.3.1.

Natural gas will be used as the primary fuel for the stand-alone CT and CC units planned for the Polk Power Station. Natural gas will be delivered to the site via a pipeline from either the existing or future natural gas transmission system in the region. Natural gas will not be stored on the Polk Power Station site. The proposed natural gas supply and delivery plans are described in Sections 3.3.2 and 6.2.

Initially, No. 2 fuel oil will be used as a primary fuel for the advanced CT unit planned for the Polk Power Station during its first year of operation, after which the CT will be converted to the IGCC unit. Fuel oil will be delivered to the site by tanker truck and/or rail. Based on current fuel cost forecasts, Tampa Electric Company anticipates that fuel oil will serve primarily as a backup fuel for the stand-alone CT and CC units and IGCC unit in CC mode after the initial project phase. Tampa Electric Company's proposed plans for fuel oil supply, delivery, and storage are described in Section 3.3.3.

3.1.4.3 Water Supply Facilities

Water to supply the potable, process, and cooling reservoir makeup needs for the operations of the Polk Power Station will be provided from groundwater withdrawn from the Floridan aquifer through onsite wells. After full build-out of the proposed facilities, the onsite wellfield to provide these operational water requirements will ultimately consist of two 10-inch and two 24-inch production wells which will be screened within the Floridan aquifer starting at a depth of approximately 300 ft bls to approximately 900 to 1,000 ft bls. Also, after full build-out, the total estimated groundwater withdrawals for potable, process, and cooling water makeup uses will be approximately 9.3 MGD on a maximum daily basis and approximately 6.6 MGD under average annual operating conditions. These estimated withdrawals are based on the use of water injection for NO_x control for the stand-alone CC and CT units when fired on the backup fuel oil.

Descriptions of the water supply requirements for the Polk Power Station operations and proposed treatment systems to provide water of suitable quality for the required uses are provided in Section 3.5 of this SCA.

3.1.4.4 Domestic and Industrial Wastewater Treatment Systems

Domestic Waste Treatment System

Discharges from domestic water uses such as from showers, wash basins, bathrooms, and drinking fountains are expected to result in approximately 10,500 gpd of combined sanitary wastewater flow on an average daily basis. This wastewater flow will be treated in an extended aeration-type package unit which will be constructed on the site. After appropriate treatment, effluent from this proposed sanitary waste treatment system will be discharged to the cooling reservoir for reuse in the heat dissipation system. Sludge will be periodically removed from this system by vacuum truck for offsite disposal in an appropriately licensed landfill. Section 3.5.2 provides a detailed description of proposed sanitary wastewater treatment system and processes.

Industrial Wastewater Treatment System

An overall industrial wastewater treatment (IWT) system will be constructed on the site to collect and appropriately treat process and service wastewater from the stand-alone CC and CT units and the CC module of the IGCC unit (e.g., non-chemical cleaning wastes and boiler blowdown from HRSG); stormwater runoff and washdown from the coal, slag, and IWT sludge storage areas; runoff and equipment washdown from the power block equipment areas of the IGCC, CC, and CT units; stormwater runoff and equipment washdown from the paved areas of the process units; and miscellaneous streams such as filter backwash.

As discussed previously in Section 3.1.1.6, a separate zero liquid discharge water handling system will be provided for process waters from the CG and syngas cleanup systems. Runoff from the active brine solids storage area will be temporarily stored in a holding tank and directed into the brine concentrator. Wastewater produced from the periodic chemical cleaning of equipment (i.e., HRSG boilers) will be collected and temporarily stored in a holding tank prior to being trucked offsite by a licensed contractor for appropriate treatment and disposal.

The proposed IWT system will be designed to treat wastewater on a continuous basis and will be comprised of the following basins and units:

- Oil/water separation;
- Neutralization tank;
- Diversion boxes;
- Coal, IWT sludge, and slag runoff retention basins;
- Oxidation tank;

- Clarification;
- Chemical restabilization tank (neutralization);
- Filtration; and
- Sludge handling system.

After treatment, the effluent from the IWT system will be routed to the cooling reservoir for reuse in the heat dissipation and condenser cooling system. The sludge filter cake produced by the system will be temporarily stored onsite in a lined area with a stormwater collection system prior to transport offsite for commercial use or disposal in a licensed landfill. The proposed sludge storage area will be capable of storing up to 5 years of sludge generated by the treatment system.

Sections 3.5.4.3 and 3.5.4.4 provide detailed descriptions of the process wastewater sources and the overall IWT system and processes.

3.1.4.5 Cooling Reservoir

The steam electric generating components of the proposed IGCC unit and two CC units require water to cool or condense the exhaust steam from the STs. The waste heat transferred to the cooling water must then be rejected to the atmosphere. The proposed cooling/heat rejection system for the Polk Power Station will be a cooling reservoir.

The proposed 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 ft-NGVD with an average elevation of 120 ft-NGVD, and the top of the surrounding ~~and internal~~ berms will be 145 ft-NGVD. The internal berms will have a top elevation of approximately 141 ft-NGVD. The finish grade on the main power plant facility area will be between 140 and 145 ft-NGVD. Under normal operating conditions, water levels in the reservoir will be approximately 136 ft-NGVD, and the total water surface area will be approximately 727 acres.

The top of the surrounding and internal earthen berms~~, both surrounding and internal~~, will be approximately 25 and 17 ft wide, respectively, to provide access for inspection and maintenance purposes. The berms will be constructed with gentle slopes (4 ft horizontal to 1 ft 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 condenser cooling water will be constructed within the cooling reservoir. The estimated circulating, condenser cooling water flow requirements are approximately 115,800 gpm for the IGCC unit, including the air separation unit, and a total of approximately 247,000 gpm after build-out of the two CC units. The discharged circulating water will have a higher temperature than the intake water. This warmed 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.

Water lost from the cooling reservoir by both naturally-occurring and forced (i.e., heat rejection) evaporative processes will be replaced by several water sources in order to minimize groundwater withdrawals for makeup purposes. The cooling reservoir makeup sources will include rainfall directly to the reservoir and runoff from the surrounding and internal berms; treated wastewater from the sanitary and IWT systems, including treated runoff from the coal, slag, and IWT sludge storage areas, process unit areas, and power block areas; and groundwater seepage from the surficial aquifer. Additional makeup water will be provided from onsite wells in the Floridan aquifer. The pumped groundwater makeup requirements are estimated to be approximately 5.0 MGD on an annual average basis and 6.5 MGD on a maximum daily basis.

The cooling reservoir will be designed with an outfall control structure to provide for the discharge of water from the reservoir for water quality management, berm and vegetation maintenance, and unanticipated emergency purposes. Surface water discharges from the reservoir are estimated to be approximately 3.1 MGD on an annual average basis. The discharge will be routed to the reclaimed lake on the eastern edge of the site and then offsite to the Little Payne Creek system.

Section 3.5.1 provides a detailed description of the cooling reservoir heat dissipation system and processes, while Section 5.1 describes the expected effects of the system operations and discharges.

3.1.4.6 By-Product Slag~~, Sulfur,~~ and Sulfuric Acid Storage Facilities

By-products from the CG and syngas cleanup processes will include slag~~, sulfur,~~ and H_2SO_4. Each of these by-products have commercial uses and will be marketed and sold by Tampa Electric Company for those offsite uses. Therefore, only temporary storage facilities for these by-products will be provided on the Polk Power Station site and the proposed project will include facilities for the handling, loading, and transporting of these by-products from the site.

Slag Storage Area

Slag will be produced in the CG process and fine slag filter cake material will be produced in the water scrubbing process to remove entrained solids from the syngas. Slag material is a vitrified or glass-like solid which is non-leachable and salable as an abrasive, roof material, industrial filler, aggregate for concrete, or road base material. Tampa Electric Company is currently seeking long-term contracts for the sale of the slag by-product.

In the event that the slag by-product cannot be sold for offsite uses 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 1 year of operation of the IGCC unit at full capacity. Additional 1-year storage areas 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 3.2.0-1 and 3.2.0-2 would provide sufficient capacity for developing storage cells for up to 5 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 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 IWT system for filtration.

~~Sulfur Storage Facilities~~

~~An elemental sulfur by-product will be produced in the proposed sulfur recovery process which will be used to treat the acid gas removed from the syngas and to treat tail gas from the sulfur recovery unit in the overall CGCU system. These systems were described previously in Sections 3.1.1.8 and 3.1.1.9. This sulfur by-product will also be marketable for offsite use, especially with the central Florida chemical fertilizer industry. Approximately 90 tpd of sulfur in a molten state will be produced in the sulfur recovery system, assuming that 100 percent of the syngas fuel for the IGCC is being treated in the CGCU system at a 100 percent generating capacity.~~

~~Temporary storage of the molten sulfur by-product will be provided on the site in tanks which will be contained within a concrete-lined pit. The sulfur will be maintained in a molten state by heat provided from steam coils at the bottom of the pit. The proposed temporary storage tankage will be capable of storing up to approximately 30 days of sulfur produced from the recovery system. The proposed sulfur handling system will include loading facilities to specifically designed tanker trucks or railcars for transport offsite. Specifically designed railcars could also be used to provide additional temporary, onsite storage capacity, if needed.~~

~~Stormwater runoff from the concrete-lined sulfur storage area and handling and loading facilities will be routed to the IWT system for treatment.~~

Sulfuric Acid Facilities

~~Similar to t~~The CGCU acid gas treatment system~~,~~ and the demonstration HGCU system produce~~s an off-gas~~ offgases containing sulfur compounds which will require treatment. ~~This off-gas~~ These offgases will be treated by converting the sulfur compounds in the gas to H_2SO_4 which is ~~again~~ a marketable by-product especially with the central Florida chemical fertilizer industry.

The H_2SO_4 by-product will be produced in a ~~skid-mounted~~ H_2SO_4 plant. Approximately ~~45,000~~ 77,000 tpy of H_2SO_4 will be produced in this plant, assuming that the demonstration HGCU system is being used to treat the 50 percent of the syngas fuel and the CGCU system is used to treat the other 50 percent or the CGCU system is used to treat 100 percent of the syngas for operation of the IGCC unit at a 100-percent capacity factor. As necessary, the H_2SO_4 will be temporarily stored onsite in a tank or in specially-designed railcars prior to shipment offsite. These storage tanks will provide for up to approximately 30 days of temporary 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.

Additional descriptions of these slag~~, sulfur,~~ and H_2SO_4 by-product storage areas are provided in Section 3.7.1.

3.1.4.7 Stormwater Management Systems

As discussed previously, stormwater runoff from the coal, IWT sludge, slag, ~~sulfur,~~ and H_2SO_4 storage areas; the immediate areas of the power blocks for all the proposed generating units; and paved equipment areas associated with gasification and other process units will be routed to the overall IWT system. Stormwater runoff from the other areas associated with industrialized activity on the main power plant facilities site will be collected and routed to the two stormwater retention basins which will be constructed on the site. The primary stormwater retention basin will be approximately 26 acres and will receive the majority of runoff from the main power plant facility area. A small stormwater management basin will also be constructed to receive runoff from the area of the administration and general services building and associated parking lot.

Both of these stormwater management basins will be designed to detain in excess of the first inch of runoff resulting from the 25-year, 24-hour storm event in accordance with applicable SWFWMD and Polk County stormwater management regulatory requirements. Overflow discharges from these basins will be routed through a series of reclaimed wetland and lake areas prior to flowing offsite to the Little Payne Creek drainage system.

3.1.4.8 Substation and Associated Electric Transmission Line Facilities

To connect the proposed Polk Power Station with the Tampa Electric Company and Florida electric transmission grid, an onsite substation and four 230-kV transmission line circuits will be needed. The onsite substation will be constructed within an approximately 1,000-ft by 500-ft (i.e., approximately 11.5 acres) area to the north of the main power plant facilities.

Two of the 230-kV circuits from the substation will be constructed within a 400-ft wide transmission line corridor which will be located entirely within the Polk Power Station site boundaries and interconnect with the existing Tampa Electric Company 230-kV Hardee-Pebbledale transmission line which runs along the eastern border of the site. The other two circuits will be located within a corridor which runs west on the site from the substation to SR 37, then north along SR 37 approximately 5 miles, and interconnects with Tampa Electric Company's existing Mines-Pebbledale 230-kV transmission line at a point to the west of the community of Bradley Junction. Detailed descriptions of these associated transmission line corridors and the expected effects of their construction and operation are provided in Section 6.1 of this SCA.

3.1.4.9 Site Reclamation and Environmentally Enhanced Land Areas

In conjunction with the overall development of the Polk Power Station site, Tampa Electric Company will reclaim onsite lands previously mined or disturbed by phosphate mining activities as required under FDNR mined-land reclamation requirements (Section 211, F.S., and Chapter 16C-16, F.A.C.).

As part of these reclamation activities, Tampa Electric Company is proposing to create several areas which will develop into significant wildlife habitat and corridor areas and resources in the southwest Polk County region. The approximately 1,511-acre portion of the site located to the west of SR 37 will be reclaimed to an integrated system of forested and non-forested wetlands and uplands. After reclamation by Tampa Electric Company and with the company's planned controlled access to the area, this reclaimed area will develop into a wildlife habitat/corridor system between the headwater areas of the Little Manatee River and Payne Creek and South Prong Alafia River systems. The proposed wildlife habitat/corridor system will provide significantly enhanced environmental qualities to the area relative to conditions which existed prior to mining or which would have resulted from currently approved reclamation plans for the area.

In addition to the property to the west of SR 37, Tampa Electric Company's proposed reclamation/development plans include the creation of other environmentally enhanced areas on mined-out lands on the portion of the site to the east of SR 37. Again, these areas will include integrated, ecological systems of wetlands and upland wildlife habitats, including specifically designed areas for bird feeding and nesting.

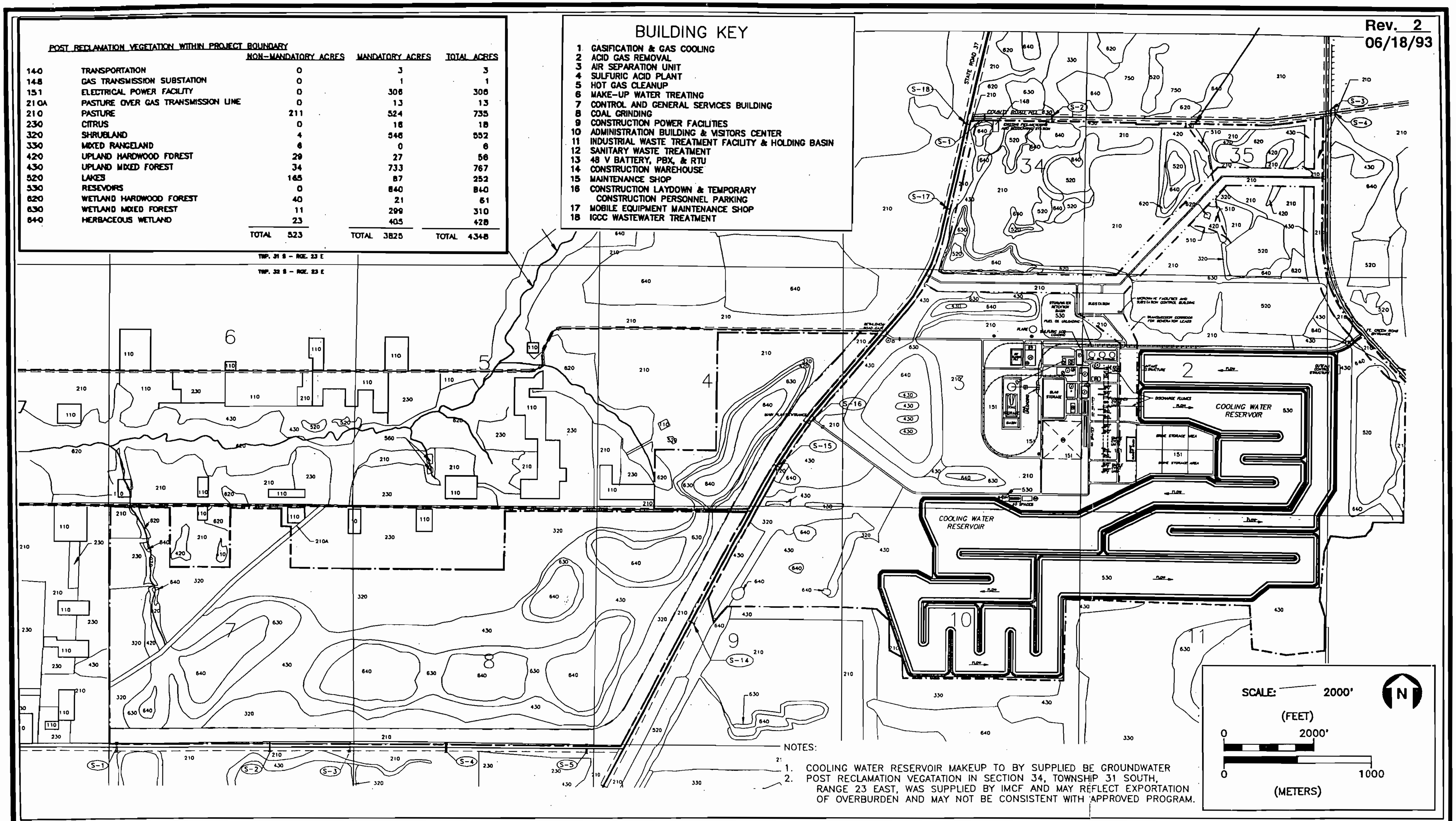
Tampa Electric Company's proposed plans for reclamation of the Polk Power Station site are described in more detail in Section 9.0 of this SCA and in the Conceptual Reclamation Plan Application submitted separately to FDNR.

3.2 SITE LAYOUT

The proposed site layout plan for the entire 4,348-acre Polk Power Station site is presented in Figure 3.2.0-1. A more detailed scale map (i.e., 1 inch equals 1,000 ft) of this figure is provided in Appendix 11.16. 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 proposed land use/land cover classifications of the site areas which will be reclaimed by Tampa Electric Company or will not be changed from existing conditions and will not include power plant facilities. These reclaimed, undeveloped areas will provide a combination of buffer, water management, and wildlife habitat/corridor functions on the site. Table 3.2.0-1 provides a summary of the approximate areas of the proposed power plant facilities and other land use/land cover classifications on the site after full build-out of the project.

As shown in Figure 3.2.0-1, 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 blocks and fuel and by-product storage areas) will be located more than 2,500 ft from offsite properties and 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 Fort Green Road).

The proposed 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



POST RECLAMATION VEGETATION WITHIN PROJECT BOUNDARY

		NON-MANDATORY ACRES	MANDATORY ACRES	TOTAL ACRES
140	TRANSPORTATION	0	3	3
148	GAS TRANSMISSION SUBSTATION	0	1	1
151	ELECTRICAL POWER FACILITY	0	306	306
210A	PASTURE OVER GAS TRANSMISSION LINE	0	13	13
210	PASTURE	211	524	735
230	CITRUS	0	18	18
320	SHRUBLAND	4	548	552
330	MIXED RANGELAND	6	0	6
420	UPLAND HARDWOOD FOREST	29	27	56
430	UPLAND MIXED FOREST	34	733	767
520	LAKES	165	87	252
530	RESEVOIRS	0	840	840
620	WETLAND HARDWOOD FOREST	40	21	61
630	WETLAND MIXED FOREST	11	299	310
640	HERBACEOUS WETLAND	23	405	428
		TOTAL 523	TOTAL 3825	TOTAL 4348

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 & VISITORS CENTER
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 & TEMPORARY CONSTRUCTION PERSONNEL PARKING
17	MOBILE EQUIPMENT MAINTENANCE SHOP
18	IGCC WASTEWATER TREATMENT

NOTES:

1. COOLING WATER RESERVOIR MAKEUP TO BY SUPPLIED BE GROUNDWATER
2. POST RECLAMATION VEGATATION IN SECTION 34, TOWNSHIP 31 SOUTH, RANGE 23 EAST, WAS SUPPLIED BY IMCF AND MAY REFLECT EXPORTATION OF OVERBURDEN AND MAY NOT BE CONSISTENT WITH APPROVED PROGRAM.

FIGURE 3.2.0-1.

SITE LAYOUT AND POST-RECLAMATION PLAN

Sources: UEC, 1992; ECT, 1992.

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Table 3.2.0-1. Acreages of Land Use/Land Cover on Polk Power Station Site After Full Build-Out

Code	Land Use/Land Cover Classification*	Acres	Percent
140	Transportation	3	0.1
148	Gas transmission pipeline	14	0.3
151	Electrical power facilities	~~337~~ 306	~~7.8~~ 7.0
152	Electrical transmission line	141	3.2
210	Pastureland	~~500~~ 594	~~11.5~~ 13.7
230	Citrus grove	18	~~0.5~~ 0.4
310	Grassland	0	0
320	Shrub and brushland	~~581~~ 552	~~13.4~~ 12.7
330	Mixed rangeland	6	0.1
410	Coniferous forest	0	0
420	Upland hardwood forest	~~101~~ 56	~~2.3~~ 1.3
430	Upland mixed forest	~~756~~ 767	~~17.4~~ 17.6
520	Lakes	252	5.8
530	Reservoirs	840	19.3
620	Wetland hardwood forest	61	1.4
630	Wetland mixed forest	310	7.1
640	Herbaceous wetland	428	9.8
	TOTAL	**4,348**	**100**

Note: Percentage figures do not add to 100 percent due to rounding.

*The FLUCCS, 1976 was used for the land use and cover classification on the Tampa Electric Company Polk Power Station project. Level II FLUCCS is used for 200 to 600 series classifications, while urban or built-up (100) uses are classified at Level III.

Source: ECT, 1992.

extending to CR 663, and the reclaimed lake to the east of the reservoir) will not be significantly altered by the proposed project. The two proposed transmission line corridors will run through the northern site area.

As discussed previously, 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.

Figure 3.2.0-2 presents the proposed arrangement of the power plant and associated facilities on the eastern portion of the site at a more detailed scale, and Figure 3.2.0-3 presents the same arrangement on an aerial photograph showing the current conditions on the site. Figure 3.2.0-4 provides a conceptual rendering of the proposed IGCC facilities. As indicated in Table 3.2.0-1, approximately ~~337~~ 306 acres (i.e., approximately ~~8~~ 7 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. As shown on Figure 3.2.0-2, of this ~~337~~ 306 acres, approximately 150 acres will actually be used for the main power plant facilities and structures, including the coal, fuel oil, by-product, and brine storage areas, and IWT systems.

Figure 3.2.0-2 also shows the proposed location of the outfall control structure for discharges from the cooling reservoir to the reclaimed lake on the eastern portion of the site (i.e., point of discharge No. 001) and the second point of discharge (i.e., No. 002) for stormwater runoff discharges from the plant site area. Water discharges from the Polk Power Station site offsite to the Little Payne Creek system will occur at the southern edge of the reclaimed lake to a man-made ditch which runs along the western side of Fort Green Road.

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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
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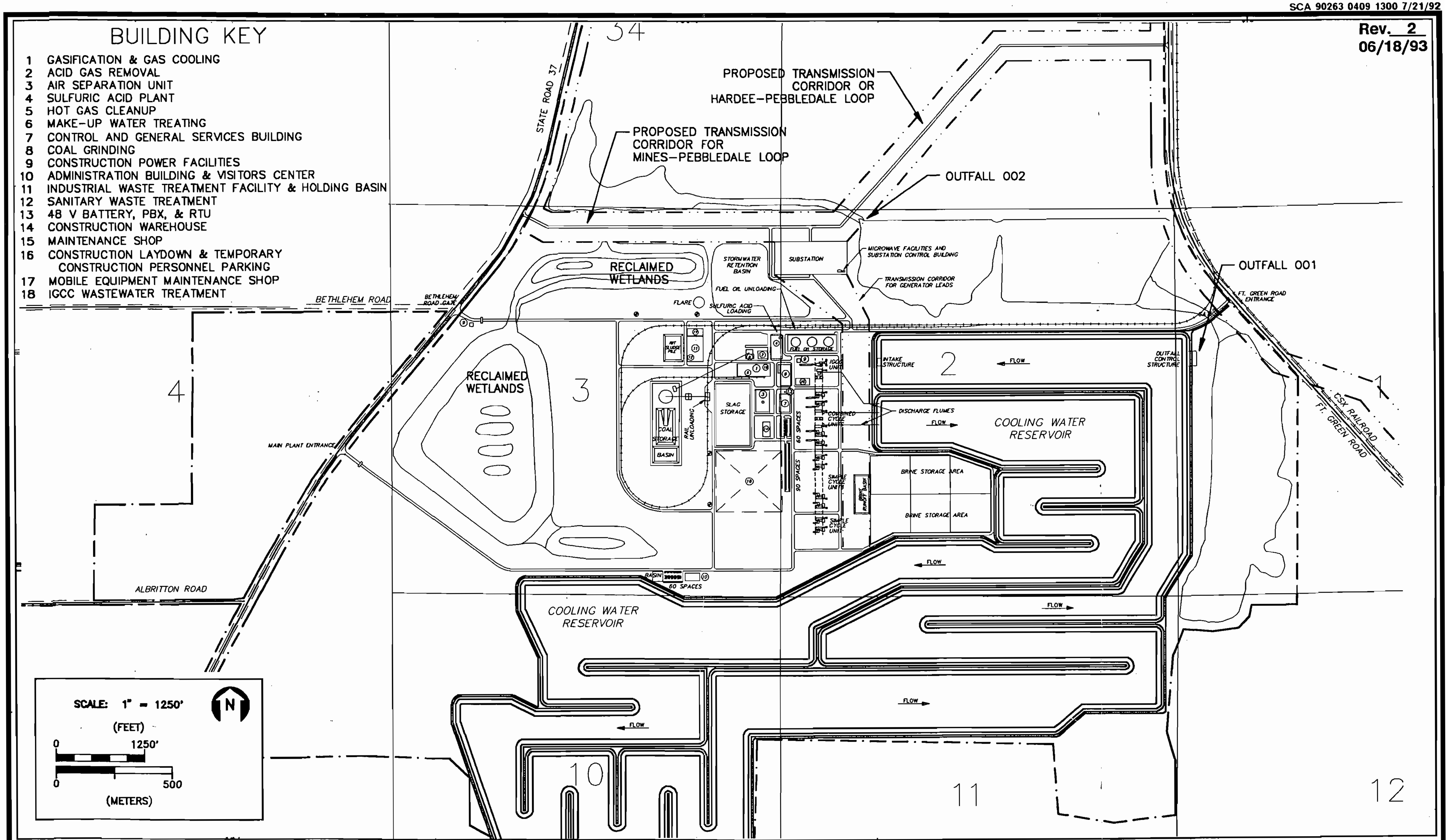

FIGURE 3.2.0-2

POWER BLOCK AND DIRECTLY ASSOCIATED FACILITIES ARRANGEMENT

SOURCES: UEC, 1992; ECT, 1992.

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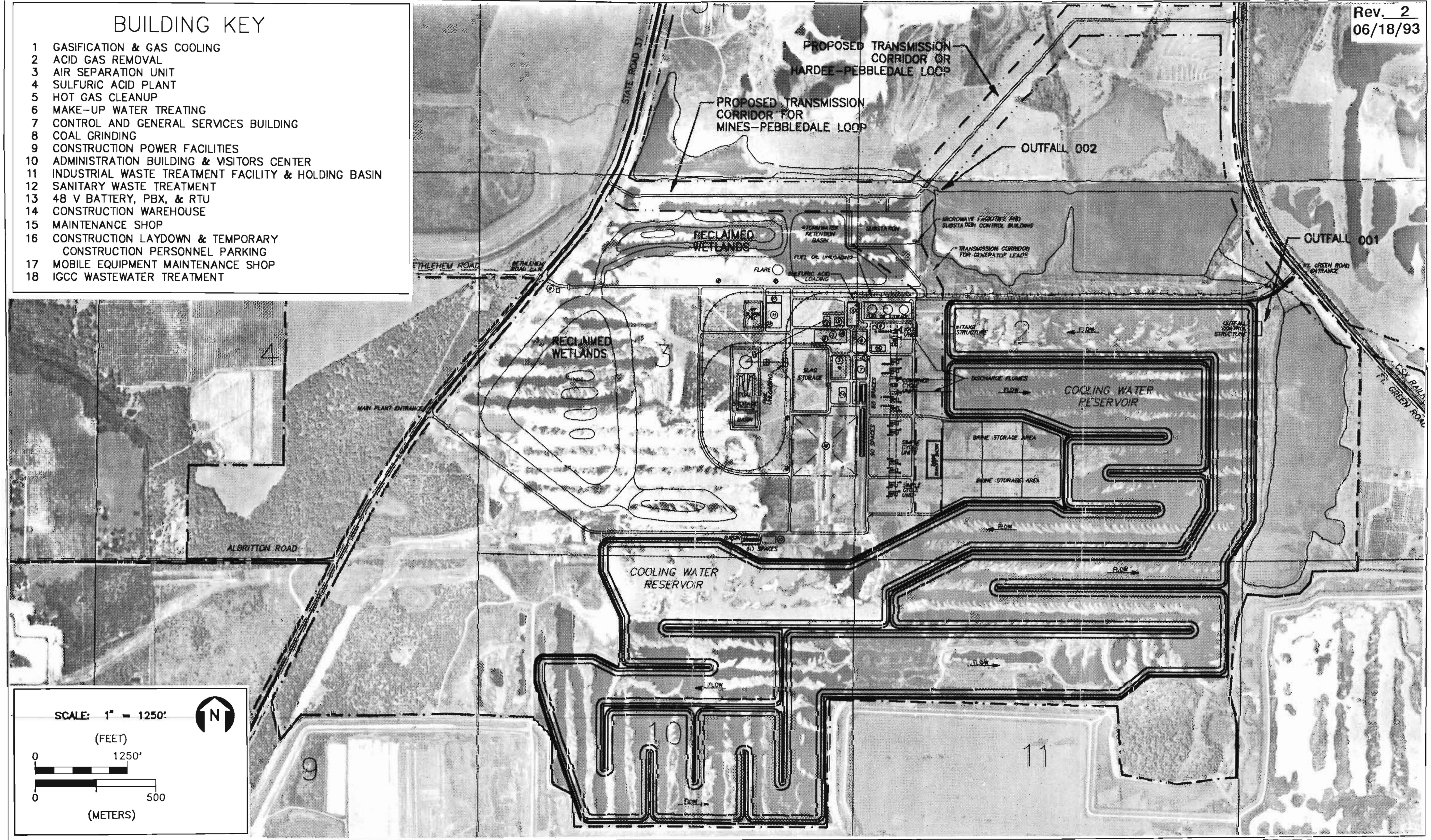

FIGURE 3.2.0-3.

AERIAL PHOTOGRAPH WITH PROPOSED FACILITY ARRANGEMENT

Sources: SRMC, 1992. UE&C, 1992. ECT, 1993.

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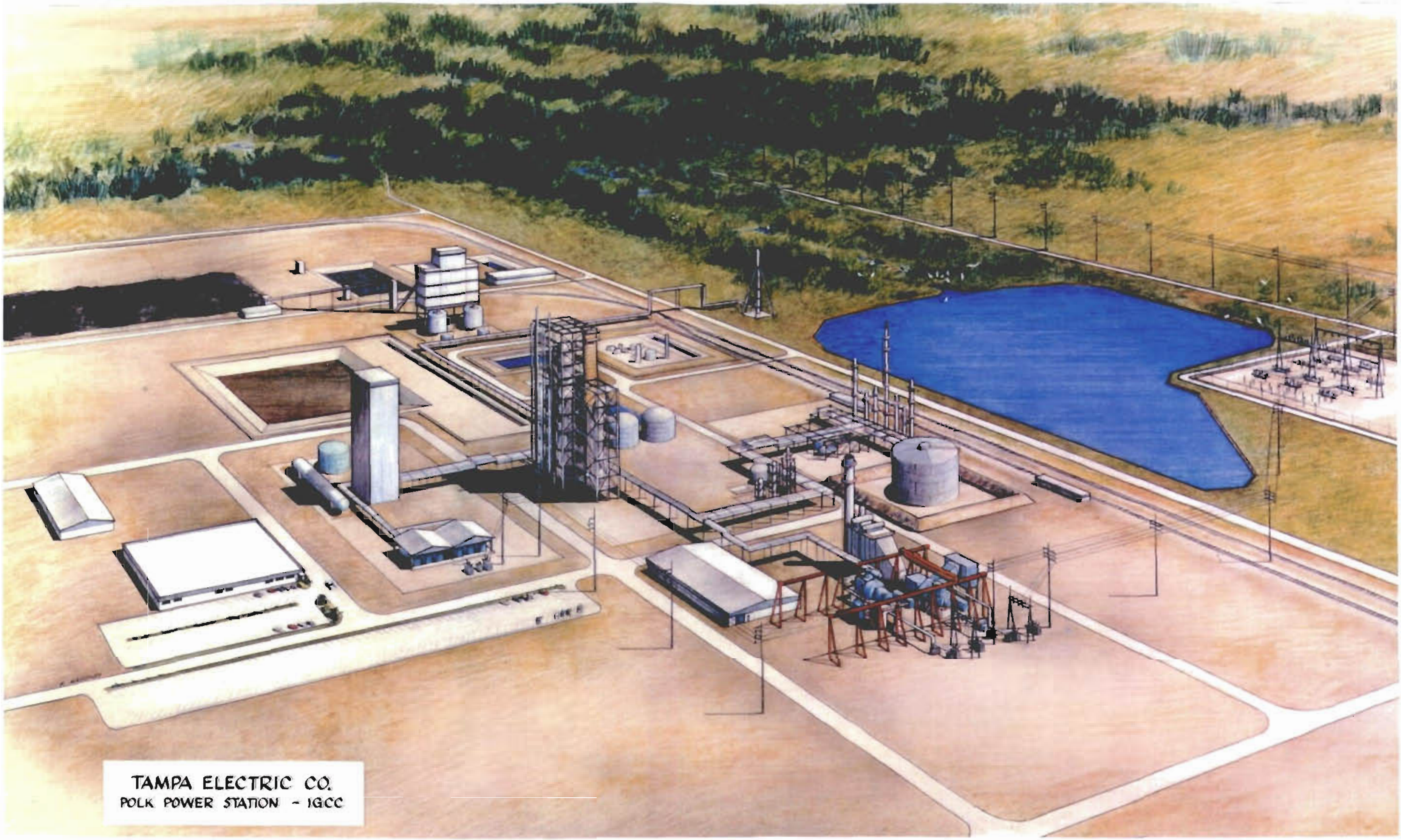

FIGURE 3.2.0-4.

CONCEPTUAL RENDERING OF PROPOSED IGCC FACILITIES

Source: Tampa Electric Company, 1992.

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A TECO ENERGY COMPANY

POLK POWER STATION

Table 3.2.0-2 presents a listing and the dimensions of the proposed buildings and structures on the site which are expected to exceed 50 ft in height and the proposed exhaust air emission stacks. The locations of the exhaust stacks and other proposed combustion sources of air emissions are shown on Figure 3.2.0-5.

Table 3.2.0-2. Dimensions of All Structures Exceeding 50 Ft in Height and Exhaust Stacks on the Polk Power Station Site

Elements	~~Building~~ Structure Dimensions Length (ft)	Width (ft)	Height (ft)
Gasifier structure	~~90~~ 60	~~60~~ 40	~~250~~ 300
Syngas cooling ~~deck~~ wings (2)	~~50~~ 180	35	~~175~~ 100
~~Oxygen plant~~ Air separation unit cold box	~~75~~ 12*	~~50~~ --	~~190~~ 110
Coal grinding structure	~~125~~ 80	~~35~~ 60	175
IGCC HRSG	150	40	80
CC HRSGs (4)	75	33	57
~~Tail gas treatment unit absorbers (2)~~	~~10~~	~~10~~	~~70~~
~~Tail gas treatment unit strippers (2)~~	~~10~~	~~10~~	~~120~~
~~Quench towers (2)~~	~~10~~	~~10~~	~~60~~
H_2SO_4 plant absorbers (2) and dryer (1)	8*	--	60
H_2SO_4 plant gas cooling tower	8*	--	70
Acid gas removal stripper	10*	~~10~~ --	~~140~~ 100
~~Acid gas removal flash tower~~	~~10~~	~~10 --~~	~~140~~
Water wash column	10*	--	80
Acid gas removal absorber	10*	~~10~~ --	~~140~~ 100
One day coal storage bin	25	25	70
HGCU	65	52	218

Exhaust Stacks	Stack Height (ft)	Stack Diameter (ft)
IGCC HRSG stack	150	19
CC HRSG stacks (4)	150	14.5
~~Thermal oxidizer~~	~~199~~	~~5~~
Auxiliary boiler	20	5
Flare	~~75~~ 150	4
CC/bypass stacks (10)	75	18†
H_2SO_4 ~~acid~~ plant ~~stack~~ thermal oxidizer	199	~~3.6~~ 7

*Diameter.
†Equivalent diameter. Stack is usually square.

Sources: Texaco, 1992.
Bechtel, 1993.

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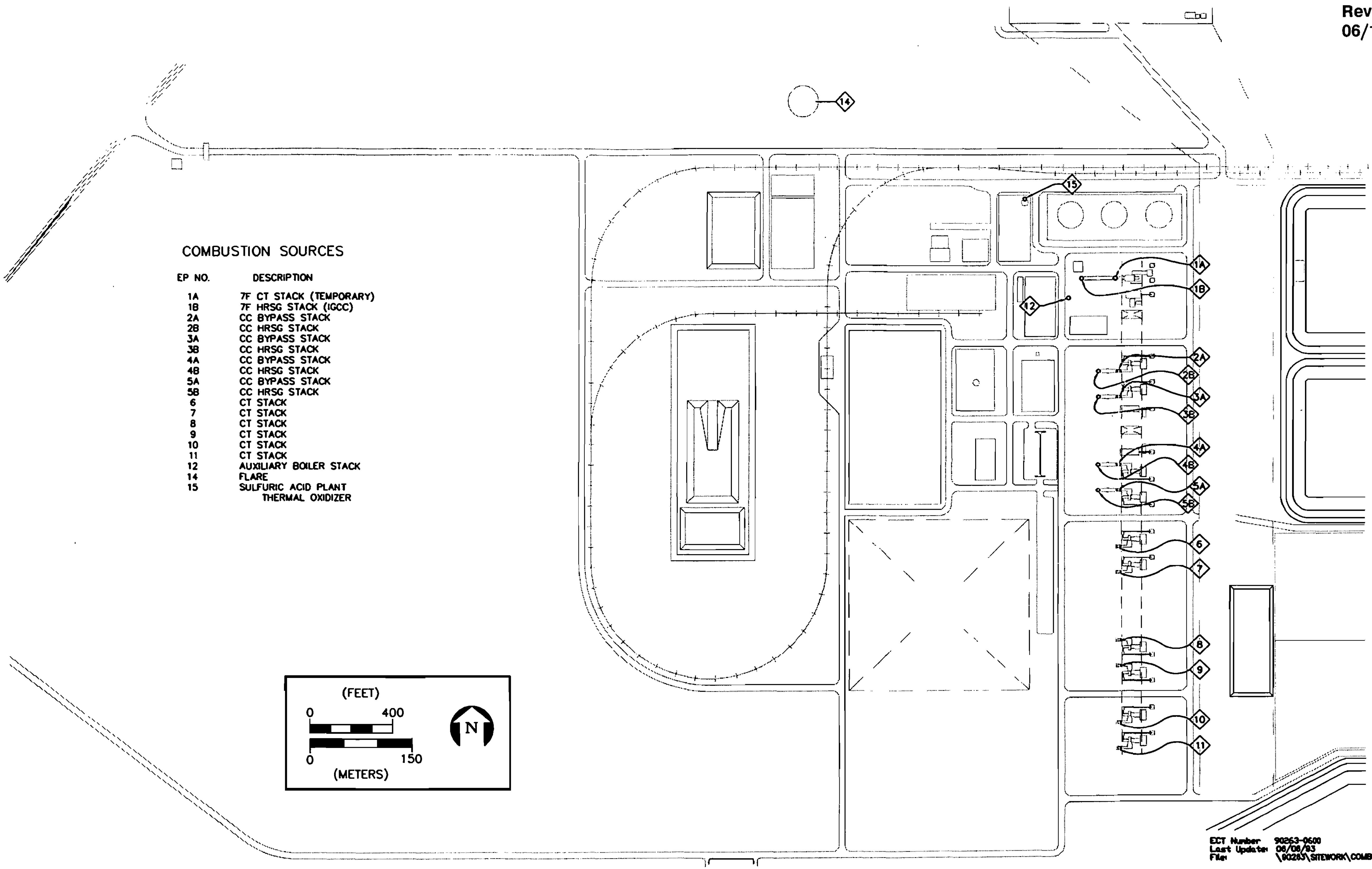

COMBUSTION SOURCES

EP NO.	DESCRIPTION
1A	7F CT STACK (TEMPORARY)
1B	7F HRSG STACK (IGCC)
2A	CC BYPASS STACK
2B	CC HRSG STACK
3A	CC BYPASS STACK
3B	CC HRSG STACK
4A	CC BYPASS STACK
4B	CC HRSG STACK
5A	CC BYPASS STACK
5B	CC HRSG STACK
6	CT STACK
7	CT STACK
8	CT STACK
9	CT STACK
10	CT STACK
11	CT STACK
12	AUXILIARY BOILER STACK
14	FLARE
15	SULFURIC ACID PLANT THERMAL OXIDIZER

ECT Number 90263-0600
Last Update: 06/08/93
File: \90263\SITEWORK\COMBUST2

FIGURE 3.2.0-5.

LOCATION OF COMBUSTION SOURCES

Source: ECT, 1993.

ECT
Environmental Consulting & Technology, Inc.

3.3 FUEL

The proposed electric generating facilities at the Polk Power Station will primarily utilize three types of fuels: natural gas, fuel oil, and coal. The CG facilities will also be capable of using petroleum coke and a coke/coal mixture as fuel. The nominal net 150-MW advanced CT, which will be used for the IGCC Polk Unit 1, will use No. 2 fuel oil during the first year of operation. Upon completion of the CG and HRSG facilities, the CT will be fired by coal-derived syngas with No. 2 fuel oil then serving as backup fuel when the unit is operated in a CC mode. The two CC units and six stand-alone CT units will use natural gas as the primary fuel and No. 2 fuel oil as backup. In addition to these fuels, the project will require electrical energy to run motors which power pumps, blowers, grinders, conveyor belts, and other machinery. Gasoline and diesel fuels will be used to fuel vehicles and certain other equipment within the site.

Also, to prevent refractory thermal shock, the gasifier and ~~sulfur recovery unit~~ H_2SO_4 plant will be preheated using a clean fuel (i.e., propane or liquid or gaseous natural gas) prior to IGCC unit initial startup, cold startup, or after an extended shutdown (e.g., for maintenance purposes). Therefore, propane or liquid natural gas fuel may be used onsite for short time periods (i.e., 2 to 3 days) for preheating purposes until gaseous natural gas is available at the site. Also until natural gas is available, small quantities of propane will be needed for several pilot flame operations, such as for the flare. As needed, these fuels will be delivered to the site by tanker truck and the fuel will be provided to the preheat and pilot flame systems directly from the truck tanks. These fuels will not be stored in permanent tanks onsite. Due to the short duration and small quantity of fuel use, the clean quality of the fuels, and the fact that other emissions from the IGCC unit will not occur during the preheating activities, potential air emissions resulting from the use of these clean fuels will be negligible.

The quantities and qualities of the primary fuels which will be used at the Polk Power Station and the proposed fuel delivery, handling, and storage facilities are described in the following sections.

3.3.1 COAL SUPPLY AND DELIVERY, HANDLING, AND STORAGE

3.3.1.1 Coal Fuel Supply and Quality

In accordance with its cooperative agreement with DOE under the Clean Coal Technology Demonstration program, Tampa Electric Company will be required to use coal from various sources for the IGCC unit during the 2-year demonstration period. Also during the demonstration period, Tampa Electric Company will be required to gather extensive information on the performance of the overall IGCC unit and the HGCU system when using the various coals. The performance information will include data on the overall plant efficiency and cost-effectiveness in generating electricity as well as environmental data on emissions rates and characteristics. The potential coal supply sources during the demonstration period are expected to be from coal seams in the eastern and midwestern United States.

At the present time, Tampa Electric Company has not selected the specific coal supply source(s) for the long-term operation of the IGCC unit after the demonstration period. The company will consider and evaluate various sources based on economic, engineering, and environmental factors. The performance information obtained during the demonstration project will also provide valuable inputs to Tampa Electric Company's ultimate selection of the coal supply source(s) for the unit.

Based on its current analyses of potential coal source seams required for the DOE demonstration project and other potential sources for long-term operation of the IGCC unit, Tampa Electric Company has determined that coal supplied from the Illinois No. 6 seam would be most representative of coal properties with margins added for certain properties (i.e., heat content, chlorine, and certain trace elements) to encompass the range of properties expected in other potential coal supply sources. Table 3.3.1-1 presents the properties of this modified Illinois No. 6 coal which will be used as the assumed coal for the IGCC unit for environmental licensing purposes. From an environmental licensing perspective in terms of potential SO_2 air emissions, amount of coal delivered and used, and by-product volumes (i.e., slag~~, sulfur,~~ and H_2SO_4), the key properties of this assumed coal on an as-received basis are the heat

Table 3.3.1-1. Assumed Properties of Modified Illinois No. 6 Coal

Property	Maximum Content (on as-received basis)
Proximate Analysis	
Moisture	15.00 percent*
Ash	11.00 percent
Sulfur	3.05 percent
Volatile matter	32.20 percent
Fixed carbon	42.20 percent
Heating value	11,035 Btu/lb (minimum)
Ultimate Analysis	
Moisture	15.00 percent
Carbon	58.70 percent
Hydrogen	4.00 percent
Nitrogen	1.11 percent
Chlorine	0.20 percent
Sulfur	3.05 percent
Ash	11.00 percent
Oxygen	7.90 percent
Trace Elements	
Arsenic (As)	12.59 ppm
Beryllium (Be)	4.73 ppm
Cadmium (Cd)	1.93 ppm
Chromium (Cr)	28.00 ppm
Fluoride (F)	81.00 ppm
Mercury (Hg)	0.28 ppm
Lead (Pb)	4.70 ppm

*Minimum moisture content is 7 percent on an as-received basis.

Note: Percentages for proximate and ultimate analyses do not add to 100 percent since assumed properties are based on a combination of contents for several coals.

Source: Tampa Electric Company, 1992.

content of 11,035 British thermal units per pound (Btu/lb), sulfur content of 3.05 percent, and ash content of 11 percent.

Based on the properties of this assumed coal, the proposed IGCC unit will require approximately 2,325 tons of coal per day, on a dry basis, when operating at full load. This peak coal fuel input to the CG facilities will result in the production and firing of approximately 6.4 million standard cubic feet (scf) per hour of coal-derived syngas in the advanced CT unit of the overall IGCC generating facility.

The coal-derived syngas produced in the gasification process will be treated in the conventional CGCU system or the demonstration HGCU system prior to being fired in the advanced CT unit. The CGCU system will be capable of treating up to 100 percent of the syngas under full load conditions for the IGCC unit, while the demonstration HGCU system will be designed to treat up to approximately 50 percent of the syngas at full load operation of the unit. At this time, the quality of the syngas resulting from the conventional, proven CGCU system can be estimated with a greater degree of confidence than the quality of the syngas from the HGCU system since this system has not been demonstrated at a commercial scale. However, based on small-scale demonstrations, the HGCU system has the potential to exceed the estimated sulfur removal efficiency of the CGCU system, while also increasing the overall efficiency (i.e., cost-effectiveness) of the IGCC unit in generating electricity.

Table 3.3.1-2 presents the composition of the coal-derived syngas resulting from the CGCU system and based on the assumed coal fuel. If petroleum coke or a coke/coal mixture is used as fuel for the IGCC unit, the resulting syngas for firing in the CT will have an equivalent composition as that shown in Table 3.3.1-2.

3.3.1.2 Coal Delivery, Handling, and Storage Facilities

The purpose of the coal handling system is to receive, stack-out, store, reclaim, and transport coal from unit train railroad cars and/or from trucks to the coal

Table 3.3.1-2. Composition of Coal-Derived Syngas to the Combustion Turbine

Component	Mole Percent (by volume)
CO	45.38
H_2	33.94
CO_2	12.87
Water	0.36
Methane	0.18
Argon	1.19
Nitrogen	6.03
H_2S	0.02
COS	0.03

Note: Composition prior to nitrogen addition at the CT

Source: Texaco, 1992.

preparation system serving the IGCC unit Polk Power Station Unit 1. Figure 3.3.1-1 presents a flow diagram of the coal receiving and handling system.

Coal will be delivered to the plant site by trains and/or trucks. The unit trains will consist of approximately 70 to 100, 100-ton capacity rapid discharge, bottom dump rail cars. If all coal was delivered by unit train, approximately two unit trains per week would be needed to meet the fuel requirements of the IGCC unit. Rail delivery of coal may also be made by using the back-haul availability of the various trains which currently transport phosphate from Polk County to terminals on Tampa Bay. The phosphate trains would include 18 to 22 cars dedicated to back-haul coal to the Polk Power Station site on a daily basis or as needed. The rail cars will be unloaded in motion with the train moving over an enclosed track hopper. If all coal was delivered by truck, delivery will be made by approximately 80 to 100 specialized bottom-dump trucks per day, each truck having a 28-ton payload. The trucks will be equipped with covers to minimize fugitive dust emissions and will unload utilizing the enclosed, below-grade, rail unloading track hopper which will be arranged to permit truck drive-over. A dust collection system will be provided to collect dust from all of the feeder and conveyor transfer points in the unloading hopper area. Dust suppression with water sprays will be employed at the top of the hopper.

The track hopper will be equipped with four outlets, four manually operated rack and pinion slide gates and four belt feeders. Two belt feeders will discharge coal onto the track hopper feeder collecting belt conveyor and the remaining two feeders onto a second track hopper feeder collecting belt conveyor. Collecting belt conveyors will transport the coal to the stack-out conveyor. The stack-out conveyor is a radial stacker equipped with a telescopic chute and water spray dust suppression. The radial stacker will be used to build a kidney-shaped active coal pile. Mobile equipment (i.e., bulldozers) will be used to build an inactive storage pile and to reclaim coal from the active storage pile. Coal reclaimed by mobile equipment will be pushed into a below-grade hopper and fed by a vibrating feeder onto the IGCC plant transfer conveyor.

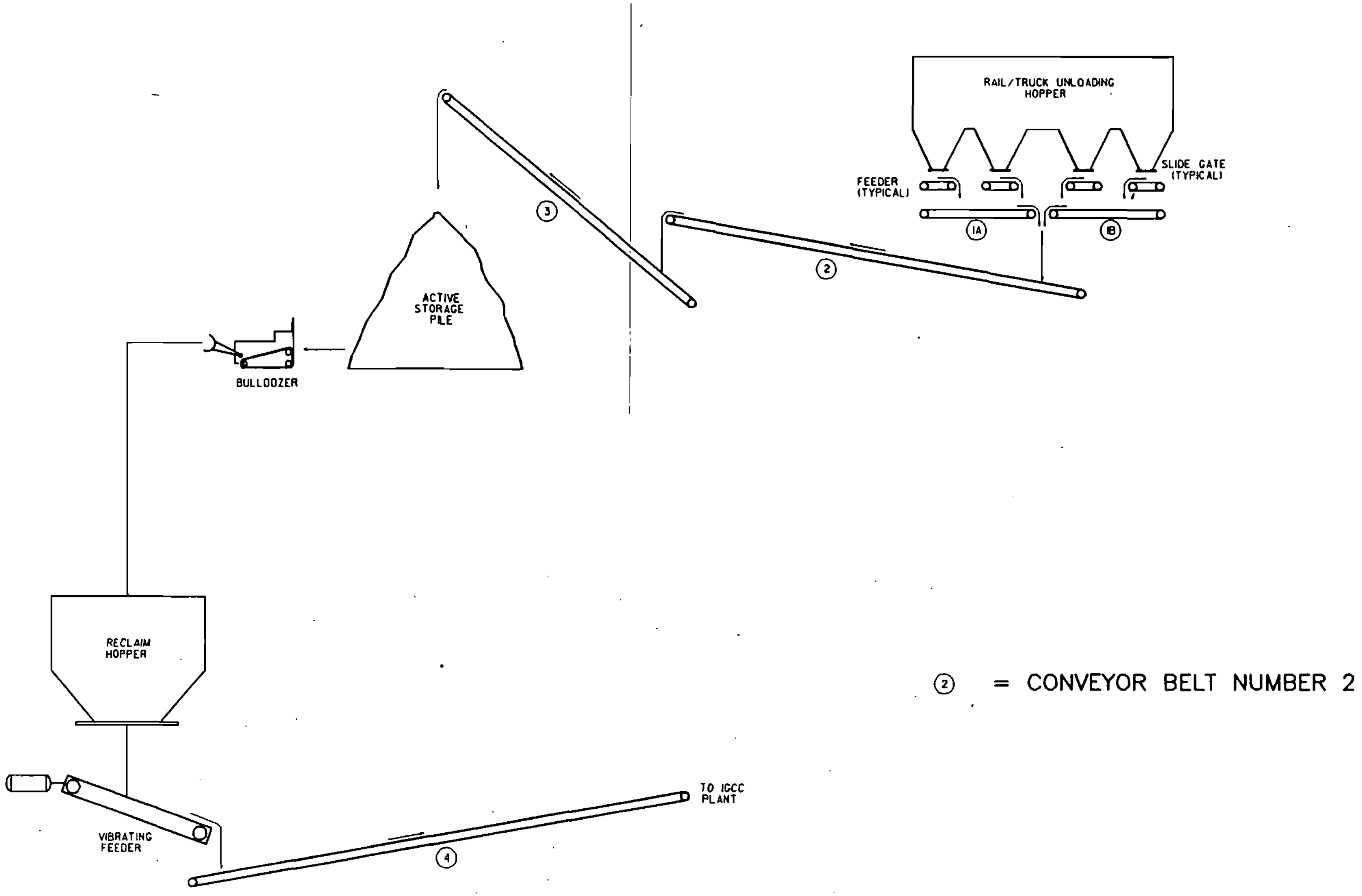

FIGURE 3.3.1-1.

COAL HANDLING SCHEMATIC

Source: UEC, 1992; ECT, 1992.

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Control of particulate emissions from coal handling operations will be achieved by a combination of wet dust suppression, chemical treatment of the coal pile, equipment enclosures, and dry dust collection systems located at the major dust emissions sources. Wet dust suppression systems employing either foam or water sprays with a wetting agent will be employed at the railcar and truck receiving hopper and at the stacker discharge to the coal pile.

Conveyors and transfer points will be provided with enclosures and water spray systems to contain dust and to minimize emissions to the atmosphere. Coal handling equipment and transfer points will be provided dust-tight enclosures and dry type dust collectors, which will maintain a slight negative pressure within the equipment enclosure to minimize emissions. The dust collection equipment will consist of pulse-jet baghouses, centrifugal exhaust fans, rotary air lock valves, dust return chutes, and control devices. The baghouses will be sized for a maximum air to cloth ratio of 6 to 1 at design air flow and will have a removal efficiency not less than 99.9 percent.

The coal storage pile will be segregated into active and inactive portions. Fugitive dust emissions from the active portion of the pile will be controlled by water sprays and/or the application of chemical dust suppression agents. The inactive portion of the pile will be sealed with a crusting agent to control dust emissions.

The coal storage area will occupy an area of approximately 10 acres, including the coal pile runoff basin and berm surrounding the entire area to prevent stormwater runoff from the area. The aggregate storage capacity of approximately 105,000 tons for both the active and inactive storage piles will be sufficient to supply coal fuel for 45 days of IGCC unit operation at full generating capacity.

The coal pile storage area and the runoff basin will be lined with a synthetic material or other materials with similar low permeability characteristics to prevent leachate and runoff from entering the surficial groundwater system. The coal storage area will also include appropriately designed leachate and stormwater collection systems which will route collected water to the lined coal pile runoff basin. The basin will be capable of containing coal pile runoff resulting from in excess of the 25-year, 24-hour design storm event. The coal pile runoff basin will function to collect coal pile runoff and leachate, to allow sedimentation of solids in the collected waters, and then transfer the runoff at a controlled rate to the IWT system for treatment. Thus, all runoff water discharges from the coal storage area will be appropriately controlled and treated with no direct discharges to groundwater or surface waters.

3.3.2 NATURAL GAS SUPPLY AND DELIVERY

Natural gas will be used as the primary fuel for the stand-alone CT and CC units planned for the Polk Power Station. Natural gas will be delivered to the site via a pipeline from the existing and future natural gas transmission system in the region. Natural gas will not be stored on the Polk Power Station site. Table 3.3.2-1 presents a typical composition for the natural gas fuel. The CC and stand-alone CT units will use a total of approximately 11 million cubic feet per hour (ft^3/hr) of natural gas fuel if all units were operating at full load and at a worst-case ambient temperature of 20°F.

As discussed in Section 6.2, Tampa Electric Company is currently evaluating the various alternatives to supply natural gas to the Polk Power Station. Therefore, specific interconnection points to the existing or planned future gas transmission system in the site area and, in turn, the pipeline route or alternative routes to the Polk Power Station site have not been determined at this time. Once the proposed pipeline route has been determined, Tampa Electric Company will submit appropriate supplemental application and supporting information to the SCA for the Polk Power Station for agency review and approval of the proposed natural gas pipeline corridor from the transmission system to the site.

Table 3.3.2-1. Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
Other Characteristics	
Heat content	1,022 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5776
Sulfur content (maximum)	10 gr/100 scf

Note: Btu/ft^3 = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

Source: Tampa Electric Company, 1992.

3.3.3 FUEL OIL SUPPLY AND DELIVERY, HANDLING, AND STORAGE FACILITIES

3.3.3.1 Fuel Oil Supply and Quality

Initially, No. 2 fuel oil will be used as a primary fuel for the advanced CT unit planned for the Polk Power Station. Fuel oil will be delivered to the site by tanker truck and/or railcar. This will occur during the first year of operation, after which the CT will be converted to the IGCC unit. At this time, Tampa Electric Company anticipates that fuel oil will serve primarily as a backup fuel for the stand-alone CT and CC units and the advanced CT component of the IGCC unit in CC mode after the initial project phase.

Table 3.3.3-1 presents a typical fuel analysis for the low-sulfur No. 2 fuel oil which will be used as backup fuel for the Polk Power Station. The stand-alone CC and CT units will use a total of approximately 77,000 gallons of No. 2 fuel oil per hour if all units were operating at full load and at the worst-case ambient temperature of 20°F. If the CG facilities were unavailable to provide syngas and the CC component of the IGCC unit was fired on the backup fuel oil, this unit would use an additional 13,500 gallons of No. 2 fuel oil per hour at full load and at the worst-case ambient temperature of 20°F.

3.3.3.2 Fuel Oil Delivery, Handling, and Storage Facilities

GATX is currently proposing to construct a new fuel oil pipeline in the site region. The proposed pipeline would parallel Fort Green Road and the CSX Railroad located adjacent to the eastern boundary of the Polk Power Station site. When constructed, fuel oil could be delivered to the site via a pipeline from the proposed GATX pipeline to the onsite fuel oil storage tanks. The corridor for this supply pipeline would be located within the boundaries of the Polk Power Station site and, therefore, would not affect offsite land uses or resources. Tampa Electric Company will submit appropriate supplemental application and supporting information to the SCA for the Polk Power Station for agency review and approval prior to construction of the onsite pipeline to supply fuel oil to the site.

Table 3.3.3-1. Typical 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)	0
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

Note: SUS = Saybolt Universal Seconds.
Btu/gal = British thermal units per gallon.
LHV = lower heating value.
HHV = higher heating value.

Source: Tampa Electric Company, 1992.

Whether or not the fuel oil pipeline is constructed, the capability to deliver the backup fuel oil by tanker truck or railcar will be provided on the site.

Fuel oil will ultimately be stored in three aboveground storage tanks on the site at full build-out of the Polk Power Station. The construction of these three tanks will be phased over time to match fuel oil needs as additional generating units are developed on the site. The tanks will be constructed of steel and each tank will have a storage capacity of 3 million gallons of fuel oil. Therefore, after full build-out, the total onsite storage capacity will be 9 million gallons of fuel oil. Each tank will be approximately 128 ft in diameter and 32 ft in height.

The storage tank area will be surrounded by a berm which will be appropriately designed to contain any unexpected spills or failures of the tanks. The area design will also include appropriate systems and safeguards to prevent, control, and recover any potential spills in accordance with federal and state regulatory requirements for aboveground storage tanks. The berms will be constructed of earthen materials primarily excavated from the overburden spoil piles in the mined-out areas of the site. The earthen berms will be covered with sealed asphalt or comparable sealer material to prevent any spilled fuel oil from penetrating or contaminating the berms.

In accordance with Rule 17-762.500(6), F.A.C., the storage tank area will be provided with an impervious secondary containment system around and under the tank containment area. This secondary containment will conform to the requirements of NFPA 30, latest edition, except that it will contain 110 percent of the volume of the largest tank per Rule 17-762.500(6)(a), F.A.C. Berms and base will be constructed of earthen materials primarily excavated from the overburden spoil piles in the mined-out area of the site. The berms and base will be lined with a material impervious to the fuel oil to be stored in the tanks. This liner will conform to the requirements of Section 17-762.500 and Rule 17-761.500(7), F.A.C.

Stormwater runoff from the fuel oil storage area will be collected and routed to an oil/water separation system which will be designed to reduce any potential oil and grease content in the water to a level not exceeding 15 mg/L. The oil/grease and solids sediment will be collected and hauled offsite by a contractor for appropriate disposal. The treated effluent from the oil/water separation system will be routed to the wastewater equalization basin.

A preliminary Spill Prevention, Control, and Countermeasure (SPCC) Plan has been developed for the fuel oil storage and handling systems according to the requirements of 40 CFR 112, including emergency response procedures for controlling and handling any unexpected spills (see Appendix 11.13.1).

3.4 AIR EMISSIONS AND CONTROLS

3.4.1 AIR EMISSION TYPES AND SOURCES

This section describes the types and sources of air pollutants that will be emitted from Polk Power Station. The maximum emission rates for the larger sources are also quantified. Additional details on both the description of emission sources and quantification of emission rates are provided in the PSD permit application, which is included as Appendix 11.1.3 of this SCA.

Air emissions associated with the proposed facility fall into three broad categories: combustion emissions, process emissions, and fugitive emissions. The combustion sources are:

- The advanced CT integral to the IGCC unit;
- ~~The IGCC unit tail gas treating unit thermal oxidizer;~~
- The IGCC unit H_2SO_4 plant thermal oxidizer;
- The IGCC unit emergency flare;
- A small auxiliary boiler associated with the IGCC unit;
- The four CTs associated with the two CC units; and
- The six stand-alone, simple-cycle CTs.

The primary source of emissions from the IGCC unit is combustion of syngas in the advanced CT (GE 7F). The exhaust gas from the CT will be emitted to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily NO_x and SO_2, with lesser quantities of CO, VOC, particulate matter (PM), and other trace constituents present in the fuel. Table 3.4.1-1 presents the estimated maximum hourly emission rates for this source. As shown in the table, emissions of some pollutants may vary with the type of syngas cleanup technology employed. The emission control capabilities of the HGCU system are yet to be fully demonstrated; therefore, some emission estimates are higher compared to estimated emissions from the CGCU system. However, after the completion of the 2-year demonstration period, the lower emission rates from the CGCU system will be achieved. Estimated emissions firing low-sulfur No. 2 distillate fuel oil are also provided in Table 3.4.1-1

Table 3.4.1-1. Maximum Emissions from the IGCC Unit's CT (all values lb/hr)

Pollutant	Syngas Post-Demonstration*	Syngas Demonstration†	No. 2 Fuel Oil
Particulate matter**	72	72	27
SO_2	518	518	92
NO_x	223	664	311
CO	98	99	99
VOCs	3	3	32
Lead	0.0035	0.023	0.10
H_2SO_4 mist	55	55	10
Fluorides	0.21	0.21	0.062
Mercury	0.0034	0.025	0.0057
Beryllium	0.0001	0.0001	0.0048
Arsenic	0.0006	0.080	0.31
Cadmium	0.0009	0.020	0.020
Chromium	0.0004	0.0005	0.17

* Maximum emissions after the 2-year demonstration period, based on emissions achievable with CGCU. Utilization of HGCU to be based on ability to achieve maximum post-demonstration emission rates.

† Maximum emissions during the 2-year demonstration period, based on up to 50 percent utilization of HGCU. Maximum post-demonstration emission rates to be achieved thereafter.

** Includes H_2SO_4 mist.

Sources: GE, 1992.
Texaco, 1992.
ECT, 1992.

since: (1) the advanced CT will operate initially (i.e., prior to the integration with the CG facilities) as an oil-fired simple-cycle CT; and (2) after the IGCC conversion, the CT may still operate in CC mode on oil during periods when syngas is not available.

Approximately 96 percent of the sulfur present in the coal will be removed by the CGCU and HGCU systems. The sulfur-laden gas produced in the CGCU and HGCU systems will be treated onsite and converted to a saleable ~~sulfur and/or~~ H_2SO_4 by-product~~s~~.~~Small amounts of the sulfur in the tail gas that is not converted in the CGCU system process will be combusted and emitted as SO_2 through the tail gas treating unit thermal oxidizer. Estimated emissions from the thermal oxidizer are presented in Table 3.4.1-2 assuming that 100 percent of the syngas is being treated within the CGCU system.~~

~~When the HGCU system is in use, off gases from this system will be routed to a H_2SO_4 plant. E~~ The estimated emissions from the acid plant thermal oxidizer are presented in Table 3.4.1-3.~~When this system is in use to treat up to approximately 50 percent of the syngas, the use of the CGCU system, and hence the thermal oxidizer emissions, will decrease correspondingly.~~

The emergency flare will operate only during gasifier startup and shutdown, and during infrequent, unanticipated interruptions of the gasifier's operating cycles. On a routine basis, emissions from the flare will result from the pilot flame, and these emissions will be negligible.

Similarly, the small oil-fired auxiliary boiler will operate only during startup and shutdown of the IGCC unit, or when steam from the IGCC unit's HRSG is unavailable. Estimated maximum emissions from this source are summarized in Table 3.4.1-4.

~~Table 3.4.1-2. Maximum Tail Gas Treating Unit Thermal Oxidizer Emissions~~

~~Pollutant~~	~~Emissions (lb/hr)*~~
~~Particulate matter~~	~~13.1~~
~~SO_2~~	~~52.0~~
~~NO_x~~	~~2.6~~
~~CO~~	~~1.4~~
~~VOC~~	~~0.8~~
~~Lead~~	~~0.002~~
~~H_2SO_4 mist~~	~~0~~
~~Fluorides~~	~~0.001~~
~~Mercury~~	~~0.002~~
~~Beryllium~~	~~0.001~~
~~Arsenic~~	~~0.001~~
~~Cadmium~~	~~0.001~~
~~Chromium~~	~~0.105~~
~~H_2S~~	~~0.4~~

~~*Maximum emissions are for 100 percent CGCU operations; emissions from this source would be less with 50 percent CGCU and 50 percent HGCU.~~

~~Source: Texaco, 1992.~~

Table 3.4.1-3. Maximum Expected Emissions from the H_2SO_4 Plant Thermal Oxidizer

Pollutant	Emissions* (lb/hr)
Particulate matter	~~2.6~~ 12.8
SO_2	~~10.1~~ 45.3
NO_x	~~1.14~~ 2.6
CO	~~0.61~~ 1.4
VOC	~~0.35~~ 0.8
Lead	~~0.001~~ 0.002
H_2SO_4 mist	~~0~~ 0
Fluorides	~~0~~ 0.001
Mercury	~~0.001~~ 0.002
Beryllium	0.001
Arsenic	0.001
Cadmium	0.001
Chromium	~~0.052~~ 0.105
H_2S	~~0.23~~ 0.4

*Maximum emissions are for ~~50~~ 100 percent CGCU ~~and 50 percent HGCU; this source would have no emissions with 100 percent CGCU~~ operation; emissions from this source would be less with 50 percent CGCU and 50 percent HGCU.

Sources: Texaco, 1992.
Bechtel, 1993.

Table 3.4.1-4. Auxiliary Boiler Emissions

Pollutant	Emissions (lb/hr)
Particulate matter	3.0
SO_2	2.6
NO_x	7.9
CO	4.3
VOC	2.4
Lead	0.003

Source: Texaco, 1992.

The stand-alone CC units and CTs will emit stack gases resulting from the combustion of natural gas or backup fuel oil. The principal pollutants will be NO_x and SO_2, with lesser quantities of CO, VOC, PM, and other trace pollutants. Table 3.4.1-5 presents the estimated maximum hourly emissions from an individual CT in either CC or simple-cycle mode.

Process and fugitive emissions will result from other facility and process operations associated primarily with the IGCC unit. Fugitive particulate emissions will be generated by material handling and storage, principally coal and slag. The coal handling and slag systems will be designed to effectively control fugitive emissions of PM. For coal handling, the dust control system involves a combination of controls, including rail car and truck unloading in enclosed buildings, enclosure of certain coal conveyors, baghouse particulate control at transfer points, wetting of the coal pile, and wet grinding in the rod mills. Slag will be conveyed wet in conveyors which will greatly minimize or eliminate potential fugitive dust emissions.

Minor, intermittent emissions of gaseous-phase pollutants may be generated within the gasification plant. The potential sources will be process vents, and leaks (fugitive emissions) from equipment such as valves, compressor seals, and flanges. The predominant gases that may be emitted include H_2S and NH_3. A small amount of particulates may also be emitted from vent sources. These emissions will be minimized by good operational and maintenance practices.

Table 3.4.1-5. Maximum Emissions from Individual Stand-Alone CT and CC Units (all values lb/hr)*

Pollutant	Fuel	
	Natural Gas	Fuel Oil
Particulate matter†	11	21
SO_2	36	53
NO_x	35	181
CO	59	71
VOC	10	10
Lead	0	0.059
H_2SO_4 mist	4	6
Fluorides	0	0.036
Mercury	0.012	0.0033
Beryllium	0	0.0028
Arsenic	0	0.18
Cadmium	0	0.012
Chromium	0	0.10

* Emission rates given are for an individual CT in either CC or simple-cycle mode.
† Includes H_2SO_4 mist.

Sources: GE, 1992.
ECT, 1992.

3.4.2 AIR EMISSION CONTROLS

Air emission controls planned for the Polk Power Station are summarized in Tables 3.4.2-1 and 3.4.2-2 for the IGCC facility and stand-alone CTs (CC or simple-cycle mode), respectively. Brief descriptions of the control systems proposed for the Polk Power Station are provided in the following sections. A complete description of the Polk Power Station air emission control systems is included in the PSD permit application contained in Appendix 11.1.3.

3.4.2.1 Particulate Matter and Heavy Metals

PM and trace heavy metals (including lead, mercury, and beryllium) controls planned for the IGCC facility consist of water scrubbing, use of clean fuels and operational practices to achieve efficient combustion. A water scrubber to remove PM from the syngas stream is an integral component of the conventional CGCU process. The scrubbed syngas is cooled prior to entering the acid gas removal system which results in the condensation of trace volatile heavy metals and further reduction in syngas particulate levels. The demonstration HGCU technology employs a high temperature barrier filter to remove 99.5 percent or more of the PM contained in the treated syngas stream.

The IGCC 7F CT will be operated in simple-cycle mode during the first year of operation (prior to installation of the CG facilities) using distillate fuel oil. The primary fuel after conversion to IGCC will be syngas; distillate fuel oil will serve as a secondary fuel source when operating in the CC mode. Syngas and distillate fuel oil are both low in ash and sulfur content resulting in low PM emissions.

Fugitive PM emissions due to the handling of coal in the IGCC facility will be controlled using a comprehensive system of equipment enclosure, fabric filter dust collection, application of water/chemical dust suppression and crusting agents, and the paving of roads within the Polk Power Station site.

Table 3.4.2-1. Summary of Air Emission Controls for the IGCC Facility

Pollutant	Fuel Type	
	Syngas	Distillate Fuel Oil
PM and heavy metals	Low ash/sulfur fuel, efficient combustion--all combustion sources	Low ash/sulfur fuel, efficient combustion--all combustion sources
	Equipment enclosure, fabric filter dust collection, water/chemical dust suppression, crusting agents, paved roads--fugitive sources	
CO and VOC	Advanced combustion equipment and efficient combustion--all combustion sources	Advanced combustion equipment and efficient combustion--all combustion sources
SO_2 and H_2SO_4	Acid gas ~~recovery and sulfur recovery/tail gas treating~~removal/ H_2SO_4 plant/thermal oxidation--CGCU	Low sulfur (≤0.05 weight percent) fuel--all combustion sources
	Zinc titanate absorption/~~and~~ H_2SO_4 plant/thermal oxidation--HGCU	
	Low sulfur (≤0.07 weight percent) fuel--all combustion sources	
NO_x	Nitrogen injection--CT, low-NO_x burners/combustion practices--all other combustion sources	Wet injection--CT, low-NO_x burners/combustion techniques--all other combustion sources

Sources: GE, 1992.
Texaco, 1992.
ECT, 1992.

Table 3.4.2-2. Summary of Air Emission Controls for Stand-Alone CC and CT Units

Pollutant	Fuel Type Natural Gas	Distillate Fuel Oil
PM and heavy metals	Low ash/sulfur fuel, efficient combustion	Low ash/sulfur fuel, efficient combustion
CO and VOC	Advanced combustion equipment and efficient combustion	Advanced combustion equipment and efficient combustion
SO_2 and H_2SO_4	Low sulfur (≤ 10 gr/scf) fuel	Low sulfur (≤ 0.05 weight percent) fuel
NO_x	Dry low-NO_x burners	Water injection

Sources: GE, 1992.
ECT, 1992.

The stand-alone CCs and CTs will be fired primarily with natural gas with distillate fuel oil as a backup fuel source. These fuels are low in sulfur and ash content resulting in low PM emissions.

3.4.2.2 Carbon Monoxide and Volatile Organic Compounds

CO and VOC emissions from the IGCC facility and stand-alone CCs and CTs will be controlled by the use of advanced combustion equipment and operational practices to obtain efficient combustion. Highly efficient combustion will, in turn, result in low CO and VOC emission rates.

3.4.2.3 Sulfur Oxides and Sulfuric Acid Mist

Sulfur oxides and H_2SO_4 mist emission control is integral to the IGCC unit. Using conventional CGCU technology, H_2S and COS present in the syngas leaving the gasifier will be removed using a promoted amine process in the acid gas removal unit. The treated low sulfur syngas stream, containing approximately 0.07 weight percent sulfur compounds, will then be burned in the advanced CT for power production. Sulfur compounds will be stripped from the amine solution and ~~treated by the sulfur recovery/tail gas treating units~~ converted to H_2SO_4 in the H_2SO_4 plant which will recover more than 99 percent of the inlet sulfur. Any sulfur compounds remaining ~~in the tail gas treating unit exhaust~~ will be converted to SO_2 in the H_2SO_4 thermal oxidizer. The demonstration HGCU technology will react H_2S present in the syngas stream with zinc titanate sorbent in a moving bed absorber. Regeneration of the absorber will yield a concentrated SO_2 stream which will then be converted to H_2SO_4 in a H_2SO_4 production plant. Sulfur removal efficiency of the HGCU technology will meet or exceed that of conventional CGCU technology.

SO_2 and H_2SO_4 mist emissions from the IGCC combustion sources will be controlled by the use of low-sulfur fuels. The advanced 7F CT, during its initial year of simple-cycle operation, will be fired with low-sulfur distillate fuel oil. Sulfur content of syngas and distillate fuel oil will be 0.07 and 0.05 weight percent, respectively.

SO_2 emissions from the future stand-alone CC and CT units will be controlled by the use of low-sulfur natural gas and distillate fuel oil. Natural gas sulfur content will be less than 10 gr/100 scf. Distillate fuel oil will contain a maximum of 0.05 weight percent sulfur.

3.4.2.4 Nitrogen Oxides

The advanced CT in the IGCC unit will use nitrogen addition to control NO_x emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection NO_x control methods. Nitrogen used for injection will be provided by the air separation unit used to generate oxygen for the gasification process. Maximum nitrogen diluent will be injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. Water injection will be employed to control NO_x emissions when backup distillate fuel oil is used and during the first year of the 7F CT simple-cycle operation and when the unit is operated in CC mode. NO_x emissions from the remaining IGCC facility combustion sources will be controlled using low-NO_x burners and/or combustion practices that reduce NO_x formation.

The stand-alone CC and CT units will be equipped with dry low-NO_x burners when fired on natural gas and water injection when fired on backup distillate fuel oil to abate NO_x emissions.

3.4.3 BEST AVAILABLE CONTROL TECHNOLOGY

Best available control technology (BACT) represents an emission limitation that reflects the maximum degree of pollutant reduction achievable, determined on a case-by-case basis, with consideration given to energy, environmental, and economic impacts. BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), National Emission Standard for Hazardous Air Pollutants (NESHAPS) (40 CFR 61), and state emission standards (Chapter 17-2, Part VI, Emission Limiting and Performance Standards, F.A.C.).

A complete BACT evaluation for the Polk Power Station project is contained in the PSD permit application in Appendix 11.1.3. Proposed BACT emission limitations for the IGCC facility and stand-alone CC and CT units are summarized in Tables 3.4.3-1 and 3.4.3-2, respectively. An abbreviated discussion of the BACT review is provided in the following sections.

3.4.3.1 Methodology

The BACT analysis was performed in accordance with the EPA *top-down* method. The first step in the top-down BACT procedure was the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Following the identification of available control technologies, the next step in the analysis was to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the EPA New Source Review (NSR) Workshop Manual (EPA, 1990b). The third step in the top-down BACT process was the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness. Assessment of energy, environmental, and economic impacts was then performed. The economic analyses of the technologies used procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1990c). The fifth and final step was the selection of a BACT emission limitation

Table 3.4.3-1. Proposed BACT Limitations for the IGCC Facility

Emission Source	Fuel Type	Pollutant	BACT Emission Limitation lb/hr	lb/MMBtu	lb/MW	ppmvd
CT (simple cycle)	Distillate fuel oil	PM*	27.0	0.014	0.180	NA
CT/HRSG	Syngas (100% CGCU)	PM*	72.0	0.037†	~~0.296~~ 0.326**	NA
	Syngas (50% CGCU/50% HGCU)	PM*	72.0	0.037†	~~0.296~~ 0.326**	NA
Auxiliary boiler	Distillate fuel oil	PM*	3.0	0.061	NA	NA
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~PM*~~	~~13.1~~	~~NA~~	~~NA~~	~~NA~~
H_2SO_4 thermal oxidizer	Distillate fuel oil	PM*	~~2.6~~ 12.8	NA	NA	NA
CT/HRSG	Syngas (100% CGCU)	PM††	17.0	0.013†	~~0.116~~ 0.115**	NA
	Syngas (50% CGCU/50% HGCU)	PM††	17.0	0.013†	~~0.116~~ 0.115**	NA
Auxiliary boiler	Distillate fuel oil	PM††	3.0	0.061	NA	NA
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~PM††~~	~~13.1~~	~~NA~~	~~NA~~	~~NA~~
H_2SO_4 thermal oxidizer	Distillate fuel oil	PM††	~~2.6~~ 12.8	NA	NA	NA
CT (simple cycle)	Distillate fuel oil	CO	99.0	0.086	1.320	40.0
CT/HRSG	Syngas (100% CGCU)	CO	98.0	0.044†	0.382**	25.0
	Syngas (50% CGCU/50% HGCU)	CO	99.0	0.044†	0.386**	25.0
Auxiliary boiler	Distillate fuel oil	CO	4.3	0.087	NA	108.0
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~CO~~	~~1.4~~	~~NA~~	~~NA~~	~~29.0~~

Table 3.4.3-1. Proposed BACT Limitations for the IGCC Facility (Continued, Page 2 of 3)

Emission Source	Fuel Type	Pollutant	BACT Emission Limitation lb/hr	 lb/MMBtu	 lb/MW	 ppmvd
H_2SO_4 thermal oxidizer	Distillate fuel oil	CO	~~0.61~~ 1.4	NA	NA	~~29.0~~ 15.1
CT (simple cycle)	Distillate fuel oil	VOC	32.0	0.028	0.427	20.0
CT/HRSG	Syngas (100% CGCU)	VOC	3.0	~~0.0013~~ 0.0017†	~~0.012~~ 0.015**	1.0
	Syngas (50% CGCU/50% HGCU)	VOC	3.0	~~0.0013~~ 0.0017†	~~0.012~~ 0.015**	1.0
Auxiliary boiler	Distillate fuel oil	VOC	2.4	0.0485	NA	27.0
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~VOC~~	~~0.8~~	~~NA~~	~~NA~~	~~37.0~~
H_2SO_4 thermal oxidizer	Distillate fuel oil	VOC	~~0.35~~ 0.8	NA	NA	~~29.0~~ 15.1
CT (simple cycle)	Distillate fuel oil	SO_2	92.2	0.048	0.615	NA
CT/HRSG	Syngas (100% CGCU)	SO_2	518.0	~~0.236~~ 0.247†	~~2.073~~ 2.167**	NA
	Syngas (50% CGCU/50% HGCU)	SO_2	518.0	~~0.236~~ 0.247†	~~2.073~~ 2.167**	NA
Auxiliary boiler	Distillate fuel oil	SO_2	2.6	0.053	NA	NA
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~SO_2~~	~~52.0~~	~~NA~~	~~NA~~	~~NA~~
H_2SO_4 thermal oxidizer	Distillate fuel oil	SO_2	~~10.1~~ 45.3	NA	NA	NA
CT (simple cycle)	Distillate fuel oil	H_2SO_4	9.7	0.005	0.065	NA
CT/HRSG	Syngas (100% CGCU)	H_2SO_4	55.0	0.024†	0.212**	NA
	Syngas (50% CGCU/50% HGCU)	H_2SO_4	55.0	0.024†	0.212**	NA

Table 3.4.3-1. Proposed BACT Limitations for the IGCC Facility (Continued, Page 3 of 3)

Emission Source	Fuel Type	Pollutant	BACT Emission Limitation lb/hr	lb/MMBtu	lb/MW	ppmvd
Auxiliary boiler	Distillate fuel oil	H_2SO_4	0.0	NA	NA	NA
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~H_2SO_4~~	~~0.0~~	~~NA~~	~~NA~~	~~NA~~
H_2SO_4 thermal oxidizer	Distillate fuel oil	H_2SO_4	0.0	NA	NA	NA
CT (simple cycle)	Distillate fuel oil	NO_2	311.0	0.163	2.073	NA
CT/HRSG	Syngas (100% CGCU)	NO_2	222.5	0.099†	0.866**	25.0
	Syngas (50% CGCU/50% HGCU)	NO_2	664.0	0.292†	2.564**	81.0
Auxiliary boiler	Distillate fuel oil	NO_2	7.9	0.159	NA	123.0
~~Tail gas treating unit thermal oxidizer~~	~~Distillate fuel oil~~	~~NO_2~~	~~2.6~~	~~NA~~	~~NA~~	~~42.0~~
H_2SO_4 thermal oxidizer	Distillate fuel oil	NO_2	~~1.14~~ 2.6	NA	NA	~~33.0~~ 17.1

Note: For distillate fuel oil, emission estimates based on following properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum fuel-bound nitrogen of 0.015 weight percent [for fuel-bound nitrogen levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the fuel-bound nitrogen allowance contained in 40 CFR 60(GG)].

*Including H_2SO_4 emissions.
†Based on heat input (HHV) to coal gasifier and includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.
**Includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.
††Excluding H_2SO_4 emissions.

Sources: GE, 1992.
Texaco, 1992.
Bechtel, 1993.

Table 3.4.3-2. Proposed BACT Limitations for Stand-Alone CC and CT Units

Emission Source	Fuel Type	Pollutant	BACT Emission Limitation lb/hr	lb/MMBtu	lb/MW	ppmvd
CC unit (per unit)	Natural gas	PM*	22.0	0.010	0.100	NA
	Distillate fuel oil	PM*	41.0	0.018	0.186	NA
CTs (per CT)	Natural gas	PM*	11.0	0.010	0.147	NA
	Distillate fuel oil	PM*	20.5	0.018	0.273	NA
CC unit (per unit)	Natural gas	PM†	14.0	0.007	0.064	NA
	Distillate fuel oil	PM†	30.0	0.013	0.136	NA
CTs (per CT)	Natural gas	PM†	7.0	0.007	0.093	NA
	Distillate fuel oil	PM†	15.0	0.013	0.200	NA
CC unit (per unit)	Natural gas	CO	118.0	0.055	0.536	25.0
	Distillate fuel oil	CO	142.0	0.064	0.645	30.0
CTs (per CT)	Natural gas	CO	59.0	0.055	0.787	25.0
	Distillate fuel oil	CO	71.0	0.064	0.945	30.0
CC unit (per unit)	Natural gas	VOC	20.0	0.0093	0.091	7.0
	Distillate fuel oil	VOC	20.0	0.0090	0.091	7.0
CTs (per CT)	Natural gas	VOC	10.0	0.0093	0.133	7.0
	Distillate fuel oil	VOC	10.0	0.0090	0.133	7.0
CC unit (per unit)	Natural gas	SO_2	72.0	0.034	0.327	NA
	Distillate fuel oil	SO_2	107.4	0.047	0.488	NA
CTs (per CT)	Natural gas	SO_2	36.0	0.034	0.480	NA
	Distillate fuel oil	SO_2	53.7	0.047	0.716	NA
CC unit (per unit)	Natural gas	H_2SO_4	8.0	0.0037	0.026	NA
	Distillate fuel oil	H_2SO_4	11.0	0.0049	0.050	NA

Table 3.4.3-2. Proposed BACT Limitations for Stand-Alone CC and CT Units (Continued, Page 2 of 2)

Emission Source	Fuel Type	Pollutant	BACT Emission Limitation			
			lb/hr	lb/MMBtu	lb/MW	ppmvd
CTs (per CT)	Natural gas	H_2SO_4	4.0	0.0037	0.053	NA
	Distillate fuel oil	H_2SO_4	5.5	0.0049	0.073	NA
CC unit (per unit)	Natural gas	NO_2	70.0	0.033	0.318	9.0
	Distillate fuel oil	NO_2	362.0	0.162	1.645	42.0
CTs (per CT)	Natural gas	NO_2	35.0	0.033	0.467	9.0
	Distillate fuel oil	NO_2	181.0	0.162	2.413	42.0

Note: For distillate fuel oil, emission estimates based on following properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum fuel-bound nitrogen of 0.015 weight percent [for fuel-bound nitrogen levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the fuel-bound nitrogen allowance contained in 40 CFR 60(GG)].

*Including H_2SO_4 emissions.
†Excluding H_2SO_4 emissions.

Source: GE, 1992.

corresponding to the most stringent technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds. Control technology analyses using the five step *top-down* BACT method were prepared for combustion products, products of incomplete combustion, and acid gases, respectively. In the following sections, the BACT analyses are discussed separately for: (a) the IGCC facility, and (b) the stand-alone CC and CT units since these emission sources are two distinct processes with differing available control technologies.

3.4.3.2 Particulate Matter and Trace Heavy Metals

Control technologies available for the IGCC facility (advanced CT and ancillary combustion sources) include use of clean fuels and efficient combustion and conventional post-combustion stack controls such as electrostatic precipitators, fabric filters, and wet scrubbers. A wet scrubber to remove PM from the syngas will be an integral part of the CGCU process. The scrubbed syngas will then be cooled prior to entering the acid gas removal unit which will result in the condensation of trace volatile heavy metals and further reduction in syngas particulate levels. The demonstration HGCU technology will employ a high temperature barrier filter to remove 99.5 percent or more of the PM contained in the syngas stream. The end product of the CG process, for both CGCU and HGCU technologies, will be a treated syngas stream which is low in PM. The low PM content of the treated syngas stream, coupled with high CT excess air rates, will produce an exhaust gas with very low PM concentrations; i.e., 0.010 grains per standard cubic foot (gr/scf) or less. Use of backup low sulfur distillate fuel oil in the advanced CT will also result in low exhaust PM concentrations, 0.0048 gr/scf or less. This low exhaust PM concentration will also occur for the 7F CT during its initial first year, distillate fuel oil-fired, simple-cycle mode operation and when operated in CC mode when syngas is unavailable. Control of exhaust stream PM concentrations of such low magnitude using available post-combustion technologies is not feasible since removal efficiencies would be unreasonably low and costs excessive. Since post-process stack controls for PM are not appropriate for the IGCC facility, the use of wet scrubbing (integral to the IGCC process), good combustion practices and clean fuels is considered to be BACT. The Polk Power Station IGCC project will use the latest CT burner technology to maximize combustion efficiency and minimize PM emission rates. Project fuels will consist of coal-derived syngas and low sulfur distillate fuel oil.

Ancillary equipment associated with the IGCC facility that emit PM include the auxiliary steam boiler, coal handling facilities, and H_2SO_4 plant ~~(HGCU technology)~~ thermal oxidizer~~, and the sulfur recovery unit (CGCU technology) tail gas thermal oxidizer~~. The auxiliary boiler~~,~~ and H_2SO_4 thermal oxidizer~~, and sulfur recovery tail gas thermal oxidizer~~ will all use low ash, low-sulfur fuels. Due to low exhaust stream PM concentrations, BACT for PM emissions from these emission sources is considered to be the use of clean fuels and good combustion practices.

Coal handling fugitive PM emissions will be controlled by a combination of wet dust suppression, equipment enclosure, and fabric filter dust collection systems located at the major dust emission points. Trucks and railcars will unload at a receiving hopper equipped with a dust collection system to collect dust from all conveyor transfer points in the dump pit area. Wet dust suppression systems using either foam, or water sprays with a wetting agent, will also be employed at the truck/railcar receiving hopper. Conveyors will be hooded to minimize dust emissions. Enclosures and dust abatement equipment (fabric filters) will be employed to control PM emissions from coal handling equipment and transfer points. A wet suppression system will be used at the stacker discharge to the coal pile. Wind blown PM emissions from the active and inactive coal piles will be controlled by the application of water/chemical dust suppressants and crusting agents, respectively. All roads within the Polk Power Station complex will be paved, except for the infrequently used transmission line service roads. Use of wet suppression, hoods and enclosures, paved roads, and fabric filters is considered to be BACT for PM emissions from coal handling operations.

Exhaust PM concentrations from the stand-alone CC and CT units are inherently low due to the combustion of clean fuels (natural gas and low sulfur distillate fuel oil) and high exhaust gas flow rates. Estimated maximum PM exhaust concentrations (including H_2SO_4 mist) from the individual stand-alone CTs in simple-cycle or CC mode using natural gas and backup distillate fuel oil are 0.0033 and 0.0065 gr/scf, respectively. Due to these low exhaust concentrations, post-process stack controls are not feasible since PM removal efficiencies would be unreasonably low and costs excessive. Use of clean fuels and good combustion practices is considered to be BACT for PM emissions from the stand-alone CC units and CTs.

3.4.3.3 Carbon Monoxide and Volatile Organic Compounds

Available technologies for reducing CO and VOC emissions from the IGCC facility (CT and ancillary combustion sources) include combustion process design and use of post-combustion oxidation catalyst controls. Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of most proposed combustion processes, CO and VOC emissions are inherently low.

Noble metal (commonly platinum or palladium) oxidation catalysts can be used to promote oxidation of CO and VOCs to CO_2 and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for these oxidation catalysts is between 650 and 1,150°F. However, these oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Thus, oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOCs. The nonselectivity characteristics of oxidation catalysts are important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist which can lead to corrosion and fouling of boiler tubes in the HRSG, plugging of the catalyst reactor, decrease in CO conversion efficiency of the catalyst, and a visible exhaust plume.

Corrosion of the HRSG boiler tubes decreases heat transfer surface area and thus decreases stream generating capabilities. Sulfur compounds in the exhaust gas stream also decrease CO removal efficiency of the catalyst since the catalyst will selectively absorb sulfur compounds. This thin layer of sulfur residue inhibits the contact between CO and the catalyst decreasing catalyst performance. CO oxidation catalysts treating streams containing sulfur compounds must be washed or heated to high temperatures periodically to eliminate catalyst sulfur residue which increases the downtime of the control system. Increased downtime is unacceptable for the Polk Power Station IGCC facility since the facility will operate as a baseload power plant.

There are no significant energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions. The application of oxidation catalyst technology to a combustion device would result in an increase in backpressure on the device due to pressure drop across the catalyst bed thereby increasing energy consumption. Concerning environmental impacts, the use of oxidation catalysts would, as previously mentioned, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing sulfur. Since the estimated CO and VOC emission rates from the IGCC combustion unit will be inherently low, further reductions through the use of oxidation catalysts will result in insignificant air quality improvements which are well below the defined PSD significant impact levels for CO and negligible reductions in ambient VOC levels. The Polk Power Station site (i.e., Polk County) is classified attainment for all criteria pollutants.

From an air quality perspective, the only benefit of CO oxidation catalysts would be to prevent localized CO *hot spots* since the catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of CO emissions from the Polk Power Station sources indicate that maximum impacts will be insignificant.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts were not considered to be technically feasible for the IGCC combustion units since these units are fired with fuels (syngas and distillate fuel oil) containing appreciable amounts of sulfur. Use of combustion controls and good operating practices to minimize incomplete combustion are proposed as BACT for the IGCC unit and associated combustion sources. Proper combustion system design, efficient operation, and minimization of low load conditions will control CO and VOC emissions to low levels consistent with NO_x emission control requirements. *CO and VOC limits proposed for the IGCC advanced CT when fired with syngas are less than the lowest BACT/Lowest Available Emission Rate (LAER) Information System (BLIS) entries for coal-fired boilers.* Overall, the proposed BACT technologies and emission limits for the IGCC unit and associated facilities are consistent with previous BACT determinations both within Florida and elsewhere in the United States (FDER, 1991; EPA, 1992; San Bernardino County Air Pollution Control District, 1989).

The two available control technologies of combustion process modifications and use of oxidation catalysts would also apply to the stand-alone CC and CT units. The energy and environmental impacts associated with oxidation catalysts as previously described would also be relevant to these units (i.e., negligible improvements in ambient CO and VOC levels, increased H_2SO_4 emissions during distillate fuel oil firing, and an energy penalty due to increased turbine backpressure).

The CTs associated with the stand-alone CC and CT units will use natural gas as the primary fuel with low sulfur distillate fuel oil as a backup fuel source. Maximum distillate oil annual capacity factors for the stand-alone CC units and CTs are 25 and 10 percent, respectively. Maximum natural gas annual capacity factors for the stand-alone CC units and CTs are 100 and 50 percent, respectively. An economic evaluation of an oxidation catalyst system having an 80-percent CO removal efficiency was performed for the future Polk Power Station CTs using OAQPS and project-specific economic cost factors. Base case CO emissions are estimated to be 25 ppmvd resulting in a controlled CO exhaust concentration of 5.0 ppmvd. Base case CO emission levels are representative of the performance of the dry low-NO_x burners planned for the future stand-alone CC units and CTs. The dry low-NO_x burners, which can attain a NO_x exhaust concentration of 9 ppmvd, produce slightly higher CO emissions in comparison to conventional CT burner technology. Cost effectiveness of oxidation catalyst for CO emissions was determined to be $5,158 per ton of CO removed for the CC units. For the simple-cycle CTs, cost effectiveness of CO oxidation catalyst was found to be $5,643 per ton. Based on the high control costs, use of oxidation catalyst technology to control CO and VOC emissions was not considered to be economically feasible. The slightly higher CO emissions which result from the proposed use of dry-low NO_x burners is an acceptable compromise with respect to overall NO_x and CO emission rates.

Use of combustion controls and good operating practices to minimize incomplete combustion are proposed as BACT for the future stand-alone CC and CT units. These control methods are consistent with prior FDER BACT determinations for CO and VOC emissions from CT units which have all been based on the use of good combustion techniques.

3.4.3.4 Sulfur Dioxide and Sulfuric Acid Mist

SO_2, SO_3, and H_2SO_4 mist emissions result from the combustion of fuels containing sulfur. H_2SO_4 emissions result from the reaction of SO_3 and water in the exhaust gas stream. The conversion rate of SO_2 to SO_3 depends on combustion parameters; e.g., temperature and excess oxygen levels, as well as fuel characteristics.

Removal ~~and recovery~~ of sulfur contained in the ~~coal fuel are~~ syngas is integral components of the CG process. The proposed IGCC unit and sulfur ~~recovery~~ removal processes are highly efficient and will result in a low rate of SO_2 emitted per megawatt of electricity produced in comparison to conventional coal-fired power plants. The syngas cleanup processes remove ~~and recover~~ sulfur compounds, primarily H_2S~~,~~ and SO_2 from the high pressure syngas generated in the gasifier.

Removal ~~and recovery~~ of sulfur compounds from the syngas stream will be much more efficient than that achieved removing the same compounds from the post-combustion, highly dilute, low pressure exhaust streams generated by conventional coal combustion in a steam boiler. The proposed IGCC unit sulfur ~~recovery~~ removal processes result in saleable, concentrated ~~by-product streams, liquid sulfur (CGCU) or~~ H_2SO_4 by-product ~~(HGCU)~~, in contrast to the large quantities of solid waste materials typically generated by conventional wet or dry FGD systems.

In the CGCU system, acid gases (CO_2, H_2S, and COS) present in the syngas will be removed using a promoted amine process in the acid gas removal unit. The promoted amine will act as a weak base to selectively absorb the weak H_2S acid while allowing most of the CO_2 to remain in the syngas. The treated syngas stream, containing approximately 0.07 weight percent sulfur, will flow from the acid gas removal unit through several coolers and knockout drums for water removal and will then be burned in the advanced CT for power production. The rich amine solution containing dissolved acid gases will be routed to the amine stripper where the acid gases are steam stripped from the rich amine solution. The concentrated acid gas overhead stream from the amine stripper will be cooled and routed to the ~~sulfur recovery unit~~ H_2SO_4 plant for processing. Lean amine solution from the amine stripper will be cooled and pumped to the amine storage tank for subsequent re-use in the amine absorber. Amine treating is the most widely used and efficient process for removing acid gases from sour gas streams. ~~For the Polk Power Station project, a three-stage catalytic sulfur recovery unit followed by a tail gas treating unit and thermal oxidation will recover over 99 percent of the sulfur entering the sulfur recovery unit/tail gas treating unit system.~~

The demonstration HGCU system will remove H_2S from the coal gasifier syngas stream at elevated temperatures by reacting the gas stream with zinc titanate sorbent in a moving bed absorber. The zinc titanate sorbent is regenerated by controlled temperature, multi-stage oxidation in a regenerator. The concentrated SO_2 stream from the regenerator will be routed to an H_2SO_4 plant for conversion to H_2SO_4 by-product. The high temperature zinc titanate absorption system has the potential to achieve sulfur removals greater than conventional CGCU technology while improving the overall efficiency of the IGCC facility. At a minimum, sulfur removal efficiency for the HGCU technology will equal that of conventional CGCU.

The proposed sulfur removal and recovery processes (both CGCU and HGCU) which are integral to the IGCC facility will achieve an overall sulfur removal efficiency of 95.6 percent. *This removal efficiency is higher than the highest efficiency listed in BLIS for large, coal-fired power plants and exceeds that required for recently permitted CG and coal-fired boiler facilities in Florida.* Sulfur content of the treated syngas is projected to be less than 0.07 weight percent. Application of FGD systems is not feasible due to the low exhaust SO_2 concentrations. Use of the integral acid gas removal and sulfur recovery processes are proposed as BACT for the IGCC facility. BACT for the ancillary IGCC combustion sources is considered to be the use of low sulfur fuels.

The stand-alone CC and CT units will use natural gas and low sulfur (maximum 0.05 weight percent sulfur) distillate oil as fuels. Natural gas is the primary fuel with distillate oil serving as a backup fuel source. Maximum distillate oil annual capacity factors for the stand-alone CC units and CTs are 25 and 10 percent, respectively. Technologies available to control SO_2 and H_2SO_4 emissions from these units include fuel treatment and post-combustion add-on controls; i.e., FGD systems. While FGD technology would be technically feasible, there have been no applications to CT operations in the United States since low sulfur fuels have been used resulting in low exhaust gas SO_2 concentrations. The sulfur content of the backup distillate oil proposed for the CTs will be more than 40 times lower than the fuels employed in coal-fired boilers using FGD systems. In addition, CTs operate with a significant amount of excess air which generates high exhaust gas flow rates. Since FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentrations, application of a FGD system to a CT exhaust stream would result in unreasonably low SO_2 removal efficiencies. Due to low SO_2 exhaust stream concentrations, FGD technology was not considered to be feasible for CTs for the Polk Power Station since removal efficiencies would be unreasonably low and costs would be excessive.

Since post-combustion controls are not applicable, use of low sulfur fuels is considered to represent BACT for SO_2 and H_2SO_4 emissions from the stand-alone CC and CT units. Thes units will use natural gas (containing less than 10 gr/100 scf) and low sulfur distillate oil as fuels.

3.4.3.5 Nitrogen Oxides

NO_x emissions from combustion sources consist of two components; thermal and fuel NO_x. Thermal NO_x results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio and, to a lesser extent, combustion pressure. Fuel NO_x arises from the oxidation of non-elemental nitrogen contained in the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion process or fuel treatment technologies available to control fuel NO_x emissions.

Available control technologies evaluated for the IGCC combustion sources consist of combustion process modifications and post-combustion exhaust gas treatment systems. Available CT combustion process technologies are standard combustor design and water/steam/diluent injection, advanced combustor design and water/steam/diluent injection, and dry low-NO_x combustors. Combustion process modifications applicable to IGCC combustion sources other than the CT include flue gas recirculation, low excess air, and low-NO_x burners. Post-combustion technologies potentially applicable to all IGCC combustion sources are selective non-catalytic reduction (SNCR), non-selective catalytic reduction (NSCR), and selective catalytic reduction (SCR). Detailed descriptions of these control technologies are provided in the PSD application contained in Appendix 11.1.3 of this SCA.

In theory, technically feasible control technologies for the IGCC CT were determined to be water/steam/diluent injection with either standard or advanced combustor technology and SCR. For the IGCC oxygen-blown process, nitrogen will be provided to serve as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection. Nitrogen used for injection will be provided by the air separation unit which also produces oxygen for the IGCC gasification process. Steam/water injection technology was not reviewed since it results in the same level of NO_x emissions in comparison to nitrogen injection.

SCR was evaluated although a number of concerns exist regarding the technical feasibility of SCR for CTs fueled with syngas. SCR catalyst deactivation can occur due to chemical poisoning. Principle poisons include arsenic, sulfur, potassium, sodium, and calcium. All of these are present in the flyash generated from coal and oil combustion. Decreased SCR catalyst activity after only a few hundred hours of operation was observed in European tests for certain coals and firing modes. The decrease in catalyst performance was subsequently attributed to arsenic poisoning of the catalyst. Gaseous arsenic trioxide, formed by the oxidation of elemental arsenic in coal, was found to condense on the SCR catalyst preventing the adsorption of NO_x and NH_3.

SCR catalyst will promote the oxidation of flue gas SO_2 to SO_3 which will then combine with water vapor to form H_2SO_4. Accordingly, corrosion of downstream piping and heat transfer equipment (which would operate at temperatures below the H_2SO_4 dew point) would be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted NH_3 to form ammonium bisulfate and ammonium sulfate. Ammonium bisulfate is a hygroscopic solid at approximately 380°F and will deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate would be expected to deposit on HRSG heat transfer equipment where temperatures below 380°F will occur. Since ammonium bisulfate is hygroscopic, the material will absorb water forming a sticky substance which can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown would be required to clean fouled equipment. Formation of ammonium salts will also result in a significant increase in PM emissions. The technical difficulties associated with SCR and sulfur bearing fuels have been documented for fuels having relatively low sulfur contents; e.g., as low as 50 to 100 parts per million (ppm) (0.005 to 0.01 percent) sulfur. Although the fuels planned for the IGCC advanced CT are low in sulfur content, the sulfur levels are more than sufficient to cause problems with operation of a SCR control system. Problems associated with ammonium salt deposition can be ameliorated to some extent by reducing the NH_3/NO_x molar ratio when firing sulfur-containing fuels. However, all known successful applications of SCR for CTs are on natural gas-fired units. There are presently no applications of SCR to CTs fired with syngas derived from coal.

There are no significant adverse energy or environmental effects due to the use of nitrogen injection and advanced combustor technology. In contrast, application of SCR technology will result in the following adverse impacts:

- Total energy penalty of 7.2 megawatt-hours per year (equivalent to an annual consumption of 23.5 million cubic feet of natural gas) due to increased backpressure on the CT and pumping and vaporization of aqueous NH_3;
- NH_3 emissions due to NH_3 slip; NH_3 emissions are estimated to total 98 tpy (at baseload and 59°F ambient temperature) for a typical SCR design NH_3 slippage rate of 10 ppmvd;
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases; total particulate emissions would increase by approximately 50 percent;
- A public risk due to potential leaks from the storage of large quantities of NH_3--NH_3 has been designated an Extraordinarily Hazardous Substance under the Federal Superfund Amendment and Reauthorization Act (SARA) Title III regulations; and

- Disposal of spent catalyst which may considered hazardous due to heavy metal contamination; vanadium pentoxide is an active component of a typical SCR catalyst and is listed as a hazardous chemical waste under Resource Conservation and Recovery Act (RCRA) Regulations 40 CFR 261.30.

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced combustion and nitrogen injection and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 25 and 42 ppmvd at 15-percent oxygen for syngas and oil-firing, respectively. Due to the problems associated with the application of SCR to exhaust streams containing sulfur, NH_3 addition must be reduced to prevent formation of ammonium salts and subsequent fouling of downstream heat transfer equipment. Based on Japanese experience, SCR technology with reduced NH_3 addition was premised to achieve NO_x concentrations of 12.5 and 21.0 ppmvd at 15-percent oxygen for syngas and oil-firing, respectively, representing a 50-percent NO_x removal efficiency. The cost impact analysis was conducted using OAQPS and project-specific economic factors. Cost effectiveness for the application of SCR technology to the IGCC advanced CT was determined to be $6,272 per ton of NO_x removed. This control cost is greater than those previously found to be reasonable for BACT NO_x determinations. Further, the economic evaluation did not include the increased costs that would also accrue due to downtime required for cleaning of fouled heat transfer equipment.

NO_x emissions during the 2-year HGCU demonstration period are expected to be higher than for CGCU technology. The primary reason for this increase is the presence of NH_3 in the HGCU syngas stream; the NH_3 will be subsequently oxidized to NO_x in the IGCC advanced CT. NH_3 will be removed from the gasifier syngas stream as part of the CGCU process and thus CGCU generates syngas with negligible NH_3 concentrations. One of the goals of the HGCU demonstration project is to determine the NO_x levels that are generated by the process.

Use of nitrogen diluent injection to achieve NO_x exhaust concentrations of 25 ppmvd at 15-percent oxygen for syngas-firing and water injection to achieve 42 ppmvd at 15 percent O_2 for oil-firing is proposed as BACT for the IGCC advanced CT. Nitrogen injection is considered to represent BACT for the following reasons:

- The 25 ppmvd NO_x concentration limit for syngas combustion together with NO_x emissions from the ~~tail gas treating unit~~ H_2SO_4 thermal oxidizer represents an overall IGCC NO_x emission rate of 0.099 pound per million British thermal unit (lb/MMBtu). *This rate is among the lowest contained in the BLIS database and is well below the most recent BACT determination of 0.17 lb/MMBtu made in Florida and New Jersey for coal-fired power plants.*
- Overall NO_x emissions from the IGCC facility in terms of pounds of NO_x per megawatt *is approximately 50 percent* of the rates recently approved by FDER for the Stanton and Indiantown coal-fired power plants and, with one exception, *is the lowest in the BLIS database.* Comparison of emissions on a pound-per-megawatt basis is felt to be more meaningful than other units such as pound-per-million-Btu since it reflects the emission reduction benefit of process efficiency.
- The 25 ppmvd NO_x concentration limit proposed for syngas combustion is well below the previous BACT concentration of 42 ppmvd assigned to CG projects in Virginia and Florida.
- Nitrogen injection will achieve the same level of NO_x control as water or steam injection without the water consumption and treatment/disposal requirements associated with wet injection.
- Power augmentation due to nitrogen addition results in lower emissions per unit of power produced since the nitrogen augmentation replaces power that would otherwise be generated by fossil fuel combustion. The concomitant emissions associated with fuel combustion are therefore avoided.

- Dry low-NO_x burner technology has not yet been developed for syngas fuels--initial research indicated comparable performance to the standard multi-nozzle combustor.
- Cost-effectiveness of SCR was found to be $6,272 per ton of NO_x removed which exceeds values previously considered to be reasonable for NO_x BACT determinations.
- The application of SCR technology to the treatment of exhaust gases generated by the combustion of sulfur-bearing fuels poses a number of technical concerns. These concerns include catalyst poisoning from arsenic and sulfur compounds and formation of ammonium salts due to the combination of SO_3 and any unreacted NH_3 causing corrosion and reduced efficiency of downstream heat transfer equipment.
- Spent SCR catalyst may require handling and disposal as a hazardous waste due to vanadium pentoxide content. Also, facility workers could be exposed to high levels of vanadium pentoxide particulates during catalyst handling.
- Emissions of NH_3 will occur due to NH_3 slip. SCR vendors typically guarantee a maximum NH_3 slip rate of 10 ppmv. Both NO_x and NH_3 participate in the photochemical ozone cycle--the substitution of 10 ppmv NH_3 (due to slip) for 12.5 ppmv NO_x (the concentration controlled by SCR) during syngas firing, the fuel which will be employed 90 percent of the time in the IGCC CT, is felt to problematical from an air quality perspective. In addition, NH_3 slip can increase significantly during start-ups, upsets/failures of the NH_3 injection system, or due to catalyst degradation. During such instances, NH_3 concentrations of 50 ppmv or greater have been measured which exceeds the odor threshold of approximately 20 ppmv.

Use of low-NO_x burner technology is proposed as BACT for the ancillary IGCC combustion sources. These sources have NO_x emission rates which are only a small fraction (approximately 5 percent) of the total IGCC facility NO_x emissions.

Control technologies to abate NO_x emissions previously described for the IGCC advanced CT are also applicable to the stand-alone CC and CT units with the exception of SCR technology for the simple-cycle units. SCR technology is not considered to be applicable to simple-cycle CTs due to temperature constraints; i.e., the CT exhaust temperature of approximately 1,100°F exceeds the maximum temperature required for successful SCR operation.

Use of dry low-NO_x burner technology will achieve lower NO_x emission rates in comparison to wet injection based on vendor data. The stand-alone CC and CT units are projected to attain NO_x exhaust concentrations of 9 and 42 ppmvd at 15-percent oxygen for gas and oil-firing, respectively. Dry low-NO_x burner technology has not yet been developed for oil-firing, and therefore conventional wet injection will be employed when backup distillate oil is used as the turbine fuel source.

The use of dry low-NO_X burner technology is considered to represent BACT for the future CC and simple-cycle CTs for the following reasons:

- Dry low-NO_x burner technology will achieve NO_x concentrations of 9 and 42 ppmvd for gas and oil-firing, respectively. A NO_x exhaust concentration of 9 ppmvd is generally considered to represent BACT for CTs *equipped with SCR control technology*. The proposed NO_x concentration is also below the current FDER BACT guideline of 15 ppmvd for natural gas-fired CTs using dry low-NO_x burners.
- Dry low-NO_x burner technology will achieve comparable emission rates as SCR for gas-firing without the adverse impacts associated with SCR technology; i.e., NH_3 emissions due to NH_3 slip, potential of ammonium salt particulate formation with subsequent downstream corrosion and reduced efficiency of heat transfer equipment, hazards associated with the storage of NH_3 and disposal of spent catalyst, and energy penalties due to increased turbine backpressure and additional system downtime for catalyst replacement.

- Use of backup distillate fuel oil will be limited to annual capacity factors of 25 and 10 percent, respectively for the combined and simple-cycle CTs.
- Application of SCR to the simple-cycle CTs is not considered to be feasible due to the substantial cost required to reduce CT exhaust temperatures to levels consistent with successful SCR operation, low backup fuel oil capacity factor, and relatively minor reduction in NO_x emissions that would result from applying SCR to CTs equipped with dry low-NO_x burners.

3.4.4 DESIGN DATA FOR CONTROL EQUIPMENT

Control of air emissions for the Polk Power Station project will be accomplished by the use of highly efficient process technologies and clean fuels. These process technologies and fuels will achieve low emission rates without the application of post-combustion control equipment. Process descriptions, emission rates and exhaust gas characteristics, and fuel specifications are provided in Sections 3.1 and 3.3 of this SCA. Tables 3.4.4-1 and 3.4.4-2 provide summaries of exhaust characteristics and pollutant emission rates for the IGCC facility and the stand-alone CT and CC units, respectively.

Table 3.4.4-1. Summary Exhaust Characteristics and Emission Rates for the IGCC Facility

Emission Source	Fuel Type	Pollutant	Emission Rate (lb/hr)	Exhaust Characteristics Temperature (°F)	Velocity (ft/sec)	Flow Rate (acfm)
CT* (simple-cycle)	Distillate fuel oil	PM†	26.0	342	69	772,782
		CO	77.0			
		VOC	10.0			
		SO_2	85.3			
		NO_x	288.0			
CT/HRSG*	Syngas (100% CGCU)	PM†	72.0	265	68	1,156,797
		CO	68.0			
		VOC	2.0			
		SO_2	518.0			
		NO_x	213.0			
CT/HRSG*	Syngas (50% CGCU/50% HGCU)	PM†	72.0	260	69	1,173,809
		CO	87.0			
		VOC	2.0			
		SO_2	518.0			
		NO_x	660.0			
Auxiliary boiler	Distillate fuel oil	PM†	3.0	500	43	18,237
		CO	4.3			
		VOC	2.4			
		SO_2	2.6			
		NO_x	7.9			
~~TGTU thermal oxidizer~~	~~Distillate fuel oil~~	~~PM‡~~	~~13.1~~	~~1,400~~	~~35~~	~~33,399~~
		~~CO~~	~~1.4~~			
		~~VOC~~	~~0.8~~			
		~~SO_2~~	~~52.0~~			
		~~NO_x~~	~~2.6~~			

Table 3.4.4-1. Summary Exhaust Characteristics and Emission Rates for the IGCC Facility (Continued, Page 2 of 2)

Emission Source	Fuel Type	Pollutant	Emission Rate (lb/hr)	Exhaust Characteristics		
				Temperature (°F)	Velocity (ft/sec)	Flow Rate (acfm)
H_2SO_4 thermal oxidizer	Distillate fuel oil	PM‡	~~2.6~~ 12.8	1,400	~~30~~ 32	~~17,318~~ 74,760
		CO	~~0.6~~ 1.4			
		VOC	~~0.4~~ 0.8			
		SO_2	~~10.1~~ 45.3			
		NO_x	~~1.1~~ 2.6			

Note: For distillate fuel oil, emission estimates based on following properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum fuel-bound nitrogen of 0.015 weight percent [for fuel-bound nitrogen levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the fuel-bound nitrogen allowance contained in 40 CFR 60(GG)].

*Emission rates and exhaust characteristics at 100-percent load and 59°F ambient temperature.
†Includes H_2SO_4.

Sources: GE, 1992.
Texaco, 1992.
Bechtel, 1993.

Table 3.4.4-2. Summary Exhaust Characteristics and Emission Rates for Stand-Alone CT and CC Units

Emission Source	Fuel Type	Pollutant	Emission Rate (lb/hr)	Exhaust Characteristics		
				Temperature (°F)	Velocity (ft/sec)	Flow Rate (acfm)
CC unit* (per unit)	Natural gas	PM†	20.0	253	72	713,361
		CO	108.0			
		VOC	18.0			
		SO_2	66.0			
		NO_x	64.0			
	Distillate fuel oil	PM†	40.0	253	72	713,361
		CO	130.0			
		VOC	18.0			
		SO_2	94.7			
		NO_x	326.0			
CT unit* (per unit)	Natural gas	PM†	10.0	985	94	1,421,280
		CO	54.0			
		VOC	9.0			
		SO_2	33.0			
		NO_x	32.0			
	Distillate fuel oil	PM†	20.0	980	72	1,451,520
		CO	65.0			
		VOC	9.0			
		SO_2	47.4			
		NO_x	163.0			

Note: For distillate fuel oil, emission estimates based on following properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum fuel-bound nitrogen of 0.015 weight percent [for fuel-bound nitrogen levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the fuel-bound nitrogen allowance contained in 40 CFR 60(GG)].
ft/sec = feet per second.
acfm = actual cubic feet per minute.

*Emission rates and exhaust characteristics at 100 percent load and 59°F ambient temperature.
†Includes H_2SO_4.

Source: GE, 1992.

3.4.5 DESIGN PHILOSOPHY

Air emission controls planned for the Polk Power Station project have been designed to fully comply with all applicable State and Federal regulations. Specific design concepts are summarized as follows:

IGCC Facility

- Use of the most efficient technology for converting coal to electrical power;
- Application of BACT for all affected pollutants and emission sources;
- Use of low sulfur and low ash fuels;
- Use of highly efficient, demonstrated integrated sulfur removal and recovery technology (CGCU);
- Demonstration of HGCU technology to potentially reduce SO_2 emissions to levels below those achieved by conventional CGCU;
- Use of water/nitrogen injection to control CT NO_x emissions;
- Use of efficient combustion to minimize emissions of pollutants associated with incomplete combustion; and
- Use of comprehensive controls to minimize fugitive dust emissions associated with coal handling.

Stand-Alone CT and CC Units

- Application of BACT for all affected pollutants and emission sources;
- Use of low sulfur and low ash fuels;
- Use of state-of-the-art dry low-NO_x burners to minimize NO_x emissions during natural gas-firing;
- Use of water injection to control NO_x emissions during oil-firing;
- Use of low distillate fuel oil capacity factors; and
- Use of efficient combustion to minimize emissions of pollutants associated with incomplete combustion.

The Polk Power Station project will use the most efficient technology available, IGCC, to convert coal to electrical power. On a total power production basis, IGCC air emissions are minimized by using a process technology which produces the most power for each unit of coal consumed. IGCC emissions, on a pound-per-megawatt basis, are generally well below the rates generated by conventional coal-fired power plants.

Air emission control technologies planned for the Polk Power Station project reflect the application of BACT for each affected pollutant and emission source. The proposed BACT limitations are well below applicable State and Federal emission standards. Specific controls include highly efficient sulfur removal and recovery integral to the gasification process; nitrogen/water injection to control NO_x emissions from the IGCC CT during syngas and oil-firing, respectively; dry low-NO_x burners and water injection to minimize NO_x emissions during natural gas and oil-firing, respectively, for the future stand-alone CTs; efficient combustion to minimize emissions of pollutants associated with incomplete combustion; and comprehensive controls to minimize fugitive dust emissions associated with coal handling.

Both the IGCC facility and future stand-alone CTs will use clean fuels to reduce particulate and sulfur emissions. Maximum sulfur content for the syngas will be 0.07 weight percent, and distillate fuel oil will be 0.05 weight percent. Distillate fuel oil will contain no more than 0.01 weight percent ash. Primary fuel for the stand-alone CTs will be natural gas containing less than 10 gr/100 scf.

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5.6 AIR QUALITY IMPACTS

5.6.1 IMPACT ASSESSMENT

5.6.1.1 Introduction

Analyses were conducted to project the potential air quality impacts of emissions from Polk Power Station. These analyses are described in detail in the PSD permit application contained in Appendix 11.1.3. This section presents a summary of the approach used and the results obtained. The results demonstrate that the operation of Polk Power Station will not cause or contribute to a violation of any PSD increment or AAQS.

5.6.1.2 Regulatory Applicability and Overview of Impact Analyses

Under federal PSD review requirements, all major new or modified sources of air pollutants regulated under CAA must be reviewed and approved by EPA or by the state agency if PSD review authority has been delegated, as is the case in Florida. A *major stationary source* is defined as any 1 of 28 named source categories that has the potential to emit 100 tpy or more, or any other stationary source that has the potential to emit 250 tpy or more, of any pollutant regulated under CAA. *Potential to emit* means the capability at maximum design capacity to emit a pollutant after the application of control equipment.

Polk Power Station constitutes a major facility since it will have the potential to emit more than 250 tpy of at least one pollutant. Therefore, the facility must undergo PSD review. Furthermore, more than one pollutant is subject to review. Table 5.6.1-1 summarizes the facility's proposed annual emissions and compares the projected totals to the significant emission rate thresholds for PSD review.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. PSD review requirements are contained in Chapter 17-2.500, F.A.C., Prevention of Significant Deterioration. Major sources may be required to undergo the following reviews related to PSD for each pollutant emitted in significant amounts:

Table 5.6.1-1. Projected Emissions Compared to PSD Significance Rates

Pollutant	Projected Maximum Annual Emissions (tpy)				Significance Rate (tpy)	Subject to PSD Review?
	IGCC*	+ CCs†	+ CTs**	= Total		
PM (TSP)	~~411~~ 399	260	246	~~917~~ 905	25	Yes
PM (PM_{10})	~~411~~ 399	260	246	~~917~~ 905	15	Yes
SO_2	~~2,543~~ 2,469	720	654	~~3,917~~ 3,843	40	Yes
NO_x	~~2,928~~ 2,923	1,308	1,014	~~5,250~~ 5,245	40	Yes
CO	~~456~~ 453	1,092	978	~~2,526~~ 2,523	100	Yes
O_3/VOC	~~46~~ 45	180	168	~~394~~ 393	40	Yes
Lead	0.15	0.28	0.17	0.6	0.6	Yes
H_2SO_4	241	80	72	393	7	Yes
Fluorides	0.92	0.17	0.10	1.2	3	No
Mercury	0.12	0.21	0.19	0.5	0.1	Yes
Beryllium	~~0.011~~ 0.007	0.013	0.008	0.03	0.0004	Yes
Total reduced sulfur (including H_2S)	~~7.1~~ 6.2	0	0	~~7.1~~ 6.2	10	No
Reduced sulfur compounds (including H_2S)	~~7.1~~ 6.2	0	0	~~7.1~~ 6.2	10	No
Vinyl chloride	0	0	0	0	1	No
Asbestos	0	0	0	0	0.007	No

*IGCC emissions include the highest annual emissions estimates from the 7F CT (based on the larger of 100 percent CGCU or 50/50 CGCU/HGCU), plus related combustion emissions (e.g., thermal oxidizer), plus other associated process and fugitive emissions (PM, CO, VOC, and H_2S).

†CC emissions represent the totals for four stand-alone CTs in CC mode.

**CT emissions represent the totals for six stand-alone CTs in simple-cycle mode.

Sources: Bechtel, 1993.
ECT, 199~~2~~3.

- Control technology review,
- Air quality analysis (monitoring),
- Source impact analysis,
- Source information, and
- Additional impact analyses.

The control technology review includes determination of BACT for each applicable pollutant. BACT emission limits cannot exceed applicable emission standards (e.g., NSPS). The air quality analysis (monitoring) portion of PSD review may require continuous ambient air monitoring data to be collected in the impact area of the proposed source. The source impact analysis requires demonstration of compliance with federal and state AAQS and allowable PSD increment limitations. Projected ambient impacts on designated nonattainment areas and federally promulgated Class I PSD areas must also be addressed, if applicable. Source information, including process design parameters and control equipment information, must be submitted to the reviewing agencies. Additional analyses of the proposed source's impact on soils, vegetation, and visibility, especially pertaining to Class I PSD areas, must be performed, as well as analysis of impacts due to growth in the area associated with the proposed source.

In addition to PSD review requirements, FDER has developed a strategy to control toxic emissions from stationary sources so that these emissions will not endanger public health. The strategy is based on comparing the predicted ambient impact of individual toxic air contaminants with an estimate of each chemical's ***no-threat level.*** A no-threat level is an ambient exposure level that is not likely to cause appreciable health risks.

Another air toxics assessment involves the estimation of cancer risk due to inhalation of emissions from a proposed facility. The metals arsenic, beryllium, cadmium, and chromium (hexavalent) are of primary interest in such an analysis since these constituents, which are emitted as a result of the combustion of most fossil fuels, are known or suspected carcinogens.

Polk Power Station will emit small quantities of pollutants addressed in FDER's air toxics review strategy. Therefore, an analysis of the facility's impacts compared to the no-threat levels applies. In addition, a conservative analysis of inhalation cancer risks was considered appropriate since Polk Power Station will emit trace metals that are known or suspected carcinogens. There is no regulatory standard or formal review requirement for this analysis, however.

5.6.1.3 Analytical Approach

Air Quality Models

Three air quality dispersion models were used in the analysis of impacts for Polk Power Station. These models were:

1. SCREEN;
2. ISC2 (both short- and long-term versions, ISCST2 and ISCLT2, respectively); and
3. MESOPUFF-II.

SCREEN is a simple model that calculates 1-hour average concentrations from a single source over a range of meteorological conditions. SCREEN was used to provide conservative estimates of impacts from combustion sources in order to select the worst-case operating configurations for each source.

The Industrial Source Complex (ISC2) models (EPA, 1992) were used for refined analyses. The ISC2 models are steady-state Gaussian plume models that can be used to assess air quality impacts from a wide variety of sources. They are capable of calculating concentrations for averaging times ranging from 1 hour to annual.

The MESOPUFF-II model (EPA, 1984) is a specialized model capable of accounting for several long-range transport and dispersion phenomena that are not addressed in conventional models such as ISC2. For this study, MESOPUFF-II was used for the specific purpose of estimating SO_2 impacts on the Chassahowitzka National Wilderness Area (NWA), a PSD Class I area.

Meteorological Data

Detailed meteorological data are needed for modeling with the ISC2 models. For this effort, meteorological data for input to these models were selected consistent with EPA (1986) guidance and FDER practice. For ISCST2, surface data from Tampa and mixing height data from Ruskin for the 5-year period 1982 through 1986 were employed. Surface data from the same 5-year period were processed into the format required for ISCLT2.

For MESOPUFF-II, a specialized set of meteorological data was required. Surface data from Tampa, Orlando, and Gainesville, along with upper air data from Ruskin and West Palm Beach for the years 1982 through 1986 were used.

Emission Source Input Data

Emission parameters for Polk Power Station sources were based primarily on information provided by equipment vendors for the project. Some emission inputs were derived using EPA and other emission factors and facility design data.

For three pollutants (SO_2, NO_x, and PM), it was necessary to evaluate the impacts of other, offsite emission sources. These data were assembled primarily from information provided by FDER.

Background Concentrations

For the same three pollutants (i.e., SO_2, NO_x, and PM), it was also necessary to estimate background concentrations in the vicinity of the Polk Power Station site. For SO_2, the estimates were derived from onsite monitoring (see Section 2.3.7). The following background SO_2 concentrations were estimated based on the monitoring results:

- 5 $\mu g/m^3$ (annual average),
- 13 $\mu g/m^3$ (24-hour average), and
- 26 $\mu g/m^3$ (3-hour average).

For NO_x (actually NO_2), a background concentration of 10 $\mu g/m^3$ (annual average) was estimated conservatively based on monitoring data collected at the Archbold research site in 1988 (Hunter/ESE, 1989). The Archbold site is approximately 75 km southeast of the Polk Power Station site. Data from Archbold were used as opposed to data from NO_2 monitors operated by FDER, which are all located in urban areas and whose data would not be representative of rural southwest Polk County.

For PM (actually PM_{10}), background concentrations were estimated from data provided from the onsite monitoring program. For the annual averaging time, background PM_{10} was estimated to be 18.4 $\mu g/m^3$. For the 24-hour averaging time, a value of 45.4 $\mu g/m^3$ was estimated.

5.6.1.4 Summary of Air Quality Impacts: Criteria Pollutants

Maximum Facility Impacts and Significant Impact Areas

Criteria pollutant emissions from all Polk Power Station sources were modeled using the ISC2 models. ISCLT2 was used for annual and quarterly computations, while ISCST2 and 5 years of hourly meteorological data were used for all short-term computations. For SO_2, NO_x, CO, and lead, the Polk Power Station source inventory included the 7F CT (IGCC), the stand-alone CTs (both CC and simple-cycle), the auxiliary boiler, ~~the tail gas treating unit thermal oxidizer,~~ and the H_2SO_4 thermal oxidizer; for CO, fugitive sources were also included. For PM, materials handling and process vent sources were added to this list.

Table 5.6.1-2 summarizes the results of the maximum facility impact modeling runs for the criteria pollutants. As appropriate, the maximum impacts are compared to the modeling significance levels. Table 5.6.1-2 shows that SO_2, NO_x, and PM impacts were found to be significant for all averaging times. CO impacts were found to be

Table 5.6.1-2. Maximum Polk Power Station Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
SO_2	Annual	~~1.58~~ 1.24	1.0
	24-hour	~~19.0~~ 14.6	5.0
	3-hour	~~68.6~~ 47.3	25.0
NO_x	Annual	~~1.78~~ 1.06	1.0
PM	Annual	~~1.49~~ 1.13	1.0
	24-hour	~~29.4~~ 33.6	5.0
CO	8-hour	~~67.1~~ 52.9	500
	1-hour	~~169.2~~ 137.4	2,000
Lead	Quarterly	~~0.0014~~ 0.0011	NA*

*The AAQS for lead is 1.5 $\mu g/m^3$.

Source: ECT, 199~~2~~3.

insignificant for both 1- and 8-hour averaging times. And while no significance level exists for lead, lead impacts were considered insignificant relative to the AAQS.

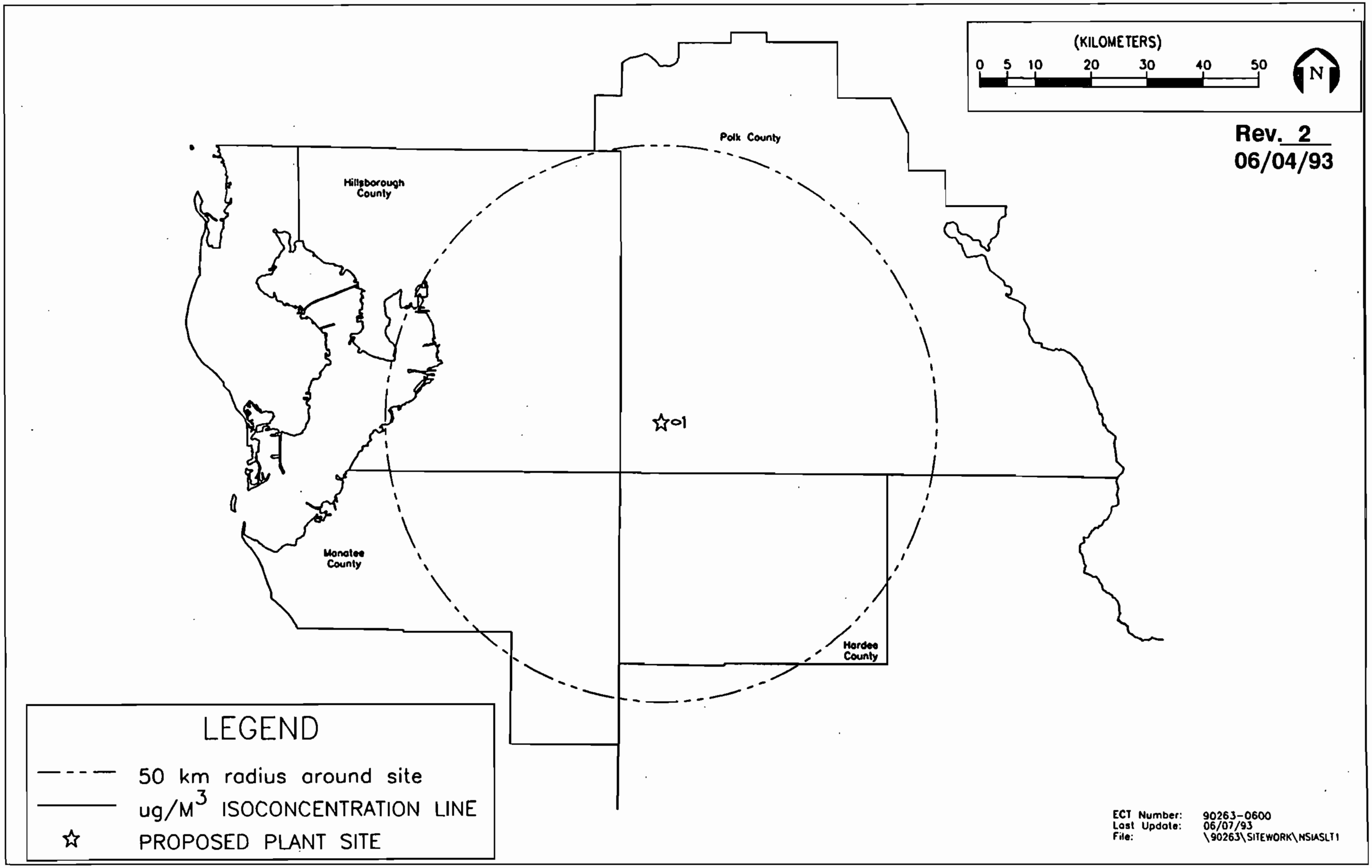
Illustrations of significant impact areas (SIAs) are provided in Figures 5.6.1-1 through 5.6.1-6. Figures 5.6.1-1, 5.6.1-2, and 5.6.1-3, respectively, present the annual, 24-hour, and 3-hour SIAs for SO_2. The annual SIA was found to have a maximum extent of approximately ~~8~~ 5 km. The 24-hour SIA extended out to approximately 25 km, while the 3-hour SIA had a maximum extent of approximately ~~20~~ 5 km.

Figure 5.6.1-4 presents the annual NO_x SIA. Its maximum extent was found to be approximately ~~6~~ 4 km from the grid origin.

Figures 5.6.1-5 and 5.6.1-6, respectively, show the PM SIAs for annual and 24-hour averages. For the annual average, the maximum extent was only approximately 2 km, while for the 24-hour average it was approximately 11 km. Superimposed on the illustrations of PM SIAs is the portion of Hillsborough County that is classified as an air quality maintenance area for PM. As shown, the SIAs for Polk Power Station PM sources were found to fall well short of the maintenance area. Therefore, new source review with respect to maintenance areas (i.e., including provisions for nonattainment review) was not triggered.

Analyses for Ambient Air Quality Standards

Total potential SO_2, NO_x, and PM (PM_{10}) impacts within the Polk Power Station SIAs were determined for comparison with AAQS. This was accomplished by adding conservative estimates of background concentrations to modeled impacts due to Polk Power Station and other sources in the area. Table 5.6.1-3 summarizes the results of these analyses. As shown, all estimates of predicted total impacts were found to be less than the AAQS. Therefore, it was concluded that the operation of the Polk Power Station facility would not threaten compliance with any AAQS.



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06/04/93

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Last Update: 06/07/93
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FIGURE 5.6.1-1.

ANNUAL SULFUR DIOXIDE SIGNIFICANT IMPACT AREAS

Source: ECT, 1993.

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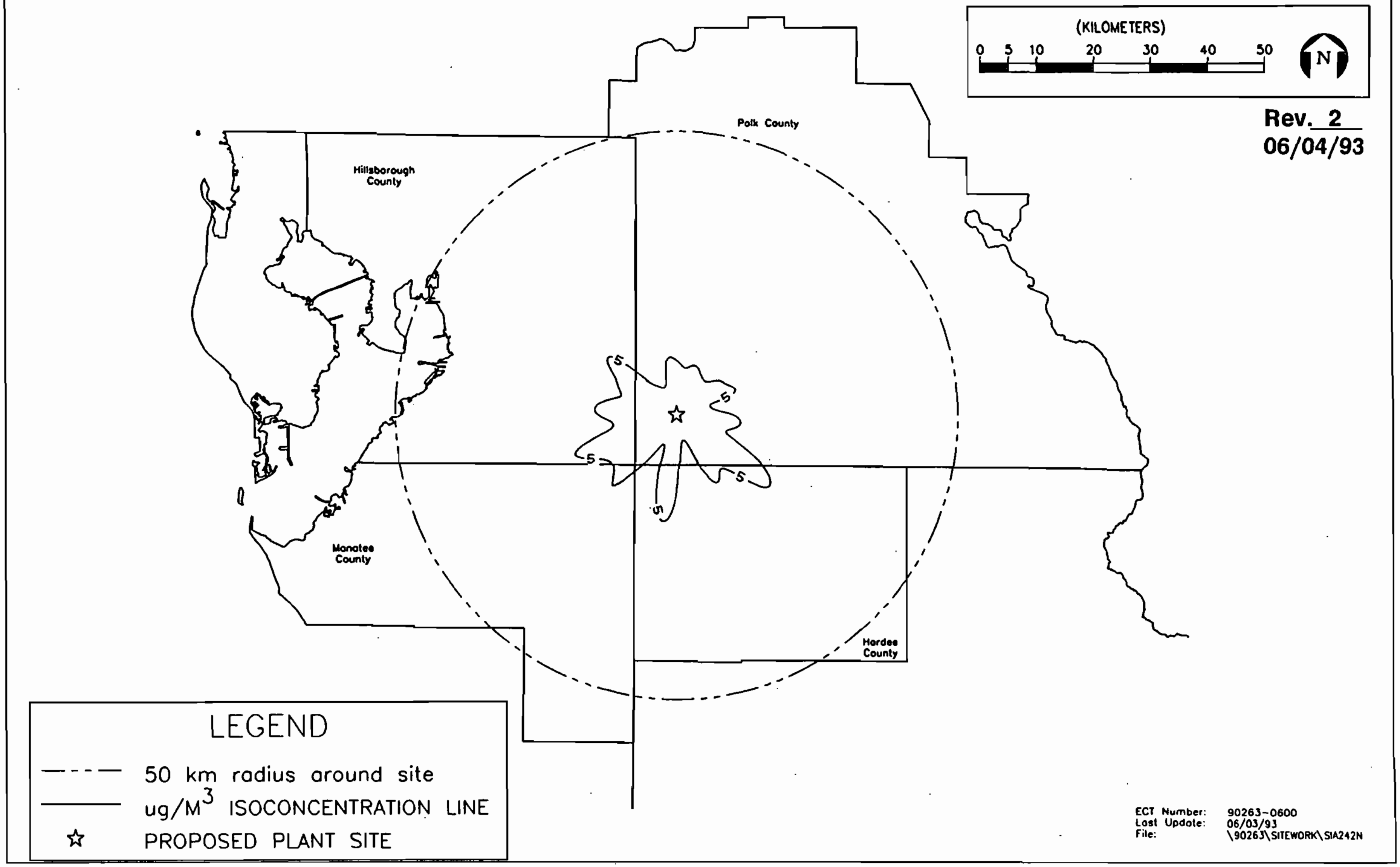
A TECO ENERGY COMPANY

**POLK
POWER
STATION**



Rev. 2
06/04/93

ECT Number: 90263-0600
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FIGURE 5.6.1-2.

24-HOUR SULFUR DIOXIDE SIGNIFICANT IMPACT AREAS

Source: ECT, 1993.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

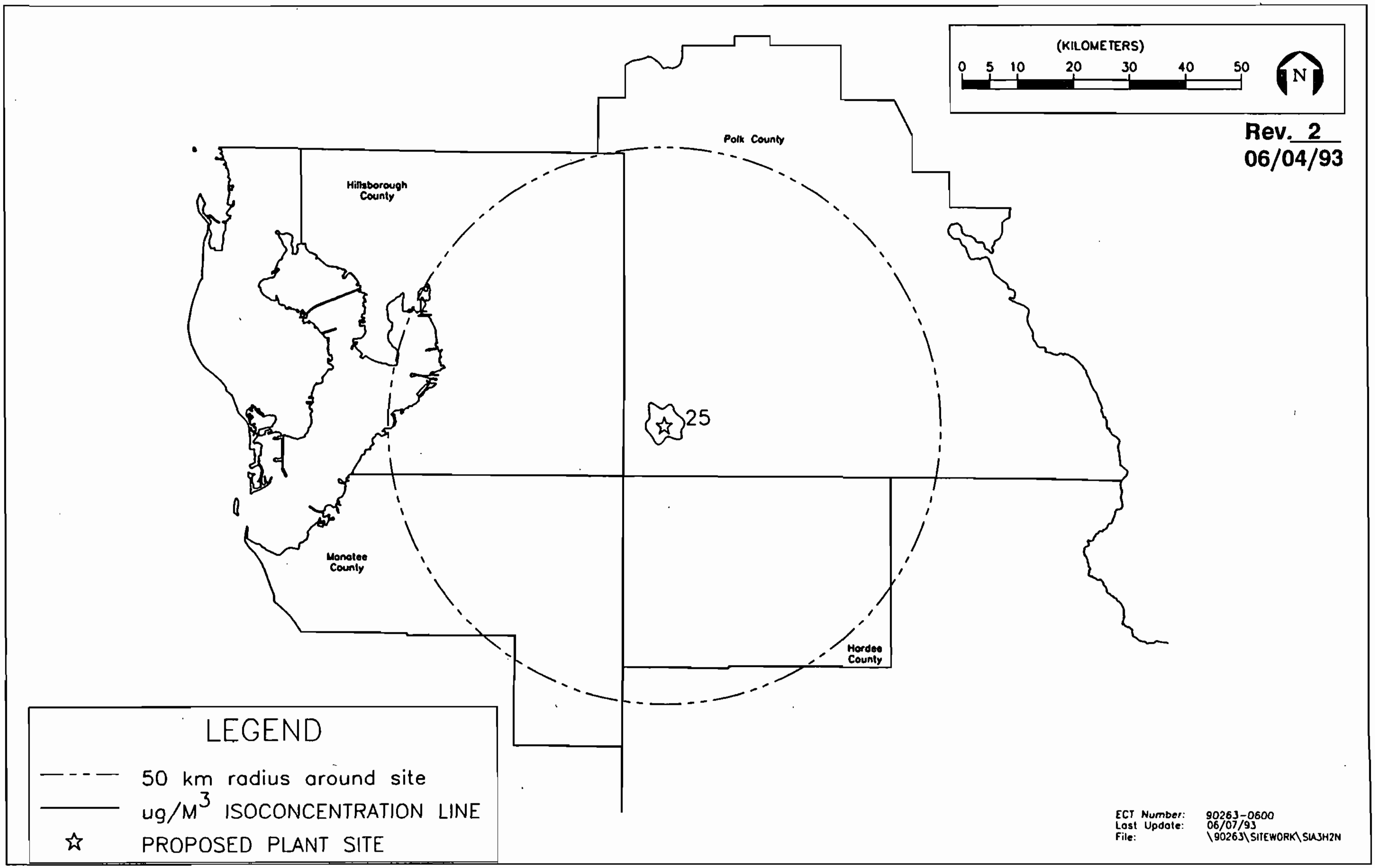

FIGURE 5.6.1-3.

3-HOUR SULFUR DIOXIDE SIGNIFICANT IMPACT AREAS

Source: ECT, 1993.

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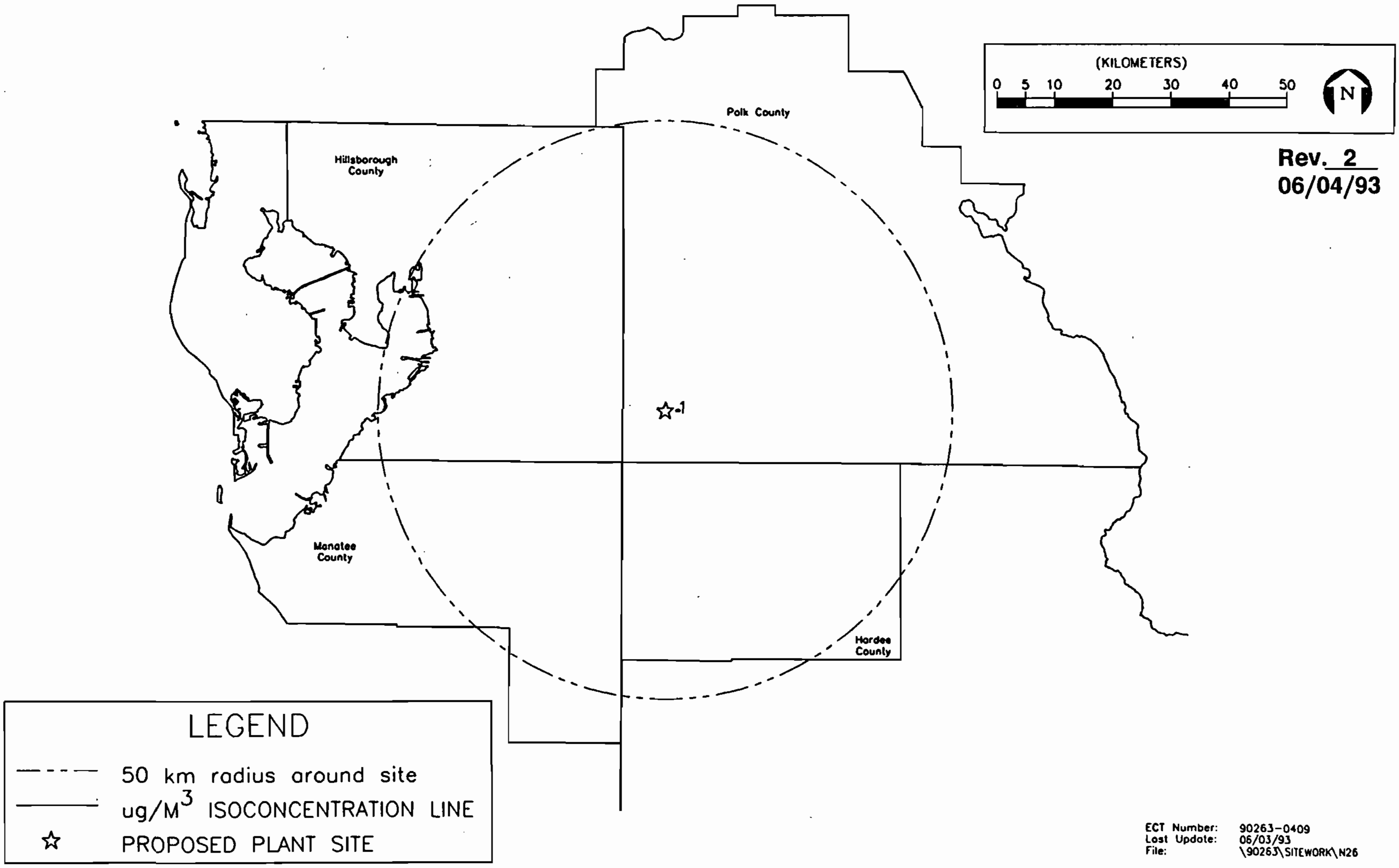

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FIGURE 5.6.1-4.

ANNUAL NITROGEN OXIDES SIGNIFICANT IMPACT AREAS

Source: ECT, 1993.

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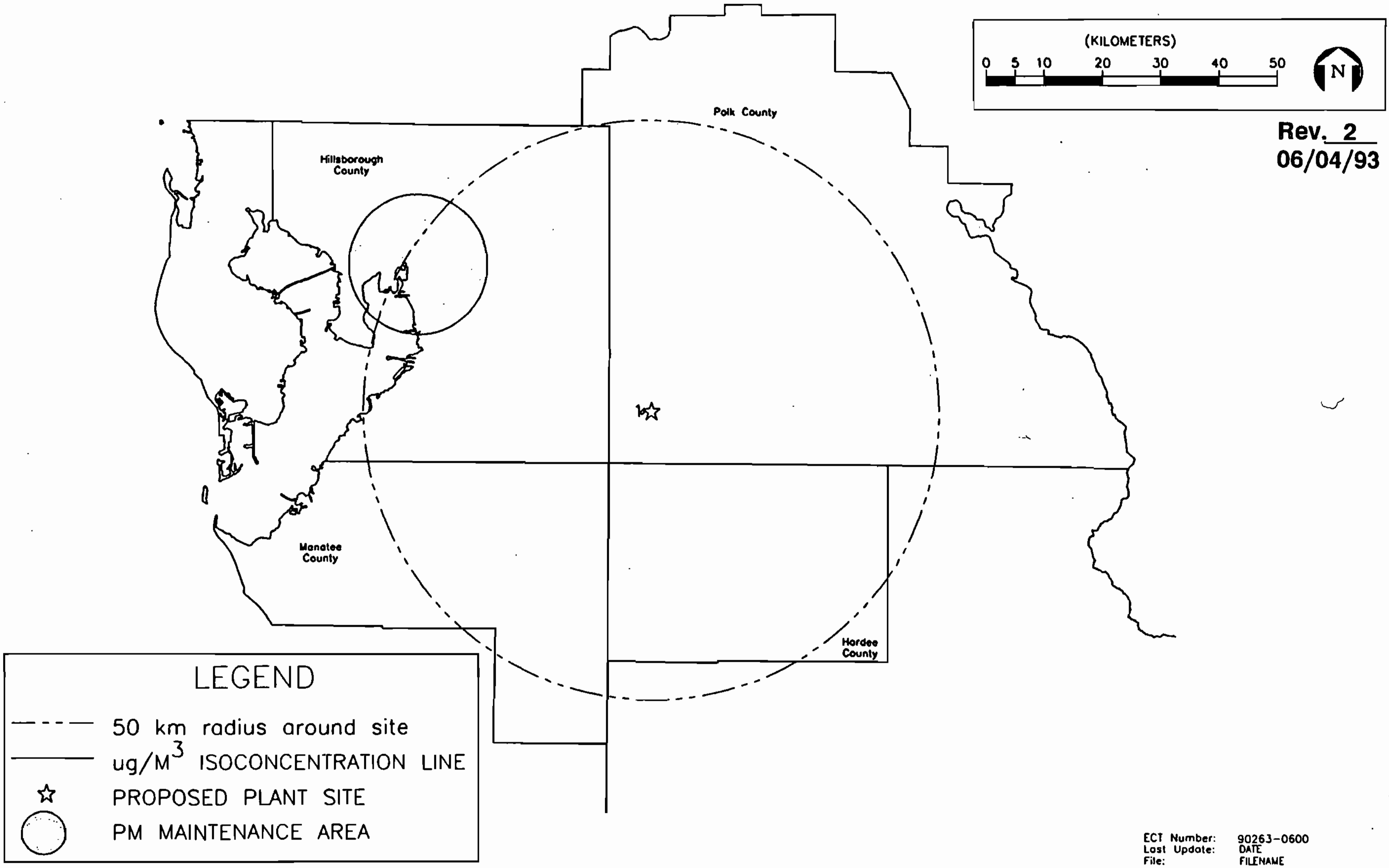

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FIGURE 5.6.1-5.

ANNUAL PARTICULATE MATTER SIGNIFICANT IMPACT AREAS

Source: ECT, 1993.

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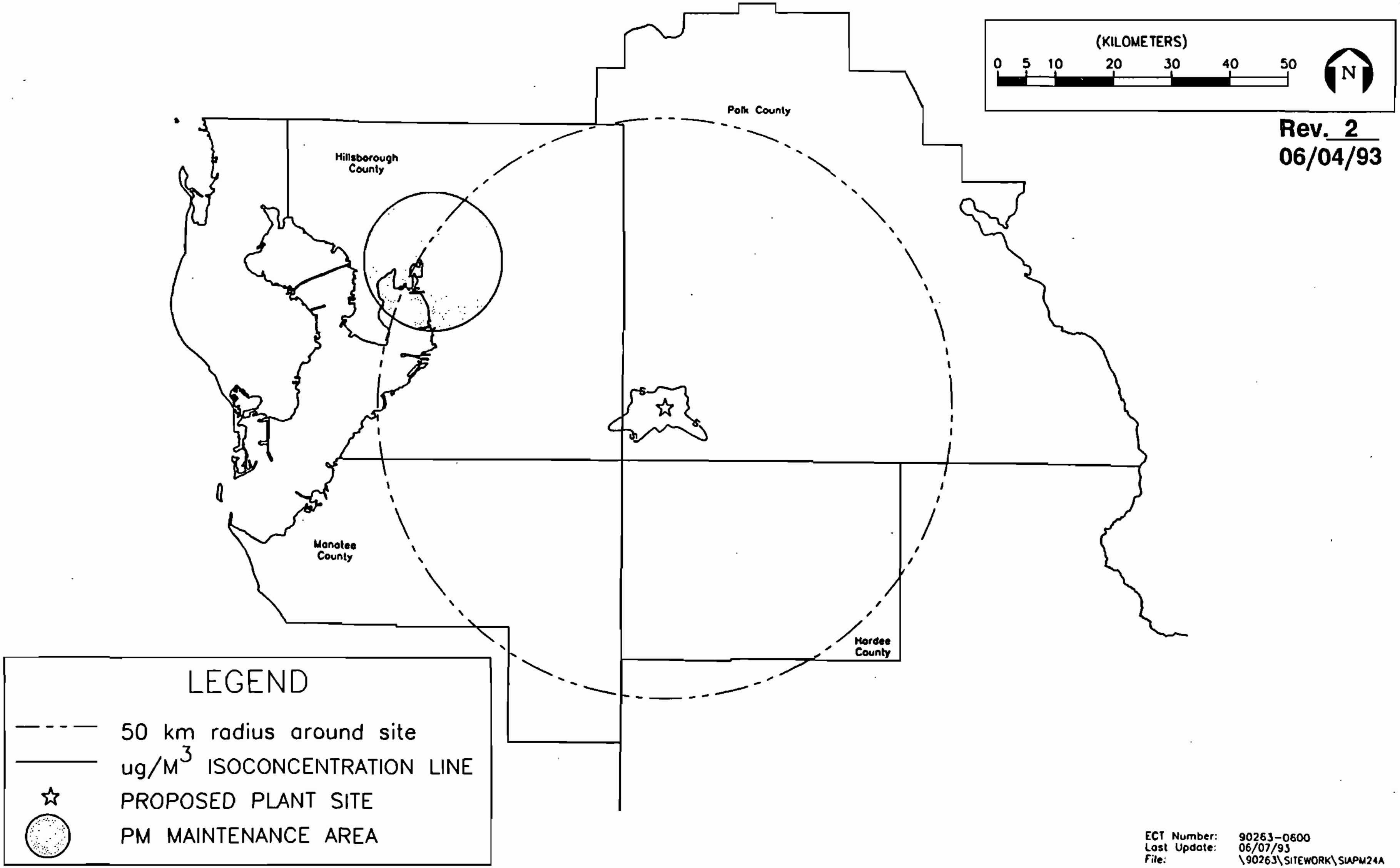

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FIGURE 5.6.1-6.

24-HOUR PARTICULATE MATTER SIGNIFICANT IMPACT AREAS

Source: ECT, 1993.

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Table 5.6.1-3. Summary of Impact Analyses for AAQS

Pollutant	Averaging Time	Modeled Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Projected Impact ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
SO_2	Annual	30.7	5	36	60
	24-hour	162.7*	13	176	260
	3-hour	521.2*	26	547	1,300
NO_x	Annual	5.85	10	16	100
PM (PM_{10})	Annual	15.4	18.4	34	50
	24-hour	79.4*	45.4	125	150

*HSH modeled impact.

Source: ECT, 1992.

Analyses for Prevention of Significant Deterioration Class II Increments

Modeling analyses were carried out to determine maximum SO_2, NO_x, and PM (TSP) increment consumption within the Polk Power Station SIAs. Table 5.6.1-4 presents a summary of these analyses. All estimates of predicted impacts were less than the allowable Class II increments. Therefore, the operation of Polk Power Station will not cause significant deterioration of air quality in the project vicinity.

Analyses for Prevention of Significant Deterioration Class I Increments

Using very conservative modeling impacts and assumptions, air quality impacts with respect to PSD Class I increments were projected using the ISC2 and MESOPUFF-II models. Table 5.6.1-5 summarizes the final results of the impact analyses for PSD Class I increments. As shown, no exceedances were predicted. Given the conservative nature of the analyses, it can be concluded that operation of the Polk Power Station facility will not cause significant deterioration of air quality at the Chassahowitzka NWA.

5.6.1.5 Air Toxics Assessment

Maximum impacts due to Polk Power Station emission sources were determined for non-criteria pollutants using the ISC2 models. Table 5.6.1-6 summarizes the results and compares the maximum impacts to the no-threat levels. All maximum impacts were predicted to be below the no-threat levels, indicating that, with an adequate margin of safety, public health in the vicinity of Polk Power Station will not be jeopardized.

In addition to the no-threat level analysis, the potential impacts of the metals arsenic, beryllium, cadmium, and chromium (hexavalent) were of additional interest since they are known or suspected carcinogens and will be emitted in amounts that make them worthy of investigation. To evaluate the potential impacts of these emissions on human health, an inhalation cancer risk assessment was conducted. The assessment was used to estimate maximum individual risk (MIR) and total population risk (TPR). MIR is the estimated increase lifetime risk for an individual exposed to

Table 5.6.1-4. Summary of Impact Analyses for PSD Class II Increments

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
SO_2	Annual	0.0*	20
	24-hour	27.0†	91
	3-hour	104.0†	512
NO_2	Annual	3.3	25
PM (TSP)	Annual	5.4	19
	24-hour	31.8†	37

*Increment consumption was negative over the entire receptor grid.
†HSH modeled impact.

Source: ECT, 1992.

Table 5.6.1-5. Summary of Impact Analyses for PSD Class I Increments

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class I Increment ($\mu g/m^3$)
SO_2	Annual	0.4	2
	24-hour	3.8*	5
	3-hour	12.9*	25
NO_2	Annual	0.8	2.5
PM (TSP)	Annual	1.1	5
	24-hour	5.7*	10

*HSH modeled impact.

Source: ECT, 1992.

Table 5.6.1-6. Summary of Worst-Case Estimates of Air Toxics Impacts Compared to FDER No-Threat Levels

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	No-Threat Level ($\mu g/m^3$)
H_2SO_4	8-hour	3.76	10
	24-hour	1.64	2.4
Fluorides	1-hour	0.060	25
Mercury	8-hour	0.011	0.1
	24-hour	0.0048	0.024
Beryllium	Annual	0.00006	0.0004
Arsenic	Annual	0.00019	0.0002

Source: ECT, 1992.

the predicted highest annual average concentration. TPR is the estimated annual incidence of excess cancers for the entire affected population.

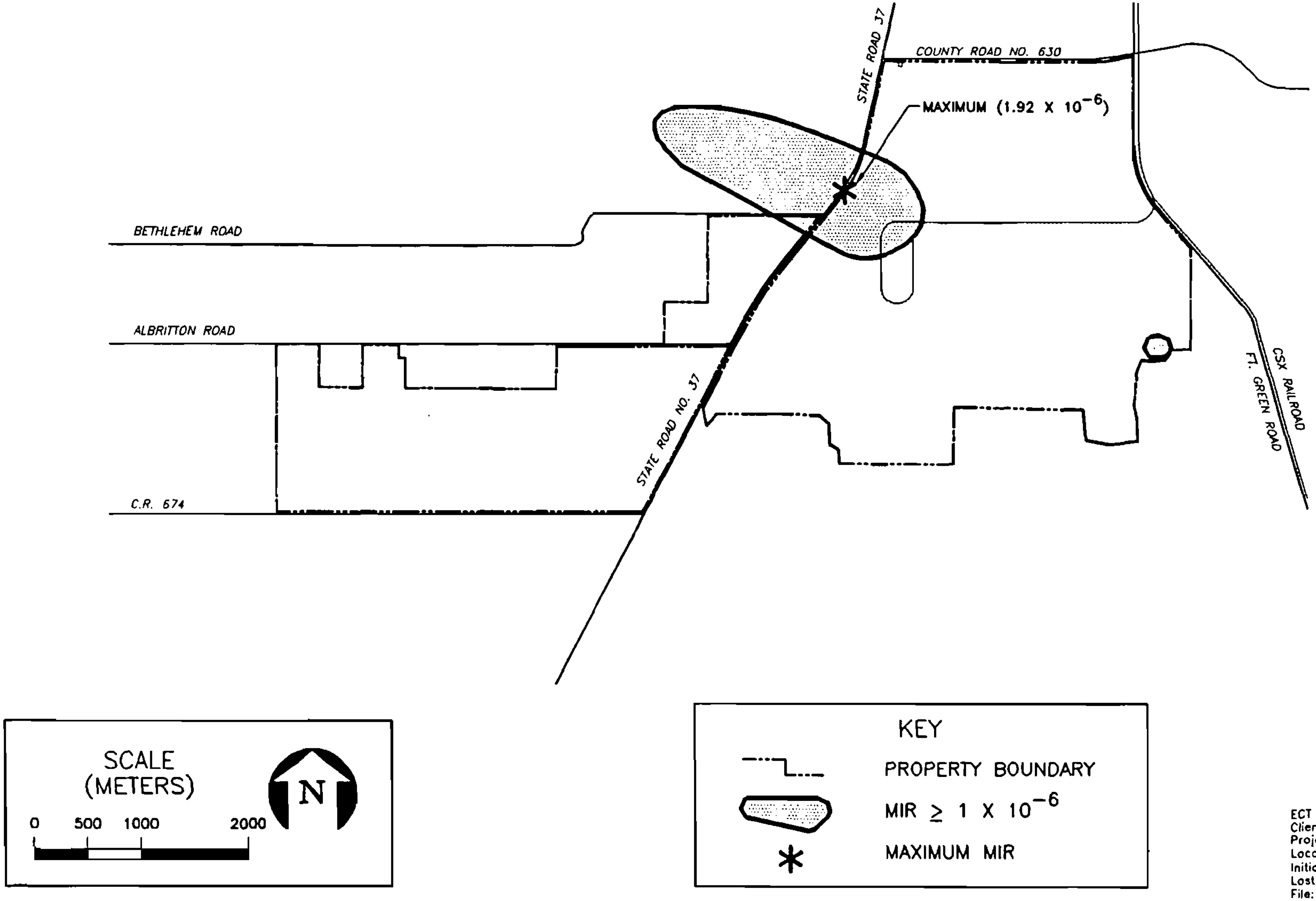
The highest estimate of MIR was calculated to be 1.9 x 10^{-6}. Figure 5.6.1-7 shows the areal distribution of MIR values of at least 1.0 x 10^{-6}. These values were predicted to occur primarily to the northwest of the site in areas of little or no population. TPR was conservatively estimated to be only 0.00027, meaning that the plant would theoretically cause an additional case of cancer only every 3,700 years.

5.6.1.6 Other Air Quality-Related Impacts

Impacts Due to Associated Growth

Construction of Polk Power Station will occur in phases. During the initial construction phase, an average of 400 workers will be employed for a 27-month construction period, with a 9-month peak of 600 construction workers. An average of 15 to 40 workers will be employed during other construction phases of the project. It is anticipated that most of these construction personnel will be drawn from Polk County and will commute to the job site from nearby cities, including Bartow, Winter Haven, and Lakeland. A portion of the work force will also commute from the Tampa metropolitan area. While not readily quantifiable, the temporary increase in vehicle-miles-traveled (VMT) in the area would be insignificant, as would any temporary increase in vehicular emissions.

The Polk Power Station will employ a total of 210 operational workers at project build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services ranging from 6 persons in 1997 to 100 at build-out in 2010. Again, it is expected that most of these persons will be drawn from the region. In 1990, the population of Lakeland was 70,576, while the population of Polk County was 405,382 persons. The workforce needed to operate the proposed plant therefore represents a small fraction of the population already present in the immediate area. Therefore, while some small increase in area VMT could result, the air quality implications in Polk County would be minimal.



ECT Number:	90263-0409
Client:	TECO
Project Name:	PPS
Location:	POLK COUNTY, FL
Initials:	MTC
Last Update:	07/16/92
File:	HRISK

FIGURE 5.6.1-7.

AREAL DISTRIBUTION OF PREDICTED MAXIMUM INDIVIDUAL RISK

Source: ECT, 1992.

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Finally, a new industrial facility can sometimes generate growth in other industrial or commercial operations needed to support the new facility. Given the site's proximity to Bartow, Lakeland, and the Tampa metropolitan area, however, the existing commercial infrastructure should be more than adequate to provide any support services that the proposed facility might require. Therefore, no air quality impacts due to associated industrial/commercial growth would be expected. Furthermore, any significant industrial development resulting from the establishment of Polk Power Station would be independently subject to PSD and other environmental review requirements.

Impacts on Visibility and on Soils and Vegetation

No visibility impairment at the local level is expected due to the types and quantities of emissions projected from Polk Power Station sources. The opacity of combustion exhausts from the facility should be low. Emissions of primary particulates and sulfur oxides due to combustion will be low due to the predominant use of low-ash, low-sulfur fuels (syngas, natural gas, and distillate fuel oil) over the lifetime of the facility. While the facility will emit NO_x, the potential to impair visibility at the local level should be relatively low, given the very low expected exhaust opacity. The contribution of emissions of VOC to the potential for haze formation in the area is expected to be minimal. Materials handling and storage operations will be controlled so that fugitive dust potential will be minimized. In addition, the aesthetic character of lands within the boundaries of and adjacent to the Polk Power Station site are largely influenced by present and past mining operations. Because these lands have been previously disturbed by mining operations, the proposed project will not adversely affect aesthetic or visual qualities in the area.

Soil types have been mapped by the U.S. Department of Agriculture (USDA) in cooperation with the Polk County Soil Conservation Services (USDA, 1990). There are 20 different soil types on the Polk Power Station plant site. Most of the onsite or adjacent soils are either hydric soils which have thick organic layers and are slightly alkaline, or highly altered soils associated with mining activities. The Polk

Power Station plant site is situated primarily on Smyrna-Myakka, Arents-Water, and Ona soil types.

Gaseous emissions impacts on soils can cause both acid leaching of nutrients and direct impacts to vegetation. Impacts to vegetation are typically associated with direct uptake of toxins through the root zone. The potential for acid-leaching of nutrients in the alkaline organic soils which exist on the site is low. No impacts to nutrient levels in the highly altered, acidic soils of the mined areas are anticipated.

Sulfates and nitrates caused by SO_2 and NO_2 deposition on soil can have beneficial effects to soil if they are currently lacking. However, they can also increase acidity, affecting nutrient recycling and plant growth. The low emission levels and resulting ambient impacts for this project should not significantly cause increased acidity levels to the already acidic soils.

In summary, based upon the soils onsite, as well as the minimal emissions levels associated with plant operation, no impacts to soils are anticipated.

The majority of the Polk Power Station site has been or is in the process of being mined for phosphate. Consequently, most of the original flora on the site has been drastically altered. As a result of past and ongoing mining activities, only small, portions of relatively undisturbed terrestrial, wetland, and aquatic habitats still remain on the site. Major land uses and vegetation represented on the site consist of mined land, developed land (e.g., transmission lines, a pipeline, and a small industrial site), uplands (e.g., pasture, shrub and brushland, overgrown spoil, old fields, orange grove, mixed oak/pine woods, palmetto rangeland, pine flatwoods, and oak hammock), remaining wetlands (e.g., hardwood swamp and marsh), and open water systems (e.g., ditches, canals, mine ponds, and an intermittent stream). The 4,348-acre Polk Power Station site is a mine site in various stages of activity with relatively small, remnant areas of undisturbed, native vegetation.

Vegetation damage is described as impacts resulting in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage as well as changes in secondary metabolites such as tannin and phenolic compounds. Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses over relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages, which have both functional and visible consequences, are usually manifested by internal physical damage to foliar tissues. Chronic injuries are typically more associated with changes in physiological processes.

In light of the previous discussion, the projected air quality impacts due to emission from Polk Power Station were evaluated as to their potential to impact vegetation in the area. The pollutants SO_2, NO_x, ozone, PM (including trace metals), CO, H_2SO_4, and fluorides and synergistic effects among gaseous pollutants were evaluated to the extent supported by the literature. Based on this assessment, it was concluded that emission from Polk Power Station will not result in impacts that will cause harm to vegetation.

Other Potential Impacts on the Chassahowitzka National Wilderness Area

The potential for Polk Power Station emissions to affect air quality-related values (AQRVs) at the Chassahowitzka NWA were also evaluated. The AQRVs of interest were visibility, soils, vegetation, and wildlife. Visibility impacts were predicted with the VISCREEN program (EPA, 1988). As a result of the low emissions from Polk Power Station and the distance of the plant from Chassahowitzka, it was predicted that the potential for visibility impairment is negligible.

Similarly, modeling of Polk Power Station emissions showed that the potential impacts at Chassahowitzka would be negligible. Given the ecology of Chassahowitzka and the negligible potential impacts, no detrimental effects on soils, vegetation, or wildlife in the wilderness area are expected.

5.6.2 MONITORING PROGRAMS

5.6.2.1 Post-Construction Ambient Air Quality Monitoring

Tampa Electric Company will provide up to two ambient air quality monitoring stations to collect post-construction ambient air quality monitoring data. The parameters to be monitored, the locations of the monitoring stations, and the operational dates of the stations will be determined at a later date.

5.6.2.2 Continuous Air Emissions Monitoring

The Polk Power Station project will be subject to 40 CFR 60, Subparts Y and GG. An initial performance test for opacity from coal processing, coal storage, and coal transfer and loading systems associated with the coal preparation process will be conducted pursuant to Subpart Y requirements. Continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine will be conducted for the Polk Power Station CTs as required by Subpart GG. Monitoring of fuel sulfur and nitrogen content will also be performed pursuant to Subpart GG, §60.334(b). Initial performance testing of the CTs for NO_x and SO_2 emissions will be conducted as stipulated by Subpart GG, §60.335.

Initial and periodic performance testing of pollutants emitted by the Polk Power Station facility will be conducted pursuant to FDER requirements as specified in the SCA Approval Order. FDER test methods are specified in Chapter 17-2.700(6), F.A.C.

VOLUME 4

APPENDIX 11.1.3

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

11.1.3 PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

TAMPA ELECTRIC COMPANY
POLK POWER STATION

APPLICATION TO CONSTRUCT AIR POLLUTION SOURCES AND PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

Prepared for:

TAMPA ELECTRIC
A TECO ENERGY COMPANY

Tampa, Florida

Prepared by:

ECT
Environmental Consulting & Technology, Inc.
Gainesville, Florida

July 1992

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LIST OF ACRONYMS

AAQS	ambient air quality standard
Agrico	Agrico Chemical Company
APIS	Air Pollution Information System
AQRV	air quality related values
BACT	best available control technology
BLIS	BACT/LAER information system
Btu/scf	British thermal unit per standard cubic foot
Btu/ft^3	British thermal unit per cubic foot
Btu	British thermal unit
CAA	Clean Air Amendments
CC	combined cycle
CFR	Code of Federal Regulations
CG	coal gasification
CGCU	cold gas cleanup
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl sulfide
CR	County Road
CT	combustion turbine
CTC	Central Technology Center
°	degree
°C	degree Celsius
°F	degree Fahrenheit
DOE	U.S. Department of Energy
ECT	Environmental Consulting & Technology, Inc.
EP	emission point
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator

LIST OF ACRONYMS
(Continued, Page 2 of 5)

F.A.C.	Florida Administrative Code
FDER	Florida Department of Environmental Regulation
FGD	flue gas desulfurization
FGR	flue gas recirculation
FPL	Florida Power & Light Company
ft/sec	foot per second
ft bls	feet below land surface
ft	feet
$ft^3/min\text{-}ft^2$	cubic feet per minute-square foot
g/sec	gram per second
GE	General Electric
GEESI	General Electric Environmental Systems, Inc.
GEP	good engineering practice
gr/100 scf	gram per 100 standard cubic feet
gr/scf	gram per standard cubic foot
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
ha	hectare
HGCU	hot gas cleanup
HHV	higher heating value
HRSG	heat recovery steam generator
HSH	highest, second highest
IGCC	integrated coal gasification combined cycle
ISC2	Industrial Source Complex
ISCLT2	Industrial Source Complex long-term
ISCST2	Industrial Source Complex short-term
ISO	International Standards Organization
K	Kelvin
km	kilometer

LIST OF ACRONYMS
(Continued, Page 3 of 5)

kPa	kilopascals
kwh/yr	kilowatt hour per year
kwh	kilowatt hour
LAER	lowest achievable emission rate
lb/MMBtu	pound per million British thermal units
lb/hr	pound per hour
LEA	low excess air
LHV	lower heating value
m/sec	meter per second
m	meter
m^3	cubic meter
MIR	Maximum Individual Risk
MMBtu/hr	million British thermal units per hour
MMcf	million cubic feet
MW	megawatt
NESHAP	National Emission Standard for Hazardous Air Pollutant
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPS	National Park Service
NSPS	new source performance standards
NSR	New Source Review
NWA	National Wilderness Area
OAQPS	Office of Air Quality Planning and Standards
PHX	primary heat exchanger
PM	particulate matter
PM_{10}	particulate matter less than or equal to 10 micrometers aerodynamic diameter

LIST OF ACRONYMS
(Continued, Page 4 of 5)

kw	kilowatt
ppb	parts per billion
ppmv	parts per million by volume
ppmvd	dry volume parts per million
PSD	prevention of significant deterioration
psi	pound per square inch
psia	pound per square inch absolute
psig	pound per square inch gauge
QA/QC	quality assurance/quality control
RCRA	Resource Conservation and Recovery Act
rpm	revolutions per minute
SARA	Superfund Amendment and Reauthorization Act
SC_2	carbon disulfide
SCA	Site Certification Application
SCR	selective catalytic reduction
SIA	significant impact area
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SOP	standard operating procedure
SR	State Road
SRU	sulfur recovery unit
ST	steam turbine
TGTU	tail gas treating unit
TPR	Total Population Risk
tpy	tons per year
TSP	total suspended particulate
$\mu g/m^3$	micrograms per cubic meter
$\mu g/g$	microgram per gram

LIST OF ACRONYMS
(Continued, Page 5 of 5)

UEC	United Engineers & Constructors, Inc.
URF	Unit Risk Factor
USDA	U.S. Department of Agriculture
UTM	Universal Transverse Mercator
VDAPC	Virginia Department of Air Pollution Control
VMT	vehicle-miles-traveled
VOC	volatile organic compound

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company is an investor-owned electric utility which serves west-central Florida, primarily Hillsborough County and portions of Polk, Pasco, Pinellas, and Highlands Counties. Currently, Tampa Electric Company serves more than 467,000 residential, commercial, industrial, and governmental Customers within its service area. Tampa Electric Company's system has an installed net electric generating capacity of 3,281 megawatts (MW) from 24 generating units located at five different sites--Big Bend, Gannon, Hookers Point, Phillips, and Dinner Lake stations.

As a public utility, Tampa Electric Company has the obligation to provide reliable and economical electric power service to its existing and future Customers. To meet this obligation, Tampa Electric Company conducts ongoing, long-range power resource planning and load (i.e., demand) forecasting programs to predict its future power supply needs and to evaluate available options to meet these needs. These programs also consider Tampa Electric Company's extensive efforts to encourage conservation, load management programs, and cogeneration projects to reduce future power needs. As a result of these programs, Tampa Electric Company has determined the need for approximately 1,150 MW of new electric generating capacity (i.e., new power plant facilities) to meet its Customer power demands beginning in the mid-1990s and continuing into the early 21st century. These additional power supply needs are primarily based on future electricity demands created by ongoing and projected population growth within its service area.

Tampa Electric Company is proposing to license/permit, construct, and operate the new power plant and associated facilities on an approximately 4,348-acre site in southwest Polk County, Florida. Figure 1-1 shows the location of the site within the State of Florida. The proposed facilities will be known as the Tampa Electric Company Polk Power Station. The total generating capacity of the units at the site will be approximately 1,150 MW. The initial generating facilities at the Polk Power

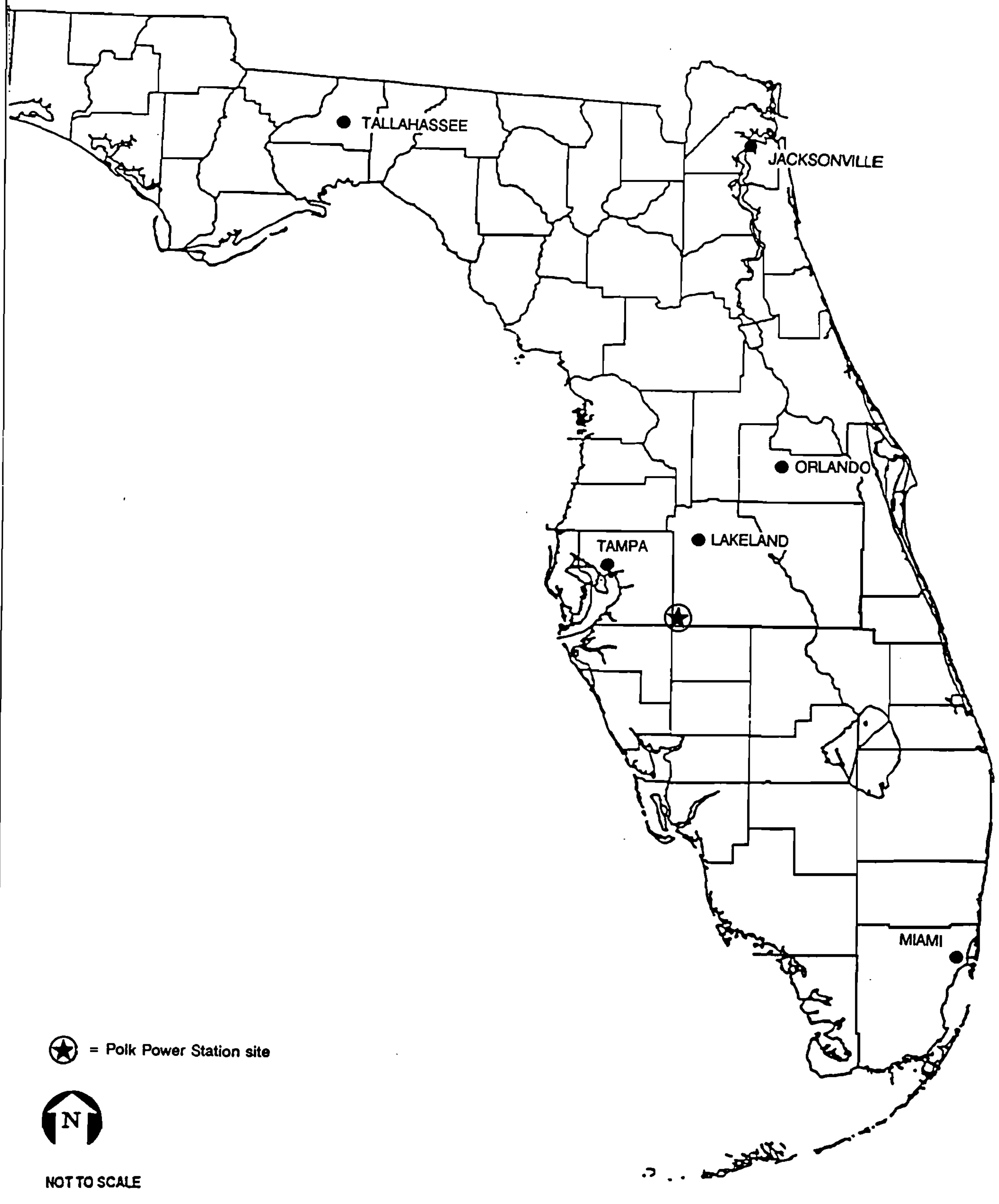

FIGURE 1-1.

LOCATION OF THE POLK POWER STATION WITHIN THE STATE OF FLORIDA
Source: ECT, 1992.

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Station site will be an integrated coal gasification combined cycle (IGCC) demonstration project developed by Tampa Electric Company and supported in part through funding from the U.S. Department of Energy (DOE) under the Clean Coal Technology Demonstration program. The facilities will consist of a nominal 150-MW advanced combustion turbine (CT), initially fueled by No. 2 fuel oil, with a heat recovery steam generator (HRSG), steam turbine (ST), and coal gasification (CG) facilities added a year later to complete the nominal 260-MW IGCC unit. This IGCC unit will be known as Polk Unit 1. Tampa Electric Company's current Power Resource Plan indicates that later facilities will consist of two combined cycle (CC) generating units and six simple-cycle CTs fueled by natural gas with fuel oil as the backup fuel. Tampa Electric Company is proposing to license the Polk Power Station site for all the currently planned electric generating units (i.e., total nominal generating capacity of 1,150 MW) and associated facilities. Therefore, all generating units and associated facilities planned for the site are the subject of this application.

The operation of Polk Power Station generating units and ancillary equipment will result in the emission of air pollutants. Therefore, a permit is required prior to beginning facility construction, per Chapter 17-2.210, Florida Administrative Code (F.A.C.). This report, along with the required state permit application forms [see Appendix 11.2.1 of the Site Certification Application (SCA)], constitutes application for authority to commence construction in accordance with the Florida Department of Environmental Regulation (FDER) rules contained in Chapter 17-2, F.A.C.

As defined in the FDER rules pertaining to prevention of significant deterioration (PSD) (Chapter 17-2.500, F.A.C.), Polk Power Station will constitute a major stationary source. Therefore, this report is submitted to satisfy the permitting requirements contained in the PSD rules and regulations.

FDER has also developed guidelines for the review of facilities that will emit pollutants considered potentially toxic. The analysis to address these guidelines has been completed and is submitted herein for review. In addition, consistent with the plan of study for this project, an analysis of inhalation cancer risk has been completed. While not a requirement of PSD review, the results of this analysis are also submitted herein.

This report is organized as follows: Section 1.2 provides an overview and a summary of the key regulatory determinations and predicted impacts. Section 2.0 describes the proposed facility and its emissions. Applicable air quality permitting requirements are presented in Section 3.0. Results of control technology determinations and analyses of existing air quality are given in Sections 4.0 and 5.0, respectively. Section 6.0 presents the approach used in the air quality impact assessments (i.e., modeling), and Section 7.0 summarizes the results. Other potential air quality impacts of the proposed facility in the vicinity are discussed in Section 8.0, and Section 9.0 presents analyses of potential impacts on the Chassahowitzka National Wilderness Area (NWA) PSD Class I area. Appendix A contains details of emission rate calculations and estimates. Appendix B provides emissions inventory data as used in modeling of other, offsite emission sources. Copies of all modeling input and output files have been provided separately (both hard copy and diskette formats).

1.2 SUMMARY

Polk Power Station will consist of several different types of generating units, which will be phased in over a period of years. Initially, a nominal 150-MW CT will be installed. This unit will be fired with No. 2 fuel oil and will serve as a peaking unit during its first year of operation. After a year, it will be converted to IGCC and will be known as Polk Unit 1. Polk Unit 1's facilities will produce syngas from coal and/or blends of coal and petroleum coke. The IGCC unit's CT will fire the syngas as its primary fuel. Further units to be added at Polk Power Station include two CC units totaling 440 MW (nominal) and six simple-cycle CTs totaling 450 MW (nominal). All of these units will be fired with natural gas as the primary fuel and No. 2 fuel oil as backup.

The planned construction start date for the initial 150-MW CT is January 1994. This CT will commence commercial operation by July 1995. A year later, construction of the IGCC Polk Unit 1 will be completed. The CC and CT units will be added over a period of years thereafter.

Based on the full Polk Power Station build-out plan, the utilization rates for the various types of units, and the fuels to be used, the overall facility will have the potential to emit ~~3,917~~ 3,843 tons per year (tpy) of sulfur dioxide (SO_2) and ~~5,250~~ 5,245 tpy of nitrogen oxides (NO_x). Regarding other criteria pollutants, the facility will potentially emit ~~917~~ 905 tpy of particulate matter (PM), ~~2,526~~ 2,523 tpy of carbon monoxide (CO), ~~394~~ 393 tpy of volatile organic compounds (VOCs), and 0.6 tpy of lead. Each of the six criteria pollutants is subject to PSD review based on these projected emissions. Of the non-criteria pollutants, emissions of sulfuric acid mist (H_2SO_4), mercury, and beryllium are projected to exceed the respective PSD review thresholds and are therefore also subject to PSD review. Emissions of reduced sulfur compounds [including hydrogen sulfide (H_2S)] and fluorides are projected to be below their review thresholds, and no emissions of vinyl chloride or asbestos are expected. Nonetheless, impacts due to fluorides emissions were evaluated, as were impacts of arsenic, cadmium, chromium, all of which are non-PSD pollutants.

For each pollutant subject to PSD review, an analysis of best available control technology (BACT) was conducted, as were analyses of existing air quality and air quality impacts. The BACT analyses were done using the required *top-down* approach. Analyses of existing air quality included the collection of a full year of onsite ambient data for appropriate pollutants. Air quality impacts were analyzed using recommended dispersion models and meteorological data. Finally, emissions of potentially toxic air pollutants were modeled, and the impacts evaluated in the context of FDER's guidelines and inhalation cancer risk thresholds.

As presented herein, the analyses required for this permit application have resulted in the following conclusions.

- The use of good combustion practices and clean fuels is considered to be BACT for PM and heavy metals. Polk Power Station combustion sources will utilize the latest burner technologies to maximize combustion efficiency and minimize PM emission rates. Project fuels will consist of low ash coal-derived syngas, natural gas and distillate oil.
- Application of advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs. CO exhaust concentrations are projected to be 25 parts per million by dry volume (ppmvd) for syngas and oil-firing for the IGCC CT at base load conditions. VOC exhaust concentrations are projected to be 1.0 and 5.0 ppmvd for syngas and oil-firing, respectively, for the IGCC CT at base load conditions. *CO and VOC limits proposed for the IGCC CT/HRSG when fired with syngas are less than the lowest known permit limits for coal-fired boilers.* Due to the oxidation of sulfur compounds and formation of sulfuric acid mist emissions, oxidation catalysts are not considered to be technically feasible for combustion sources fired with sulfur-bearing fuels.
- Exhaust concentrations of CO for the stand-alone CC and simple-cycle CTs (using dry low-NO_x combustors) are projected to be 25 and 30 ppmvd for natural gas and distillate fuel oil firing, respectively. Exhaust concentrations of VOC for the stand-alone CTs are projected to be 7.0 ppmvd for natural gas and distillate fuel oil firing. Cost effectiveness of oxidation catalyst was determined to be $5,158 and $5,643 per ton of CO removed for the combined and simple-cycle CTs, respectively. The slightly higher CO emissions which result from the use of advanced dry-low NO_x combustors is felt to be an acceptable compromise with respect to overall NO_x and CO emission rates.
- Use of low sulfur fuels is considered to represent BACT for the Polk Power Station combustion sources since post-combustion SO_2 controls are not applicable. The IGCC facility will use ~~integral~~ acid gas removal and ~~recovery~~ H_2SO_4 production processes to recover sulfur from the inlet coal

as H_2SO_4. *Overall sulfur recovery efficiency is 95.6 percent which surpasses prior coal gasification BACT determinations and exceeds the highest SO_2 removal efficiency permitted for large, coal-fired power plants.* Use of low sulfur distillate oil is proposed as BACT for the ancillary IGCC combustion sources; i.e., auxiliary boiler and thermal oxidizers.

- The Polk Power Station stand-alone CTs will utilize natural gas (containing less than 10 grains of sulfur per hundred standard cubic feet [gr/100 scf]) and low sulfur distillate oil. The use of distillate fuel oil containing no more than 0.05 weight percent sulfur is considered to represent the "top" or most stringent technology with respect to combustion turbine SO_2 emissions.
- BACT for NO_x was determined to be the use of nitrogen injection and advanced burner design to achieve NO_x exhaust concentrations of 25 and 42 ppmvd for syngas and oil-firing, respectively, for the IGCC CT. The 25 ppmvd NO_x concentration limit for syngas combustion together with NO_x emissions from the ~~tail gas~~ H_2SO_4 plant thermal oxidizer represents an overall IGCC NO_x emission rate of 0.099 pounds per million British Thermal units (lb/MMBtu). *This rate is among the lowest permitted rates and is well below the most recent BACT determination of 0.17 lb/MMBtu made in Florida and New Jersey for coal-fired power plants. Overall NO_x emissions from the IGCC facility in terms of lb NO_x/MW are approximately 50 percent of the rates recently approved by FDER for the Stanton and Indiantown coal-fired power plants.* Comparison of emissions on a lb/MW basis is felt to be more meaningful than other units such as lb/MMBtu since it reflects the emission reduction benefit of process efficiency. The 25 ppmvd NO_x concentration limit proposed for syngas combustion is well below the previous BACT concentration of 42 ppmvd assigned to coal gasification projects in Virginia and Florida. Cost-effectiveness of selective catalytic reduction (SCR) was found to be \$6,272 per ton of NO_x removed which exceeds values previously considered to be reasonable by FDER for NO_x BACT determinations. The application of SCR technology to the

treatment of exhaust gases generated by the combustion of sulfur-bearing fuels poses a number of technical concerns including ammonia "slip" emissions, catalyst poisoning from arsenic and sulfur compounds, formation of ammonium salts due to the combination of sulfate and any unreacted ammonia causing corrosion and reduced efficiency of downstream heat transfer equipment, disposal and handling of spent SCR catalyst as a hazardous waste due to vanadium pentoxide content.

- The use of dry low-NO_x burner technology is considered to represent BACT for the future CC and simple-cycle CTs. Dry low-NO_x burner technology will achieve NO_x concentrations of 9 and 42 ppmvd for gas and oil firing, respectively. A NO_x exhaust concentration of 9 ppmvd has generally been considered to represent BACT for CTs *equipped with SCR control technology*. The proposed NO_x concentration is also below the current FDER BACT guideline of 15 ppmvd for natural gas-fired CTs using dry low-NO_x burners. Dry low-NO_x burner technology will achieve comparable emission rates as SCR for gas-firing without the adverse impacts associated with SCR technology; i.e., ammonia emissions due to ammonia slip, potential of ammonium salt particulate formation with subsequent downstream corrosion and reduced efficiency of heat transfer equipment, hazards associated with the storage of ammonia and disposal of spent catalyst, and energy penalties due to increased turbine backpressure and additional system downtime for catalyst replacement. Application of SCR to the simple-cycle CTs is not considered to be feasible due to the substantial cost required to reduce CT exhaust temperatures to levels consistent with successful SCR operation, low back-up fuel oil capacity factor, and relatively minor reduction in NO_x emissions that would result from applying SCR to CTs equipped with dry low-NO_x burners.
- An exemption from the PSD preconstruction monitoring requirements is appropriate for NO_x, lead, total suspended particulates (TSP), mercury, beryllium, and CO on the basis of projected facility impacts less than the *de minimis* values.

- Monitoring data for SO_2, particulate matter nominally 10 micrometers and less (PM_{10}), and ozone were collected during the 1-year period from April 1991 through March 1992. These data have been submitted in fulfillment of the preconstruction monitoring requirements for those pollutants. Analyses of the data were used to : (1) show that existing air quality in the project vicinity is within the appropriate ambient air quality standards (AAQS), and (2) derive estimates of background concentrations.
- Dispersion modeling for SO_2, NO_x, and PM resulted in impacts due to Polk Power Station that were greater than modeling significance levels. Therefore, further analyses relative to AAQS and PSD Class II increments were necessary. These further analyses showed compliance with all standards.
- Dispersion modeling for CO and lead resulted in maximum Polk Power Station impacts which were insignificant. No further analyses were conducted for these two pollutants.
- Modeling of potentially toxic air pollutant emissions showed that maximum impacts will be below the FDER no-threat levels.
- The proposed facility will have no adverse impacts on soils or vegetation in the plant vicinity, and growth-related air quality impacts should be minimal.
- The Chassahowitzka NWA PSD Class I area is approximately 120 kilometers (km) to the northwest of the Polk Power Station site. Rigorous analyses showed that the impacts of emissions on this area will be slight and that no increments should be exceeded. Impacts on visibility and on soils, vegetation, and wildlife are predicted to be minimal.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 FACILITY LOCATION, DESCRIPTION, AND LAYOUT

2.1.1 SITE LOCATION AND CHARACTERISTICS

The Tampa Electric Company Polk Power Station site is located approximately 17 miles south of the City of Lakeland, approximately 11 miles south of the City of Mulberry, and approximately 13 miles southwest of the City of Bartow in southwest Polk County, Florida. Figure 2-1 provides a vicinity location map and approximate boundaries of the site. The site consists of approximately 4,348 acres and is bounded by the Hillsborough County line along the western boundary; Fort Green Road [County Road (CR) 663] on the east; CR 630, Bethlehem and Albritton Roads along the north; and State Road (SR) 674 and several phosphate clay settling ponds on the south. SR 37 bisects the property, running in a southwest to northeast direction. The portion of the property to the east of SR 37 consists primarily of mined-out lands with water-filled mine cuts between spoil piles surrounding an unmined parcel of land and old mined and unreclaimed lands. The area to the west of SR 37 is currently being mined for phosphate matrix and these operations are scheduled to continue into 1994. In general, lands surrounding the site and in the region have also been impacted by previous and ongoing phosphate mining operations.

The majority of the site has been mined by Agrico Chemical Company (Agrico), a division of Freeport MacMoRan, Ltd., as part of Agrico's Fort Green Mine. The remaining acreage, approximately 775 acres, located south of CR 630, is property of American Cyanamid Company. A portion of American Cyanamid property has been leased, re-mined, and recently reclaimed by IMC Fertilizer, Inc.

2.1.2 FACILITY DESCRIPTION

2.1.2.1 General Facility Description

Tampa Electric Company is planning to construct and operate new electric generating units at the Polk Power Station site with units added according to a phased schedule designed to match the projected growth of Tampa Electric Company's

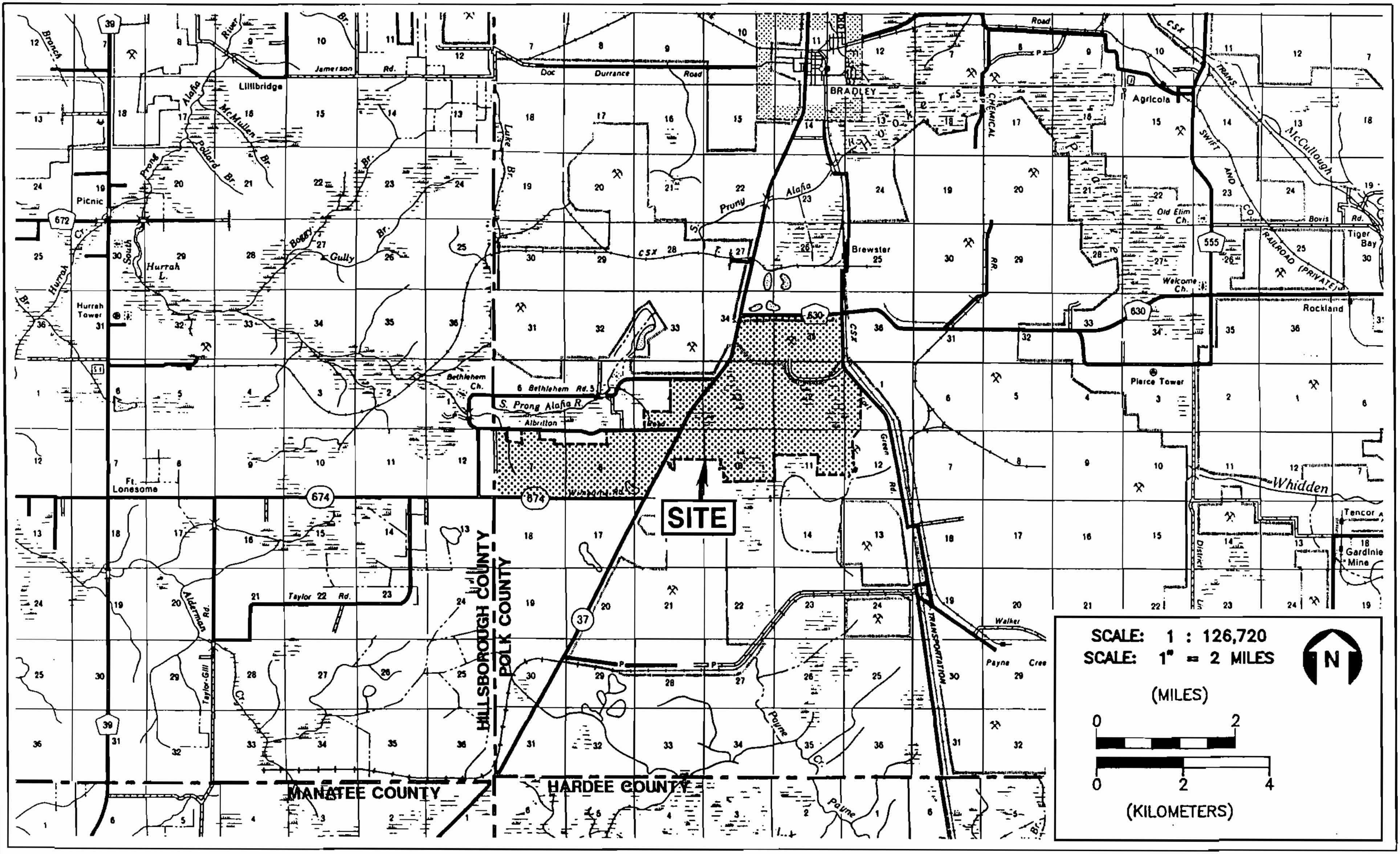

FIGURE 2-1.

VICINITY MAP AND BOUNDARIES OF POLK POWER STATION SITE

Sources: FDOT Map, FL. ECT, 1992.

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Customer power demands. The phased schedule for operation of all electric generating units at the Polk Power Station site is presented in Table 2-1. The total generating capacity of the units at the site will be approximately 1,150 MW. The first generating unit at the Polk Power Station site will be an IGCC generating unit developed by Tampa Electric Company supported in part through funding from the DOE under the Clean Coal Technology Demonstration Program. The unit will consist of a nominal net 150-MW advanced CT, initially fueled by low sulfur No. 2 fuel oil, with an HRSG, ST, and CG facilities added a year later to complete the nominal net 260-MW IGCC unit. During its first year of simple-cycle operation on fuel oil, this advanced CT will be used for a maximum 10-percent capacity factor. After its conversion to IGCC unit, the coal-fueled advanced CT will be capable of baseload operations (i.e., 100 percent capacity factor) on syngas, while retaining the option to fire fuel oil as backup (maximum 10 percent capacity factor). Annual capacity factor is defined as the actual megawatt hours produced by the unit versus the maximum of possible megawatt hours that could be produced, expressed on a percent basis.

Tampa Electric Company's current long-range power resource planning efforts indicate that later facilities will consist of two nominal net 220-MW CC generating units and six stand-alone nominal net 75-MW CTs fueled by natural gas with fuel oil as backup fuel. The CC units will operate on an annual basis at up to 100-percent capacity factor on natural gas and up to 25-percent capacity factor on backup fuel oil. The simple-cycle CTs will have annual maximum capacity factors of 50 percent on natural gas and 10 percent on the backup fuel oil.

The coal-fueled IGCC facilities will consist of an oxygen-blown entrained flow gasification system to produce syngas fuel for the CT. The planned CG system will be based on commercially available technology from Texaco, Inc. The IGCC power block facilities will be based on a General Electric Company (GE) advanced nominal net 150-MW GE 7F CT and nominal net 70-MW HRSG/ST generator configuration. The GE 7F advanced CT is expected to be capable of a nominal net 190-MW capacity when operating with the coal gasifier and air separation unit. The other two

Table 2-1. Phased Schedule for Ultimate Electric Generating Capacity at the Polk Power Station Site

Year In Service	Nominal Generating Capacity Addition	Ultimate Unit Configuration
1995	150/190 MW advanced CT*	260 MW IGCC (Polk Unit 1)
1996	70 MW HRSG/ST/CG	
1997	--	
1998	--	
1999	75 MW CT	220 MW CC
2000	75 MW CT	
2001	70 MW HRSG/ST	
2002	75 MW CT	
2003	220 MW CC	
2004	--	
2005	--	
2006	75 MW CT	
2007	75 MW CT	
2008	75 MW CT	
2009	75 MW CT	
2010	75 MW CT	

*150 MW when operated in simple-cycle or CC mode and fired on fuel oil, 190 MW when operated in IGCC mode with gasifier and air separation unit.

Source: Tampa Electric Company, 1992.

CC units are based on a configuration of two nominal net 75-MW CTs with nominal net 70-MW HRSG/ST generator facilities. The six stand-alone CTs are currently planned to be nominal 75-MW units. For the purposes of this application, the future CC units and stand-alone CTs have been based on GE 7EA CTs.

Under DOE's Clean Coal Technology Demonstration Program, the IGCC unit will be used to demonstrate the integration of CG and CC technologies and to demonstrate a more efficient method for removal of sulfur from coal gas. Tampa Electric Company will demonstrate oxygen-blown entrained-flow IGCC Technology. Such a demonstration is expected to show that an oxygen blown, entrained-flow IGCC can achieve significant reductions of SO_2 and NO_x emissions when compared to coal-burning power plants using available technologies. The integrated performance to be demonstrated will include all major subsystems in the IGCC system entailing coal feeding: a pressurized, oxygen-blown entrained-flow gasifier capable of using caking coal; an air separation unit to provide oxygen to the gasifier as an oxidant and also to provide nitrogen to the CT for NO_x control by controlling the combustion temperature and power augmentation; a cold gas cleanup (CGCU) system capable of full flow in parallel with hot gas cleanup (HGCU) system capable of a nominal 50-percent flow for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and CT fuel requirements; an advanced CT appropriately modified to use low-British thermal unit (Btu) syngas as fuel; the steam cycle; all control systems; and the balance of the plant.

The new cleanup technology to be demonstrated by this unit is called HGCU, which involves the method by which the syngas is cleaned (i.e., sulfur removed) prior to being fed into a CT. Conventional methods for sulfur removal for IGCC units require that the gas be cooled prior to cleaning, called CGCU, and then reheated. By comparison, the HGCU technology efficiently cleans the gas at high temperatures, thereby increasing the overall plant efficiency. Energy loss is reduced by eliminating the need to cool the syngas and to reheat it prior to injection into the CT, while achieving sulfur removal rates equivalent to current, advanced sulfur removal technologies such as flue gas desulfurization (FGD) systems or scrubbers on conventional coal-fired units.

Under the agreement with DOE, Tampa Electric Company will demonstrate the HGCU system for a 2-year period. The demonstration period will involve significant testing and optimization to determine the cost and performance of the HGCU system. Successful operation of the HGCU system will enable future IGCC systems to operate more efficiently, providing more opportunities to meet the goals of the Clean Coal Technology Program. The demonstration project systems will include the capability to use the new HGCU technology for approximately 50 percent of the syngas fuel flow rate for the IGCC unit and the use of the proven CGCU technology for 100 percent of the fuel flow rate. The HGCU technology will be used up to 8,760 hr/yr in conjunction with the CGCU system during each of the 2 years of demonstration. By providing the conventional CGCU technology, the IGCC demonstration project will be capable of maintaining reliable sulfur removal rates to comply with environmental requirements and standards, and meet Tampa Electric Company's power resource needs over the life of the unit's operation.

2.1.2.2 Detailed Descriptions of the Integrated Coal Gasification Combined Cycle Facilities and Systems

For the air quality impact analyses in this PSD permit application, the IGCC unit will consist of the following major systems and process operations, which will or have the potential to involve point source and/or fugitive air emissions:

- Coal receiving and handling;
- Coal grinding and slurry preparation;
- Air separation unit;
- Gasification and syngas scrubbing and cooling systems;
- Acid gas removal unit;
- ~~Sulfur by product recovery, handling, and storage;~~
- ~~Tail gas treating unit;~~
- HGCU system ~~and H_2SO_4 by product plant~~;

- H_2SO_4 plant;
- Slag handling and storage; and
- Power production.

Figure 2-2 presents a generalized block flow schematic of the IGCC unit. Each of the major systems is described in the following paragraphs.

Coal Receiving and Handling

The coal handling system will receive, store, reclaim, and transport coal from unit train railroad cars and/or trucks to the coal preparation system serving the IGCC unit. Figure 2-3 presents a flow diagram of the coal receiving and handling system.

Coal will be delivered to the plant site by unit trains and/or trucks. The unit trains will consist of approximately 70 to 100, 100-ton capacity, rapid discharge, bottom-dump rail cars. If all coal was delivered by rail, approximately two unit trains per week would be needed to meet the fuel requirements of the IGCC unit. The rail cars will be unloaded in motion with the train moving over an enclosed track hopper. If all coal was delivered by truck, delivery will be made by approximately 80 to 100 specialized bottom-dump trucks per day, each truck having a 28-ton payload. The trucks will be equipped with covers to minimize fugitive dust emissions and will unload utilizing the enclosed rail unloading track hopper, which will be arranged to permit truck drive-over. Dust suppression with water sprays will be employed at the top of the hopper, and dust collection will be provided for feeder/conveyor transfer points within the unloading hopper area.

The track hopper will be equipped with four outlets, four manually operated rack and pinion slide gates, and four belt feeders. As shown in Figure 2-3, two belt feeders will discharge coal onto track hopper feeder collecting belt conveyor (No. 1A) and the remaining two onto track hopper feeder collecting belt conveyor (No. 1B). The collecting belt conveyors will transport the coal to the transfer belt conveyor (No. 2) which will be fitted with a precision belt scale and an as-received coal sampling system housed in the transfer enclosure. The stack-out conveyor

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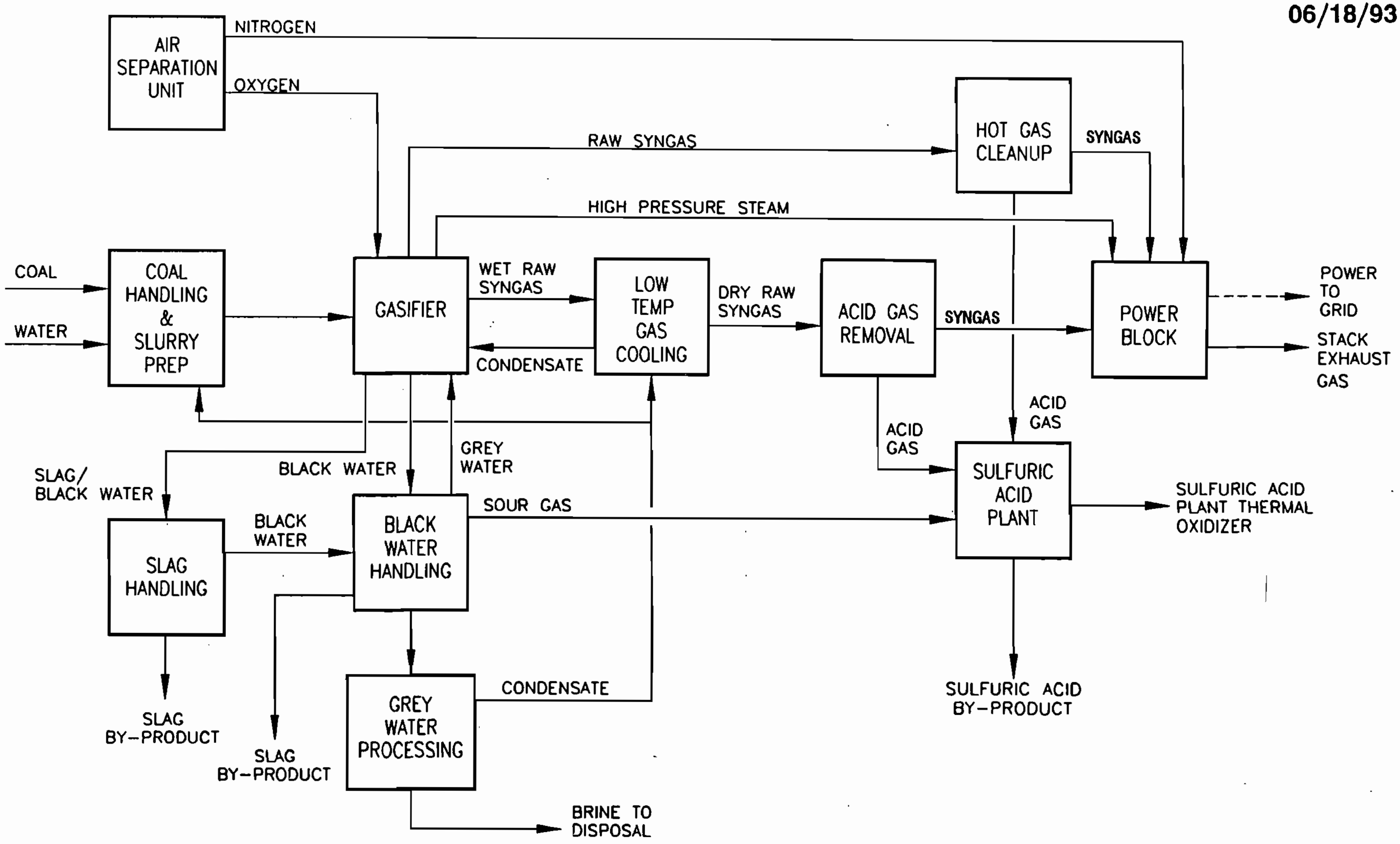

FIGURE 2-2.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1993.

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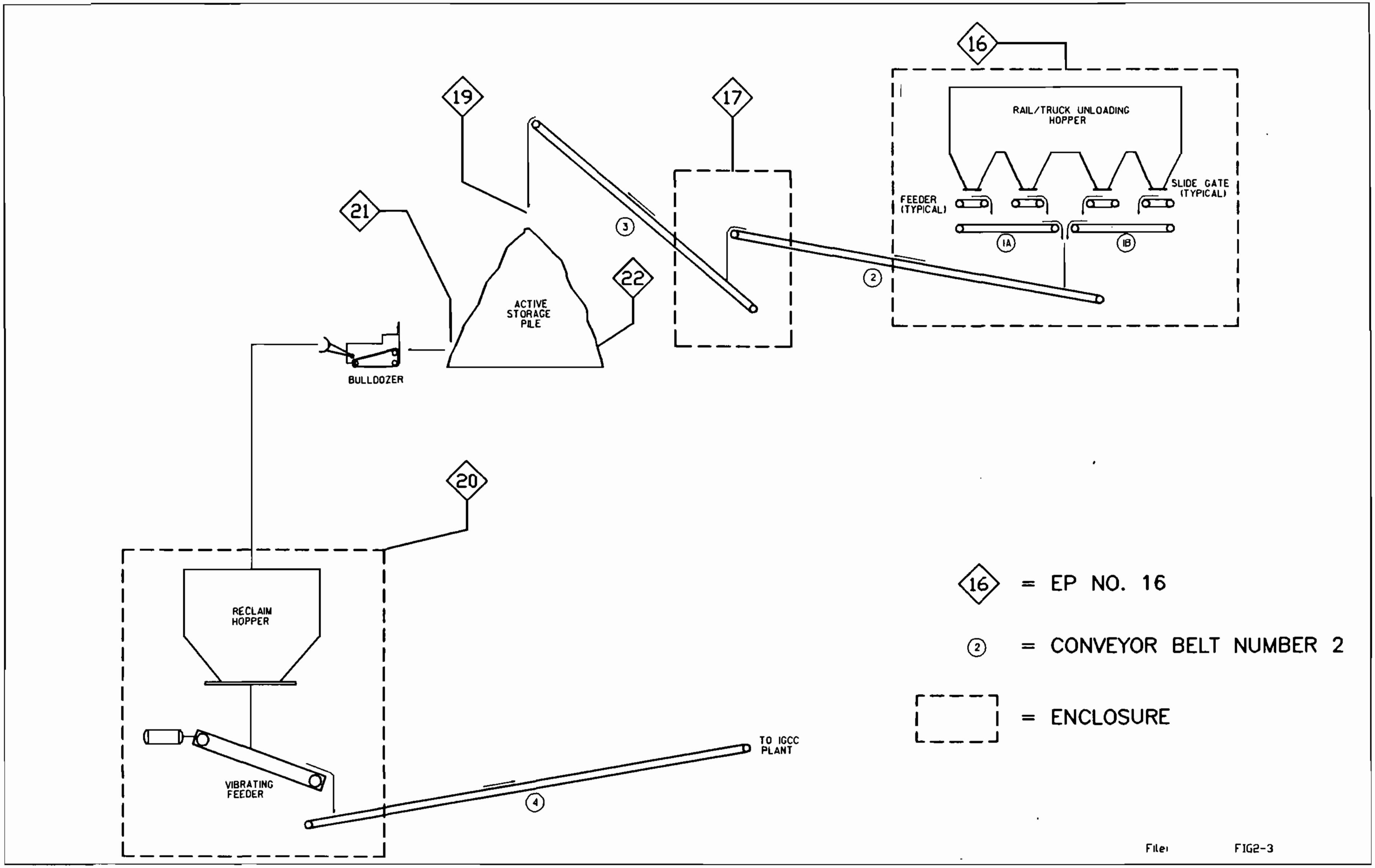

FIGURE 2-3.

COAL HANDLING SCHEMATIC

Sources: UEC, 1992; ECT, 1992.

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(No. 3) is a radial stack equipped with a telescopic chute and water spray dust suppression. The radial stacker will be used to build a kidney-shaped active coal pile. Mobile equipment will be used to build an inactive storage pile and to reclaim coal from the active storage pile. Coal reclaimed by mobile equipment will be pushed into a below-grade hopper and fed by a vibrating feeder onto the IGCC plant transfer conveyor (No. 4).

Reclaim of coal from the pile as well as pile maintenance will be performed by bulldozers. It is estimated that a bulldozer would spend approximately 3 hours per day, 7 days per week, 52 weeks per year reclaiming coal from the coal pile. The reclaim/plant transfer conveyor (No. 4) will be totally enclosed and will transport the coal to the IGCC coal preparation facility.

Coal receiving and handling operations will result in PM emissions. As shown in Figure 2-3, the sources or points of PM emissions associated with these operations are:

- Coal unloading handling baghouse [emission point (EP) 16],
- Coal transfer baghouse (EP 17),
- Coal transfer between stacker and stockpile (EP 19),
- Coal reclaim/plant transfer conveyor enclosure (EP 20),
- Bulldozer operations on coal stockpile (EP 21),
- Active coal pile wind erosion (EP 22), and
- Inactive coal pile wind erosion (EP 23).

Control of PM emissions from coal handling operations will be achieved by a combination of wet dust suppression, chemical treatment of the coal pile, equipment enclosures, and dry dust collection systems located at the major dust emissions sources. Wet dust suppression systems employing either foam or water sprays with a wetting agent will be employed at the railcar and truck receiving hopper and at the stacker discharge to the coal pile.

Conveyor Nos. 1A, 1B, 2, and 4 and transfer points will be provided with enclosures to contain dust and to minimize emissions to the atmosphere. Coal handling equipment and transfer points will be provided dust-tight enclosures and dry type dust collectors, which will maintain a slight negative pressure within the equipment enclosure to minimize emissions. The dust collection equipment will consist of pulse-jet baghouses, centrifugal exhaust fans, rotary air lock valves, dust return chutes, and control devices. The baghouses will be sized for a maximum air to cloth ratio of 6 to 1 at design air flow and will have a removal efficiency not less than 99.9 percent. Particulate loadings will not exceed 0.02 grains per standard cubic foot (gr/scf) at the exhaust fan outlet.

The coal storage pile will be segregated into active and inactive portions. Fugitive dust emissions from the active portion of the pile will be controlled by water sprays and/or the application of chemical dust suppression agents. The inactive portion of the pile will be sealed with a crusting agent to control dust emissions.

Coal Grinding and Slurry Preparation

The coal grinding and slurry preparation system will prepare the coal for input to the gasifier. Figure 2-4 presents a schematic of this system.

As shown in Figure 2-4, coal will be withdrawn from the coal storage bin and fed to the grinding mill with recycled and makeup water. The grinding mill may also be fed fine coal recovered by the dust collection system. Slurry additive for reducing viscosity will be pumped continuously to the grinding mill. The grinding mill will reduce the feed coal to the design particulate 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 the trommel and over a vibrating screen to remove any oversized particles before entering the slurry tank. Oversized particles will be recycled to the grinding mill.

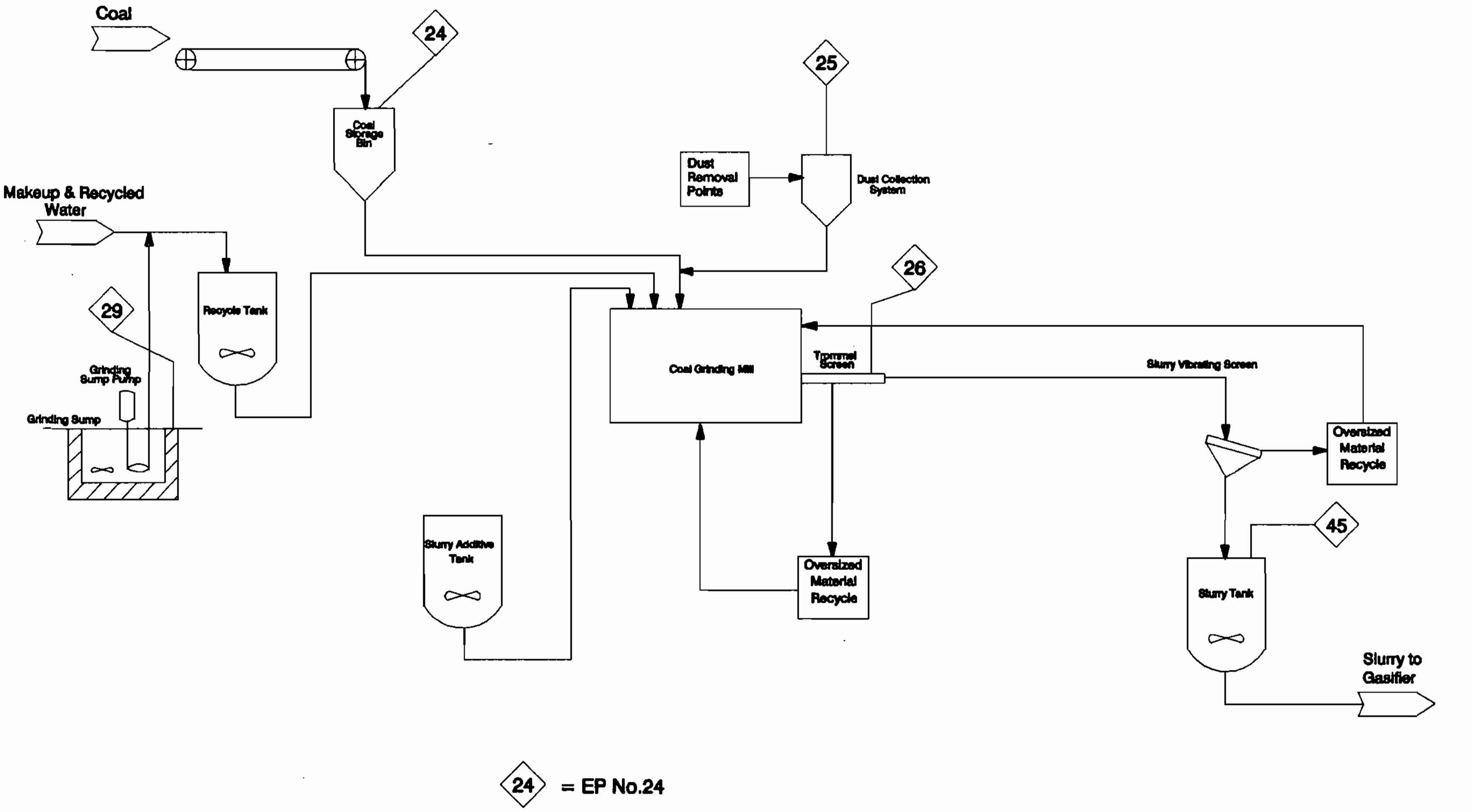

FIGURE 2-4.

COAL GRINDING AND SLURRY PREPARATION SCHEMATIC

Source: Texaco, 1992.

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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. Material collected in the sump will be routed to the recycle tank for reuse in the process.

Operations within the coal grinding and slurry preparation system will result in emissions of PM, H_2S, and ammonia (NH_3). As shown in Figure 2-4, the emissions sources/points are:

- Coal storage bin baghouse (EP 24) (PM),
- Grinding tower baghouse (EP 25) (PM),
- Rod mill discharge (EP 26) (PM),
- Grinding sump (EP 29) (H_2S),
- Mill discharge tank vents (EP 44) (NH_3), and
- Slurry tank vents (EP 45) (NH_3).

The coal storage bin and grinding mill will each be enclosed and vented through fabric filters or baghouses to limit PM emissions. The grinding sump, mill discharge tank vents, and slurry tank vents will each be equipped with carbon canisters for absorption of potential H_2S or NH_3 emissions.

Air Separation Unit

The air separation unit, shown schematically in Figure 2-5, will produce oxygen for use in the gasification system and sulfur recovery unit and nitrogen to be used as a diluent for NO_x control and power augmentation in the advanced CT.

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 blanket roll 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.

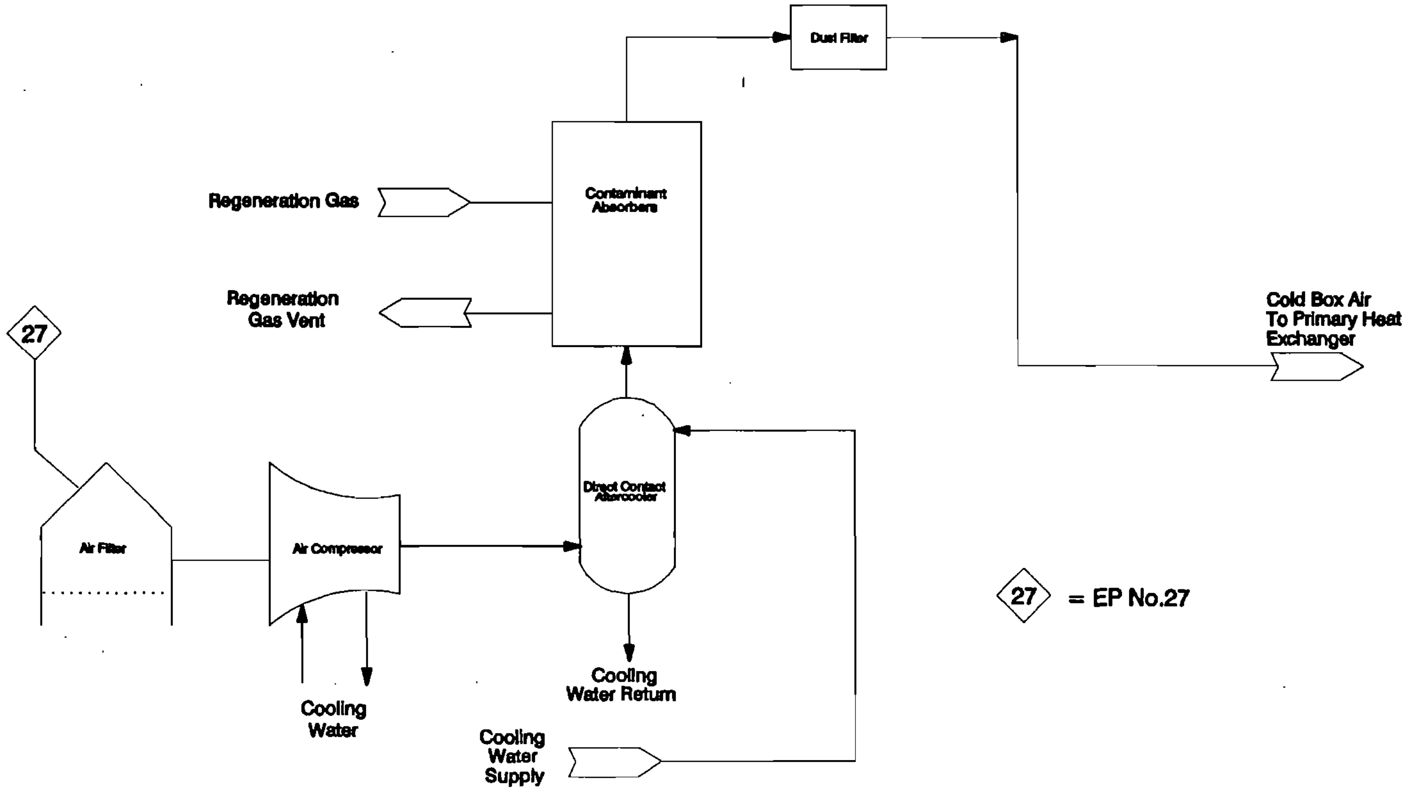

FIGURE 2-5.

AIR SEPARATION UNIT SCHEMATIC (PAGE 1 OF 2)

Source: Texaco, 1992.

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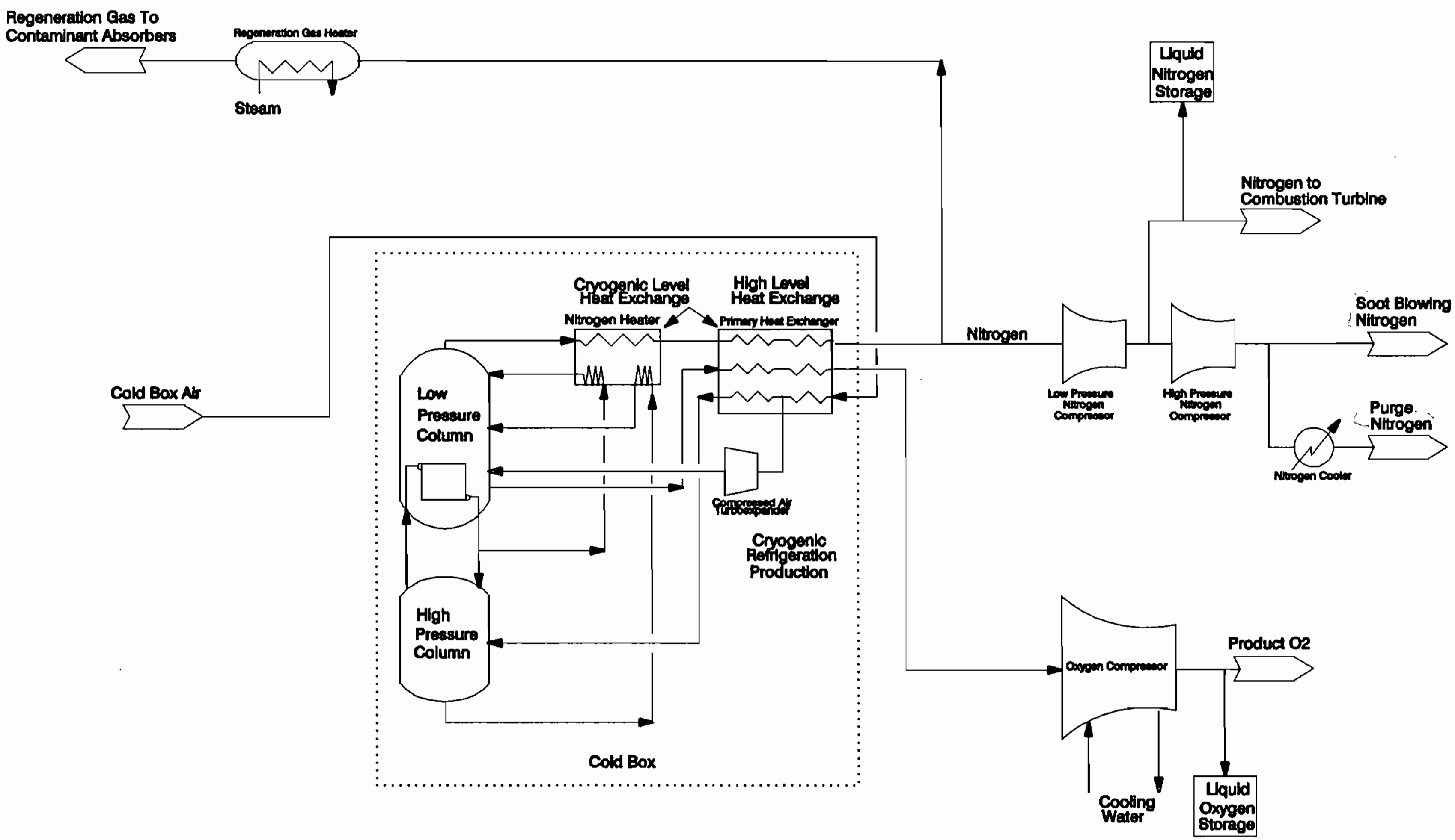

FIGURE 2-5.

AIR SEPARATION UNIT SCHEMATIC (PAGE 2 OF 2)

Source: Texaco, 1992.

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The compressed air will be cooled and scrubbed in an aftercooler. Chilled air from the aftercooler will be fed to the molecular sieve contaminant adsorbers. The molecular sieves will remove any remaining water vapor, carbon dioxide (CO_2), and unsaturated and saturated hydrocarbons from the air. The air will then be filtered in the dust filter to remove any entrained molecular sieve particles. Regeneration of the molecular sieve adsorbent will be accomplished by heating a nitrogen stream in the regeneration heater and passing it through the off-stream bed countercurrently to drive off the adsorbed contaminants. The regeneration gas will then be vented. PM emissions will intermittently result from this regeneration (EP 27).

The purified air 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 at its midpoint and expanded through the compressed air turboexpander to provide refrigeration for the cryogenic process. The cooled 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 dew point. The air will be fed to the high pressure distillation column and then to the low pressure distillation column where it is 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.

Liquid nitrogen reflux, kettle liquid, and turbine discharge will be fed to the low pressure distillation column where they will be separated into oxygen and nitrogen. Heat from the condensing air 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 is compressed to the pressure required by the gasification unit.

Nitrogen vapor from the low pressure distillation column will be warmed slightly in a superheater against subcooling nitrogen reflux liquid. The nitrogen will then be warmed to near-ambient temperature in the PHX. The nitrogen vapor will be compressed and sent to the advanced CT.

Gasification System

The gasification system will produce the raw syngas from the coal slurry feed. The schematic for this system is provided in Figure 2-6. This schematic also shows the proposed slag handling and syngas cooling systems.

As shown in Figure 2-6, coal slurry from the slurry feed tank and oxygen from the air separation unit will be fed to the gasifier.

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, carbonyl sulfide (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 the 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 synthesis gas 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 which will supplement the heat input 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 syngas will then be sent to the convection

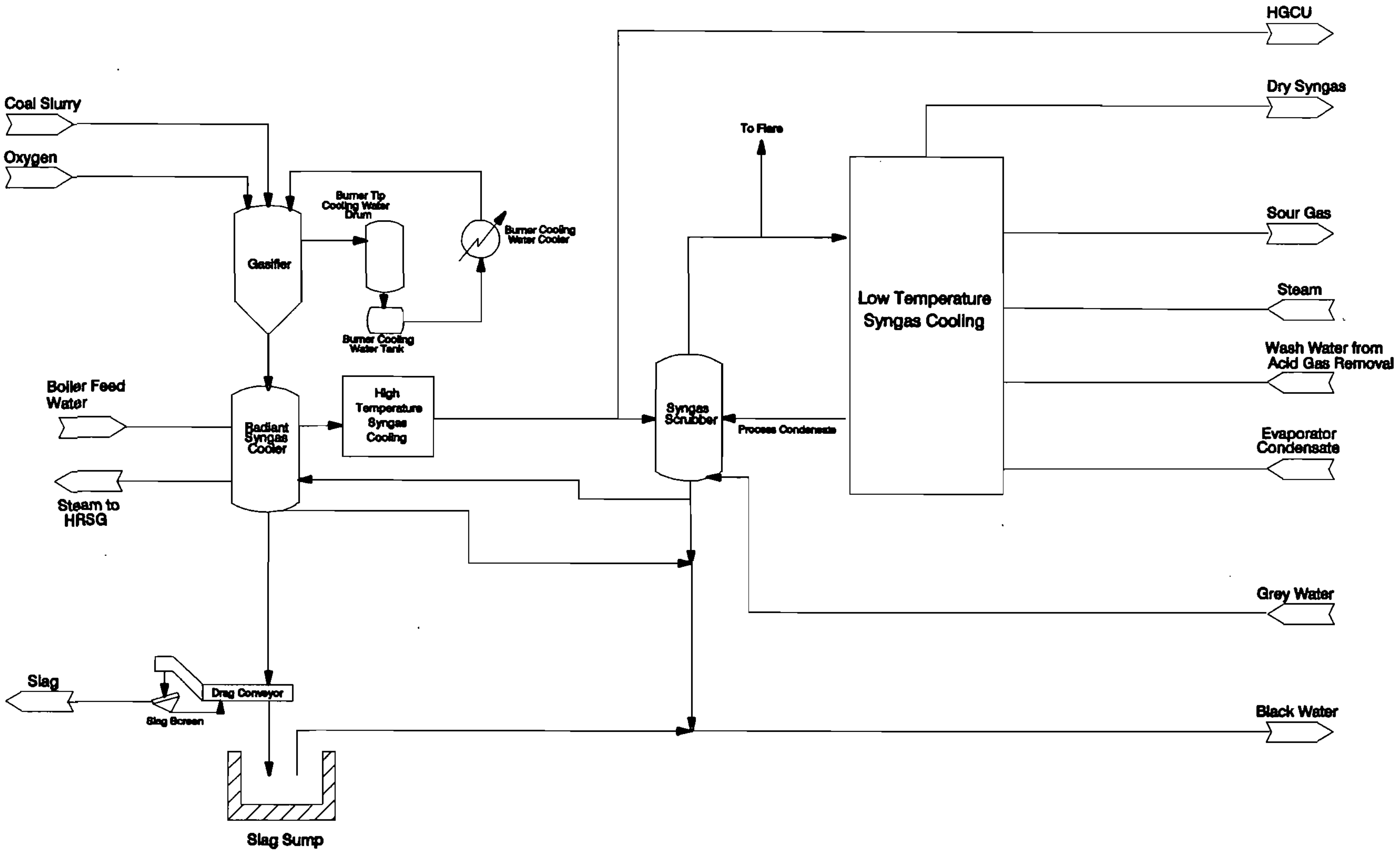

FIGURE 2-6.

GASIFICATION, SLAG HANDLING, AND SYNGAS COOLING SYSTEM SCHEMATIC

Source: ECT, 1992.

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cooler for further heat recovery. The slag will drop into the water pool and will be fed to the slag sump tank.

Syngas Scrubbing and Cooling Systems

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 50 percent of the syngas when the unit is operating at full capacity. The CGCU system is described in the following subsections.

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 2-6.

As shown in Figure 2-6, the raw hot syngas from the gasifier will be fed through the high temperature syngas cooling system to the syngas scrubber where entrained solids are removed. The syngas will then be routed to the low temperature gas cooling section. The low temperature gas cooling section will cool the syngas by recovering its useful heat and will condense out much of the water from the syngas prior to its routing to the acid gas removal system.

During startups, shutdowns, and upsets, particle-free syngas will be routed to the flare for short periods of time.

Acid Gas Removal Unit

In the CGCU system, the acid gas removal unit will remove acid gases such as CO_2 and H_2S from the syngas. The schematic for this unit is provided in Figure 2-7.

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 flow through a liquid coalescer to collect entrained water droplets and 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 CO_2 and H_2S by chemical reaction. The purified syngas will flow through a knock-out drum located on top of the water wash column to remove entrained amine. The recovered liquid will be returned to the amine sump.

During startups, shutdowns, and upsets, particulate-free syngas will be routed to the flare for short periods of time.

The rich amine will be stripped of 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 from the reflux accumulator will go to the ~~sulfur recovery unit (SRU)~~ sulfuric acid (H_2SO_4) plant, and the condensed liquid reflux will be returned to the amine stripper.

~~Sulfur Recovery Unit~~

~~The sulfur recovery unit, shown schematically in Figure 2-8, will convert H_2S gas to a liquid molten sulfur by-product. Approximately one third of the feed H_2S will be oxidized in the thermal reactor to form SO_2. The SO_2 will then react with the remaining H_2S to form elemental sulfur and water. NH_3 from the NH_3 stripper will~~

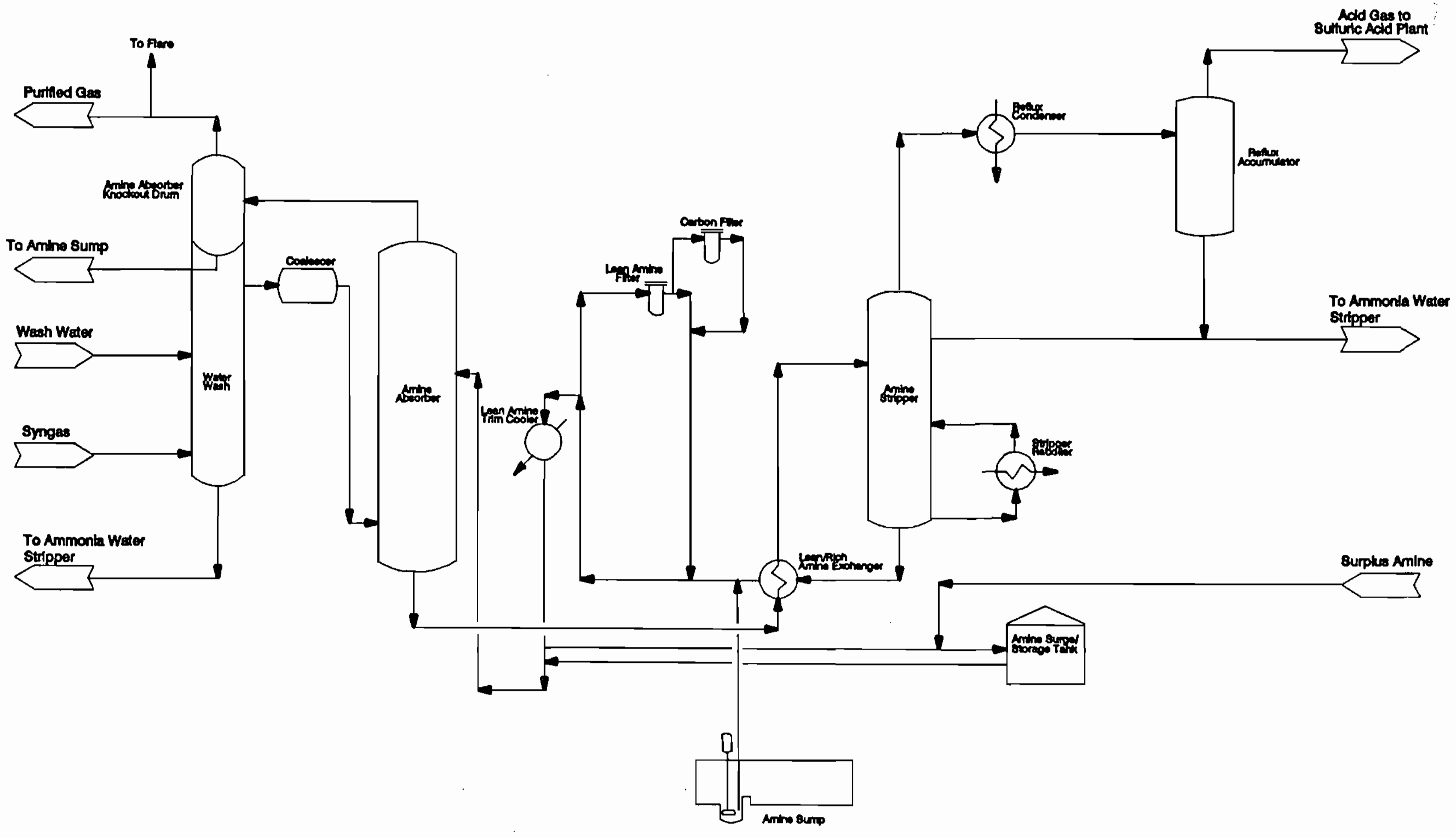

FIGURE 2-7.

ACID GAS REMOVAL UNIT SCHEMATIC

Sources: Texaco, 1992. Bechtel, 1993.

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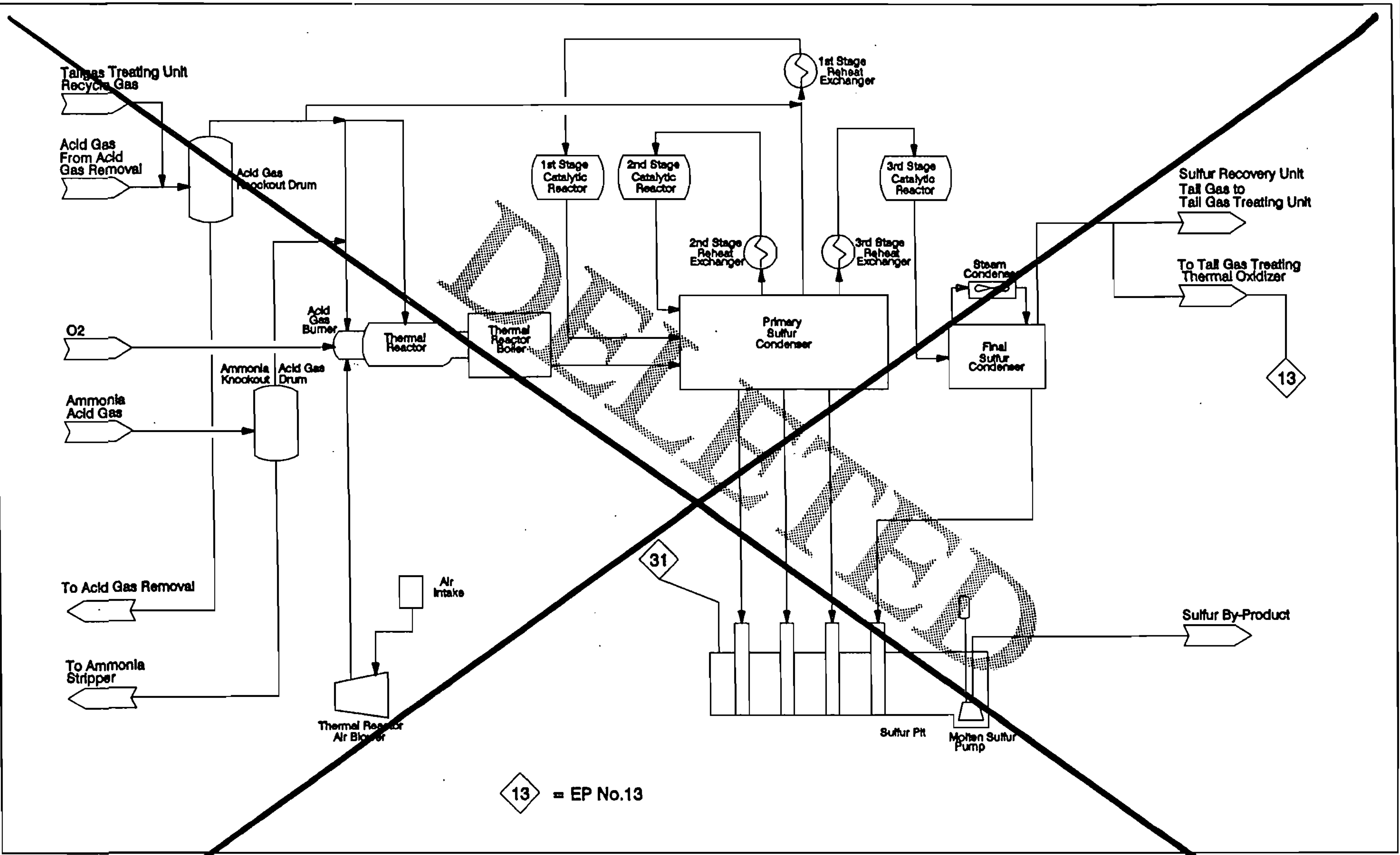

~~FIGURE 2-8.~~

~~SULFUR RECOVERY UNIT SCHEMATIC~~

~~Source: Texaco, 1992.~~

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~~also be oxidized to nitrogen and water. Any hydrocarbons in the acid gas feed will be oxidized in the thermal reactor to CO and water.~~

~~The basic reactions are:~~

~~1. $H_2S + 1.5\ O_2 \rightarrow SO_2 + H_2O$, and~~
~~2. $2H_2S + SO_2 \rightarrow 1.5\ S_2 + 2H_2O$.~~

~~Depending on the concentration of H_2S in the acid gas feeds, as much as half of the unit's total sulfur production will come from the non-catalytic reactions in the thermal reactor. This sulfur will be condensed and removed from the stream prior to feeding the first catalytic reactor. The balance of the sulfur production will be formed in the following three catalytic reactors.~~

~~The acid gas knock out drum and the NH_3-water stripper gas knock out drum will be designed to remove entrained water and condensed hydrocarbons from the amine acid gas and the NH_3-water stripper gas feeds upstream of the thermal reactor.~~

~~The NH_3-water stripper gas stream will be fed entirely to the thermal reactor burner located in the front chamber of the thermal reactor. The amine acid gas from the acid gas removal unit may be split to assist the reaction. Pure oxygen will be added if necessary to maintain the front chamber temperature to ensure NH_3 combustion. If NH_3 is not present, then lower temperatures may be used. The remainder of the amine acid gas stream will be fed to the second chamber of the thermal reactor or by-passed to the inlet of the first stage reheat exchanger. Approximately one third of the total H_2S feed will be converted to SO_2 and water in the thermal reactor. Sufficient air from the air blower and oxygen will be supplied to the thermal reactor to oxidize the H_2S in the NH_3-stripper gas to SO_2 and water, to oxidize the NH_3 to nitrogen and water, and to oxidize any hydrocarbons in the NH_3-stripper gas to CO_2 and water.~~

~~The hot combustion gas from the thermal reactor second chamber will enter the boiler where the gas is cooled. The effluent gas from the boiler will enter the primary sulfur condenser. Sulfur produced in the thermal reactor will be condensed in the primary sulfur condenser first pass as the gas is cooled. Steam will be produced as the gas is cooled and the sulfur is condensed. The liquid sulfur will be separated from the gas in a separator chamber at the outlet end of the primary sulfur condenser and will be drained to the sulfur seal pot. The liquid sulfur seal in the pot will prevent the process gas from escaping to the sulfur pit. The uncondensed gas from the first pass of the primary sulfur condenser will be routed to the first reheat exchanger where the gas is re-heated. The steam condensate produced from the reheat exchanger will flow to the primary sulfur condenser.~~

~~The gas from the first reheat exchanger will pass through the first catalytic reactor where the reaction of SO_2 with H_2S occurs over a fixed bed of activated alumina catalyst. The heat given off by the reaction in the first bed is the greatest of all the catalytic reactor beds. The catalytic reactor product gas, containing the newly formed elemental sulfur, will exit the catalytic reactor and enter the second pass of the primary sulfur condenser. Sulfur formed in the first catalytic reactor will be condensed and drained to the sulfur seal pot.~~

~~The uncondensed gas will then be routed to the second reheat exchanger where it is heated prior to being fed to the second catalytic reactor. The second catalytic reactor will be similar in size and function to the first catalytic reactor. Since the concentration of the reactants is lower in the second catalytic reactor feed than in the first, less reaction will take place. The second catalytic reactor effluent gas will again enter the primary sulfur condenser, where the bulk of the sulfur formed in the reactor will be condensed, and will be drained to the sulfur seal pot.~~

~~The uncondensed gas from the third pass of the primary sulfur condenser will be routed to the third catalytic reactor via the third reheat exchanger. Again, the steam condensate from this reheat exchanger will be sent to the primary sulfur condenser.~~

~~Since the concentrations of H_2S and SO_2 will be low in the third catalytic reactor, only a relatively small amount of sulfur will be formed in this reactor. The sulfur formed in the third catalytic reactor will be condensed in the final sulfur condenser as the stream is cooled and drained to the sulfur seal pot.~~

~~The uncondensed gas (tail gas) will exit the final sulfur condenser via a mist eliminator pad and will be routed either to the tail gas treating unit or to the thermal oxidizer (EP-13) based on the tail gas sulfur content.~~

~~The thermal oxidizer will be designed to oxidize the tail gas from the sulfur recovery unit at approximately 1,500 degrees Fahrenheit (°F) with 50 percent excess air. The unreacted H_2S, CS_2, COS, elemental sulfur, and any other combustible sulfur compounds will be oxidized almost entirely to SO_2 in the thermal oxidizer. The design thermal oxidizer combustion temperature will be maintained by burning a syngas stream when available or low sulfur fuel oil or natural gas in addition to the process effluent vapor. The incinerated products will be dispersed to the atmosphere via a 199 ft high stack. Normally, however, only the tail gas treating unit vent gas will be oxidized in the thermal oxidizer at approximately 1,200°F with 25 percent excess air.~~

~~The sulfur recovery unit will have a sulfur day tank within a concrete pit. The tank will hold approximately 150 long tons of molten sulfur product. Heat is provided by steam coils at the bottom of the pit. The tank will have pumps to transfer the molten sulfur to either the truck loading rack or the railcar loading rack for transport offsite. Some emissions of H_2S will occur sporadically during sulfur loading and other operations when the pit must be opened (EP-31).~~

~~Tail Gas Treating Unit~~

~~The sulfur recovery unit will typically convert approximately 96 percent of its H_2S feed gas to molten liquid sulfur. However, the concentration of H_2S and SO_2 in the tail gas from the sulfur recovery unit may still be too high to release to the~~

~~atmosphere under normal operating conditions. The tail gas treating unit will be designed to recover this remaining H_2S and SO_2 for recycle back to the sulfur recovery unit and to meet applicable emission levels in the tail gas vented to the atmosphere. Reaction and recovery sections of the tail gas treating unit are presented schematically in Figures 2-9 and 2-10, respectively.~~

~~As shown in Figure 2-9, the sulfur recovery unit tail gas will be fed to the feed heater and hydrogen-rich reducing gas will be added to the heated gas leaving the feed heater. The mixed gas stream will be fed to a catalytic reactor.~~

~~The reactor feed gas will pass downward through the catalyst bed and virtually all of the SO_2, sulfur, COS, and CS_2 will be converted to H_2S. In the reactor, the following basic reactions of SO_2 and elemental sulfur will take place:~~

~~1. $SO_2 + 3H_2 \rightarrow H_2S + 2H_2O$, and~~

~~2. $S + H_2 \rightarrow H_2S$.~~

~~The COS and CS_2 will be hydrolyzed by the water vapor present in the sulfur recovery unit tail gas to H_2S and CO_2. A small portion of the COS and CS_2 may not be hydrolyzed by water vapor present and may be reduced by hydrogen directly to H_2S. To assure complete reaction of the COS and CS_2 to H_2S, a minimum excess of approximately 50 percent of the stoichiometric requirement of hydrogen-rich gas will be fed to the reactor. The CO in the sulfur recovery unit tail gas will also act like hydrogen as a reducing gas; i.e., it reacts with the water vapor in the reactor to form hydrogen and CO_2. Therefore, minimal unreacted sulfur compounds will remain in the reactor outlet.~~

~~The hot gas leaving the reactor will be cooled in the waste heat boiler, which generates steam. Water will be condensed out of the gas when it is further cooled by direct contact with the circulating quench water in the quench tower. The temperature of the quench water will increase as it cools the gas in the tower. The quench water bottoms will be pumped through the quench water cooler and quench~~

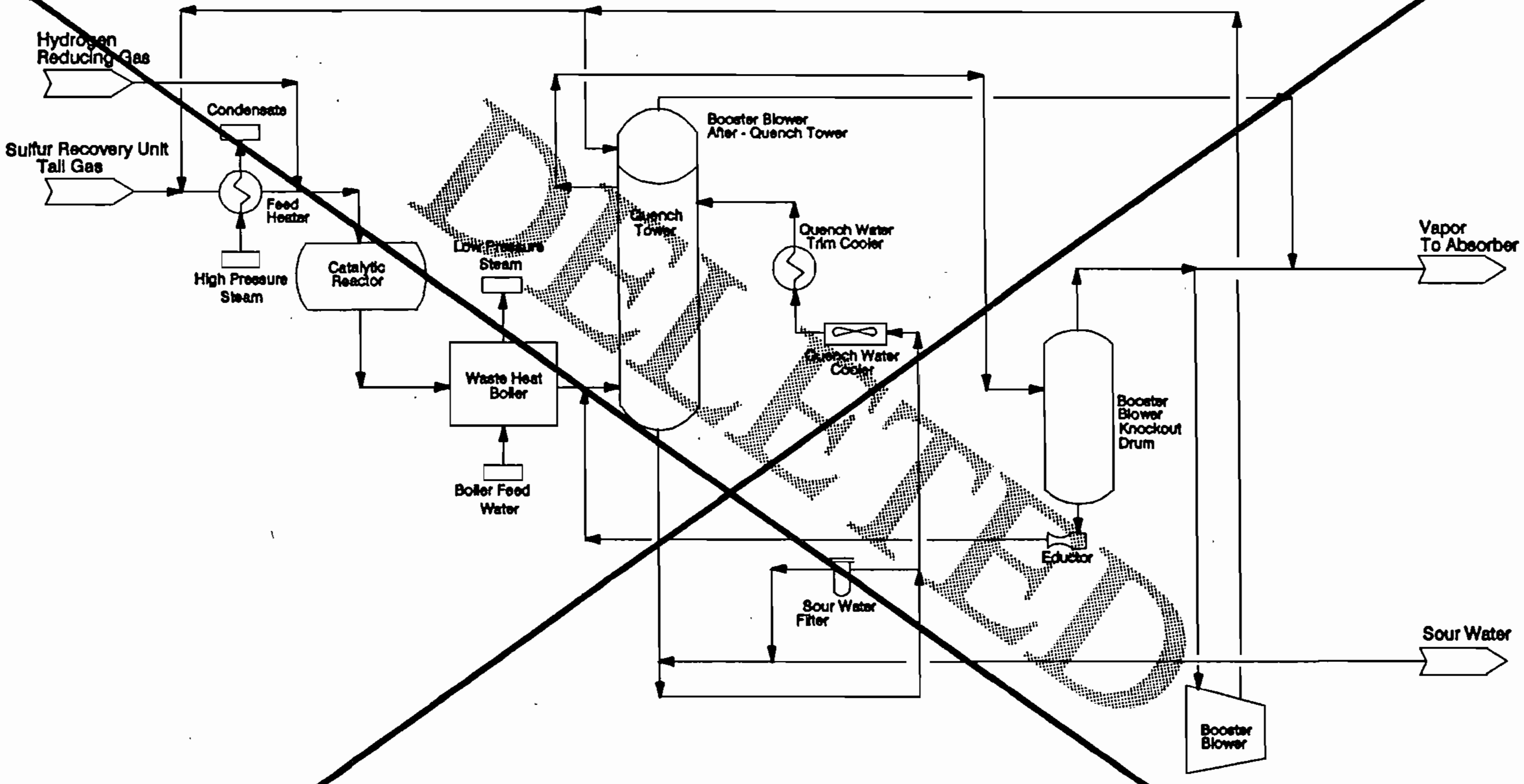

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FIGURE 2-9.

TAIL GAS TREATING UNIT REACTION SECTION SCHEMATIC

Source: Texaco, 1992.

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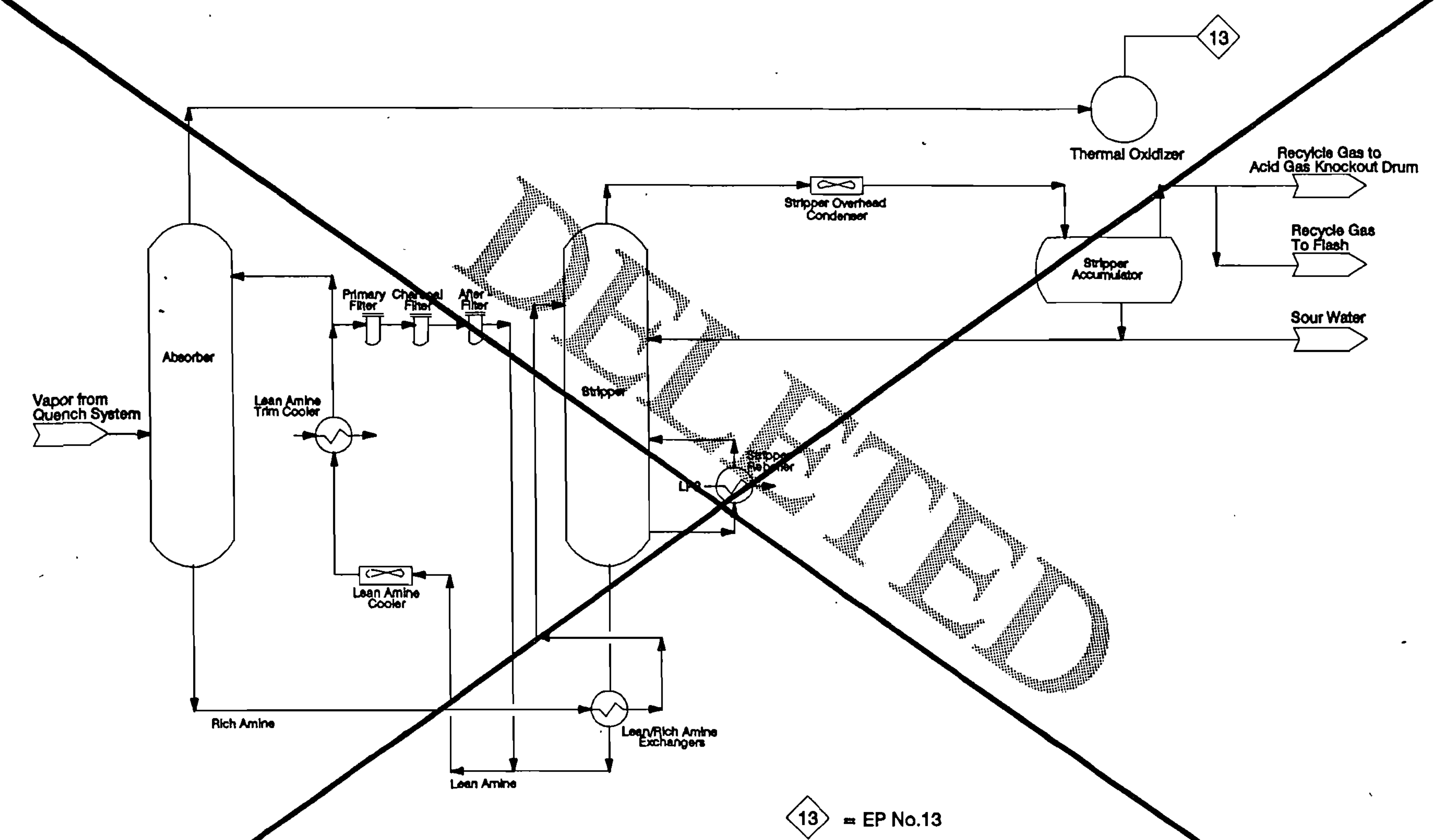

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FIGURE 2-10

TAIL GAS TREATING UNIT RECOVERY SECTION SCHEMATIC

Source: Texaco, 1992.

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~~water trim cooler before being returned to the top section of the quench tower. A slipstream of the quench water flow will be routed through the quench water filter which removes solids in the quench water.~~

~~The quench tower overhead gas stream will be fed to the booster blower knockout drum where any entrained liquid will be separated from the gas. The separated liquid will then be removed and returned to the quench tower bottoms above the normal liquid level. From the booster blower knockout drum, the gas normally will go to the absorber where it flows upward through the absorber through lean amine flowing downward in the absorber to remove the H_2S. The absorber overhead gas, which will have less than 260 parts per million by volume (ppmv) of H_2S, will be fed to the thermal oxidizer. In the thermal oxidizer (EP 13), H_2S and any other remaining sulfur compounds will be converted to SO_2 and vented to a stack.~~

Hot Gas Cleanup ~~and Sulfuric Acid Plant~~

A schematic of the HGCU system is presented in Figure 2-11. For the system demonstration, a portion of the hot raw syngas will be routed from the gasifier to the HGCU system for cleanup prior to firing in the advanced CT.

Particulate Removal

~~Entrained fine particles in the syngas from the gasifier will be removed in the primary high efficiency cyclone as shown in Figure 2-11 and recycled to the black water handling system. A large fraction of the remaining PM entering the absorber will be captured by the bed, reducing particle concentration to below 30 ppm. A small amount of zinc titanate fines will be entrained from the absorber and collected in a high efficiency secondary cyclone. The high efficiency secondary cyclone will effectively capture most of the high density zinc titanate dust and will practically eliminate all fines larger than 5 microns. Entrained particles from the regenerator will be captured in a cyclone located downstream of the regenerator. The solids from both the high efficiency secondary cyclone and the regenerator cyclone are non-hazardous and will be sent offsite for disposal. Larger fines will be sieved on screens~~

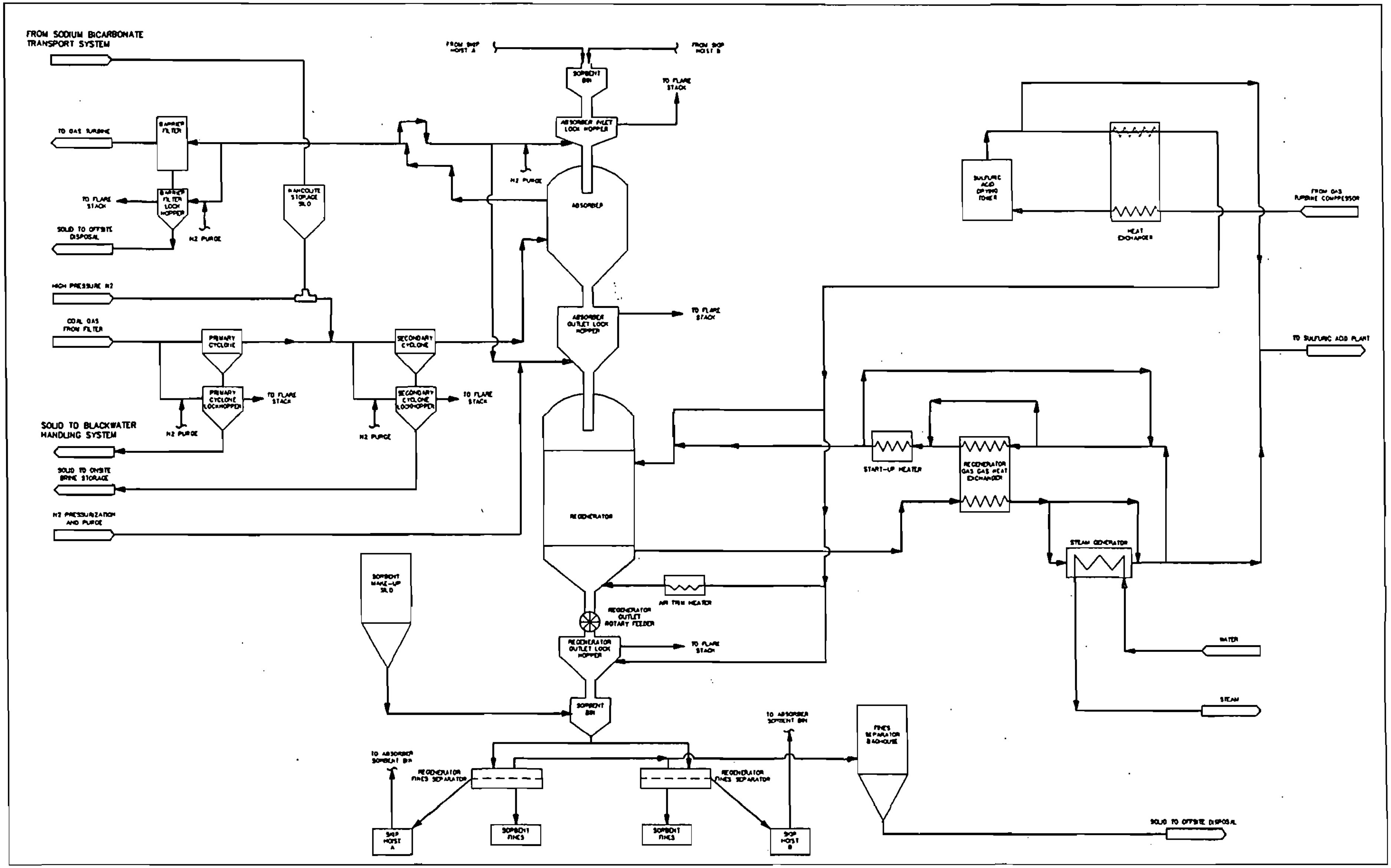

FIGURE 2-11.

HOT GAS CLEANUP SYSTEM

Source: GEESI, 1992.

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~~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. A high temperature barrier filter, employing pulse cleaning, will remove greater than 99.5 percent of the residual PM prior to the CT. The collected solids will be sent to the onsite brine disposal area.~~

Entrained fine particles in the syngas from the gasifier will be removed in the primary high efficiency cyclone as shown in Figure 3.1.1-9 and recycled to the black water handling system. Following this high efficiency cyclone is a second high efficiency cyclone whose function is to remove the sodium bicarbonate which is introduced upstream for halogen removal. The collected solids from the second high efficiency cyclone will be sent to the onsite brine disposal area. A large fraction of the remaining PM entering the absorber will be captured by the bed, reducing particle concentration to below 30 ppm. A small amount of zinc titanate fines will be entrained from the absorber and collected in a high efficiency barrier filter. The high efficiency barrier filter will effectively capture all of the high-density zinc titanate 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 non-hazardous 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.

Desulfurization

The absorber is the intermittently moving bed reactor shown schematically in Figure 2-11. The sulfur-laden coal gas from the primary cyclone enters the absorber through a gas manifold at its bottom and flows upward countercurrent to the moving bed of zinc titanate pellets.

The sulfur compounds, mainly H_2S, in the coal gas 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 is stationary at low H_2S outlet concentration and is moved upon H_2S breakthrough. The H_2S breakthrough control signal activates 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 zinc titanate is replaced by regenerated sorbent from the absorber's inlet lockhopper.

When regenerated zinc titanate sorbent is loaded into the absorber's inlet lockhopper, a slip stream of syngas can be activated. This stream decomposes any zinc sulfate residual from the regeneration step according to:

$$2ZnSO_4 + 5H_2 \rightarrow ZnO + ZnS + SO_2 + 5H_2O$$

The reductive regeneration stream flows through the absorber's inlet lockhopper until complete sulfate decomposition, detected by low SO_2 concentration, is achieved. The amount of sulfate in the regenerated zinc titanate depends on the quality of the regeneration step, and is expected to be very small.

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 sinters and destroys the sorbent structure and reduces its ability to react with sulfur in consecutive absorption steps. Low temperature results in sulfate formation and a loss of reactive sorbent to the desulfurization process.

~~In order to effectively control the reaction and achieve a complete regeneration, t~~The reactor is divided into up to ~~three zones~~ two stages: an upper stage and a lower stage. As the sorbent moves down the reactor zones, the reaction proceeds in a controlled atmosphere. Nearly continuous sorbent movement in the regenerator is 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. Zinc sulfate is formed in the initial stage of regeneration, but decomposes under the high-temperature, low oxygen concentration conditions at the lower end of the regenerator prior to introduction of the pure air stream.

Sulfided zinc titanate is fed from the absorber's outlet lockhopper to the top of the regenerator where partial oxidation of the sulfided sorbent occurs. The sorbent moves down the reactor in cocurrent flow with the regeneration gas. The regeneration gas flows downward from the top of the regenerator into the second-stage regeneration zone. Oxygen concentration is controlled to limit the gas temperature. Under these conditions, no thermal damage occurs to the sorbent. The relatively low temperature in the first regeneration stage results in the formation of some sulfate. This sulfate decomposes at the higher temperature during further regeneration.

The sorbent and the regeneration gas, mixed with the gas stream from the primary stage, flow concurrently downward into the final regeneration stage. The oxygen concentration is controlled by the ratio of air to recycle gas to limit the temperature in the bed. The recycle flow rate is controlled to maintain oxygen concentration at the gas outlet from the regenerator. The high outlet temperature of the gas and sorbent at the end of secondary regeneration ensures complete sulfate decomposition.

The final polishing phase of regeneration is done at the lower end of the reactor where dry air flows countercurrent to the sorbent. This stream cools the sorbent to a temperature acceptable for downstream equipment, purges the SO_2-rich gas, and ensures complete regeneration. The gas streams from the cocurrent and countercurrent flows mix to form the recycle gas stream.

Regeneration Gas Recycle Subsystem

The regeneration gas recycle is shown in Figure 2-11 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 is designed as an internal diluent that reduces 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 also enriches the SO_2 concentration of the product stream.

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

Halogen Removal

Commercial grade sodium bicarbonate~~, trade named Nahcolite,~~ is injected with a small quantity of high temperature nitrogen, upstream of the barrier filter as shown in Figure 2-11. Chloride and fluoride species will be removed by direct contact reaction and on the barrier filter media with the sodium bicarbonate forming stable solids. These salts will be routed to the barrier filter hoppers for disposal in the onsite brine disposal area.

Sulfuric Acid Plant

~~In the HGCU process, an offgas is produced which has a high SO_2 concentration. For the proposed project, this offgas will be treated by converting the SO_2 to H_2SO_4. The conversion involves a multi-step catalytic process based on proven technology in widespread commercial use, especially within the chemical fertilizer industry in central Florida. The liquid H_2SO_4 produced by this process is commercial grade and will be marketed and sold by Tampa Electric Company for offsite uses.~~

~~A skid-mounted H_2SO_4 unit will be constructed adjacent to the CG facilities on the site. The facilities will include an aboveground tank to provide for temporary storage of the H_2SO_4 and appropriate handling and loading equipment. The H_2SO_4 will be transported offsite for commercial use in specially designed rail cars or trucks. Assuming the HGCU system is used to cleanup approximately 50 percent of the syngas for the IGCC unit, the unit would produce approximately 45,000 tpy of liquid H_2SO_4.~~

In the CGCU process, hydrogen sulfide (H_2S) containing gases from the acid gas removal unit and the ammonia (NH_3) stripping unit will be routed through knock-out drums to remove any entrained water. These gases will then be introduced into a combustion chamber, along with combustion air or oxygen. 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 combustion chamber and mix with the combusted gases from the CGCU unit.

The conversion of these mixed gases involves a multi-step catalytic process based on proven technology in widespread commercial use, especially within the chemical fertilizer industry in central Florida. The liquid H_2SO_4 produced by this process is commercial grade and will be marketed and sold by Tampa Electric Company.

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 above 350 psig to avoid condensing acid in the tubes. The gases from the waste heat boiler will be quenched (cooled) in a scrubbing tower, with a circulating stream of water, i.e., a conventional open spray water tower.

Reaction air 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 tower. Depending on the available pressure of the acid gas (H_2S) feed stream(s), it may be possible to eliminate the blower.

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. The SO_2 concentration will determine the exact location of the various heat exchangers and heaters. An indirect fuel gas heater may be used to supplement the reaction heat for startup, turndown, or low SO_2 operations. The gases from the reactor will be cooled and sent to the absorber tower(s), where

93-percent acid absorbs the SO_3 from the process gas stream. The high concentration acid will be circulated from the absorber tower(s) bottom, through the acid cooler(s), and then returned to the top of the absorber tower(s). The gases from the absorber tower will pass through a mist eliminator to remove acid mist, and are then routed to the thermal oxidizer. The thermal oxidizer, which also operates during startup and shutdown, will burn distillate fuel gases and combustion products will be discharged to the atmosphere at approximately 1,400°F.

Slag Handling and Storage

The slag handling system will remove ungasified solids from the gasification process equipment. These solids are made up from the coal ash and unconverted coal components (primarily carbon) that exit the gasifier in the solid phase.

Coarse solids and some of the fine solids will flow by gravity from the radiant cooler into the slag sump tank.

Solids flushed to the slag sump tank will enter the tank in the section that houses the drag conveyor. In this section, the solids settle onto the drag conveyor and are carried out of the sump. The solids fall onto the slag screen where they are dewatered. The slag is then transported by the slag conveyors to trucks or the onsite slag pit. The water removed from the slag is pumped to the black water handling and processing system.

Power Production

The power production system is illustrated in Figures 2-12 and 2-13. The key components are the gas turbine generator, the HRSG, and the ST generator.

The CT will be a GE 7F. The unit will be designed for low-NO_x emissions firing syngas, with fuel oil for startup and as backup fuel. The unit's nominal net rating is 192,000 kilowatts (kw), 3,600 revolutions per minute (rpm).

One HRSG will be employed to recover the CT exhaust heat and generate steam to power the ST. The HRSG will be a three-pressure level, reheat, natural circulation design. The HRSG will produce high pressure superheated steam for the high pressure ST, and will reheat the high pressure turbine exhaust steam for admission into the intermediate pressure ST. The HRSG will also produce intermediate pressure steam which is combined with high pressure turbine exhaust steam (cold reheat steam). Low pressure steam will also be produced for supply to the CG facilities for process use. The HRSG also will receive additional high pressure steam

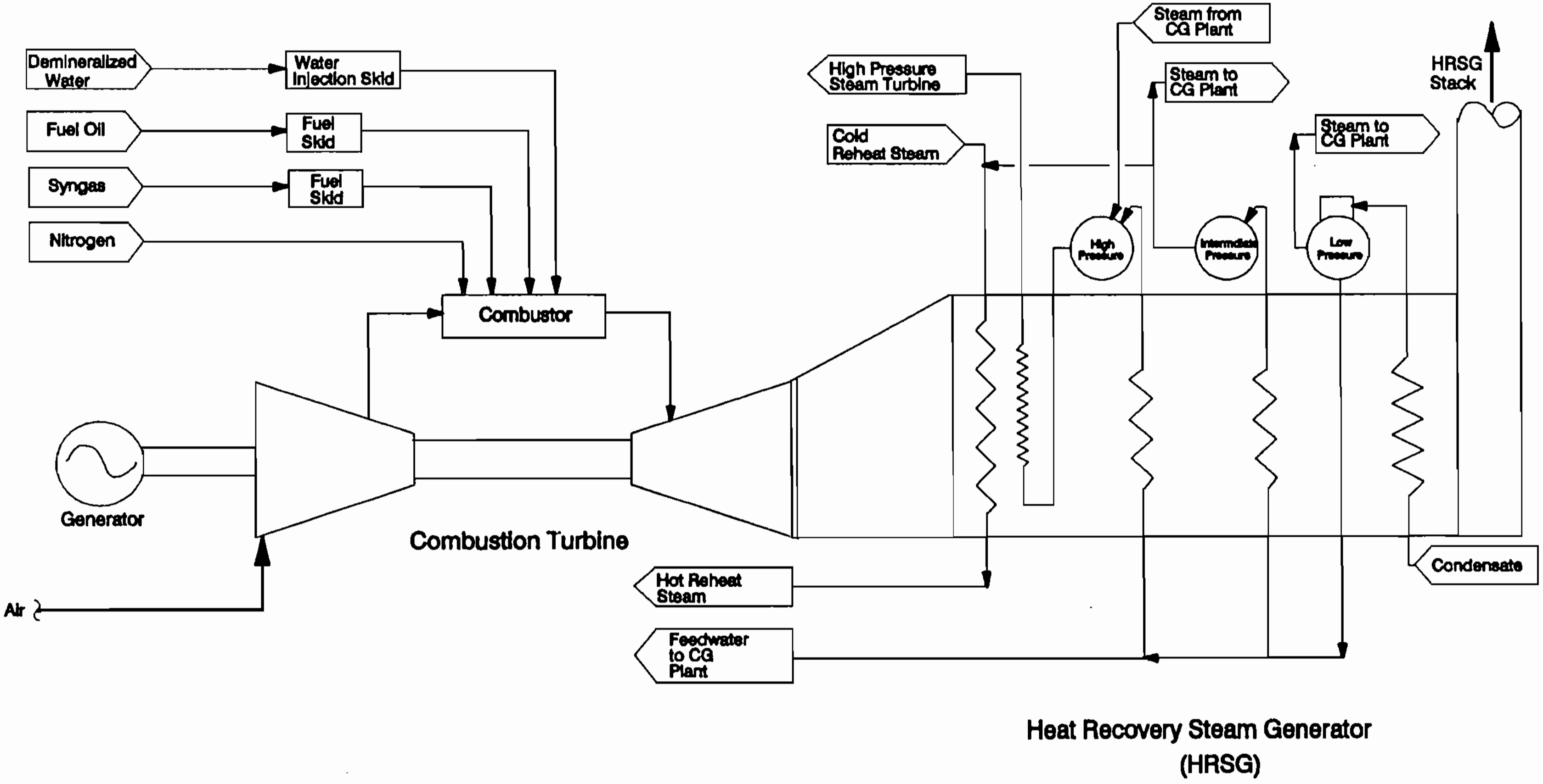

FIGURE 2-12.

COMBUSTION TURBINE PROCESS FLOW SCHEMATIC

Source: GE, 1992.

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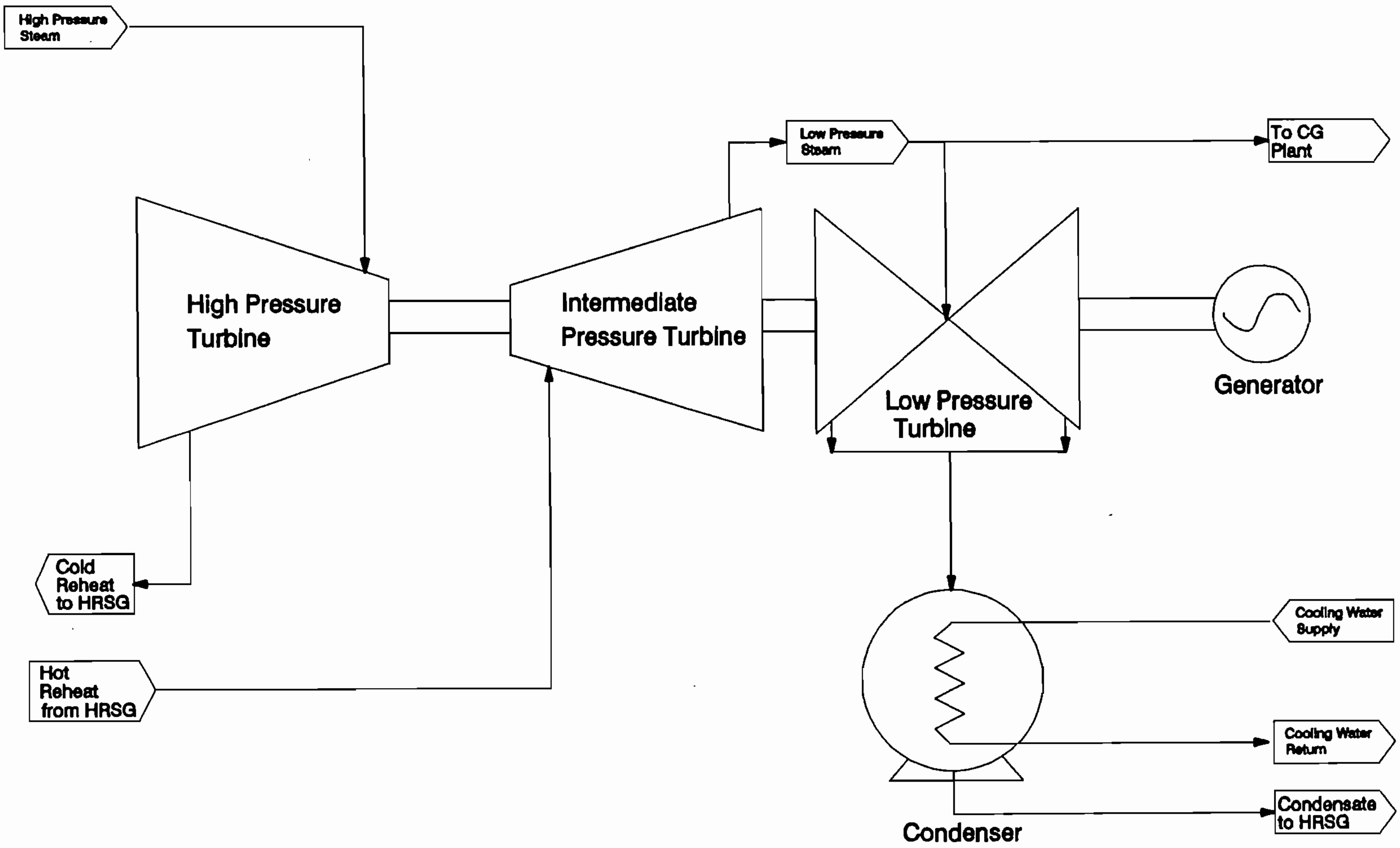

FIGURE 2-13.

STEAM TURBINE PROCESS FLOW SCHEMATIC

Source: GE, 1992.

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and heat energy from the gasification process to supplement the steam cycle power output. No auxiliary firing is proposed within the HRSG system.

The ST will be designed as a double flow reheat, with low pressure crossover extraction. The ST generator will be designed specifically for highly efficient CC operation with nominal turbine inlet throttle steam conditions of 1,450 pounds per square inch gauge (psig) and 1,000°F, with 1,000°F reheat inlet temperature.

The operation of the CC power plant will be coordinated with the startup and operation of the CG process plant. The initial startup of the power plant will be carried out on low-sulfur distillate fuel oil. Transfer to syngas will occur upon establishment of fuel production from the CG plant.

Under normal operation, syngas and nitrogen from the air separation unit will be provided to the CT. The syngas/nitrogen mix in the CT combustion chamber will be regulated by the CT control system to control the NO_x emission levels from the CT and provide power augmentation.

Hot exhaust from the CT will be channeled through the HRSG to recover the CT exhaust heat energy. The HRSG high pressure steam production will be augmented by high pressure steam production from the CG process. All high pressure steam will be superheated in the HRSG before delivery to the high pressure ST.

Cold reheat steam from the high-pressure turbine exhaust and HRSG intermediate pressure steam are then combined together before reheating in the HRSG and subsequent admission to the intermediate pressure ST. Some intermediate pressure steam will also be supplied from the HRSG to the sulfur recovery system.

Additional low level energy integration will occur between the HRSG and the CG plant. Low pressure steam is provided by the HRSG to the CG plant for process use, and some low level waste heat in the CG plant is used for condensate heating for the HRSG. Extraction steam from the low pressure crossover will be available to supplement the HRSG low pressure steam production for the CG plant when necessary.

The low pressure turbine will exhaust to a water cooled condenser which will receive cooling water from the cooling reservoir. Condensate from the ST condenser will be returned to the HRSG/integral deaerator by way of the CG plant, where some condensate preheating occurs.

Emissions from power production will result from the combustion of fuels in the 7F CT. During the first year of operation (i.e., prior to conversion to IGCC), CT emissions will exit via the temporary CT stack (EP 1A). After conversion, the CT stack will be removed, and emissions will exhaust via the HRSG stack (EP 1B).

2.1.2.3 Detailed Descriptions of the Stand-Alone Combined Cycle Units and Combustion Turbines

The proposed Polk Power Station will include two nominal net 220-MW CC units. Each of the CC units will be comprised of two nominal 75-MW CTs (e.g., GE 7EA), two HRSGs, and one ST generator. The CTs will be designed with dry low-NO_x combustors to control NO_x air emissions when firing natural gas which will be the primary fuel for the units. NO_x emission control will be by water injection when the units are fired on the backup low-sulfur distillate fuel oil. SO_2 air emissions from the units will be controlled by the use of fuels with low sulfur contents (i.e., natural gas with trace sulfur content and fuel oil with a maximum sulfur content of 0.05 percent). The CTs will also be designed with by-pass exhaust stacks to be capable of operating in both CC and simple-cycle modes.

For each CC unit, two HRSGs (one per CT) will be employed to recover exhaust heat from the CTs and produce steam to power the ST generator. The HRSG/ST generator facilities will have a nominal net 70 MW generating capacity.

The two CC units will be expected to operate at up to 100-percent capacity factor annually when fired on natural gas and up to a 25-percent annual capacity factor when fired on the backup, low-sulfur distillate fuel oil.

The proposed Polk Power Station will also include six stand-alone simple-cycle CT units. Each of the CTs will have a nominal net generating capacity of 75 MW, similar to the CTs comprising the CC units. Also, like the CTs in CC mode, the stand-alone CTs will be designed with dry low-NO_x combustors to control NO_x air emissions when firing natural gas, the proposed primary fuel for the units. NO_x emission control will again be water injection when the units are fired on the backup distillate fuel oil. SO_2 air emissions from the CTs will be controlled by the use of low sulfur fuels (i.e., natural gas with only trace sulfur content and distillate fuel oil with a maximum sulfur content of 0.05 percent).

The CT units will be expected to operate at up to an annual capacity rate factor of 50 percent when fired on natural gas and 10 percent when fired on the backup fuel oil.

2.1.3 SITE LAYOUT

Figure 2-14 shows Tampa Electric Company's proposed site layout plan for the main power plant facilities and structures, which are all located to the east of SR 37. The site layout plan shows the planned locations for the main power plant structures (i.e., power block, fuel storage, and by-product storage), parking areas, and road and railroad accesses.

The main power block, fuel storage, and associated facilities will occupy only approximately 150 acres of the entire 4,348-acre site. These facilities will be located in the central portion of the site property to the east of SR 37. The power block and fuel storage facilities will be located approximately 2,600 ft from the nearest roadway, SR 37, or to offsite properties which are located northwest of the facility location. In all other directions, the power block and fuel storage areas, will be located at least

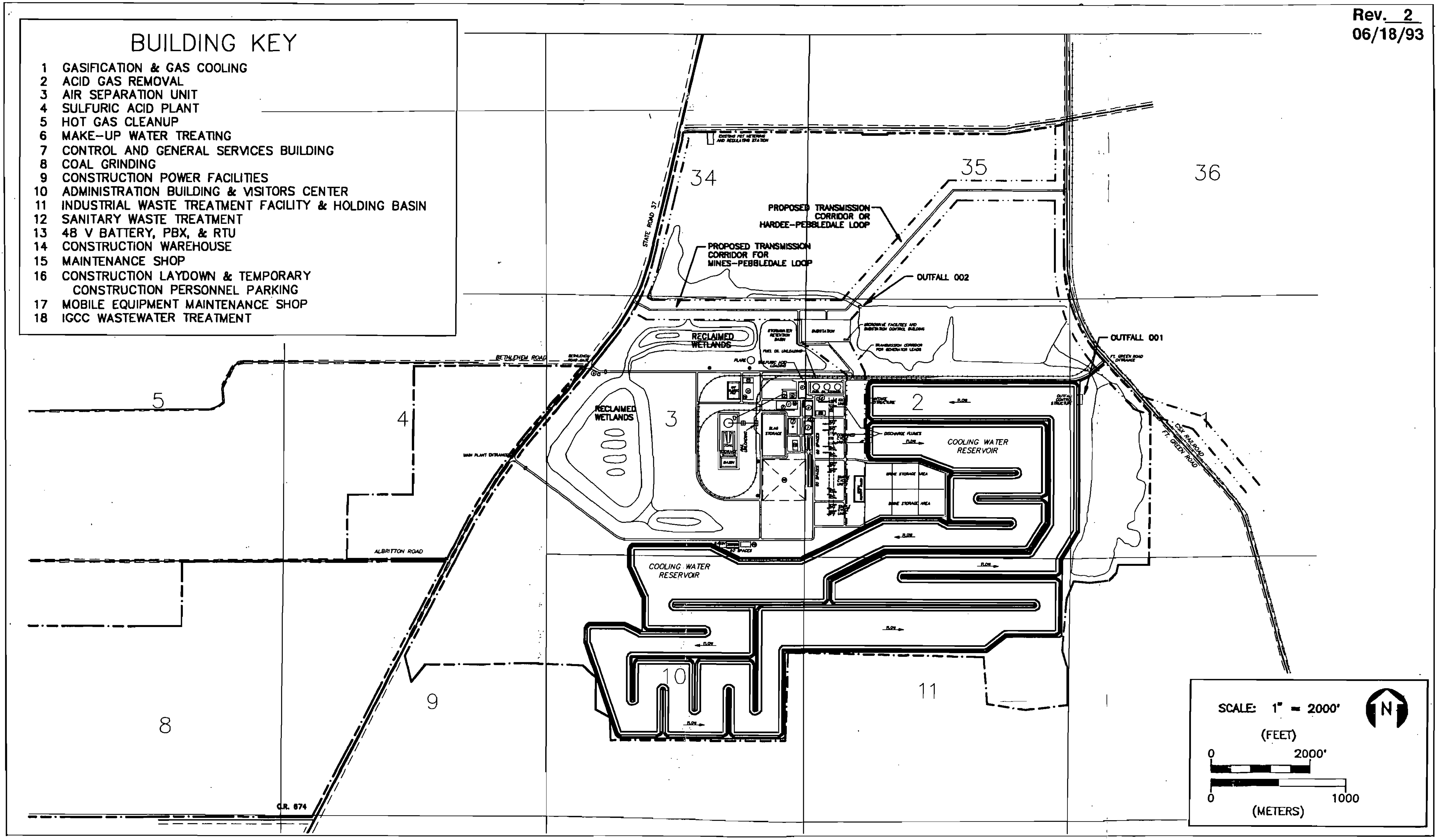

FIGURE 2-14.

CONCEPTUAL POWER BLOCK AND DIRECTLY ASSOCIATED FACILITIES LAYOUT

Sources: Bechtel, 1993. ECT, 1993.

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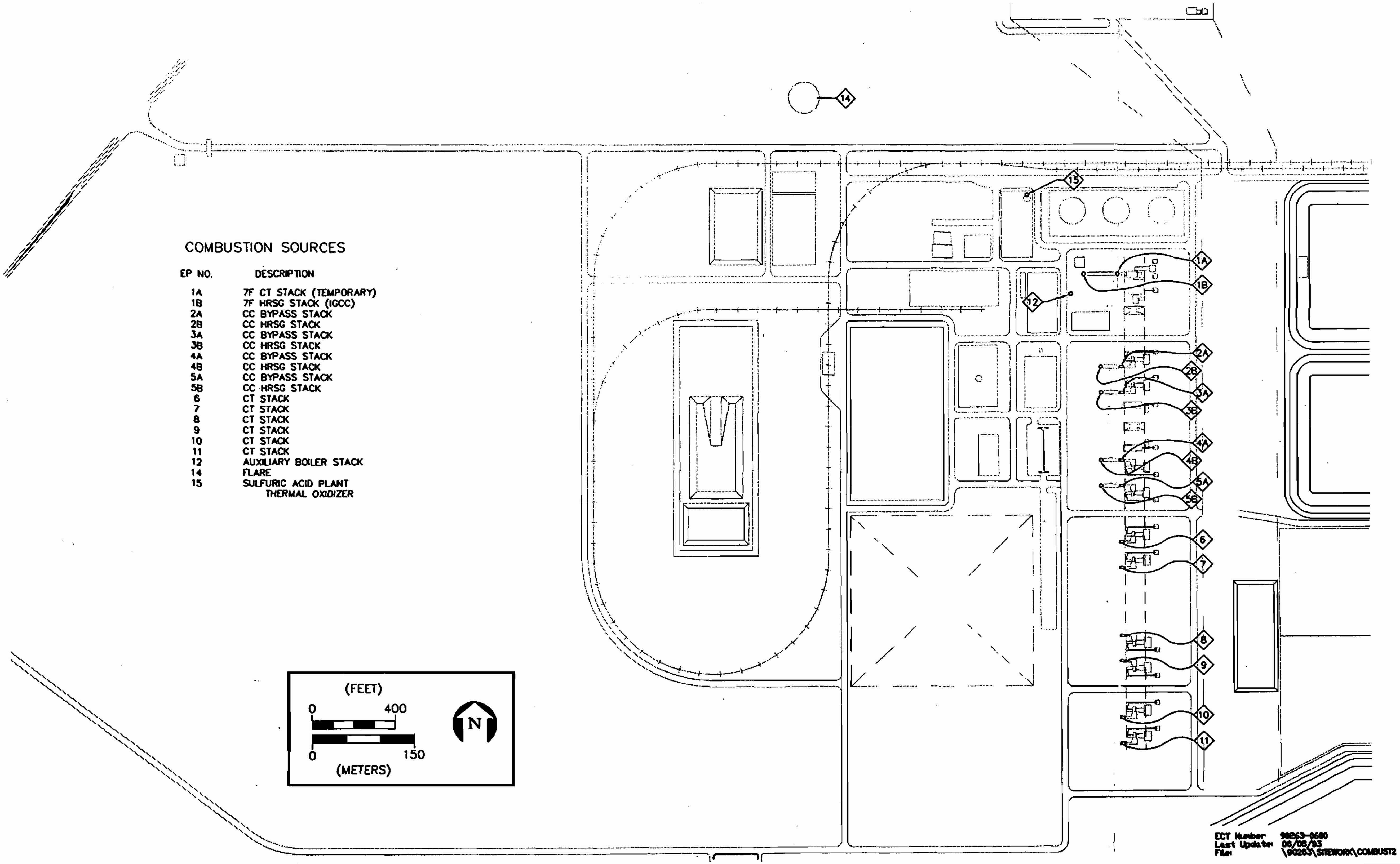
1 mile from offsite properties. Tampa Electric Company is planning to provide vegetative visual buffers along SR 37 and Fort Green Road so that only the tallest structures on the site (e.g., CG facilities and exhaust stacks) are potentially visible from roadways or offsite property.

Roadway access to the main power plant facilities will be provided by two entrances on SR 37 and an entrance from Fort Green Road. All entrance roads will have security gates to control access to the site. The entire perimeter of the site east of SR 37 will be fenced at the property line.

Figures 2-15 through 2-17 show the locations of all emission points on the site. Figure 2-15 shows the combustion emission points. Figure 2-16 identifies the PM emission points associated with coal handling and storage and other minor process sources, while Figure 2-17 shows the locations of gaseous process emission points associated with the IGCC unit. The emission point numbers shown on each figure correspond to the EP numbers used in the text and elsewhere in this report.



COMBUSTION SOURCES

EP NO.	DESCRIPTION
1A	7F CT STACK (TEMPORARY)
1B	7F HRSG STACK (IGCC)
2A	CC BYPASS STACK
2B	CC HRSG STACK
3A	CC BYPASS STACK
3B	CC HRSG STACK
4A	CC BYPASS STACK
4B	CC HRSG STACK
5A	CC BYPASS STACK
5B	CC HRSG STACK
6	CT STACK
7	CT STACK
8	CT STACK
9	CT STACK
10	CT STACK
11	CT STACK
12	AUXILIARY BOILER STACK
14	FLARE
15	SULFURIC ACID PLANT THERMAL OXIDIZER

FIGURE 2-15.

LOCATION OF COMBUSTION SOURCES

Source: ECT, 1993.

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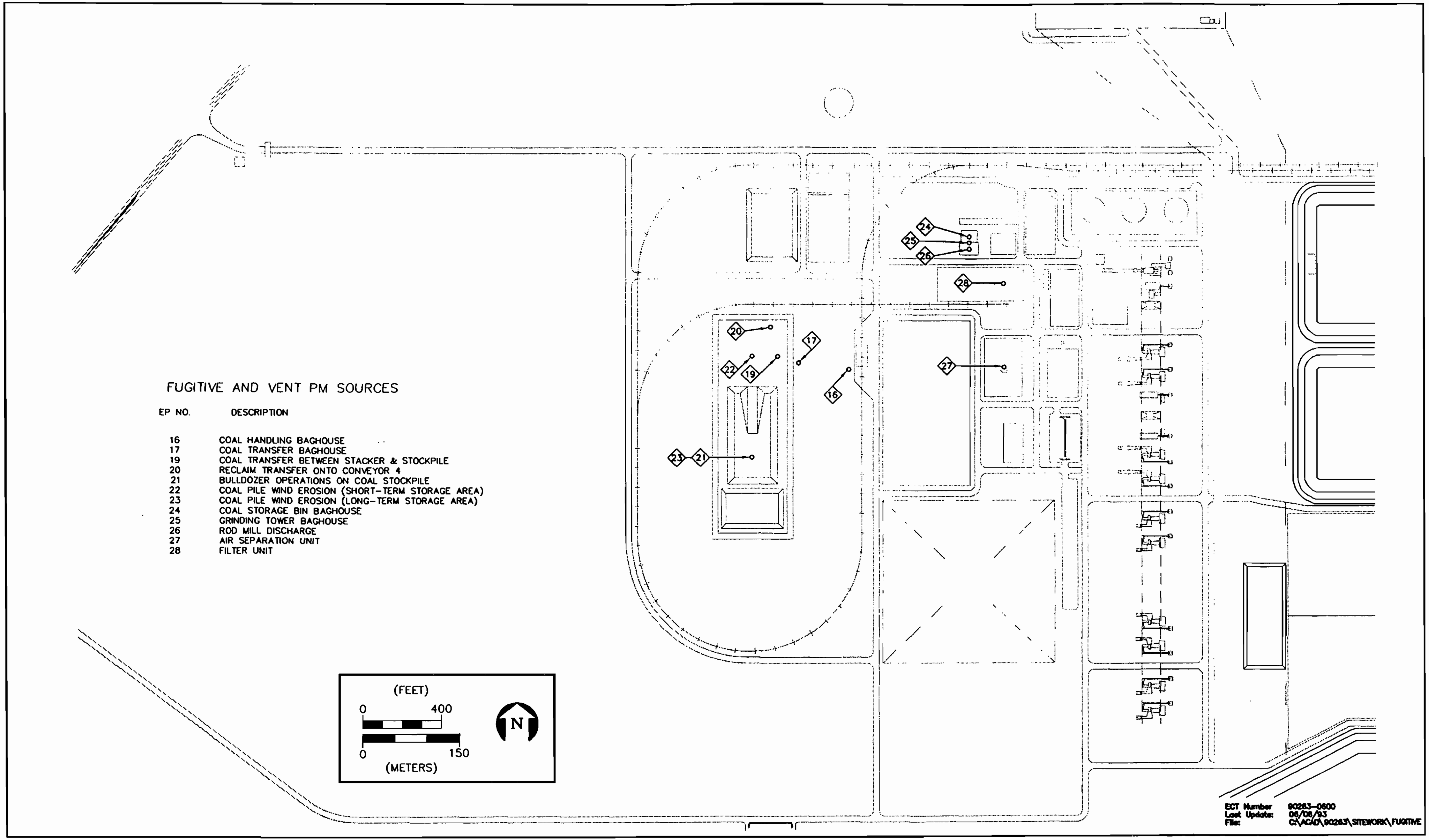

FUGITIVE AND VENT PM SOURCES

EP NO.	DESCRIPTION
16	COAL HANDLING BAGHOUSE
17	COAL TRANSFER BAGHOUSE
19	COAL TRANSFER BETWEEN STACKER & STOCKPILE
20	RECLAIM TRANSFER ONTO CONVEYOR 4
21	BULLDOZER OPERATIONS ON COAL STOCKPILE
22	COAL PILE WIND EROSION (SHORT-TERM STORAGE AREA)
23	COAL PILE WIND EROSION (LONG-TERM STORAGE AREA)
24	COAL STORAGE BIN BAGHOUSE
25	GRINDING TOWER BAGHOUSE
26	ROD MILL DISCHARGE
27	AIR SEPARATION UNIT
28	FILTER UNIT

FIGURE 2-16.

LOCATION OF FUGITIVE AND VENT PARTICULATE MATTER SOURCES

Source: ECT, 1993.

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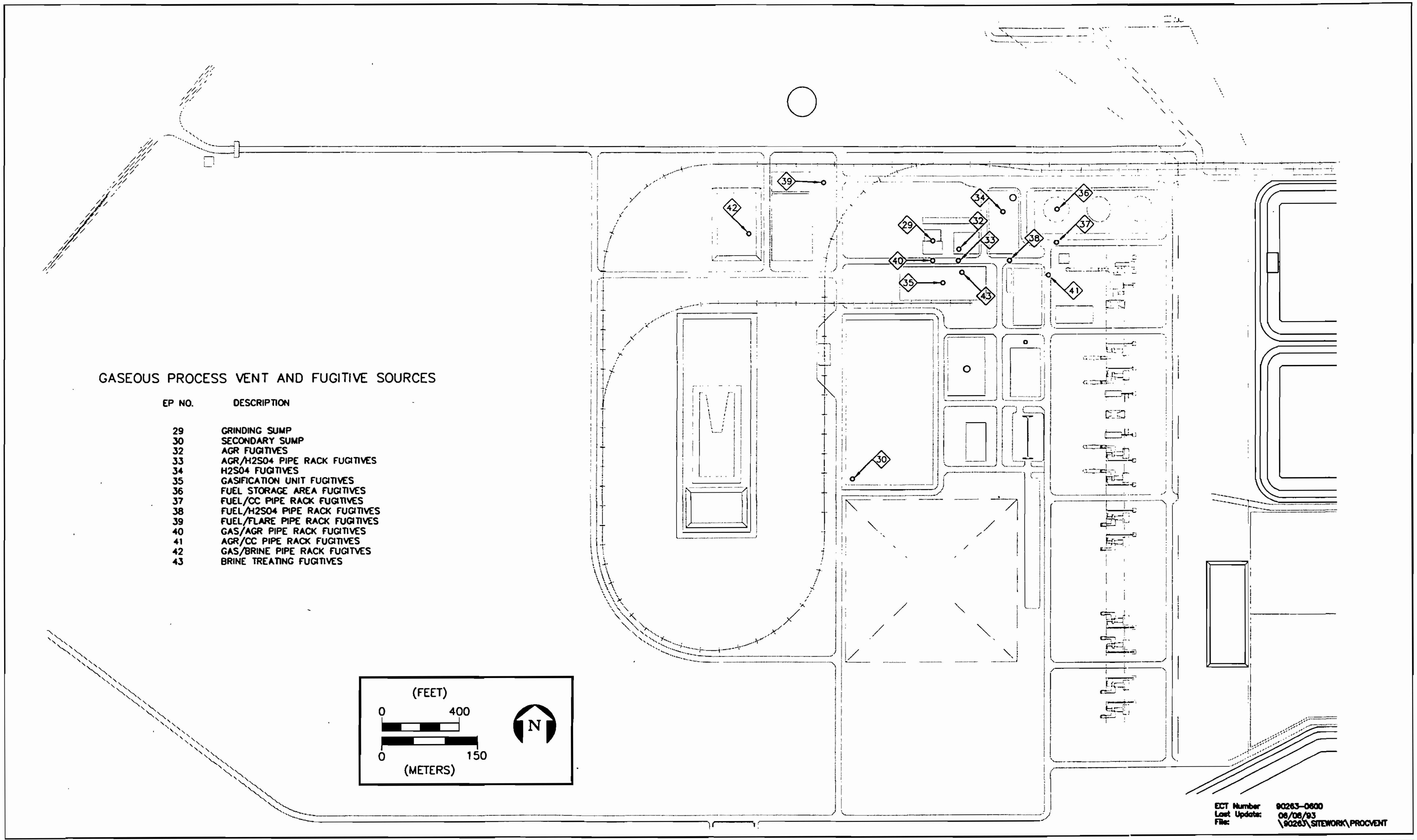

GASEOUS PROCESS VENT AND FUGITIVE SOURCES

EP NO.	DESCRIPTION
29	GRINDING SUMP
30	SECONDARY SUMP
32	AGR FUGITIVES
33	AGR/H2SO4 PIPE RACK FUGITIVES
34	H2SO4 FUGITIVES
35	GASIFICATION UNIT FUGITIVES
36	FUEL STORAGE AREA FUGITIVES
37	FUEL/CC PIPE RACK FUGITIVES
38	FUEL/H2SO4 PIPE RACK FUGITIVES
39	FUEL/FLARE PIPE RACK FUGITIVES
40	GAS/AGR PIPE RACK FUGITIVES
41	AGR/CC PIPE RACK FUGITIVES
42	GAS/BRINE PIPE RACK FUGITVES
43	BRINE TREATING FUGITIVES

FIGURE 2-17.

LOCATION OF GASEOUS PROCESS VENT AND FUGITIVE SOURCES

Source: ECT, 1993.

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2.2 FACILITY EMISSIONS AND STACK PARAMETERS

2.2.1 INTEGRATED COAL GASIFICATION COMBINED CYCLE UNIT

The largest single emissions source in the IGCC unit will be the 7F CT (EPs 1A and 1B). This CT will fire fuel oil during its first year of operation (i.e., as a simple-cycle CT). After its conversion to IGCC, it will fire syngas as the primary fuel. Two syngas cleanup scenarios are possible: 100 percent CGCU, and 50 percent CGCU with 50 percent HGCU. After conversion to IGCC, the 7F CT will fire fuel oil as backup only.

Tables 2-2 through 2-4 provide maximum hourly emission rates for criteria pollutants from the 7F CT. In each table, rates are provided over the expected range of load operations and, for each load, over a range of ambient temperatures. Table 2-2 addresses fuel oil, while Tables 2-3 and 2-4 address the two syngas cleanup scenarios. Tables 2-5 through 2-7 similarly provide maximum estimated emission rates for non-criteria pollutants. The bases for CT emission rates are provided in Appendix A.1. It is noted that non-criteria pollutant emission rates from fuel oil combustion were conservatively based on the highest documented emission factors. However, a degree of uncertainty is associated with these emission factors since they are based on limited data.

Table 2-8 presents maximum annualized emissions from the 7F CT. These emissions are based on the capacity factors for this unit for various configurations and with various fuels. The highest hourly emission rate for each pollutant was used, independent of load and ambient temperature, to produce conservatively high estimates of annualized emissions.

Stack parameters for the 7F in its various configurations, various fuels, and the combinations of load and ambient temperature are provided in Tables 2-9 through 2-12.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures: 7F CT Firing No. 2 Fuel Oil (EPs 1A or 1B)

Unit Load (%)	Ambient Temperature (°F)	TSP/PM$_{10}$*		SO$_2$		NO$_x$		CO		VOC		Lead	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	27	3.40	92	11.60	311	39.22	83	10.47	11	1.39	0.101	0.013
	59	26	3.28	85	10.72	288	36.32	77	9.71	10	1.26	0.094	0.012
	90	25	3.15	78	9.84	264	33.29	71	8.95	9	1.13	0.086	0.011
75	20	25	3.15	75	9.46	254	32.03	61	7.69	11	1.39	0.082	0.010
	59	24	3.03	70	8.83	237	29.89	58	7.31	11	1.39	0.077	0.010
	90	24	3.03	65	8.20	221	27.87	56	7.06	10	1.26	0.072	0.009
50	20	23	2.90	56	7.06	188	23.71	99	12.48	32	4.04	0.061	0.008
	59	23	2.90	52	6.56	177	22.32	93	11.73	28	3.53	0.057	0.007
	90	22	2.77	49	6.18	165	20.81	88	11.10	28	3.53	0.054	0.007

Note: Emission estimates based on following fuel oil properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum FBN of 0.015 weight percent [for FBN levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the FBN allowance contained in 40 CFR 60(GG)].

*Includes H_2SO_4 mist.

Sources: GE, 1992.
ECT, 1992.

Table 2-3. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures: 7F CT Firing Coal Gas with 100 Percent CGCU (EP 1B)

Unit Load (%)	Ambient Temperature (°F)	TSP/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	72	9.08	516	65.07	207	26.10	98	12.36	3	0.38	0.0035	0.0004
	59	72	9.08	518	65.32	213	26.86	87	10.97	3	0.38	0.0035	0.0004
	90	70	8.83	496	62.55	223	28.12	82	10.34	3	0.38	0.0035	0.0004
75	20	60	7.57	405	51.07	163	20.55	80	10.09	2	0.25	0.0028	0.0004
	59	60	7.57	403	50.82	168	21.18	75	9.46	2	0.25	0.0028	0.0004
	90	59	7.44	394	49.68	185	23.33	71	8.95	2	0.25	0.0028	0.0004
50	20	50	6.31	310	39.09	125	15.76	70	8.83	2	0.25	0.0021	0.0003
	59	50	6.31	305	38.46	127	16.01	67	8.45	2	0.25	0.0021	0.0003
	90	48	6.05	294	37.07	132	16.65	65	8.20	2	0.25	0.0021	0.0003

*Includes H_2SO_4 mist.

Sources: Texaco, 1992.
GE, 1992.
ECT, 1992.

Table 2-4. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures: 7F CT Firing Coal Gas with 50 Percent CGCU and 50 Percent HGCU (EP 1B)

Unit Load (%)	Ambient Temperature (°F)	TSP/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	72	9.08	516	65.07	664	83.73	99	12.48	3	0.38	0.023	0.0029
	59	72	9.08	518	65.32	660	83.23	87	10.97	3	0.38	0.023	0.0029
	90	70	8.83	496	62.55	633	79.82	82	10.34	3	0.38	0.023	0.0029
75	20	60	7.57	405	51.07	523	65.95	81	10.21	2	0.25	0.022	0.0028
	59	60	7.57	403	50.82	519	65.45	75	9.46	2	0.25	0.022	0.0028
	90	59	7.44	394	49.68	498	62.80	69	8.70	2	0.25	0.022	0.0028
50	20	50	6.31	310	39.09	401	50.57	71	8.95	2	0.25	0.021	0.0026
	59	50	6.31	305	38.46	394	49.68	68	8.57	2	0.25	0.021	0.0026
	90	48	6.05	294	37.07	374	47.16	64	8.07	2	0.25	0.021	0.0026

*Includes H_2SO_4 mist.

Sources: Texaco, 1992.
GE, 1992.
ECT, 1992.

Table 2-5. Non-Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures: 7F CT Firing No. 2 Fuel Oil (EPs 1A or 1B)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4		Fluorides		Mercury		Beryllium		Arsenic		Cadmium		Chromium	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	9.7	1.2232	0.062	0.0078	0.0057	0.0007	0.0048	0.0006	0.039	0.0049	0.020	0.0025	0.17	0.0214
	59	9.0	1.1349	0.057	0.0072	0.0053	0.0007	0.0044	0.0006	0.035	0.0044	0.019	0.0024	0.16	0.0202
	90	8.2	1.0340	0.053	0.0067	0.0049	0.0006	0.0040	0.0005	0.032	0.0040	0.017	0.0021	0.15	0.0189
75	20	7.8	0.9836	0.051	0.0064	0.0047	0.0006	0.0039	0.0005	0.031	0.0039	0.016	0.0020	0.14	0.0177
	59	7.3	0.9205	0.047	0.0059	0.0044	0.0006	0.0036	0.0005	0.029	0.0037	0.015	0.0019	0.13	0.0164
	90	6.8	0.8575	0.044	0.0055	0.0041	0.0005	0.0034	0.0004	0.027	0.0034	0.014	0.0018	0.12	0.0151
50	20	5.8	0.7314	0.038	0.0048	0.0035	0.0004	0.0029	0.0004	0.024	0.0030	0.012	0.0015	0.10	0.0126
	59	5.5	0.6936	0.035	0.0044	0.0033	0.0004	0.0027	0.0003	0.021	0.0026	0.011	0.0014	0.10	0.0126
	90	5.2	0.6557	0.033	0.0042	0.0030	0.0004	0.0025	0.0003	0.020	0.0025	0.011	0.0014	0.09	0.0113

Sources: Texaco, 1992.
GE, 1992.
ECT, 1992.

Table 2-6. Non-Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures: 7F CT Firing Coal Gas with 100 Percent CGCU (EP 1B)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4		Fluorides		Mercury		Beryllium		Arsenic		Cadmium		Chromium	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	55	6.9355	0.21	0.0265	0.0034	0.0004	0.0001	0.0000	0.0006	0.0001	0.0009	0.0001	0.0004	0.0001
	59	55	6.9355	0.21	0.0265	0.0034	0.0004	0.0001	0.0000	0.0006	0.0001	0.0009	0.0001	0.0004	0.0001
	90	53	6.6833	0.21	0.0265	0.0034	0.0004	0.0001	0.0000	0.0006	0.0001	0.0009	0.0001	0.0004	0.0001
75	20	43	5.4223	0.17	0.0214	0.0027	0.0003	<0.0001	0.0000	0.0005	0.0001	0.0007	0.0001	0.0003	0.0000
	59	43	5.4223	0.17	0.0214	0.0027	0.0003	<0.0001	0.0000	0.0005	0.0001	0.0007	0.0001	0.0003	0.0000
	90	42	5.2962	0.17	0.0214	0.0027	0.0003	<0.0001	0.0000	0.0005	0.0001	0.0007	0.0001	0.0003	0.0000
50	20	33	4.1613	0.13	0.0164	0.0021	0.0003	<0.0001	0.0000	0.0004	0.0001	0.0005	0.0001	0.0002	0.0000
	59	33	4.1613	0.13	0.0164	0.0021	0.0003	<0.0001	0.0000	0.0004	0.0001	0.0005	0.0001	0.0002	0.0000
	90	31	3.9091	0.13	0.0164	0.0021	0.0003	<0.0001	0.0000	0.0004	0.0001	0.0005	0.0001	0.0002	0.0000

Sources: Texaco, 1992.
GE, 1992.
ECT, 1992.

Table 2-7. Non-Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures: 7F CT Firing Coal Gas with 50 Percent CGCU and 50 Percent HGCU (EP 1B)

Unit Load (%)	Ambient Temperature (AF)	H_2SO_4		Fluorides		Mercury		Beryllium		Arsenic		Cadmium		Chromium	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	55	6.9355	0.21	0.0265	0.025	0.0032	0.0001	0.0000	0.080	0.0101	0.020	0.0025	0.0005	0.0001
	59	55	6.9355	0.21	0.0265	0.025	0.0032	0.0001	0.0000	0.080	0.0101	0.020	0.0025	0.0005	0.0001
	90	53	6.6833	0.21	0.0265	0.025	0.0032	0.0001	0.0000	0.080	0.0101	0.020	0.0025	0.0005	0.0001
75	20	43	5.4223	0.17	0.0214	0.024	0.0030	<0.0001	0.0000	0.080	0.0101	0.019	0.0024	0.0003	0.0000
	59	43	5.4223	0.17	0.0214	0.024	0.0030	<0.0001	0.0000	0.080	0.0101	0.019	0.0024	0.0003	0.0000
	90	42	5.2962	0.17	0.0214	0.024	0.0030	<0.0001	0.0000	0.080	0.0101	0.019	0.0024	0.0003	0.0000
50	20	33	4.1613	0.13	0.0164	0.023	0.0029	<0.0001	0.0000	0.080	0.0101	0.019	0.0024	0.0002	0.0000
	59	33	4.1613	0.13	0.0164	0.023	0.0029	<0.0001	0.0000	0.080	0.0101	0.019	0.0024	0.0002	0.0000
	90	31	3.9091	0.13	0.0164	0.023	0.0029	<0.0001	0.0000	0.080	0.0101	0.019	0.0024	0.0002	0.0000

Sources: Texaco, 1992.
GE, 1992.
ECT, 1992.

Table 2-8. Maximum Annualized Emissions from the 7F CT for Various Operating Configurations

Pollutant	Initial Year (EP 1A)*		Demonstration Period 2-yrs. (EP 1B)†		Post-Demonstration Period (EP 1B)**	
	tpy	g/sec	tpy	g/sec	tpy	g/sec
×PM	20.1	0.58	315	9.07	315	9.07
×SO_2	49.1	1.41	2,269	65.35	2,269	65.35
NO_x	164.7	4.74	2,908	83.75	1,044	30.07
CO	86.7	2.50	434	12.50	429	12.36
VOC	28.0	0.81	39.8	1.15	39.8	1.15
H_2SO_4	5.1	0.15	241	6.94	241	6.94
Lead	0.053	0.0015	0.14	0.0040	0.067	0.0019
Fluorides	0.033	0.0010	0.92	0.0265	0.92	0.0265
Mercury	0.0031	0.0001	0.11	0.0032	0.017	0.0005
Beryllium	0.0025	0.0001	0.0029	0.0001	0.0029	0.0001
Arsenic	0.017	0.0005	0.35	0.0101	0.019	0.0005
Cadmium	0.011	0.0003	0.090	0.0026	0.015	0.0004
Chromium	0.088	0.0025	0.090	0.0026	0.090	0.0026

* Based on 10-percent maximum annual capacity factor firing fuel oil.

† Based on baseload operations firing syngas, with a maximum of 8,760 hr/yr utilization of HGCU and up to 10-percent annual capacity factor firing fuel oil.

** Based on baseload operations firing syngas, with emission rates equivalent to 100-percent CGCU operations; up to 10-percent annual capacity factor firing fuel oil.

Source: ECT, 1992.

Table 2-9. Stack Parameters for Three Unit Loads and Three Ambient Temperatures: 7F CT (Simple Cycle) Firing No. 2 Fuel Oil (EP 1A)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	75	22.86	1,027	826	142	43.28	19	5.79
	59	75	22.86	1,068	849	135	41.15	19	5.79
	90	75	22.86	1,108	871	129	39.32	19	5.79
75	20	75	22.86	1,173	907	116	35.36	19	5.79
	59	75	22.86	1,192	918	112	34.14	19	5.79
	90	75	22.86	1,200	922	110	33.53	19	5.79
50	20	75	22.86	986	803	99	30.18	19	5.79
	59	75	22.86	1,023	824	96	29.26	19	5.79
	90	75	22.86	1,051	839	94	28.65	19	5.79

Sources: GE, 1992.
ECT, 1992.

Table 2-10. Stack Parameters for Three Unit Loads and Three Ambient Temperatures: 7F CT (Combined Cycle) Firing No. 2 Fuel Oil (EP 1B)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	150	45.72	352	451	76	23.17	19	5.79
	59	150	45.72	342	445	69	21.03	19	5.79
	90	150	45.72	333	440	63	19.20	19	5.79
75	20	150	45.72	352	451	56	17.07	19	5.79
	59	150	45.72	342	445	53	16.15	19	5.79
	90	150	45.72	333	440	51	15.55	19	5.79
50	20	150	45.72	352	451	55	16.76	19	5.79
	59	150	45.72	342	445	51	15.55	19	5.79
	90	150	45.72	333	440	48	14.63	19	5.79

Sources: GE, 1992.
United Engineers & Constructors, Inc. (ECT), 1992.
ECT, 1992.

Table 2-11. Stack Parameters for Three Unit Loads and Three Ambient Temperatures: 7F CT (Combined Cycle) Firing Coal Gas with 100 Percent CGCU (EP 1B)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	150	45.72	265	403	76	23.17	19	5.79
	59	150	45.72	265	403	68	20.73	19	5.79
	90	150	45.72	265	403	70	21.34	19	5.79
75	20	150	45.72	265	403	59	17.98	19	5.79
	59	150	45.72	265	403	59	17.98	19	5.79
	90	150	45.72	265	403	57	17.37	19	5.79
50	20	150	45.72	265	403	52	15.85	19	5.79
	59	150	45.72	265	403	52	15.85	19	5.79
	90	150	45.72	265	403	51	15.55	19	5.79

Sources: Texaco, 1992.
GE, 1992.
UEC, 1992.
ECT, 1992.

Table 2-12. Stack Parameters for Three Unit Loads and Three Ambient Temperatures: 7F CT (Combined Cycle) Firing Coal Gas with 50 Percent CGCU and 50 Percent HGCU (EP 1B)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	150	45.72	260	400	77	23.47	19	5.79
	59	150	45.72	260	400	69	21.03	19	5.79
	90	150	45.72	260	400	70	21.34	19	5.79
75	20	150	45.72	260	400	63	19.20	19	5.79
	59	150	45.72	260	400	59	17.98	19	5.79
	90	150	45.72	260	400	55	16.76	19	5.79
50	20	150	45.72	260	400	54	16.46	19	5.79
	59	150	45.72	260	400	53	16.15	19	5.79
	90	150	45.72	260	400	51	15.55	19	5.79

Sources: Texaco, 1992.
UEC, 1992.
GE, 1992.
ECT, 1992.

Other combustion emissions sources associated with the IGCC unit are the auxiliary boiler (EP 12), ~~tail gas treating unit thermal oxidizer (EP 13),~~ flare (EP 14), and thermal oxidizer for the H_2SO_4 plant (EP 15)~~, which is associated with HGCU~~. The small [49.5 million British thermal units per hour (MMBtu/hr)] auxiliary boiler will fire low-sulfur distillate fuel oil. Table 2-13 summarizes emissions and stack parameters for this source. Annualized emissions are based on 1,000 hr/yr of operation; this source would normally be expected to operate considerably less. Similarly, Tables 2-14 ~~and 2-15~~ presents data for the ~~tail gas treating unit thermal oxidizer and the~~ H_2SO_4 plant thermal oxidizer~~, respectively~~. Annualized emissions for both of these sources assume continuous operations. All emission rate estimates for the auxiliary boiler~~, thermal oxidizer,~~ and H_2SO_4 plant stack were based on vendor data. The flare's pilot flame will, under normal operations, require only 0.35 MMBtu/hr of fuel oil; emissions will be negligible.

As discussed in Section 2.1.2.2, various activities associated with coal and slag handling will result in PM emissions. Table 2-16 presents estimated maximum PM emission rates and stack or release parameters for these emission points. The derivation of these emission rates is provided in Appendix A.2.

PM will also be emitted from several transfer points and vents within the IGCC unit's gasification processes. Table 2-17 presents the emission and stack parameters for these emission points. The derivation of these emission rates is given in Appendix A.3.

H_2S, NH_3, and CO will be emitted from several points within the IGCC unit as well. Tables 2-18 through 2-20 present the emission and stack parameters for H_2S, NH_3, and CO, respectively. Also shown in Tables 2-18 through 2-20 are fugitive emissions of these three pollutants. These emissions will originate from valves, flanges, pumps, etc. where leaks are possible. The derivation of all H_2S, NH_3, and CO emissions from these sources is presented in Appendix A.4.

Table 2-13. Emissions and Stack Parameters for the Auxiliary Boiler (EP 12)

Pollutant	Short-Term lb/hr	Short-Term g/sec	Annualized* tpy	Annualized* g/sec
Emissions				
PM	3.0	0.38	1.5	0.043
SO_2	2.6	0.33	1.3	0.037
NO_x	7.9	0.99	4.0	0.115
CO	4.3	0.54	2.2	0.063
VOC	2.4	0.30	1.2	0.035
Lead	0.003	0.0004	0.0015	<0.0001

Stack Parameters		
Stack height	20 ft	6.1 m
Stack exit temperature	500°F	533 K
Stack exit velocity	43 ft/sec	13.1 m/sec
Stack diameter	3 ft	0.91 m

Note: lb/hr = pounds per hour.
m = meter.
K = Kelvin.
ft/sec = feet per second.
m/sec = meters per second.

*Annualized emissions based on 1,000 hr/yr of operation.

Sources: Texaco, 1992.
ECT, 1992.

~~Table 2-14. Emissions and Stack Parameters for the Tail Gas Treating Unit Thermal Oxidizer (EP 13)~~

~~Pollutant~~	~~lb/hr~~	~~tpy~~	~~g/sec~~
~~Emissions~~			
~~PM~~	~~13.0~~	~~57~~	~~1.64~~
~~SO_2~~	~~52.0~~	~~228~~	~~6.56~~
~~NO_x~~	~~2.6~~	~~11.4~~	~~0.33~~
~~CO~~	~~1.4~~	~~6.1~~	~~0.18~~
~~VOC~~	~~0.8~~	~~3.5~~	~~0.10~~
~~Lead~~	~~0.002~~	~~0.009~~	~~0.0003~~
~~H_2SO_4~~	~~0~~	~~0~~	~~0~~
~~Fluorides~~	~~0.001~~	~~0.004~~	~~0.0001~~
~~Mercury~~	~~0.002~~	~~0.009~~	~~0.0003~~
~~Beryllium~~	~~0.001~~	~~0.004~~	~~0.0001~~
~~Arsenic~~	~~0.001~~	~~0.004~~	~~0.0001~~
~~Cadmium~~	~~0.001~~	~~0.004~~	~~0.0001~~
~~Chromium~~	~~0.105~~	~~0.46~~	~~0.0132~~
~~H_2S~~	~~0.4~~	~~1.75~~	~~0.05~~
~~Stack Parameters~~			
~~Stack height~~	~~199 ft~~		~~60.7 m~~
~~Stack exit temperature~~	~~1,400°F~~		~~1,033 K~~
~~Stack exit velocity~~	~~35 ft/sec~~		~~10.7 m/sec~~
~~Stack diameter~~	~~4.5 ft~~		~~1.4 m~~

~~Sources: Texaco, 1992.~~
~~ECT, 1992.~~

Table 2-15. Emissions and Stack Parameters for the Sulfuric Acid Plant Thermal Oxidizer (EP 15)

Pollutant	lb/hr	tpy	g/sec
Emissions			
PM	~~2.6~~ 12.8	~~11.4~~ 56.1	~~0.33~~ 1.61
SO_2	~~10.1~~ 45.3	~~44.2~~ 198.4	~~1.27~~ 5.71
NO_x	~~1.14~~ 2.6	~~5.0~~ 11.4	~~0.14~~ 0.33
CO	~~0.61~~ 1.4	~~2.7~~ 6.1	~~0.08~~ 0.18
VOC	~~0.35~~ 0.8	~~1.5~~ 3.5	~~0.04~~ 0.10
Lead	~~0.001~~ 0.002	~~0.004~~ 0.009	~~0.0001~~ 0.0003
H_2SO_4	0	0	0
Fluorides	~~0~~ 0.001	~~0~~ 0.004	~~0~~ 0.0001
Mercury	~~0.001~~ 0.002	~~0.004~~ 0.009	~~0.0001~~ 0.0003
Beryllium	0.001	0.004	0.0001
Arsenic	0.001	0.004	0.0001
Cadmium	0.001	0.004	0.0001
Chromium	~~0.052~~ 0.105	~~0.23~~ 0.46	~~0.0066~~ 0.0132
H_2S	~~0.23~~ 0.4	~~1.0~~ 1.8	~~0.03~~ 0.05

Stack Parameters

Stack height	199 ft	60.7 m
Stack exit temperature	1,400°F	1,033 K
Stack exit velocity	~~30~~ 32 ft/sec	~~9.1~~ 9.8 m/sec
Stack diameter	~~3.5~~ 7.0 ft	~~1.1~~ 2.1 m

Sources: Texaco, 1992.
Bechtel, 1993.
ECT, 199~~2~~3.

Table 2-16. PM Emission Rates and Stack Parameters for Coal Handling Sources

EP Number	Source	Short-Term PM Emission Rate lb/hr	Short-Term PM Emission Rate g/sec	Annualized PM Emission Rate tpy	Annualized PM Emission Rate g/sec	Stack Height ft	Stack Height m	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter m
16	Coal handling baghouse	5.14	0.65	5.14	0.15	50	15.2	Ambient		20.8	6.35	5.5	1.68
17	Coal transfer baghouse	2.14	0.27	2.14	0.06	45	13.7	Ambient		23.1	7.06	3.4	1.03
19	Coal transfer between stacker and stockpile	2.49	0.31	0.40	0.011	35	10.7	Ambient		NA	0.01*	NA	1.0*
20	Reclaim transfer onto conveyor 4	0.64	0.08	0.40	0.011	4	1.2	Ambient		NA	0.01*	NA	1.0*
21	Bulldozer operations on coal stockpile†	3.05	0.38	3.0	0.085	25	7.6	NA		NA	NA	NA	NA
22	Coal pile wind erosion (short-term storage area)†	3.9	0.49	0.01	0.0003	25	7.6	NA		NA	NA	NA	NA
23	Coal pile wind erosion (long-term storage area)†	3.0	0.38	0.09	0.0025	25	7.6	NA		NA	NA	NA	NA

*Point source emission parameters used for modeling a volume source.
†Area source.

Note: EP 18 not used.

Sources: UEC, 1992.
ECT, 1992.

Table 2-17. PM Emission Rates and Stack Parameters for IGCC Process Vent Sources

EP Number	Source	Short-Term PM Emission Rate		Annualized PM Emission Rate		Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		lb/hr	g/sec	tpy	g/sec	ft	m	°F	K	ft/sec	m/sec	ft	m
24	Coal storage bin baghouse	3.8	0.48	5.5	0.16	230	70.1	Ambient		26	7.9	1.9	0.56
25	Grinding tower baghouse	3.4	0.43	5.0	0.14	175	53.3	100	311	0.2	0.06	1.0	0.30
26	Rod mill discharge	1.6	0.20	2.3	0.07	50	15.2	150	339	0.2	0.06	0.7	0.20
27	Air separation unit	100*	12.6*	0.3	0.01	50	15.2	130	327	0.2	0.06	1.0	0.30
28	Filter unit	0.5	0.06	2.2	0.06	50	15.2	100	311	0.6	0.2	0.3	0.10

*Emissions at this rate will occur for only approximately 30 minutes every 4 weeks. For short-term modeling, a 24-hour average emission rate of 2.1 lb/hr (0.26 g/sec) was used.

Sources: Texaco, 1992.
ECT, 1992.

Table 2-18. H_2S Emission Rates and Stack Parameters for IGCC Process Vent and Fugitive Sources

EP Number	Source	Short-Term H_2S Emission Rate		Annualized H_2S Emission Rate		Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		lb/hr	g/sec	tpy	g/sec	ft	m	°F	K	ft/sec	m/sec	ft	m
29	Grinding sump	0.5	0.06	2.1	0.06	15	4.6	100	311	1.1	0.3	0.2	0.05
30	Secondary sump	0.2	0.03	0.04	0.001	2	0.6	100	311	1.1	0.3	0.2	0.05
~~31~~	~~Sulfur pits~~	~~0.5~~	~~0.06~~	~~0.09~~	~~0.003~~	~~1~~	~~0.3~~	~~180~~	~~355~~	~~0.1~~	~~0.02~~	~~1.0~~	~~0.30~~
32	AGR fugitives	0.28	0.04	1.2	0.04	12	3.7	Ambient		NA	0.01*	NA	1.0*
33	AGR/~~SRU H_2SO_4~~ pipe rack fugitives	0.04	0.005	0.2	0.005	20	6.1	Ambient		NA	0.01*	NA	1.0*
34	~~SRU H_2SO_4~~ fugitives	0.08	0.01	0.3	0.01	12	3.7	Ambient		NA	0.01*	NA	1.0*
35	Gasification unit fugitives	0.07	0.009	0.3	0.009	12	3.7	Ambient		NA	0.01*	NA	1.0*
36	Fuel storage area fugitives	0.004	0.0005	0.02	0.0005	5	1.5	Ambient		NA	0.01*	NA	1.0*
37	Fuel/CC pipe rack fugitives	0.007	0.001	0.03	0.001	20	6.1	Ambient		NA	0.01*	NA	1.0*
38	Fuel/~~SRU H_2SO_4~~ pipe rack fugitives	0.002	0.0002	0.01	0.0002	20	6.1	Ambient		NA	0.01*	NA	1.0*
39	Fuel/flare pipe rack fugitives	0.002	0.0002	0.01	0.0002	20	6.1	Ambient		NA	0.01*	NA	1.0*
40	Gas/AGR pipe rack fugitives	0.009	0.001	0.04	0.001	20	6.1	Ambient		NA	0.01*	NA	1.0*
41	AGR/CC pipe rack fugitives	0.009	0.001	0.04	0.001	20	6.1	Ambient		NA	0.01*	NA	1.0*
42	Gas/brine pipe rack fugitives	0.0005	0.0001	0.002	0.0001	20	6.1	Ambient		NA	0.01*	NA	1.0*
43	Brine treating fugitives	0.0005	0.0001	0.002	0.0001	12	3.7	Ambient		NA	0.01*	NA	1.0*

Note: Fugitive emissions are from valves, flanges, etc.

*Point source emission parameters used for modeling an area or volume source.

Sources: Texaco, 1992.
Bechtel, 1993.
ECT, 1992.

Table 2-19. NH_3 Emission Rates and Stack Parameters for IGCC Process Vent and Fugitive Sources

EP Number	Source	Short-Term NH_3 Emission Rate lb/hr	g/sec	Annualized NH_3 Emission Rate tpy	g/sec	Stack Height ft	m	Stack Exit Temperature °F	K	Stack Exit Velocity ft/sec	m/sec	Stack Diameter ft	m
32	AGR fugitives	0.001	0.0002	0.005	0.0002	12	3.7	Ambient		NA	0.01*	NA	1.0*
35	Gasification unit fugitives	0.01	0.001	0.05	0.001	12	3.7	Ambient		NA	0.01*	NA	1.0*
40	Gas/AGR pipe rack fugitives	0.001	0.0002	0.005	0.0002	20	6.1	Ambient		NA	0.01*	NA	1.0*
41	AGR/CC pipe rack fugitives	0.001	0.0002	0.005	0.0002	20	6.1	Ambient		NA	0.01*	NA	1.0*
42	Gas/brine pipe rack fugitives	0.0005	0.0001	0.002	0.0001	20	6.1	Ambient		NA	0.01*	NA	1.0*
43	Brine treating fugitives	0.0005	0.0001	0.002	0.0001	12	3.7	Ambient		NA	0.01*	NA	1.0*
44	Mill discharge tank vents	19	2.40	3.5	0.10	10	3.0	140	333	0.8	0.2	0.2	0.05
45	Slurry tank vents	19	2.40	3.5	0.10	75	22.9	140	333	0.4	0.1	0.3	0.10
46	Deaerator vent	13	1.64	2.4	0.07	25	7.6	290	416	0.4	0.1	0.3	0.08

Note: Fugitive emissions are from valves, flanges, etc.

*Point source emission parameters used for modeling an area or volume source.

Sources: Texaco, 1992.
ECT, 1992.

Table 2-20. CO Emission Rates and Stack Parameters for IGCC Fugitive Sources

EP Number	Source	Short-Term CO Emission Rate		Annualized CO Emission Rate		Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		lb/hr	g/sec	tpy	g/sec	ft	m	°F	K	ft/sec	m/sec	ft	m
32	AGR fugitives	0.28	0.04	1.23	0.04	12	3.7	Ambient		NA	0.01*	NA	1.0*
33	AGR/~~SRU H_2SO_4~~ pipe rack fugitives	negl.	negl.	negl.	negl.	20	6.1	Ambient		NA	0.01*	NA	1.0*
34	~~SRU H_2SO_4~~ fugitives	negl.	negl.	negl.	negl.	12	3.7	Ambient		NA	0.01*	NA	1.0*
35	Gasification unit fugitives	1.69	0.2	7.4	0.2	12	3.7	Ambient		NA	0.01*	NA	1.0*
40	Gas/AGR pipe rack fugitives	0.28	0.04	1.22	0.04	20	6.1	Ambient		NA	0.01*	NA	1.0*
41	AGR/CC pipe rack fugitives	0.28	0.04	1.22	0.04	20	6.1	Ambient		NA	0.01*	NA	1.0*
42	Gas/brine pipe rack fugitives	0.0005	0.0001	0.002	0.0001	20	6.1	Ambient		NA	0.01*	NA	1.0*
43	Brine treating fugitives	0.0005	0.0001	0.002	0.0001	12	3.7	Ambient		NA	0.01*	NA	1.0*

Note: Fugitive emissions are from valves, flanges, etc.
negl. = negligible.

*Point source emission parameters used for modeling an area or volume source.

Sources: Texaco, 1992.
Bechtel, 1993.
ECT, 1992.

2.2.2 STAND-ALONE COMBINED CYCLE UNITS AND COMBUSTION TURBINES

Tables 2-21 and 2-22 provide maximum hourly criteria pollutant emission rates from individual CTs (based on GE 7EA machines) firing natural gas and distillate fuel oil, respectively. Emissions from the CTs will be the same in both simple-cycle and CC modes. Similarly, Tables 2-23 and 2-24 give non-criteria pollutant emission rates for the two fuels. The derivation of these emission rates is provided in Appendix A.5.

Table 2-25 presents maximum annualized emissions from an individual CT. The utilization rates for the CTs for the two configurations and two fuels provided the basis for these emissions. The highest hourly emission rate for each pollutant was used, independent of load and ambient temperature, to produce conservatively high estimates of annualized emissions.

Stack parameters for the CTs in their two configurations, their two fuels, and the combinations of load and ambient temperature are provided in Tables 2-26 through 2-29.

Table 2-21. Maximum Criteria Pollutant Emission Rates for Two Unit Loads and Three Ambient Temperatures: CT Firing Natural Gas (EPs 2A through 5A or 2B through 5B, and EPs 6 through 11)

Unit Load (%)	Ambient Temperature (°F)	TSP/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	11	1.39	36	4.54	35	4.41	59	7.44	10	1.26	0.0	0.00
	59	10	1.26	33	4.16	33	4.16	54	6.81	9	1.13	0.0	0.00
	90	10	1.26	30	3.78	30	3.78	49	6.18	9	1.13	0.0	0.00
75	20	10	1.26	29	3.66	29	3.66	45	5.67	8	1.01	0.0	0.00
	59	10	1.26	26	3.28	26	3.28	42	5.30	7	0.88	0.0	0.00
	90	10	1.26	24	3.03	24	3.03	39	4.92	7	0.88	0.0	0.00

*Includes H_2SO_4 mist.

Sources: GE, 1992.
ECT, 1992.

Table 2-22. Maximum Criteria Pollutant Emission Rates for Two Unit Loads and Three Ambient Temperatures: CT Firing No. 2 Fuel Oil(EPs 2A through 5A or 2B through 5B, and EPs 6 through 11)

Unit Load (%)	Ambient Temperature (°F)	TSP/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	21	2.65	53	6.68	181	22.82	71	8.95	10	1.26	0.059	0.0074
	59	20	2.52	48	6.05	163	20.55	65	8.20	9	1.13	0.053	0.0067
	90	20	2.52	43	5.42	148	18.66	59	7.44	9	1.13	0.048	0.0061
75	20	20	2.52	42	5.30	145	18.28	54	6.81	8	1.01	0.048	0.0061
	59	19	2.40	38	4.79	131	16.52	50	6.31	7	0.88	0.043	0.0054
	90	19	2.40	35	4.41	120	15.13	47	5.93	7	0.88	0.039	0.0049

Note: Emission estimates based on following fuel oil properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum FBN of 0.015 weight percent [for FBN levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the FBN allowance contained in 40 CFR 60(GG)].

*Includes H_2SO_4 mist.

Sources: GE, 1992.
ECT, 1992.

Table 2-23. Non-Criteria Pollutant Emission Rates for Two Unit Loads and Three Ambient Temperatures: CT Firing Natural Gas (EPs 2A through 5A or 2B through 5B, and EPs 6 through 11)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4		Hg	
		lb/hr	g/sec	lb/hr	g/sec
100	20	4	0.5044	0.012	0.0015
	59	3	0.3783	0.011	0.0014
	90	3	0.3783	0.010	0.0013
75	20	3	0.3783	0.010	0.0013
	59	3	0.3783	0.009	0.0011
	90	3	0.3783	0.008	0.0010

Sources: GE, 1992.
ECT, 1992.

Table 2-24. Non-Criteria Pollutant Emission Rate for Two Unit Loads and Three Ambient Temperatures: CT Firing No. 2 Fuel Oil (EPs 2A through 5A or 2B through 5B, and EPs 6 through 11)

Unit Load (%)	Ambient Temperature (AF)	H_2SO_4		Fluorides		Mercury		Beryllium		Arsenic		Cadmium		Chromium	
		lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
100	20	6	0.7566	0.036	0.0045	0.0033	0.0004	0.0028	0.0004	0.022	0.0028	0.012	0.0015	0.10	0.0126
	59	5	0.6305	0.033	0.0042	0.0030	0.0004	0.0025	0.0003	0.020	0.0025	0.011	0.0014	0.09	0.0113
	90	5	0.6305	0.029	0.0037	0.0027	0.0003	0.0023	0.0003	0.019	0.0024	0.010	0.0013	0.08	0.0101
75	20	5	0.6305	0.029	0.0037	0.0027	0.0003	0.0022	0.0003	0.017	0.0021	0.009	0.0011	0.08	0.0101
	59	4	0.5044	0.026	0.0033	0.0024	0.0003	0.0020	0.0003	0.016	0.0020	0.009	0.0011	0.07	0.0088
	90	4	0.5044	0.024	0.0030	0.0022	0.0003	0.0019	0.0002	0.015	0.0019	0.008	0.0010	0.07	0.0088

Sources: GE, 1992.
ECT, 1992.

Table 2-25. Maximum Annualized Emissions from Individual CTs in Simple-Cycle and CC Modes

Pollutant	Simple-Cycle* tpy	Simple-Cycle* g/sec	CC† tpy	CC† g/sec
PM	41	1.18	65	1.87
SO_2	109	3.14	180	5.18
NO_x	169	4.87	327	9.42
CO	163	4.69	273	7.86
VOC	28	0.81	45	1.30
H_2SO_4	12	0.35	20	0.58
Lead	0.028	0.0008	0.070	0.0020
Fluorides	0.017	0.0005	0.042	0.0012
Mercury	0.031	0.0009	0.053	0.0015
Beryllium	0.0013	0.0000	0.0032	0.0001
Arsenic	0.010	0.0003	0.025	0.0007
Cadmium	0.0053	0.0002	0.013	0.0004
Chromium	0.046	0.0013	0.12	0.0035

*Based on maximum annual capacity factors firing natural gas and fuel oil of 50 and 10 percent, respectively.

†Based on maximum annual capacity factors firing natural gas and fuel oil of 100 and 25 percent, respectively.

Source: ECT, 1992.

Table 2-26. Stack Parameters for Two Unit Loads and Three Ambient Temperatures: CT (Simple Cycle or Bypass) Firing Natural Gas (EPs 2A through 5A and EPs 6 through 11)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	75	22.86	959	788	101	30.79	18	5.49
	59	75	22.86	985	803	94	28.65	18	5.49
	90	75	22.86	1,007	815	88	26.82	18	5.49
75	20	75	22.86	1,025	825	81	24.69	18	5.49
	59	75	22.86	1,040	833	76	23.17	18	5.49
	90	75	22.86	1,053	840	73	22.25	18	5.49

Sources: GE, 1992.
ECT, 1992.

Table 2-27. Stack Parameters for Two Unit Loads and Three Ambient Temperatures: CT (Simple Cycle or Bypass) Firing No. 2 Fuel Oil (EPs 2A through 5A and EPs 6 through 11)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	75	22.86	953	785	103	31.39	18	5.49
	59	75	22.86	980	800	96	29.26	18	5.49
	90	75	22.86	1,002	812	90	27.43	18	5.49
75	20	75	22.86	1,021	823	82	24.99	18	5.49
	59	75	22.86	1,037	832	78	23.77	18	5.49
	90	75	22.86	1,049	838	74	22.56	18	5.49

Sources: GE, 1992.
ECT, 1992.

Table 2-28. Stack Parameters for Two Unit Loads and Three Ambient Temperatures: CT (Combined Cycle) Firing Natural Gas (EPs 2B through 5B)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	150	45.72	257	398	79	24.08	14.5	4.42
	59	150	45.72	253	396	72	21.95	14.5	4.42
	90	150	45.72	251	395	67	20.42	14.5	4.42
75	20	150	45.72	248	393	59	17.98	14.5	4.42
	59	150	45.72	245	391	56	17.07	14.5	4.42
	90	150	45.72	244	391	53	16.15	14.5	4.42

Sources: GE, 1992.
UEC, 1992.
ECT, 1992.

Table 2-29. Stack Parameters for Two Unit Loads and Three Ambient Temperatures: CT (Combined Cycle) Firing No. 2 Fuel Oil (EPs 2B through 5B)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	150	45.72	253	396	80	24.38	14.5	4.42
	59	150	45.72	249	394	73	22.25	14.5	4.42
	90	150	45.72	248	393	67	20.42	14.5	4.42
75	20	150	45.72	246	392	61	18.59	14.5	4.42
	59	150	45.72	244	391	57	17.37	14.5	4.42
	90	150	45.72	241	389	53	16.15	14.5	4.42

Sources: GE, 1992.
UEC, 1992.
ECT, 1992.

3.0 AIR QUALITY STANDARDS AND REVIEW REQUIREMENTS AND THEIR APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act Amendments (CAA), the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary national AAQS for six air pollutants [40 Code of Federal Regulations (CFR) 50]. Primary national AAQS are intended to protect the public health, and secondary national AAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. FDER has also adopted AAQS (Chapter 17-2.300, F.A.C.). The existing national and Florida AAQS are presented in Table 3-1. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal PSD review requirements, all major new or modified sources of air pollutants regulated under CAA must be reviewed and approved by EPA or by the state agency if PSD review authority has been delegated, as is the case in Florida. A *major stationary source* is defined as any 1 of 28 named source categories that has the potential to emit 100 tpy or more, or any other stationary source that has the potential to emit 250 tpy or more, of any pollutant regulated under CAA. *Potential to emit* means the capability at maximum design capacity to emit a pollutant after the application of control equipment.

Major modification means any physical change in the design or operation of a major stationary source, or a series of contemporaneous changes in the design or operation of a major stationary source, that would result in a significant net emission increase of any pollutant regulated under CAA. *Significant* is defined as any increase in emissions in excess of specified levels in Table 3-2.

Table 3-1. National and Florida AAQS ($\mu g/m^3$)

Pollutant	Averaging Time	National AAQS Primary	National AAQS Secondary	Florida AAQS
PM_{10}	Annual arithmetic mean*	50	50	50
	24-hour maximum†	150	150	150
SO_2	Annual arithmetic mean	80	NA	60
	24-hour maximum**	365	NA	260
	3-hour maximum**	NA	1,300	1,300
NO_2	Annual arithmetic mean	100	100	100
CO	8-hour maximum**	10,000	NA	10,000
	1-hour maximum**	40,000	NA	40,000
Ozone	1-hour maximum††	235	235	235
Lead	Calendar quarter arithmetic mean	1.5	1.5	1.5

Note: $\mu g/m^3$ = micrograms per cubic meter.

* Achieved when the expected annual arithmetic mean is less than or equal to the standard.

† Achieved when the expected number of days per calendar year with concentrations above the standard is equal to or less than one.

** Maximum concentration not to be exceeded more than once per year.

†† The ozone standard is attained when the expected number of days per calendar year with a maximum hourly average concentration above the standard is equal to or less than one.

Sources: 40 CFR 50.
Chapter 17-2.300, F.A.C.

Table 3-2. Significant Emission Rates for PSD Review

Pollutant	Emission Rate (tpy)	Emission Rate (lb/yr)
CO	100	
NO_x	40	
SO_2	40	
Ozone	40 (as VOC)	
PM (TSP)	25	
PM (PM_{10})	15	
Total reduced sulfur (including H_2S)	10	
Reduced sulfur compounds (including H_2S)	10	
Sulfuric acid mist	7	
Fluorides	3	
Vinyl chloride	1	
Lead		1,200
Mercury		200
Asbestos		14
Beryllium		0.8

Source: Chapter 17-2.500, F.A.C.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. PSD review requirements are contained in Chapter 17-2.500, F.A.C., Prevention of Significant Deterioration. Major sources may be required to undergo the following reviews related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Air quality analysis (monitoring),
3. Source impact analysis,
4. Source information, and
5. Additional impact analyses.

The control technology review includes determination of BACT for each applicable pollutant. BACT emission limits cannot exceed applicable emission standards [e.g., new source performance standards (NSPS)]. The air quality analysis (monitoring) portion of PSD review may require continuous ambient air monitoring data to be collected in the impact area of the proposed source. The source impact analysis requires demonstration of compliance with federal and state AAQS and allowable PSD increment limitations. Projected ambient impacts on designated nonattainment areas and federally promulgated Class I PSD areas must also be addressed, if applicable. Source information, including process design parameters and control equipment information, must be submitted to the reviewing agencies. Additional analyses of the proposed source's impact on soils, vegetation, and visibility, especially pertaining to Class I PSD areas, must be performed, as well as analysis of impacts due to growth in the area associated with the proposed source.

The following sections discuss in more detail the requirements for a PSD review, focusing on those relevant to the proposed project.

3.2.2 CONTROL TECHNOLOGY REVIEW

An analysis of BACT is required for each pollutant which is emitted in excess of the PSD significant emission rates listed in Table 3-2. All emission units involved in a major modification or a new major source that emit or increase emissions of the applicable pollutants must undergo BACT analysis. Since each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

BACT is defined as an emissions limitation based on the maximum degree of reduction of each pollutant subject to regulation which the administrative authority, on a case-by-case basis, determines if it is achievable. The BACT determination takes into account energy, environmental, economic, and other costs, as well as technical feasibility. BACT limitations must not exceed any applicable federal or state NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP), or any other emission limitation established by state regulations.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment, specific production processes, methods, systems or techniques, fuel cleaning, or combustion techniques.

BACT analyses must now be conducted using the *top-down* analysis approach, which was outlined in a December 1, 1987, memorandum from Craig Potter, EPA Assistant Administrator, to EPA Regional Administrators on the subject of "Improving New Source Review (NSR) Implementation." In the top-down methodology, available control technology alternatives are identified based on knowledge of the particular industry of the applicant and previous control technology permitting decisions for other identical or similar sources. These alternatives are rank ordered by stringency into a control technology hierarchy. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts, and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is not applicable, or if it is technically or economically infeasible, it is rejected as BACT, and the next most stringent alternative is then considered. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the pollutant in question emitted from the particular facility under consideration.

3.2.3 AIR QUALITY ANALYSIS

In accordance with the PSD requirements, any application for a PSD permit must contain, for each pollutant subject to review, an analysis of continuous ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those that the source would potentially emit in significant amounts.

Ambient air monitoring for a period of up to 1 year generally is appropriate to complete the PSD requirements. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided by EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (1987a).

The regulations provide an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that the Administrator may exempt a proposed major stationary source or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-3. Furthermore, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the *de minimis* levels.

3.2.4 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The PSD regulations specifically require the use of

Table 3-3. PSD *De Minimis* Impact Levels

Averaging Time	Pollutant	*De Minimis* Air Quality Impact ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	Vinyl chloride	15
	SO_2	13
	TSP	10
	Fluorides	0.25
	Mercury	0.25
	Beryllium	0.001
8-Hour	CO	575
1-Hour	H_2S	0.2
--	Ozone	100 tpy of VOC emissions

Source: Chapter 17-2.500, F.A.C.

atmospheric dispersion models in performing the impact analysis, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models must normally be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication, "Guideline on Air Quality Models (Revised)" (1986). Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate significance level, as presented in Table 3-4.

Ozone is one pollutant for which a source impact analysis, previously described, is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas. The "Guideline on Air Quality Models (Revised)" does not recommend any model to address the impacts of an isolated source located outside an urban area.

Various lengths of record for meteorological data can be utilized for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the second-highest short-term concentrations for comparison to AAQS or PSD increments. The term *highest, second-highest* (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality *baseline concentration* level of SO_2 and TSP concentrations would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based

Table 3-4. Significant Impact Levels for Criteria Pollutants

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	1
	24-Hour	5
	3-Hour	25
PM	Annual	1
	24-Hour	5
NO_2	Annual	1
CO	8-Hour	500
	1-Hour	2,000

Source: Chapter 17-2.100(193), F.A.C.

on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I [international parks, national wilderness areas, and memorial parks larger than 2,024 hectares (ha) (5,000 acres), and national parks larger than 2,428 ha (6,000 acres)] or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations. FDER has adopted the EPA class designations and allowable PSD increments (see Table 3-5).

On October 17, 1988, EPA promulgated PSD increments for nitrogen dioxide (NO_2); the effective date of the new regulation was October 17, 1989. However, the baseline date for NO_2 increment consumption was set at February 8, 1988; new major sources or modifications constructed after this date will consume NO_2 increment. States with current state implementation plan-approved PSD programs were required to revise their PSD rules to include the NO_2 increments by July 17, 1989. The NO_2 PSD increments are shown in Table 3-5.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes an imaginary concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and shall include:

1. The actual emissions representative of sources in existence on the applicable minor source baseline date; and
2. The allowable emissions of major stationary sources which commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

Table 3-5. PSD Allowable Increments ($\mu g/m^3$)

Pollutant	Averaging Time	Class I	Class II	Class III
PM (TSP)	Annual geometric mean	5	19	37
	24-hour maximum*	10	37	75
SO_2	Annual arithmetic mean	2	20	40
	24-hour maximum*	5	91	182
	3-hour maximum*	25	512	700
NO_2	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year.

Source: Chapter 17-2.310, F.A.C.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s) (allowed increment consumption):

1. Actual emissions from any major stationary source on which construction commenced after the major source baseline date, and
2. Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

Major source baseline date means January 6, 1975, for PM (TSP) and SO_2, and February 8, 1988, for NO_2. *Minor source baseline date* means the earliest date after the trigger date, on which the first complete application under 40 CFR 52.21 was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21. The trigger dates are August 7, 1977, for PM (TSP) and SO_2; February 8, 1988, for NO_2.

3.2.5 ADDITIONAL IMPACT ANALYSES

The PSD regulations require additional impact analyses for three areas: (1) associated growth, (2) soils and vegetation impact, and (3) visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes: (1) a projection of the associated industrial, commercial, and residential growth that will occur in the area; (2) an estimate of the air pollution emissions generated by the permanent associated growth; and (3) an air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the national AAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project.

3.3 AIR TOXICS ASSESSMENTS

FDER has developed a strategy to control toxic emissions from stationary sources so that these emissions will not endanger public health. The strategy is based on comparing the predicted ambient impact of individual toxic air contaminants with an estimate of each chemical's *no-threat level.* A no-threat level is an ambient exposure level that is not likely to cause appreciable health risks.

Determining the concentrations at which toxic chemicals will not cause potential health effects requires the use of theoretical procedures to estimate the thresholds where human health effects or significant cancer risks may occur since these levels are rarely known. Because of the protective nature of regulatory agencies, the assumptions used to calculate the no-threat levels are intentionally conservative. It is unlikely that public health effects will occur if an ambient concentration approaches the no-threat level, because an ample margin of safety is incorporated in developing the no-threat levels. This conservative bias is added to protect the public from the possible additive or synergistic effects from simultaneous exposures to multiple toxic air contaminants, and from additional exposures to the same toxics through other environmental pathways. The Florida Air Toxics Working Group, composed of FDER and local county air toxics staff, developed the list of no-threat levels, which were based on the best science available to the working group at the time the strategy was drafted.

The purpose of this strategy is to provide a screening evaluation procedure for source emissions and air permit applications. By using a conservative approach, the strategy allows permit applications for sources which do not emit significant concentrations of air toxics to be reviewed more quickly than source applicants, which, because of the quantity or toxicity of their emission, require a more detailed review. Source applicants whose emissions fail to meet a no-threat level may use a number of options to lessen their source's impact or they may provide more detailed assurances that the predicted impact will not endanger public health.

Another air toxics assessment involves the estimation of cancer risk due to inhalation of emissions from a proposed facility. The metals arsenic, beryllium, cadmium, and chromium (hexavalent) are of primary interest in such an analysis since these constituents, which are emitted as a result of the combustion of most fossil fuels, are known or suspected carcinogens.

An inhalation cancer risk assessment is also conducted using conservative procedures and assumptions. While there is some uncertainty in the pollutant-specific risk factors, for example, in general the methodology tends to overestimate risk. One key assumption associated with an inhalation cancer risk assessment is that people live in the same location for 70 years, exposed to the predicted annual average pollutant concentration during this time. This can be considered conservative because few people tend to live in the same location for 70 years, few power plants operate continuously for 70 years, and emissions from an outdoor source do not always penetrate to a large degree to the indoors, where most people spend a significant portion of their time.

3.4 APPLICABILITY TO THE PROPOSED PROJECT

As specified in Part IV of Chapter 17-2, F.A.C., all of Polk County is classified as attainment for all criteria pollutants. Therefore, Polk Power Station is subject to the new source review requirements appropriate to attainment areas.

Nearby Hillsborough County is classified as nonattainment for ozone, and Polk Power Station is located within the *area of influence* for this nonattainment area. An area of influence includes any point within 50 kilometers of the boundary of a nonattainment area [see Chapter 17-2.100(18), F.A.C.]. However, sources of VOC emissions that are located within an area of influence of an ozone nonattainment area are exempt from nonattainment review, per Chapter 17-2.510(2)(a)2.a., F.A.C. Therefore, Polk Power Station is exempt from ozone nonattainment review.

A portion of Hillsborough County is also classified as an air quality maintenance area for PM. Polk Power Station is within the area of influence of this PM maintenance area. However, Polk Power Station would be subject to the applicable review provisions only if PM emissions from the facility would have a significant impact at the maintenance area.

Regarding PSD review, Polk Power Station constitutes a major facility since it will have the potential to emit more than 250 tpy of at least one pollutant. Therefore, the facility must undergo PSD review. Furthermore, more than one pollutant is subject to review. Table 3-6 summarizes the facility's proposed annual emissions, which were presented in Section 2.2, and compares the projected totals to the significant emission rate thresholds for PSD review.

Polk Power Station will emit quantities of pollutants addressed in FDER's air toxics review strategy. Therefore, an analysis of the facility's impacts compared to the no-threat levels applies. In addition, a conservative analysis of inhalation cancer risks was considered appropriate since Polk Power Station will emit trace metals that are known or suspected carcinogens. There is no regulatory standard or formal review requirement for this analysis, however.

Table 3-6. Projected Emissions Compared to PSD Significance Rates

	Projected Maximum Annual Emissions (tpy)				Significance Rate (tpy)	Subject to PSD Review?
Pollutant	IGCC*	+ CCs†	+ CTs**	= Total		
PM (TSP)	~~411~~ 399	260	246	~~917~~ 905	25	Yes
PM (PM_{10})	~~411~~ 399	260	246	~~917~~ 905	15	Yes
SO_2	~~2,543~~ 2,469	720	654	~~3,917~~ 3,843	40	Yes
NO_x	~~2,928~~ 2,923	1,308	1,014	~~5,250~~ 5,245	40	Yes
CO	~~456~~ 453	1,092	978	~~2,526~~ 2,523	100	Yes
Ozone/VOC	~~46~~ 45	180	168	~~394~~ 393	40	Yes
Lead	0.15	0.28	0.17	0.6	0.6	Yes
H_2SO_4	241	80	72	393	7	Yes
Fluorides	0.92	0.17	0.10	1.2	3	No
Mercury	0.12	0.21	0.19	0.5	0.1	Yes
Beryllium	~~0.011~~ 0.007	0.013	0.008	0.03	0.0004	Yes
Total reduced sulfur (including H_2S)	~~7.1~~ 6.2	0	0	~~7.1~~ 6.2	10	No
Reduced sulfur compounds (including H_2S)	~~7.1~~ 6.2	0	0	~~7.1~~ 6.2	10	No
Vinyl chloride	0	0	0	0	1	No
Asbestos	0	0	0	0	0.007	No

* IGCC emissions include the highest annual emissions estimates from the 7F CT (based on the larger of 100 percent CGCU or 50/50 CGCU/HGCU), plus related combustion emissions (e.g., thermal oxidizer), plus other associated process and fugitive emissions (PM, CO, VOC, and H_2S).

† CC emissions represent the totals for four stand-alone CTs in CC mode.

** CT emissions represent the totals for six stand-alone CTs in simple-cycle mode.

Source: Bechtel, 1993.
ECT, 199~~2~~3.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSES

4.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA *top-down* method as previously described in Section 3.2.2. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information which were used to identify control alternatives include:

- EPA BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse via the BACT/LAER Information System (BLIS) computer database;
- EPA NSR bulletin board;
- EPA Control Technology Center (CTC) bulletin board;
- Recent FDER BACT determinations for similar facilities;
- Vendor information; and
- Environmental Consulting & Technology, Inc. (ECT) experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the EPA NSR Workshop Manual (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

Assessment of energy, environmental, and economic impacts is then performed. Economic analysis employed procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1990b). Specific factors used in estimating capital and annual operating costs are summarized in Table 4-1.

Table 4-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Capital Costs--Direct Installation	
Foundations and supports	0.08 x purchased equipment cost
Handling and erection	0.14 x purchased equipment cost
Electrical	0.04 x purchased equipment cost
Piping	0.02 x purchased equipment cost
Insulation	0.01 x purchased equipment cost
Painting	0.01 x purchased equipment cost
Capital Costs--Indirect Installation	
Engineering	0.10 x purchased equipment cost
Construction and field expenses	0.05 x purchased equipment cost
Contractor fees	0.10 x purchased equipment cost
Start-up	0.02 x purchased equipment cost
Performance testing	0.01 x purchased equipment cost
Contingencies	0.25 x purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 x total operator labor cost
Maintenance labor	1.10 x operator labor direct wage
Maintenance materials	1.00 x total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 x total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 x total capital investment
Property taxes	0.01 x total capital investment
Insurance	0.01 x total capital investment

Note: Purchased equipment cost includes all basic and auxiliary equipment, instrumentation, sales taxes, and freight.

Source: EPA, 1990b.

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds. Control technology analyses using the five step top-down BACT method are provided in Sections 4.3, 4.4, and 4.5 for combustion products, products of incomplete combustion, and acid gases, respectively. BACT is discussed separately for: (a) the IGCC facility, and (b) the stand-alone CC units and CTs since these emission sources are two distinct processes with differing available control technologies.

One simple-cycle CT fired with low sulfur distillate fuel oil will be used during the first year of Polk Power Station operation prior to the installation of gasification facilities. Use of the simple-cycle CT will be infrequent--annual capacity factor is a maximum of 10 percent. The simple-cycle CT will subsequently be incorporated into the IGCC facility during the second year of operations. Proposed BACT emission limits are included for the IGCC CT for its initial, first year of operation in simple-cycle mode using distillate fuel oil.

The IGCC facility design includes provisions for a two year demonstration of HGCU technology. If proven successful, HGCU offers significant improvement in overall IGCC efficiency as well as the potential for substantially lower SO_2 emissions in comparison to conventional CGCU controls. During the 2-year demonstration period, up to 50 percent of the syngas produced by the gasification process will be processed by the HGCU treatment system and the remaining by conventional CGCU technology. The IGCC CT will, therefore, receive up to a 50/50 mixture of HGCU and CGCU processed syngas during the demonstration period. The HGCU portion of the Polk Power Station IGCC project is designed to demonstrate a specific process for application to CG and therefore is not amenable to a BACT analysis. For completeness, a discussion of control technologies and expected emissions from the HGCU process is included in the IGCC BACT analysis.

but higher NO_x emission

The HGCU demonstration technology has the potential to achieve significantly greater reductions in SO_2 emissions in comparison to conventional CGCU technology and increase the overall efficiency of the IGCC process. Overall HGCU sulfur recovery, at a minimum, will equal that of CGCU. HGCU technology is also expected to generate higher NO_x and heavy metal emissions compared to CGCU. The purpose of the 2-year demonstration period is to demonstrate the technical and commercial viability of the HGCU technology by determining overall system performance with respect to emissions and operability. Following the 2-year demonstration period, Tampa Electric Company will review the performance and economic data and decide whether the system is technologically and economically viable. If HGCU is found to be viable, Tampa Electric Company may elect to modify, if necessary, and continue operation of the HGCU system on the basis that emission rates using HGCU will be equivalent or less than those achieved by conventional CGCU for all regulated pollutants. If HGCU is not found to be technologically or economically viable, the system will be shut down and the Polk Power Station IGCC unit will operate using 100 percent CGCU.

NO_x emissions 3X

The stand-alone CC units and CTs will be installed in phases over an 11-year period beginning in 1999. A detailed BACT analysis is provided for these units at this time with the understanding that the BACT determination will need to be reviewed and modified, as appropriate, no later than 18 months prior to actual construction of the future units.

4.2 FEDERAL AND STATE EMISSION STANDARDS

BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAP (40 CFR 61), and state emission standards (Chapter 17-2, Part VI; Emission Limiting and Performance Standards, F.A.C.).

4.2.1 INTEGRATED COAL GASIFICATION COMBINED CYCLE FACILITY

On the federal level, there are no NSPS or NESHAP that would apply to the air separation unit, CG, sulfur removal and recovery, or HRSG sections of the IGCC facility.

40 CFR 60 Subpart Y applies to coal preparation plants which process more than 200 tons per day of coal. Coal preparation plants are defined in Subpart Y to include "any facility which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying". The Polk Power Station IGCC coal grinding and slurry preparation process is subject to the emission limitations of 40 CFR 60, Subpart Y, § 60.252(c) since this process grinds coal in a rod-mill at rates above 200 tons per day. 40 CFR 60, Subpart Y, § 60.252(c) establishes an opacity limitation (less than 20 percent) for coal processing and conveying equipment, coal storage (excluding open storage piles), and coal transfer and loading systems associated with the coal preparation process.

The CT employed to produce power from the combustion of coal-derived syngas may be subject to NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the lower heating value (LHV) of the fuel,
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV, and
- Stationary gas turbines with a manufacturer's rated baseload at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines which sell more than one-third of their potential electric output to any utility power distribution system. The Polk Power Station IGCC CT qualifies as an electric utility stationary gas turbine and therefore may be subject to the emission limitations of NSPS 40 CFR 60, Subpart GG, § 60.332(a)(1).

The IGCC facility will include an auxiliary steam boiler rated at 49.5 MMBtu/hr heat input [higher heating value (HHV)] and three, distillate fuel oil storage tanks. The auxiliary steam boiler, which will be fired with low sulfur distillate fuel oil, will be subject to NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The general NSPS provisions (40 CFR 60, Subpart A) and provisions of NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, do not apply to vessels with capacities greater than or equal to 151 cubic meters (m^3) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) [0.508 pounds per square inch absolute (psia)] [40 CFR 60, Subpart Kb, § 60.110b(c)]. The Polk Power Station distillate oil storage tanks, each having a storage capacity of approximately 11,350 m^3 or 3 million gallons, are exempt from the provisions of NSPS Subpart A and Subpart Kb since the maximum true vapor pressure of distillate fuel oil at 100°F of 0.152 kPa (0.022 psia) is below the Subpart Kb 3.5-kPa applicability criterion.

Control technology planned for the ~~demonstration HGCU process~~ IGCC facility includes a ~~skid-mounted~~ H_2SO_4 plant to convert offgases from the HGCU ~~purge gas~~ and CGCU systems to H_2SO_4. The provisions of NSPS Subpart H, Standards of Performance for Sulfuric Acid Plants, do not apply to facilities where the conversion to H_2SO_4 is used primarily as a means of preventing emissions to the atmosphere of SO_2 or other sulfur compounds [40 CFR 60, Subpart H, § 60.81(a)]. However, the H_2SO_4 plant will be designed to meet the NSPS limits, i.e., 4 lbs SO_2 per ton of 100-percent H_2SO_4 produced and 0.15 lb acid mist per ton of 100-percent H_2SO_4 produced.

In addition to the applicable Subparts Dc, GG, and Y, there are three other NSPS which address similar emission sources, although none of these would apply directly: (1) Subparts Da and Db, Fossil Fuel Fired Steam Generators; (2) Subpart J, Petroleum Refineries; and (3) Subpart H, Sulfuric Acid Plants. There are no NESHAP standards that would apply to the IGCC facility.

FDER emission standards for stationary sources are contained in Chapter 17-2, Part VI, Emission Limiting and Performance Standards, F.A.C. Part VI specifies emission standards for 14 categories of sources. Source categories which apply to the IGCC facility are as follows:

Source Category	Part VI Citation	IGCC Unit Affected
H_2SO_4	17-2.600(2)	~~HGCU purge stream~~ Offgas control system
Fossil fuel fired steam generators	17-2.600(6)	Auxiliary steam boiler
~~Sulfur storage and handling facilities~~	~~17-2.600(11)~~	~~Sulfur recovery system~~

Part VI also contains general emission standards for sources emitting PM and VOCs, which would apply to the Polk Power Station project. Visible emissions are limited to a maximum of 20-percent opacity [Chapter 17-2.610(2)(a), F.A.C.]. Sources having unconfined emissions of PM (fugitive dust) must take reasonable precautions to prevent such emissions [Chapter 17-2.610(3)(a), F.A.C.]. If deemed necessary by FDER, vapor emission control devices or systems must be employed during the handling of any VOC, e.g., storage and pumping of distillate fuel oil [Chapter 17-2.620(1)(a), F.A.C.].

Applicable federal standards are summarized in Table 4-2. Federal standards for similar emission sources are summarized in Table 4-3. State emission standards are summarized in Table 4-4. BACT emission limitations proposed for the IGCC facility are all more stringent than the Federal and State standards cited in Tables 4-2 through 4-4.

4.2.2 STAND-ALONE COMBINED CYCLE UNITS AND COMBUSTION TURBINES

On the federal level, emissions from the stand-alone CC and simple-cycle CTs are regulated by NSPS Subpart GG. The Polk Power Station stand-alone CC units and

Table 4-2. Federal Emission Limitations

A. NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	STD = 0.0075 x (14.4/Y) + **F**

where: STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis);

Y = manufacturer's rated heat rate in kilojoules per watt hour at manufacturer's rated load, or actual measured heat rate based on LHV of fuel as measured at actual peak load. Y cannot exceed 14.4 kilojoules per watt hour;

F = NO_x emission allowance for fuel-bound nitrogen per:

Fuel Bound Nitrogen (weight percent)	F (NO_x - volume percent)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04 x N
$0.1 < N \leq 0.25$	0.004 + 0.0067 x (N-0.1)
$N > 0.25$	0.005

where: N = nitrogen content of fuel; percent by weight.

SO_2 = ≤0.015 percent by volume at 15 percent oxygen and on a dry basis; or fuel sulfur content ≤0.8 weight percent.

B. NSPS Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units ≥10 MMBtu/hr and ≤ 100 MMBtu/hr Heat Input

Pollutant	Emission Limitation*
SO_2	≤0.50 lb/MMBtu heat input (HHV); or fuel sulfur content ≤0.5 weight percent.
PM	≤20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Table 4-2. Federal Emission Limitations (Continued, Page 2 of 2)

C. NSPS Subpart Y, Coal Preparation Plants	
PM†	<20 percent opacity

*Limits are applicable to affected steam generators which combust oil.

†Limitation is applicable to any coal processing and conveying equipment, storage system, and transfer and loading system.

Source: 40 CFR 60, Subparts Dc, GG, and Y.

Table 4-3. Federal Emission Limitations for Similar Sources

Pollutant	Emission Limitation[a]
A. NSPS Subpart Da, Electric Utility Steam Generating Units Greater Than 250 MMBtu/hr Heat Input	
• PM[b]	≤0.03 lb/MMBtu heat input (HHV) and 99 percent reduction
	≤20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity
• SO_2[c]	≤1.20 lb/MMBtu heat input (HHV) and 90 percent reduction
	70 percent reduction when emissions are less than 0.60 lb/MMBtu heat input (HHV)
• NO_x[d]	≤0.50 lb/MMBtu heat input (HHV)
B. NSPS Subpart Db, Industrial-Commercial-Institutional Steam Generating Units >100 MMBtu/hr Heat Input	
• PM[e]	≤0.05 lb/MMBtu heat input (HHV)
	≤20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity
• SO_2[f]	≤1.20 lb/MMBtu heat input (HHV) and 90 percent reduction
• NO_x[g]	≤0.50 lb/MMBtu heat input (HHV)
C. NSPS Subpart J, Petroleum Refineries	
• SO_2[h]	≤0.025 percent by volume (250 ppmv) at 0 percent oxygen on a dry basis

Table 4-3. Federal Emission Limitations for Similar Sources
(Continued, Page 2 of 2)

Pollutant	Emission Limitation[a]
D. NSPS Subpart H, Sulfuric Acid Plants	
• SO_2	≤4 lb/ton of 100-percent H_2SO_4 produced
• H_2SO_4 mist	≤ 0.15 lb/ton of 100-percent H_2SO_4 produced

[a] Percent reduction requirements were repealed by Title IV, Section 403 of the 1990 Clean Air Act Amendments.

[b] Limitations are applicable to affected facilities which combust solid fuels.

[c] Limitations are applicable to affected facilities which combust solid or solid-derived fuels. Compliance is determined on a 30-day rolling average basis.

[d] Limitation is applicable to affected facilities which combust coal-derived gaseous fuels. Compliance is determined on a 30-day rolling average basis.

[e] Limitations are applicable to affected facilities which combust coal.

[f] Limitation is applicable to affected facilities which combust coal. Compliance is determined on a 30-day rolling average basis.

[g] Limitation is applicable to affected facilities which combust coal-derived synthetic fuels. Compliance is determined on a 30-day rolling average basis.

[h] Limitation is applicable to affected sulfur recovery plants which are controlled by an oxidation control system, or a reduction control system followed by incineration.

Source: 40 CFR 60, Subparts Da, Db, J, and H.

Table 4-4. State Emission Limitations

Pollutant	Emission Limitation
A. Chapter 17-2.600(2), F.A.C.: Sulfuric Acid Plants	
• SO_2	≤4 lb/ton of 100-percent H_2SO_4 produced
• H_2SO_4 mist	≤0.15 lb/ton of 100-percent H_2SO_4 produced
• Visible emissions	≤ 10 percent opacity
B. Chapter 17-2.600(6), F.A.C.: Fossil Fuel Steam Generators with Less than 250 MMBtu/hr Heat Input	
• SO_2	BACT
• PM	BACT
• Visible emissions	≤20 percent opacity (6-minute average), except for either opacity, or one 2-minute period per hour of not more than 40 percent opacity
~~C. Chapter 17-2.600(11), F.A.C.: Sulfur Storage and Handling Facilities~~	
~~• Sulfur particulate~~	~~Chapter 17-2.600(1)(a), F.A.C. contains nine requirements applicable to molten sulfur storage and handling facilities:~~ ~~1. All molten sulfur transfer shall be through enclosed piping systems where feasible and practical. In user facilities, molten sulfur may be transferred by covered trench or a movable spout positioned over a receiving pit. Contact surfaces between movable unloading arms and stationary pipes shall seat effectively around the entire circumference to minimize spillage;~~ ~~2. All pipes surrounding points where molten sulfur pipes are routinely disconnected and areas where molten sulfur is transferred to trucks or railcars shall be paved and curbed within 20 ft of the point of disconnection or transfer to contain any spilled molten sulfur, or shall be provided with noncorrosible drop pans or other secondary containment, positioned to collect spills, that are adequate to~~

Table 4-4. State Emission Limitations (Continued, Page 2 of 3)

Pollutant	Emission Limitation
~~(contd.)~~	~~contain amounts of sulfur that may escape during routine disconnection, reconnection or operation of the piping system;~~
	~~3. Emissions of sulfur PM from molten sulfur storage tanks and transfer systems in particulate air quality maintenance areas or within 5 kilometers of such areas shall not exceed 0.03 lb/hr per thousand tons of storage capacity;~~
	~~4. All spilled molten sulfur shall be collected and properly disposed of whenever the containment area is filled to one half its containment capacity, or monthly, whichever is more frequent. Spills of molten sulfur outside of a containment area, or where subject to vehicular traffic, shall be collected and disposed of as soon as possible, but no later than 24 hours after the spill occurs. Drip pans or other secondary containment shall be cleaned as needed to prevent exceedance of capacity, but at least weekly;~~
	~~5. All vent surfaces shall be cleaned monthly to remove captured particles.~~
	~~6. All owners and operators of molten sulfur storage and handling facilities shall maintain records of spills outside of containment areas and of collection and disposal of spilled sulfur. Such records shall be retained for a minimum of 2 years and shall be available for inspection by the Department upon request;~~
	~~7. In any PM air quality maintenance area, PSD Class I area, or within 5 kilometers of such area, visible emissions from any emission point in a molten sulfur facility shall not exceed 10 percent opacity (6 minute average). In other areas, visible emissions from any point in a molten sulfur facility shall not exceed 20 percent opacity (6 minute average);~~

Table 4-4. State Emission Limitations (Continued, Page 3 of 3)

Pollutant	Emission Limitation
	~~8. Operational procedures approved by the Department shall be established to minimize spills from any movable loading arm or pipe upon disconnection, reconnection or operation; and~~
	~~9. Visible emissions of sulfur PM during ship unloading in a PM air quality maintenance area shall not exceed 15 percent (6-minute average).~~
~~D.~~ C. Chapter 17-2.610(2), F.A.C.: General Visible Emissions Standard	
• Visible emissions	<20 percent opacity
~~E.~~ D. Chapter 17-2.620(1)(a), F.A.C.: General Volatile Organic Compounds or Organic Solvents Standard	
• VOC	No person shall store, pump, handle, process, load, unload, or use in any process or installation VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

Source: Chapter 17-2, F.A.C.

CTs qualify as electric utility stationary gas turbines and therefore are subject to the emission limitations of NSPS 40 CFR 60, Subpart GG, § 60.332(a)(1). There are no other NSPS or NESHAP that would apply to these units.

On the state level, none of the 14 categories of emission sources contained in Section 17-2.600, F.A.C. are applicable to the stand-alone CC units and CTs. The general PM [Chapter 17-2.610(2)(a), F.A.C.] and VOC [Chapter 17-2.620(1)(a), F.A.C.] emission standards would apply to the combined and simple-cycle CT units.

Summaries of the Subpart GG NSPS and FDER requirements are provided in Tables 4-2 and 4-4, respectively. BACT emission limitations proposed for the stand-alone CC units and CTs units are all more stringent than the applicable federal and state standards cited in Tables 4-2 and 4-4.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR COMBUSTION PRODUCTS--INTEGRATED COAL GASIFICATION COMBINED CYCLE FACILITY

Control technology review for combustion products (PM and trace heavy metals) was conducted as a category since similar technologies are utilized for these pollutants.

4.3.1 CONTROL TECHNOLOGIES

Available technologies used for controlling PM and heavy metal emissions include the following:

- Centrifugal collectors,
- Electrostatic precipitators (ESPs),
- Fabric filters or baghouses, and
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large (greater than 10 microns) size particles.

Particles generated from natural gas and distillate fuel oil combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot ($ft^3/min\text{-}ft^2$). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

While all of these post-process technologies would be technically feasible for controlling PM and heavy metal emissions from the IGCC facility, none of the above listed control equipment have been applied to IGCC installations since exhaust gas PM concentrations are inherently low. A wet scrubber to remove PM from the syngas is an integral part of the Texaco CGCU process. The scrubbed syngas is then cooled prior to entering the acid gas removal system which results in the condensation of trace volatile heavy metals and further reduction in syngas particulate levels. The end product of the CG process is a treated syngas stream which is low in PM and which can be used in a CT without causing erosion or corrosion.

The IGCC CT operates with a significant amount of excess air which generates large exhaust gas flow rates. The IGCC CT will be fired with coal-derived syngas with backup low sulfur distillate fuel oil. Both fuels have low ash and sulfur contents and will therefore generate low PM emissions in comparison to other fuels. The minor PM emissions due to the use of clean fuels coupled with a large volume of exhaust gas produce extremely low exhaust stream PM concentrations. Estimated maximum PM exhaust concentrations (including H_2SO_4 mist) from the IGCC facility CT are summarized as follows:

Fuel Type	Exhaust Gas PM Concentration (gr/scf)
Syngas, 100 percent CGCU	0.0100
Syngas, 50/50 HGCU/CGCU	0.0100
Distillate fuel oil	0.0048

Exhaust stream PM concentrations of such low magnitude are not amenable to control using available technologies since removal efficiencies would be unreasonably low and costs excessive.

Since post-process stack controls for PM are not appropriate for the IGCC facility, the use of wet scrubbing (integral to the CGCU process), good combustion practices and clean fuels is considered to be BACT. The Polk Power Station IGCC project will use the latest CT burner technology to maximize combustion efficiency and minimize PM emission rates. Combustion efficiency, defined as the percentage of fuel that is completely oxidized in the combustion process, is projected to be greater than 99 percent. Project fuels will consist of coal and petroleum coke-derived syngas and low sulfur distillate fuel oil.

Ancillary equipment associated with the IGCC facility that emit PM include the auxiliary steam boiler, coal handling, and thermal oxidizers. The auxiliary boiler and thermal oxidizers will both use low sulfur distillate fuel oil. Due to low exhaust stream PM concentrations, BACT for PM emissions from the auxiliary boiler and thermal oxidizers is considered to be the use of clean fuels and good combustion practices.

Coal handling fugitive PM emissions will be controlled by a combination of wet dust suppression, equipment enclosure, and fabric filter dust collection systems located at the major dust emission points. Trucks delivering coal will be equipped with covers to control fugitive dust emissions during transit. Trucks and railcars will unload at a receiving hopper equipped with a dust collection system to collect dust from all conveyor transfer points in the car dump pit area. A wet dust suppression system using either foam, or water sprays with a wetting agent, will also be employed at the truck/railcar receiving hopper. Conveyors will be hooded to minimize dust emissions. Enclosures and dust abatement equipment will be employed to control PM emissions from coal handling equipment and transfer points. The dust abatement equipment will consist of pulse jet baghouses, centrifugal exhaust fans, rotary air lock valves, and dust return chutes. Fabric filters will be sized for a maximum air to cloth ratio of 6:1 at design air flows with a PM removal efficiency of not less than 99.9 percent. A wet suppression system will be used at the stacker discharge to the coal pile. Wind blown PM emissions from the active and inactive coal piles will be controlled by the application of water/chemical dust suppressant and crusting agents, respectively. All roads, excluding infrequently traveled transmission line access roads, within the Polk Power Station complex will be paved. Use of wet suppression, hoods and enclosures, paved roads, and fabric filters is considered to be BACT for PM emissions from coal handling operations.

4.3.2 PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY EMISSION LIMITATIONS

Prior BACT determinations for CG facilities are limited. The BLIS database for CG contains entries for four facilities: (a) Southern California Edison Cool Water Station, Daggett, California; (b) Tennessee Eastman Company, Kingsport, Tennessee; (c) Continental Energy Association, Hazelton, Pennsylvania; and (d) Virginia Power, Chesterfield, Virginia. Southern California Edison's Cool Water facility is the location of Texaco's demonstration IGCC unit. The Tennessee Eastman and Continental Energy Association facilities are not comparable to the Polk Power Station IGCC since these facilities are not CC systems. Virginia Power's Chesterfield facility includes two CTs which can be fired with coal-derived gas. In addition to these facilities, FDER issued a BACT determination to Florida Power & Light Company (FPL) for their Martin County project. The FPL Martin County project includes four CC units (two CTs and HRSGs per unit) rated at 400 MW each with provisions for future use of coal-derived gas. The FDER permit stipulates that the BACT determination for the CG portion of the project will be reviewed prior to installation of the gasification facilities. BACT limitations for PM for the Southern California Edison Cool Water, FPL Martin County, and Virginia Power Chesterfield CG facilities are summarized in Table 4-5.

Since the IGCC facility is an alternative process to conventional coal-fired power plants, a summary of BLIS PM determinations for coal-fired boilers is provided in

Table 4-5. PM Emission Limitation Summary of CG Facilities

State	BLIS I.D. Number	Permit Date	Source Name	Heat Input (MMBtu/hr)	PM Emission Limit			Control Technology
					lb/hr	lb/MMBtu	gr/dscf	
California	0027	12/09/81	Southern California Edison Coolwater Station SCOT unit thermal oxidizer	20.9	NA	NA	0.050	
			CT	842.0	11.0	0.013	0.010 (≤0.7 percent S coal) 0.050 (0.7 to 3.5 percent S coal)	
Florida	NA	05/31/91	FPL Martin County (per CT)	2,100.0	19.0	0.009	NA	Good combustion
Virginia	0098	04/15/88	Virginia Power	1,875.0	19.0	0.011	NA	Equipment design

Note: gr/dscf = grains per dry standard cubic foot.

Sources: EPA, 1992a.
FDER, 1991a.
SBCAPCD, 1989.

Table 4-6 and shown graphically in Figure 4-1. Data shown in Table 4-6 represent recent BACT/LAER determinations, i.e., those entered into BLIS from January 1986 through May 1992. BACT determinations range from 0.006 to 0.430 pound per million British thermal unit (lb/MMBtu) with an average of 0.043 lb/MMBtu. Recent FDER BACT decisions for coal-fired power plants are summarized in Table 4-7. A summary of BLIS PM determinations for oil-fired boilers is provided in Table 4-8 and shown graphically in Figure 4-2.

Use of clean fuels (syngas and low sulfur distillate fuel oil) and good combustion techniques are proposed as BACT for PM/PM_{10} from the IGCC facility. Specific BACT PM emission limits proposed for the IGCC CT/HRSG, auxiliary boiler, and thermal oxidizers are summarized in Table 4-9. A significant portion of the total PM/PM_{10} emission rates is comprised of H_2SO_4, i.e., approximately 76 percent for syngas and 36 percent for oil. PM/PM_{10} emission rates excluding H_2SO_4 are also shown in Table 4-9.

4.4 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR COMBUSTION PRODUCTS--STAND-ALONE COMBINED CYCLE UNITS AND COMBUSTION TURBINES

Control technology review for combustion products (PM and trace heavy metals) was conducted as a category since similar technologies are utilized for these pollutants.

4.4.1 CONTROL TECHNOLOGIES

Available post-process PM control technologies for the stand-alone CC units and CTs are the same as described in Section 4.3.1 for the IGCC facility. Exhaust PM concentrations for the stand-alone CC units and CTs are inherently low due to the combustion of clean fuels (natural gas and low sulfur distillate fuel oil) and high exhaust gas flow rates. Estimated maximum PM exhaust concentrations (including H_2SO_4 mist) from the stand-alone CTs using natural gas and backup distillate fuel oil are 0.0033 and 0.0065 gr/scf, respectively. Due to these low exhaust concentrations, post-process stack controls are not feasible since PM removal efficiencies would be unreasonably low and costs excessive. BACT for PM emissions from the

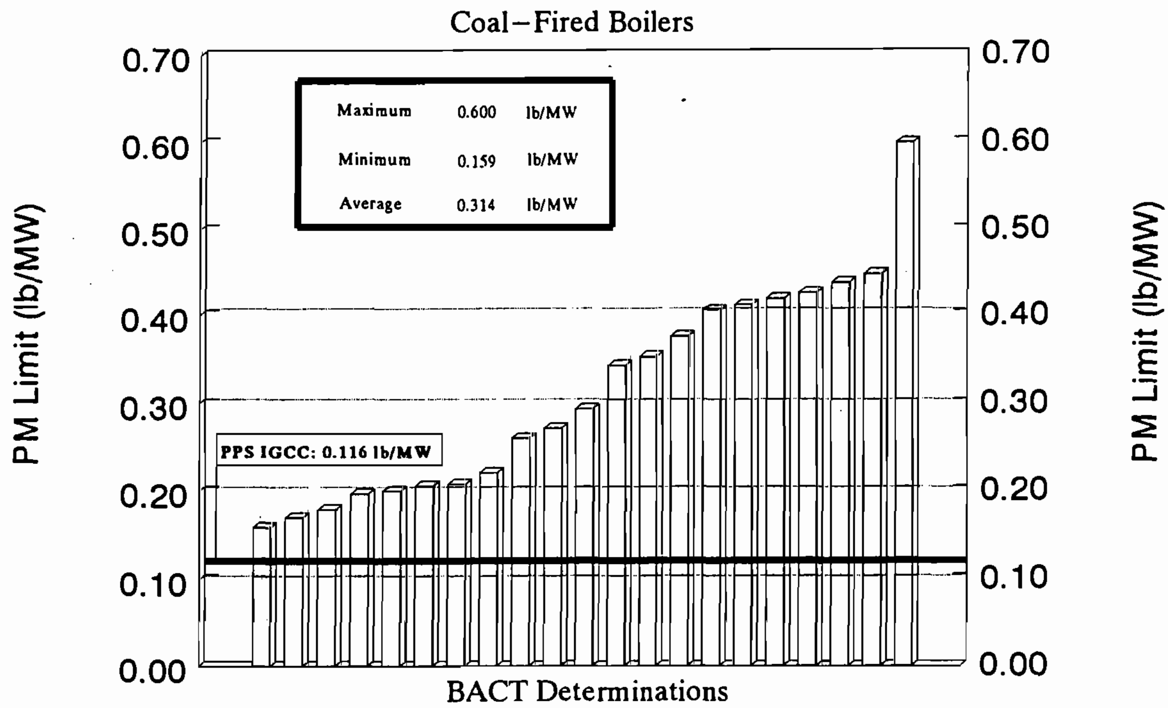
Table 4-6. BLIS PM Emission Limitation Summary for Coal-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	PM Emission Limit				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	gr/dscf	lb/MW		
California	0120	04/26/85	SCF - Ridgen Power Project	16.5	212.0	4.5	0.021	0.010	0.272	99.9	Baghouse
	0128A	10/29/85	Corn Products	N/A	620.0	10.0	0.016	0.008	N/A	N/A	Baghouse
	0372	12/13/85	Cogeneration National Corp.	N/A	280.0	5.0	0.018	N/A	N/A	99.0	Baghouse
				N/A	620.0	10.0	0.016	0.008	N/A	99.0	Baghouse
	0158	06/20/86	BMCP	N/A	N/A	N/A	N/A	0.016	N/A	N/A	Baghouse
	0165	12/01/86	Pyropower Corp.	49.9	640.0	7.92	0.012	0.005 (gr/acf)	0.159	99.9	Baghouse
	0178	01/12/87	Mount Poso Cogeneration Co.	50.0	N/A	N/A	N/A	0.010	N/A	N/A	Baghouse
	0282	02/11/88	GWF Power Systems Co., Inc.	N/A	202.0	1.25	0.006	0.005	N/A	N/A	Baghouse
Connecticut	0067	08/09/89	AES Thames, Inc.	N/A	923.0	18.5	0.020	N/A	N/A	99.9	Baghouse
Georgia	0030	09/21/90	Thomaston Mills, Inc.	N/A	214.76	6.4	0.030	N/A	N/A	99.5	Baghouse
Hawaii	0009	01/25/90	Applied Energy Services	N/A	2,150.0	32.2	0.015	0.007	N/A	99.9	Baghouse
Iowa	0010	10/29/82	Iowa Electric Light & Power	650.0	N/A	N/A	0.030	N/A	N/A	N/A	ESP
Kentucky	0007B	12/13/85	Tennessee Valley Authority	N/A	200.0	20.0	0.100	N/A	N/A	98.85	Baghouse
	0007A	04/15/86	Tennessee Valley Authority	N/A	1,430.0	42.9	0.030	N/A	N/A	99.0	Baghouse, NSPS
	0007C	05/04/88	Tennessee Valley Authority	N/A	1,579.0	47.4	0.030	N/A	N/A	99.0	Baghouse, NSPS
Michigan	0048	07/31/87	Cogentrix Michigan Leasing	N/A	214.0	6.4	0.030	N/A	N/A	99.1	Baghouse
	0051	12/07/87	City of Wyandotte	N/A	369.0	4.1	0.011	N/A	N/A	99.9	Baghouse
North Carolina	0039	07/07/86	Cogentrix Carolina Leasing	106.0	1,212.0	36.4	0.030	N/A	0.343	99.1	Baghouse
	0050	07/20/89	Cogentrix of Rocky Mount	N/A	1,500.0	30.0	0.020	N/A	N/A	N/A	Baghouse
	0054	01/24/91	Roanoke Valley Project	N/A	1,700.0	34.0	0.020	N/A	N/A	99.0	Baghouse
New Jersey	--	Draft	Keystone Cogeneration	224.0	2,116.0	38.1	0.018	N/A	0.170	99.9	Baghouse
	--	Draft	Chambers Works Cogeneration	250.0	2,778.0	50.0	0.018	N/A	0.200	99.9	Baghouse
New York	0016	12/11/85	Northern Energy Group	N/A	250.0	20.0	0.080	N/A	N/A	94.0	Electric gravel bed
	0014	04/01/87	Fort Drum Heating Plant	N/A	190.0	9.5	0.050	N/A	N/A	N/A	Baghouse
	0030	09/25/88	United Development Group	N/A	577.0	12.7	0.022	N/A	N/A	99.8	Baghouse
Ohio	0145	02/05/87	Wm. H. Zimmer Generating	N/A	11,968.0	299.2	0.025	N/A	N/A	99.5	ESP
Pennsylvania	0047	12/02/85	Signal Frackville Energy	40.0	N/A	N/A	0.012	N/A	N/A	99.9	Baghouse

Table 4-6. BLIS PM Emission Limitation Summary for Coal-Fired Boilers (Continued, Page 2 of 2)

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	PM Emission Limit lb/hr	lb/MMBtu	gr/dscf	lb/MW	Control Efficiency (%)	Control Technology
	0046	01/06/86	Westwood Energy Properties	30.0	425.0	12.8	0.030	N/A	0.427	99.92	Baghouse
	0044	06/27/86	Northeastern Power Co.	77.0	540.0	15.1	0.028	N/A		N/A	Baghouse
	0035	11/01/86	J. Pagnotti Enterprises	80.0	1,082.0	32.5	0.030	N/A	0.406	N/A	Baghouse
	0034	12/01/86	Sheridan Coal Co.	40.0	550.0	16.5	0.030	N/A	0.413	N/A	Baghouse
	0036	12/29/86	Foster Wheeler Power	77.0	566.0	17.0	0.030	N/A	0.221	99.9	Baghouse
	0045	01/16/87	Archbald Power Corp.	20.0	240.0	12.0	0.050	N/A	0.600	N/A	Baghouse
	0042	02/17/88	Panther Creek Energy	80.0	1,170.0	35.1	0.030	N/A	0.439	99.0	Baghouse
	0049	06/06/88	Edensburg Power Co.	N/A	617.0	18.5	0.030	N/A	N/A	99.98	Baghouse
	0044A	06/17/88	Northeastern Power Co.	49.0	513.0	14.4	0.028	N/A	0.294	N/A	Baghouse
	0057	01/18/89	Scrubgrass Power Corp.	80.0	1,198.0	35.9	0.030	N/A	0.449	99.96	Baghouse
	0062	05/26/89	Cambria Cogen, Inc.	79.8	1,118.0	33.5	0.030	N/A	0.420	99.9	Baghouse
	0058	09/26/88	North Branch Energy Partners	90.0	1,126.0	33.8	0.030	N/A	0.376	99.0	Baghouse
	0072	06/08/90	Panther Creek Partners	80.0	1,228.0	20.9	0.017	N/A	0.261	99.9	Baghouse
	0073	07/23/90	MidAtlantic Energy of PA	30.0	392.0	10.6	0.027	N/A	0.353	99.95	Baghouse
Rhode Island	0009	03/11/91	East Providence Cogeneration	72.0	856.5	12.9	0.015	N/A	0.179	N/A	Baghouse
Utah	0034	10/01/86	Utah Power & Light Co.	400.0	N/A	N/A	0.100	N/A	N/A	99.0	Baghouse
Virginia	0033	07/01/85	Union Camp	N/A	245.0	12.3	0.050	N/A	N/A	99.0	ESP
	0034	06/12/86	Cogentrix of Virginia, Inc.	N/A	200.0	6.0	0.030	N/A	N/A	99.1	Baghouse
	0044	12/18/86	Tultex Corp.	N/A	12.0	5.2	0.430	N/A	N/A	35.0	Settling chamber
	0178	01/02/91	Cogentrix of Richmond	304.0	3,000.0	60.0	0.020	N/A	0.197	99.9	Baghouse
	0181	04/29/91	Old Dominion Electric Coop.	786.0	8,170.0	163.4	0.020	N/A	0.208	99.9	Baghouse
Wisconsin	0036	N/A	Wisconsin Electric Power Co.	80.0	825.0	16.5	0.020	N/A	0.206	N/A	ESP
	0041	09/21/88	Fort Howard Corp.	N/A	505.0	25.3	0.050	N/A	N/A	N/A	Baghouse
	0055	09/05/90	Wisconsin Electric Power Co.	N/A	879.0	61.5	0.070	N/A	N/A	N/A	ESP
				N/A	873.0	131.0	0.150	N/A	N/A	N/A	ESP
				N/A	880.0	132.0	0.150	N/A	N/A	N/A	ESP
				N/A	872.0	40.1	0.046	N/A	N/A	N/A	ESP
	0061	91/01/92	Milwaukee County Power Plant	N/A	157.0	3.1	0.020	N/A	N/A	99.8	Baghouse

Source: EPA, 1992a.



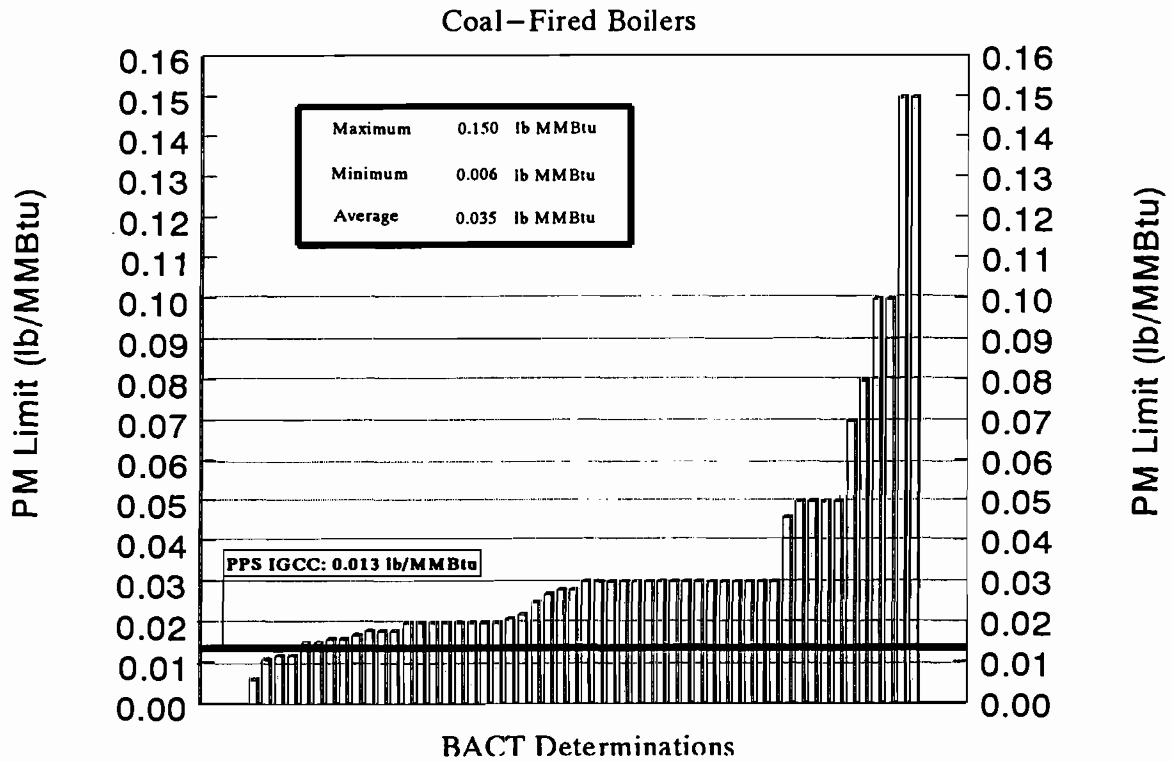


FIGURE 4-1.

SUMMARY OF PM BACT DETERMINATIONS: COAL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

Table 4-7. Florida BACT PM Emission Limitation Summary for Coal-Fired Boilers

Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	PM Emission Limit lb/MW	Control Technology
12/23/91	Orlando Utilities Stanton Unit No. 2	465.0	4,286	85.7	0.020	0.184	ESP
03/25/92	Indiantown cogeneration	330.0	3,422	61.6	0.018	0.187	Baghouse

Source: FDER, 1991a.

Table 4-8. BLIS PM Emission Limitation Summary for Oil-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	PM Emission Limit				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	gr/dscf	lb/MW		
Connecticut	0080	09/23/88	Northeast Utilities, NNECO	N/A	28.3	5.7	0.200	N/A	N/A	N/A	Diesel fired
	0074	08/28/89	Exeter Energy Limited	N/A	11.2	2.8	0.246	N/A	N/A	N/A	Diesel fired
Ohio	0094	N/A	Georgia-Pacific Corp.	N/A	118.0	10.6	0.090	N/A	N/A	N/A	1 percent S Oil
	0117	11/26/86	Owens-Illinois Inc.	N/A	10.3	0.2	0.020	N/A	N/A	N/A	Natural gas/No. 2 oil firing
Virginia	0044	12/18/86	Tultex Corp.	N/A	93.3	1.3	0.014	N/A	N/A	N/A	
	0177	05/04/90	Doswell Limited Partnership	N/A	40.0	0.8	0.020	N/A	N/A	N/A	Clean fuel
	0181	04/29/91	Old Dominion Elect. Coop.	N/A	213.9	6.4	0.030	N/A	N/A	N/A	
Wisconsin	0037A	10/10/88	Wisconsin Tissue Mills, Inc.	N/A	146.4	13.2	0.090	N/A	N/A	N/A	1 percent S, No. 6 oil

Source: EPA, 1992a.

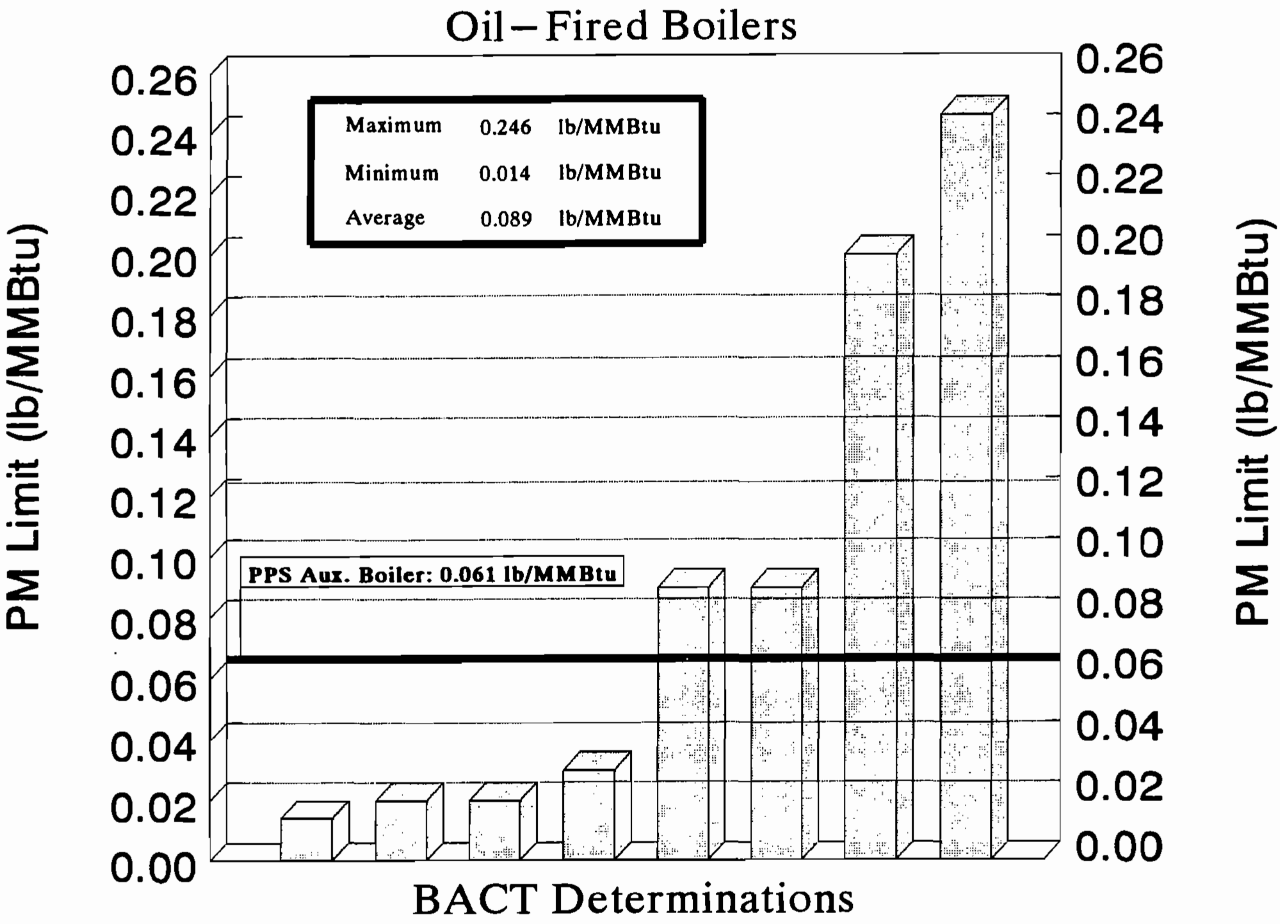


FIGURE 4-2.

SUMMARY OF PM BACT DETERMINATIONS:
OIL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

TAMPA
ELECTRIC
A TECO ENERGY COMPANY

**POLK
POWER
STATION**

Table 4-9. Proposed PM/PM_{10} BACT Emission Limits for the IGCC Facility

Process	Proposed BACT Emission Limits lb/hr	 lb/MMBtu	 lb/MW
Including H_2SO_4			
CT, Simple-Cycle			
No. 2 fuel oil	27.0	0.014	0.180
IGCC, CT/HRSG			
100 percent CGCU	72.0	0.037*	~~0.296~~ 0.326†
50 percent CGCU/50 percent HGCU	72.0	0.037*	~~0.296~~ 0.326†
No. 2 fuel oil	26.7	0.014	~~0.152~~ 0.121
IGCC, auxiliary boiler	3.0	0.061	N/A
~~IGCC, tail gas treating unit thermal oxidizer~~	~~13.1~~	~~N/A~~	~~N/A~~
IGCC, ~~HGCU~~ H_2SO_4 plant thermal oxidizer	~~2.6~~ 12.8	N/A	N/A
Excluding H_2SO_4			
CT, Simple-Cycle			
No. 2 fuel oil	17.0	0.009	0.113
IGCC, CT/HRSG			
100 percent CGCU	17.0	0.013*	~~0.116~~ 0.115†
50 percent CGCU/50 percent HGCU	17.0	0.013*	~~0.116~~ 0.115†
No. 2 fuel oil	17.0	0.009	0.077
IGCC, auxiliary boiler	3.0	0.061	N/A
~~IGCC, tail gas treating unit thermal oxidizer~~	~~13.1~~	~~N/A~~	~~N/A~~
IGCC, ~~HGCU~~ H_2SO_4 plant thermal oxidizer	~~2.6~~ 12.8	N/A	N/A

*Based on heat input (HHV) to coal gasifier and includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.

†Includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.

Sources: GE, 1992.
Texaco, 1992.
Bechtel, 1993.
ECT, 199~~2~~ 3.

stand-alone CC units and CTs is considered to be the use of clean fuels and good combustion practices.

4.4.2 PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY EMISSION LIMITATIONS

BACT emission limitations for PM obtained from the BLIS database are summarized in Table 4-10 and shown graphically in Figure 4-3. Data shown in Table 4-10 represents recent BACT/LAER determinations, i.e., those entered into BLIS from January 1986 through May 1992.

For natural gas firing, PM emission limits range from 0.002 to 0.028 lb/MMBtu with an average rate of 0.010 lb/MMBtu. The range for distillate fuel oil-fired turbines is 0.009 to 0.080 lb/MMBtu with an average rate of 0.038 lb/MMBtu. All determinations are based on the use of clean fuels and good combustion techniques. Recent Florida BACT determinations for gas turbines are summarized in Table 4-11.

Use of clean fuels (natural gas and low sulfur distillate fuel oil) and combustion controls are proposed as BACT for PM/PM_{10} and heavy metals. Specific BACT emission limits proposed for the Polk Power Station stand-alone CC units and CTs are summarized in Table 4-12. The proposed BACT technology and emission limits are consistent with previous determinations both within Florida and on the national level. It is noted that PM/PM_{10} emissions as measured by EPA Reference Method 5 include H_2SO_4 mist. A significant portion of the total PM/PM_{10} emission rate is comprised of H_2SO_4, i.e., approximately 27 percent for oil and 36 percent for gas. PM/PM_{10} emission rates excluding H_2SO_4 are also shown in Table 4-12.

4.5 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR PRODUCTS OF INCOMPLETE COMBUSTION--INTEGRATED COAL GASIFICATION COMBINED CYCLE FACILITY

Control technology review for products of incomplete combustion (CO and VOCs) was conducted as a category since similar technologies are utilized for these two pollutants.

Table 4-10. BLIS PM Emission Limitation Summary for CTs

I.D. State	BLIS Permit Number	Source Date	Size Name	Turbine Input (MW)	Heat Fuel (MMBtu/hr)	Type	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Technology
Alabama	0040	11/30/88	Champion International	35.0	N/A	Gas	2.5	N/A	N/A
California	0112	04/30/85	Shell California Production	22.0	N/A	Gas	3.92	N/A	N/A
	0186	02/20/87	U.S. Borax and Chemical Corporation	45.0	N/A	Gas	12.0	N/A	N/A
						Oil	48.0	N/A	N/A
	0273	01/12/89	Mojave Cogeneration Company	N/A	490.0	Gas	N/A	0.017	N/A
						Oil	N/A	0.036	N/A
	0298	04/06/89	Pacific Thermonetics, Inc.	N/A	995.0	Gas	N/A	0.002	Use of natural gas
Colorado	0017	02/19/92	Thermo Industries, Ltd.	N/A	1,230.0	Gas	25.8	0.021	
Connecticut	0027	08/19/87	Downtown Cogeneration Association	N/A	71.9	Gas	N/A	0.014	Good combustion techniques
						Oil	N/A	0.036	Good combustion techniques
	0031	05/18/88	CCF-1	N/A	110.0	Gas	N/A	0.012	Good combustion techniques
						Oil	N/A	0.035	Good combustion techniques
	0022	08/08/88	O'Brien Cogeneration	N/A	499.9	Gas	N/A	0.009	Good combustion techniques
						Oil	N/A	0.025	Good combustion techniques
	0025	10/23/89	Capital District Energy Center	N/A	738.8	Gas	N/A	0.014	Good combustion techniques
						Oil	N/A	0.035	Good combustion techniques
Michigan	0054	02/16/88	Midland Cogeneration Venture	N/A	82.0	Gas	0.5	0.006	Use of natural gas
North Carolina	0051	09/06/89	Panda-Rosemary Corp.	N/A	499.0	Gas	2.5	0.005	Combustion control
				N/A	509.0	Oil	17.0	0.033	Combustion control
				N/A	1,047.0	Gas	5.0	0.005	Combustion control
				N/A	1,060.0	Oil	10.0	0.009	Combustion control
New Jersey	0006	01/03/85	Ciba-Geigy Corporation	3.0	N/A	Gas	1.85	N/A	N/A
New York	0013	03/10/88	TBG/Grumman	16.0	N/A	N/A	N/A	0.011	N/A

Table 4-10. BLIS PM Emission Limitation Summary for CTs (Continued, Page 2 of 3)

I.D. State	BLIS Permit Number	Source Date	Size Name	Turbine Input (MW)	Heat Fuel (MMBtu/hr)	Type	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Technology
	0027	07/01/88	Trigen	40.0	N/A	Gas	N/A	0.006	Combustion control
						Kerosene	N/A	0.040	Combustion control
	0026	07/01/88	Kamine Carthage	40.0	N/A	Gas	N/A	0.005	Combustion control
						Kerosene	N/A	0.040	Combustion control
	0022	09/01/88	Kamine South Glen Falls	40.0	N/A	Gas	N/A	0.005	Combustion control
						Oil	N/A	0.040	Combustion control
	0024	11/01/88	Long Island Lighting Company	75.0	N/A	Gas	N/A	0.006	Combustion control
	0031	11/04/88	Indeck-Yerks Energy Services, Inc.	40.0	N/A	Gas	N/A	0.005	Combustion control
						Oil	N/A	0.040	Combustion control
	0032	01/15/89	L & J Energy System Cogeneration	40.0	N/A	Gas	N/A	0.028	Combustion control
						Oil	N/A	0.080	Combustion control
	0029	02/07/89	Indec/Oswego Hill Cogeneration	40.0	N/A	Gas	N/A	0.008	Combustion control
						Oil	N/A	0.033	Combustion control
	0037	03/06/89	Megan-Racine Associates	N/A	430.0	Gas	N/A	0.028	Includes duct burner
						Oil	N/A	0.080	Includes duct burner
	0038	05/02/89	Empire Energy - Niagara Cogeneration	N/A	416.0	Gas	N/A	0.006	Combustion control
						Oil	N/A	0.024	Combustion control
	0033	09/01/89	Kamine Syracuse	79.0	N/A	Oil	N/A	0.053	Combustion control
	0040	11/21/89	JMC Selkirk, Inc.	80.0	N/A	Gas	N/A	0.007	Combustion control
						Oil	N/A	0.014	Combustion control
	0039	01/29/90	Fulton Cogeneration Associates	N/A	500.0	Gas	N/A	0.024	Includes duct burner
						Oil	N/A	0.063	
	0036	02/26/90	Oneida Cogeneration	N/A	417.0	Gas	N/A	0.006	Combustion control

Table 4-10. BLIS PM Emission Limitation Summary for CTs (Continued, Page 3 of 3)

I.D. State	BLIS Permit Number	Source Date	Size Name	Turbine Input (MW)	Heat Fuel (MMBtu/hr)	Type	PM Emission Limit lb/hr	lb/MMBtu	Technology
Pennsylvania	0052	10/12/88	Amtrak	20.0	N/A	Gas	0.98	N/A	Constrained by national AAQS
Rhode Island	0008	01/30/89	Pawtucket Power	N/A	533.0	Gas	N/A	0.007	N/A
						Oil	N/A	0.045	N/A
South Carolina	0021	09/23/91	Carolina Power and Light Company	80.0	N/A	Oil	15.0	N/A	
Texas	0178A	03/05/85	Champion International	30.6	1,342.0	Gas	17.5 tpy	N/A	Low NO_x burners
	0048A	05/29/86	Formosa Plastic Corporation	38.4	N/A	Gas	28.6 tpy	N/A	N/A
Virginia	0177	05/04/90	Doswell Limited Partnership	N/A	1,261.0	Gas/Oil	33.0	0.026	Clean burning fuel (No. 2 oil)
	0175	03/05/91	Commonwealth Atlantic Ltd. Partnership	100.0	1,533.0	Gas	6.0	0.004	Low ash fuel
				100.0	1,400.0	Oil	22.0	0.016	Low ash fuel (Grade 76 No. 2 oil)
	0184	03/03/92	Bermuda Energy Limited	N/A	1,175.0	Gas	5.9	0.005	Clean burn fuel
				N/A	1,117.0	Oil	39.1	0.035	Clean burn fuel
Vermont	0005	12/20/89	Arrowhead Cogeneration Company	N/A	282.0	Oil	N/A	0.023	Design and good combustion
	0008	07/27/90	Vermont Marble Company	8.0	100.0	Oil	6.0	0.060	Proper design and operation
	0007	08/10/90	East Georgia Cogeneration	28.0	400.0	Oil	N/A	0.036	Limited use of distillate oil

Source: EPA, 1992a.

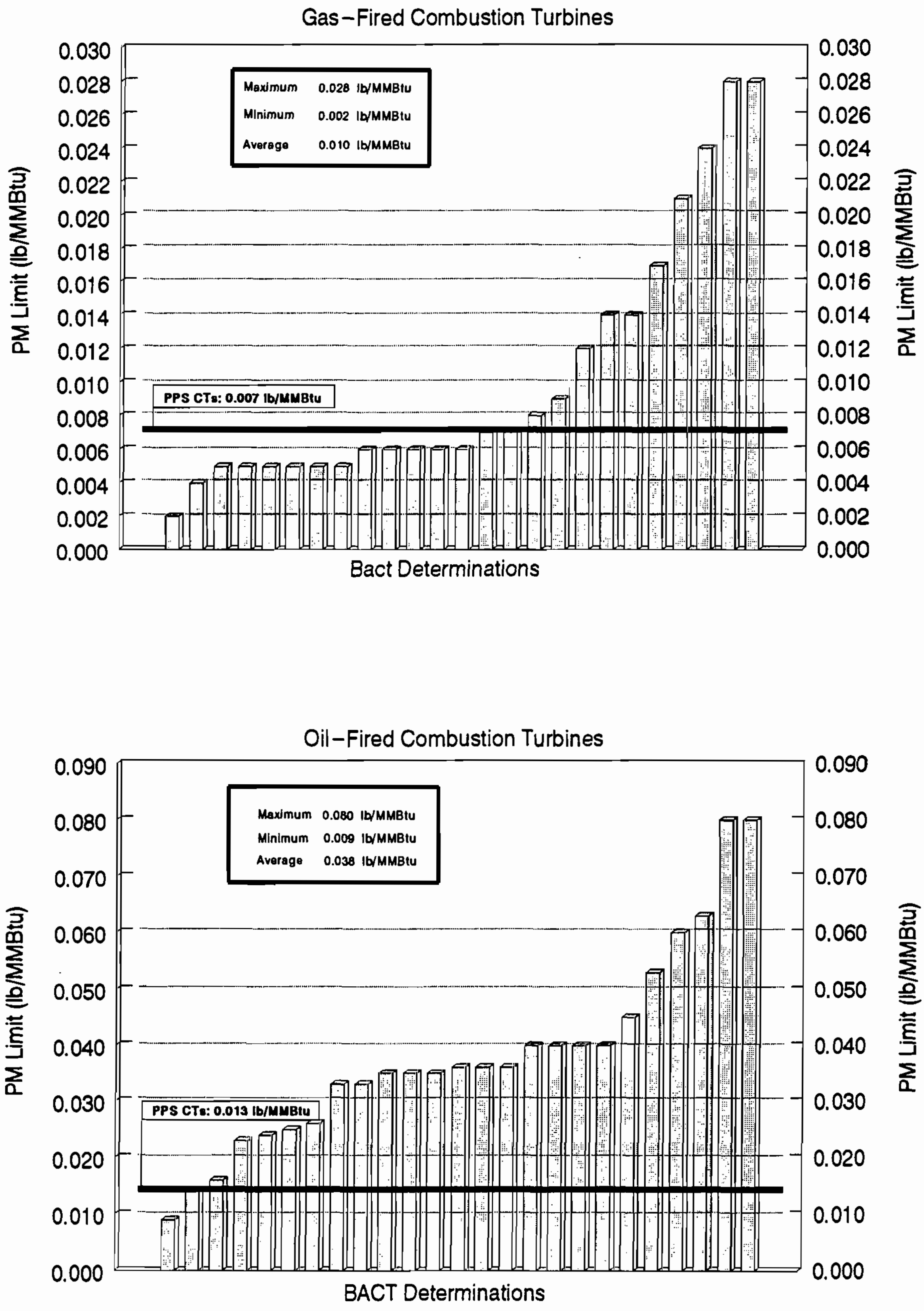


FIGURE 4-3.

SUMMARY OF PM BACT DETERMINATIONS:
GAS- AND OIL-FIRED CTs
Sources: EPA, 1992a; ECT, 1992.

ECT
Environmental Consulting & Technology, Inc.

Table 4-11. Florida BACT PM Emission Limitation Summary for CTs

Permit Date	Source Name	Turbine Size		Fuel Type	PM Emission Limit		Control Technology
		MW	MMBtu/hr		lb/hr	lb/MMBtu	
05/31/91	Florida Power & Light Company Martin Expansion Project	150.0	1,966.0	Gas	18.0	(0.009)	Combustion design and clean fuels
			1,846.0	Oil	60.6	(0.033)	Combustion design and clean fuels
01/04/91	TECO Power Services Hardee Power Station	75.0	1,268.4	Gas	5.0	(0.004)	Combustion design and clean fuels
			1,312.3	Oil	10.0	(0.008)	Combustion design and clean fuels
07/26/91	City of Lakeland Charles Larsen Plant	80.0	1,055	Gas	6.3	0.006	Combustion design and clean fuels
			1,040	Oil	26.0	0.025	Combustion design and clean fuels
10/18/91	Florida Power Corporation Debary Facility	92.9	1,144	Oil	15.0	0.025	Combustion design and clean fuels
11/20/91	Pasco Cogen Limited	42.0	384	Gas	5.0	0.0065	Combustion design and clean fuels
			387	Oil	20.0	0.026	Combustion design and clean fuels

Note: ( ) = calculated from hourly emission limit and heat input.

Source: FDER, 1991a.

Table 4-12. Proposed PM/PM$_{10}$ BACT Emission Limits for Stand-Alone CC Units and CTs

Process	Proposed BACT Emission Limits lb/hr	 lb/MMBtu	 lb/MW
Including H_2SO_4			
CC units (per unit)			
Natural gas	22.0	0.010	0.100
No. 2 fuel oil	41.0	0.018	0.186
CTs (per CT)			
Natural gas	11.0	0.010	0.147
No. 2 fuel oil	20.5	0.018	0.273
Excluding H_2SO_4			
CC units (per unit)			
Natural gas	14.0	0.007	0.064
No. 2 fuel oil	30.0	0.013	0.136
CTs (per CT)			
Natural gas	7.0	0.007	0.093
No. 2 fuel oil	15.0	0.013	0.200

Sources: GE, 1992.
ECT, 1992.

4.5.1 CONTROL TECHNOLOGIES

CO and VOC emissions results from the incomplete combustion of carbon and organic compounds. The IGCC facility will include ~~four~~ three combustion sources: (a) CT, (b) auxiliary boiler, and (c) ~~SRU/TGTU thermal oxidizer, and (d)~~ H_2SO_4 plant thermal oxidizer. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Since higher combustion temperatures will increase oxidation rates, emissions of both CO and VOCs will generally increase during partial load conditions since combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water, steam, or nitrogen for NO_x control will also result in an increase in CO and VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO and VOC emission rates.

There are two available technologies for controlling CO and VOCs from fossil-fuel fired combustion sources: (1) combustion process design, and (2) oxidation catalysts. Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of most combustion processes CO and VOC emissions are inherently low.

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOCs to CO_2 and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for both CO and VOCs up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F; higher temperatures on the order of 900°F are needed to oxidize VOCs. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. Properly designed and operated oxidation catalyst systems are capable of achieving a CO removal efficiency of between 90 and 95 percent. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be technically feasible for combustion devices that are fired with fuels containing appreciable amounts of sulfur.

4.5.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing sulfur. Since CO and VOC emission rates from the IGCC combustion units (CT, auxiliary boiler, and thermal ~~oxidizers~~) are inherently low, further reductions through the use of oxidation catalysts will result in air quality improvements well below the defined PSD significant impact levels for CO and negligible reductions in ambient VOC levels. The location of the Polk Power Station project (Polk County, Florida) is classified attainment for all criteria pollutants.

The application of oxidation catalyst technology to a combustion device will result in an increase in backpressure on the device due to pressure drop across the catalyst bed. A catalyst system would typically have a pressure drop across the catalyst bed of approximately 2.0 inches of water. This pressure drop will result in an energy penalty due to increased turbine compressor power consumption.

The Polk Power Station IGCC project will use syngas as the primary fuel for the CT and distillate fuel oil for the auxiliary boiler and thermal ~~oxidizers~~. Distillate fuel oil will also serve as backup fuel for the IGCC CT. Maximum sulfur contents of syngas and distillate oil planned for the Polk Power Station project are 0.07 and 0.05 weight percent, respectively. As previously mentioned, the application of oxidation catalysts to combustion units fired with fuels containing sulfur is not technically feasible due to the oxidation of SO_2 to SO_3 and formation of H_2SO_4 mist.

4.5.3 PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY EMISSION LIMITATIONS

BACT emission limitations for CO and VOCs obtained from the BLIS database for CG facilities are summarized in Table 4-13.

A summary of BLIS CO determinations for coal-fired boilers is provided in Table 4-14 and shown graphically in Figure 4-4. VOC BLIS determinations are summarized in Table 4-15 and shown graphically in Figure 4-5. Data shown in Tables 4-14 and 4-15 represent recent BACT/LAER determinations, i.e., those

Table 4-13. CO and VOC Emission Limitation Summary for CG Facilities

State	BLIS I.D. Number	Permit Date	Source Name	Heat Input (MMBtu/hr)	Emission Limits			Control Technology
					lb/hr	lb/MMBtu	ppmvd	
CO								
California	0027	12/09/81	Southern California Edison Coolwater Station SCOT unit thermal oxidizer	20.9	NA	NA	NA	
			CT	842.0	15.4	0.018	10.0	
Florida	N/A	05/31/91	FPL Martin County (per CT)	2,100.0	134.0	0.064	33.0	Good combustion
Virginia	0098	04/15/88	Virginia Power	1,875.0	140.0	0.075	N/A	Equipment design
VOC								
California	0027	12/09/81	Southern California Edison Coolwater Station SCOT unit thermal oxidizer	20.9	N/A	N/A	N/A	
			CT	842.0	N/A	N/A	N/A	
Florida	N/A	05/31/91	FPL Martin County (per CT)	2,100.0	21.4	0.010 (Excluding background)	9.0	Good combustion
Virginia	0098	04/15/88	Virginia Power	1,875.0	17.0	0.009	N/A	

Sources: EPA, 1992a.
FDER, 1991a.
SBCAPCD, 1989.

Table 4-14. BLIS CO Emission Limitation Summary for Coal-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	CO Emission Limit				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
California	0120	04/26/85	SCF - Ridgen Power Project	16.5	212.0	25.2	0.119	150.0	1.527	N/A	Boiler combustion controls
	0128A	10/29/85	Corn Products	N/A	620.0	76.8	0.124	N/A	N/A	N/A	Excess air and stgd. combust.
	0372	12/13/85	Cogeneration National Corp.	N/A	280.0	N/A	N/A	N/A	N/A	N/A	Optimum combustion
				N/A	620.0	76.8	0.124	N/A	N/A	N/A	Auto excess air control
	0178	01/12/87	Mount Poso Cogeneration Co.	50.0	N/A	50.0	N/A	N/A	1.000	N/A	Control of overfire air
	0282	02/11/88	GWF Power Systems Co., Inc.	N/A	202.0	22.9	0.090	N/A	N/A	N/A	Best engineering practices
Connecticut	0067	08/09/89	AES Thames, Inc.	N/A	923.0	101.5	0.110	N/A	N/A	N/A	
Georgia	0030	09/21/90	Thomaston Mills, Inc.	N/A	214.76	43.0	0.200	N/A	N/A	N/A	Combustion controls
Hawaii	0009	01/25/90	Applied Energy Services	N/A	2,150.0	408.4	0.190	70.0	N/A	N/A	
Kentucky	0007A	04/15/86	Tennessee Valley Authority	N/A	1,430.0	572.0	0.400	N/A	N/A	N/A	Basis: national AAQS
	0007C	05/04/88	Tennessee Valley Authority	N/A	1,579.0	631.6	0.400	N/A	N/A	N/A	Basis: national AAQS
Michigan	0048	07/31/87	Cogentrix Michigan Leasing	N/A	214.0	42.8	0.200	N/A	N/A	N/A	Design and operating practices
	0051	12/07/87	City of Wyandotte	N/A	369.0	51.7	0.140	N/A	N/A	N/A	Equipment design
North Carolina	0039	07/07/86	Cogentrix Carolina Leasing	106.0	1,212.0	436.3	0.600	N/A	4.12	N/A	Control of excess air
	0050	07/20/89	Cogentrix of Rocky Mount	N/A	1,500.0	300.0	0.200	N/A	N/A	N/A	Combustion control
	0054	01/24/91	Roanoke Valley Project	N/A	1,700.0	340.0	0.200	N/A	N/A	N/A	Combustion control
New Jersey	-	Draft	Keystone Cogeneration	224.0	2,116.0	232.8	0.110	100.0	1.039	N/A	
	-	Draft	Chambers Works Cogeneration	250.0	2,778.0	305.6	0.110	100.0	1.222	N/A	
New York	0016	12/11/85	Northern Energy Group	N/A	250.0	87.5	0.350	N/A	N/A	N/A	Combustion control
	0014	04/01/87	Fort Drum Heating Plant	N/A	190.0	47.5	0.250	N/A	N/A	N/A	Combustion control
	0030	09/25/88	United Development Group	N/A	577.0	115.4	0.200	N/A	N/A	N/A	Combustion control
Pennsylvania	0036	12/29/86	Foster Wheeler Power	77.0	566.0	283.0	0.500	N/A	3.675	N/A	
	0057	01/18/89	Scrubgrass Power Corp.	80.0	1,198.0	119.8	0.100	N/A	1.498	N/A	

Table 4-14. BLIS CO Emission Limitation Summary for Coal-Fired Boilers (Continued, Page 2 of 2)

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	CO Emission Limit				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
	0062	05/26/89	Cambria Cogen, Inc.	79.8	1,118.0	167.8	0.150	N/A	2.103	N/A	Combustion control
	0058	09/26/88	North Branch Energy Partners	90.0	1,126.0	168.9	0.150	N/A	1.877	N/A	
	0072	06/08/90	Panther Creek Partners	80.0	1,228.0	221.0	0.180	N/A	2.763	N/A	Combustion control
	0073	07/23/90	MidAtlantic Energy of PA	30.0	392.0	90.2	0.230	N/A	3.005	N/A	Combustion control
Rhode Island	0009	03/11/91	East Providence Cogeneration	72.0	856.5	111.3	0.130	N/A	1.547	N/A	Combustion control
Virginia	0034	06/12/86	Cogentrix of Virginia, Inc.	N/A	200.0	49.2	0.600	N/A	N/A	N/A	
	0044	12/18/86	Tultex Corp.	N/A	12.0	4.88	0.407	N/A	N/A	N/A	
	0178	01/02/91	Cogentrix of Richmond	304.0	3,000.0	900.0	0.300	N/A	2.961	N/A	Combustion control
	0181	04/29/91	Old Dominion Electric Coop.	786.0	8,170.0	817.0	0.100	N/A	1.039	N/A	Boiler design
Wisconsin	0036	N/A	Wisconsin Electric Power Co.	80.0	825.0	74.3	0.090	N/A	0.928	N/A	Proper combustion
	0041	09/21/88	Fort Howard Corp.	N/A	505.0	101.0	0.200	N/A	N/A	N/A	Proper bed operation

Source: EPA, 1992a.

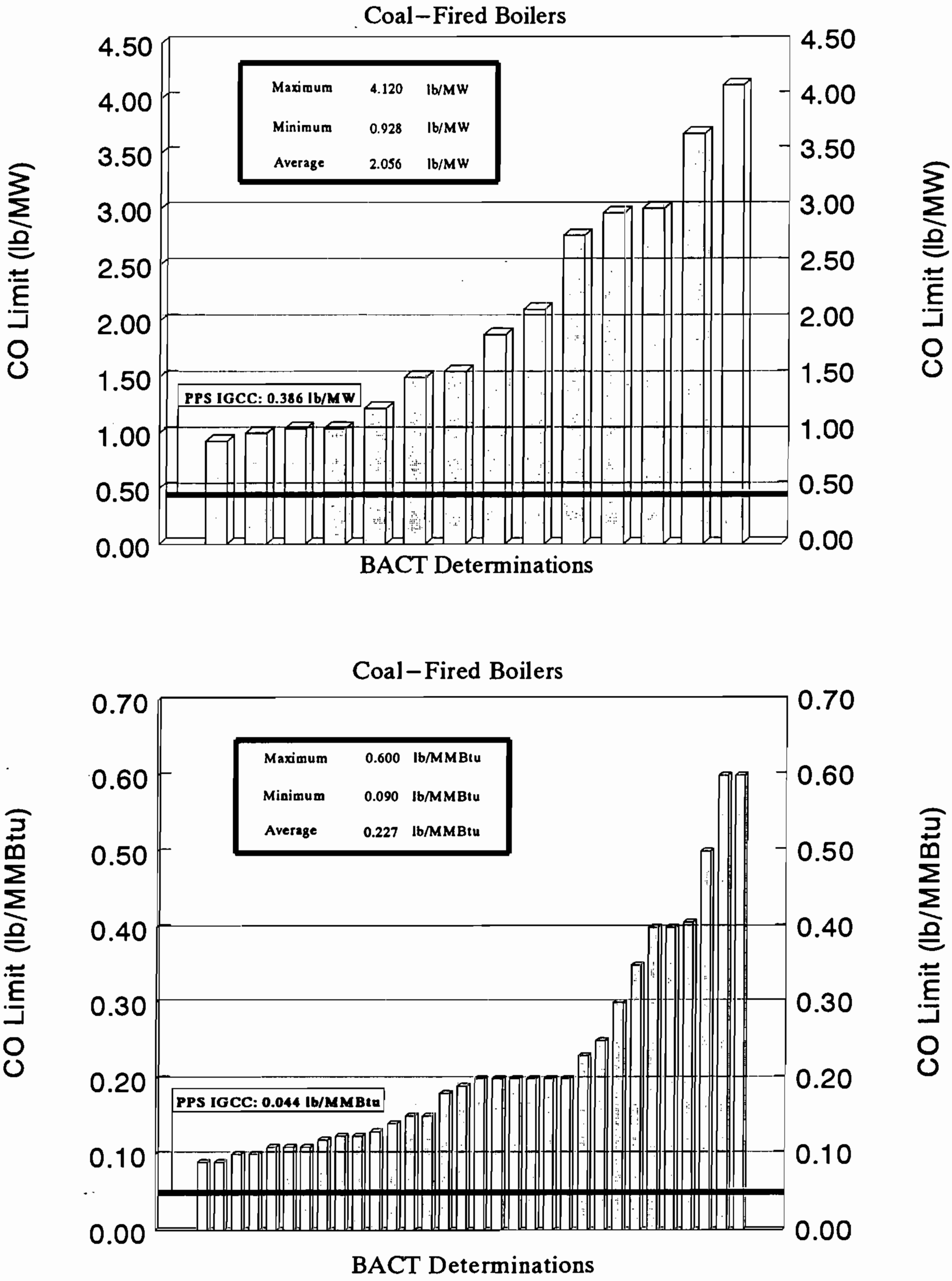


FIGURE 4-4.

SUMMARY OF CO BACT DETERMINATIONS:
COAL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

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Table 4-15. BLIS VOC Emission Limitation Summary for Coal-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	VOC Emission Limit				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
Connecticut	0067	08/09/89	AES Thames, Inc.	N/A	923.0	18.5	0.020	N/A	N/A	N/A	
Hawaii	0009	01/25/90	Applied Energy Services	N/A	2,150.0	32.2	0.015	3.5	N/A	N/A	
Michigan	0051	12/07/87	City of Wyandotte	N/A	369.0	8.86	0.024	N/A	N/A	N/A	
North Carolina	0054	01/24/91	Roanoke Valley Project	N/A	1,700.0	51.0	0.030	N/A	N/A	N/A	Combustion control
New Jersey	-	Draft	Keystone Cogeneration	224.0	2,116.0	7.6	0.0036	N/A	0.034	N/A	Non-methane hydrocarbons
	-	Draft	Chambers Works Cogeneration	250.0	2,778.0	10.0	0.0036	N/A	0.040	N/A	Non-methane hydrocarbons
New York	0016	12/11/85	Northern Energy Group	N/A	250.0	25.0	0.100	N/A	N/A	N/A	Combustion control
Pennsylvania	0057	01/18/89	Scrubgrass Power Corp.	80.0	1,198.0	6.0	0.005	N/A	0.075	N/A	
	0058	09/26/88	North Branch Energy Partners	90.0	1,126.0	22.5	0.020	N/A	0.250	N/A	
	0072	06/08/90	Panther Creek Partners	80.0	1,228.0	6.1	0.005	N/A	0.077	N/A	Combustion control
	0073	07/23/90	MidAtlantic Energy of PA	30.0	392.0	9.4	0.024	N/A	0.314	N/A	Combustion control
Rhode Island	0009	03/11/91	East Providence Cogeneration	72.0	856.5	7.7	0.009	N/A	0.107	N/A	Combustion control
Virginia	0034	06/12/86	Cogentrix of Virginia, Inc.	N/A	200.0	0.7	0.003	N/A	N/A	N/A	
	0044	12/18/86	Tultex Corp.	N/A	12.0	0.58	0.048	N/A	N/A	N/A	
	0178	01/02/91	Cogentrix of Richmond	304.0	3,000.0	9.0	0.003	N/A	0.030	N/A	Combustion control
	0181	04/29/91	Old Dominion Electric Coop.	786.0.	8,170.0	81.7	0.010	N/A	0.104	N/A	Boiler design
Wisconsin	0041	09/21/88	Fort Howard Corp.	N/A	505.0	2.21	0.004	N/A	N/A	N/A	

Source: EPA, 1992a.

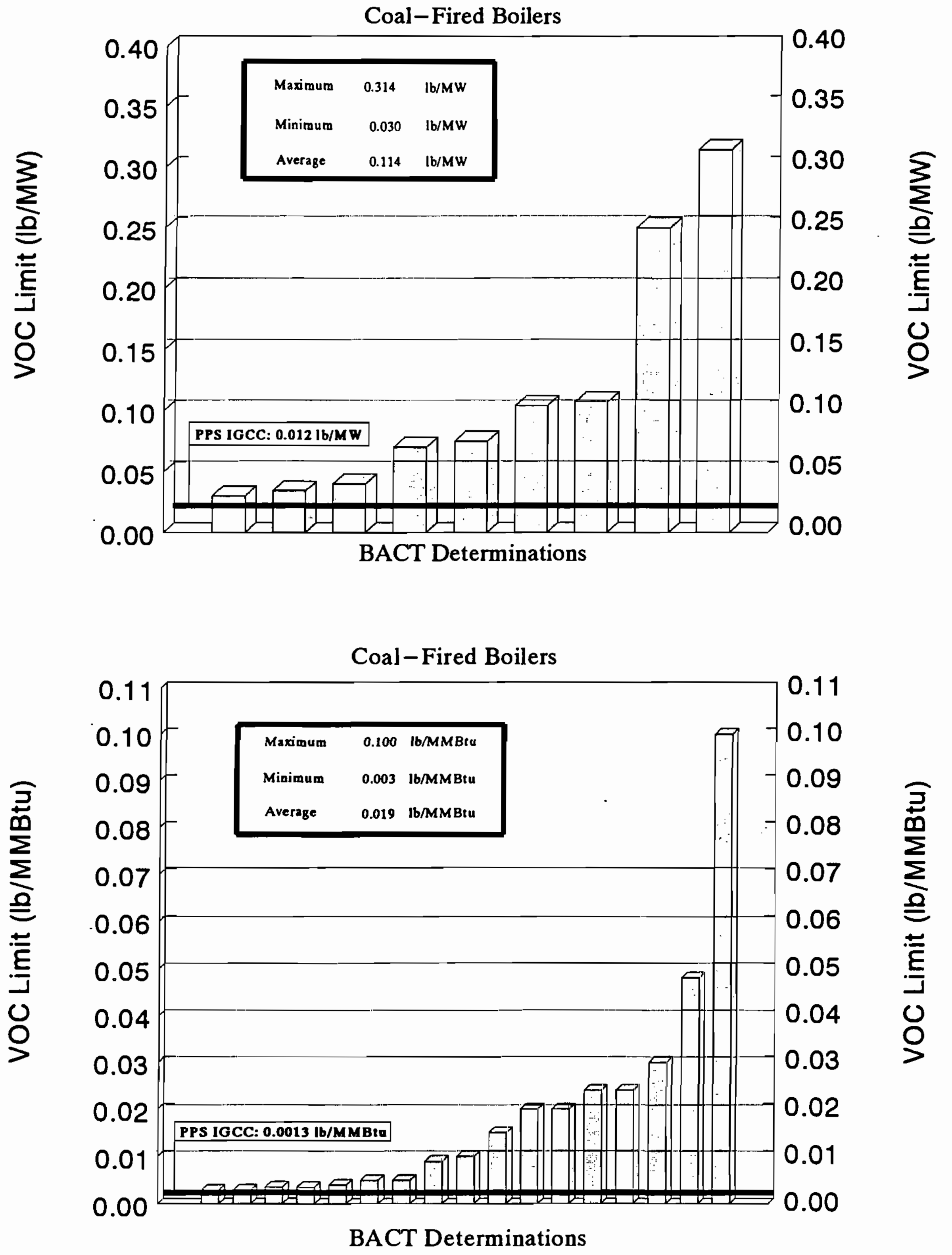

FIGURE 4-5.

SUMMARY OF VOC BACT DETERMINATIONS:
COAL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

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entered into BLIS from January 1986 through May 1992. CO BACT determinations range from 0.090 to 0.600 lb/MMBtu with an average of 0.227 lb/MMBtu. VOC BACT determinations range from 0.003 to 0.100 lb/MMBtu with an average of 0.019 lb/MMBtu. Recent FDER CO and VOC BACT decisions for coal-fired power plants are summarized in Table 4-16. A summary of BLIS CO and VOC determinations for oil-fired boilers is provided in Table 4-17 and shown graphically in Figure 4-6.

Use of combustion controls and good operating practices to minimize incomplete combustion are proposed as BACT for the IGCC facility. Specific BACT emission limits proposed for the Polk Power Station IGCC facility are summarized in Table 4-18. *The proposed BACT limits for CO and VOC, on both a lb/MMBtu and lb/MW basis, are the lowest limits in the BLIS database and well below recent determinations made in Florida and New Jersey for coal-fired power plants.* The proposed BACT technology and emission limits are consistent with previous determinations both within Florida and elsewhere in the country.

4.6 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR PRODUCTS OF INCOMPLETE COMBUSTION--STAND-ALONE COMBINED CYCLE UNITS AND COMBUSTION TURBINES

Control technology review for incomplete combustion products (CO and VOCs) was conducted as a category since similar technologies are used for these two pollutants.

4.6.1 CONTROL TECHNOLOGIES

The two available control technologies of combustion process modifications and use of oxidation catalysts previously noted in Section 4.5.1 would also apply to the stand-alone CC units and CTs. The CTs will employ natural gas as the primary fuel with low sulfur distillate fuel oil as a back-up fuel source.

Table 4-16. Florida BACT CO and VOC Emission Limitation Summary for Coal-Fired Boilers

Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	Emission Limits lb/hr	Emission Limits lb/MMBtu	Emission Limits lb/MW	Control Technology
CO							
12/31/91	Orlando Utilities Stanton unit No. 2	465.0	4,286	643.0	0.150	1.383	Combustion controls
03/25/92	Indiantown cogeneration	330.0	3,422	376.4	0.110	1.141	Combustion controls
VOC							
12/31/91	Orlando Utilities Stanton unit No. 2	465.0	4,286	64.0	0.015	0.138	Combustion controls
03/25/92	Indiantown cogeneration	330.0	3,422	12.3	0.0036	0.037	Combustion controls

Source: FDER, 1991a.

Table 4-17. BLIS CO and VOC Emission Limitation Summary for Oil-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	Emission Limit lb/hr	lb/MMBtu	ppmvd	lb/MW	Control Efficiency (%)	Control Technology
CO											
Connecticut	0080	09/23/88	Northeast Utilities, NNECO	N/A	28.3	20.1	0.710	N/A	N/A	N/A	Diesel fired
	0074	08/28/89	Exeter Energy Limited	N/A	11.2	8.4	0.746	N/A	N/A	N/A	Diesel fired
Ohio	0117	11/26/86	Owens-Illinois Inc.	N/A	10.3	0.4	0.040	N/A	N/A	N/A	Nat gas/#2 oil firing
Virginia	0044	12/18/86	Tultex Corp.	N/A	93.3	3.33	0.036	N/A	N/A	N/A	
	0177	05/04/90	Doswell Limited Partnership	N/A	40.0	11.0	0.275	N/A	N/A	N/A	Boiler operation
	0181	04/29/91	Old Dominion Elect. Coop.	N/A	213.9	34.2	0.160	N/A	N/A	N/A	
VOC											
Connecticut	0080	09/23/88	Northeast Utilities, NNECO	N/A	28.3	6.2	0.220	N/A	N/A	N/A	Diesel fired
	0074	08/28/89	Exeter Energy Limited	N/A	11.2	2.6	0.235	N/A	N/A	N/A	Diesel fired
Ohio	0117	11/26/86	Owens-Illinois Inc.	N/A	10.3	0.03	0.003	N/A	N/A	N/A	Nat gas/#2 oil firing
Virginia	0044	12/18/86	Tultex Corp.	N/A	93.3	0.26	0.003	N/A	N/A	N/A	
	0177	05/04/90	Doswell Limited Partnership	N/A	40.0	5.12	0.128	N/A	N/A	N/A	Boiler operation
	0181	04/29/91	Old Dominion Elect. Coop.	N/A	213.9	2.6	0.012	N/A	N/A	N/A	

Source: EPA, 1992a.

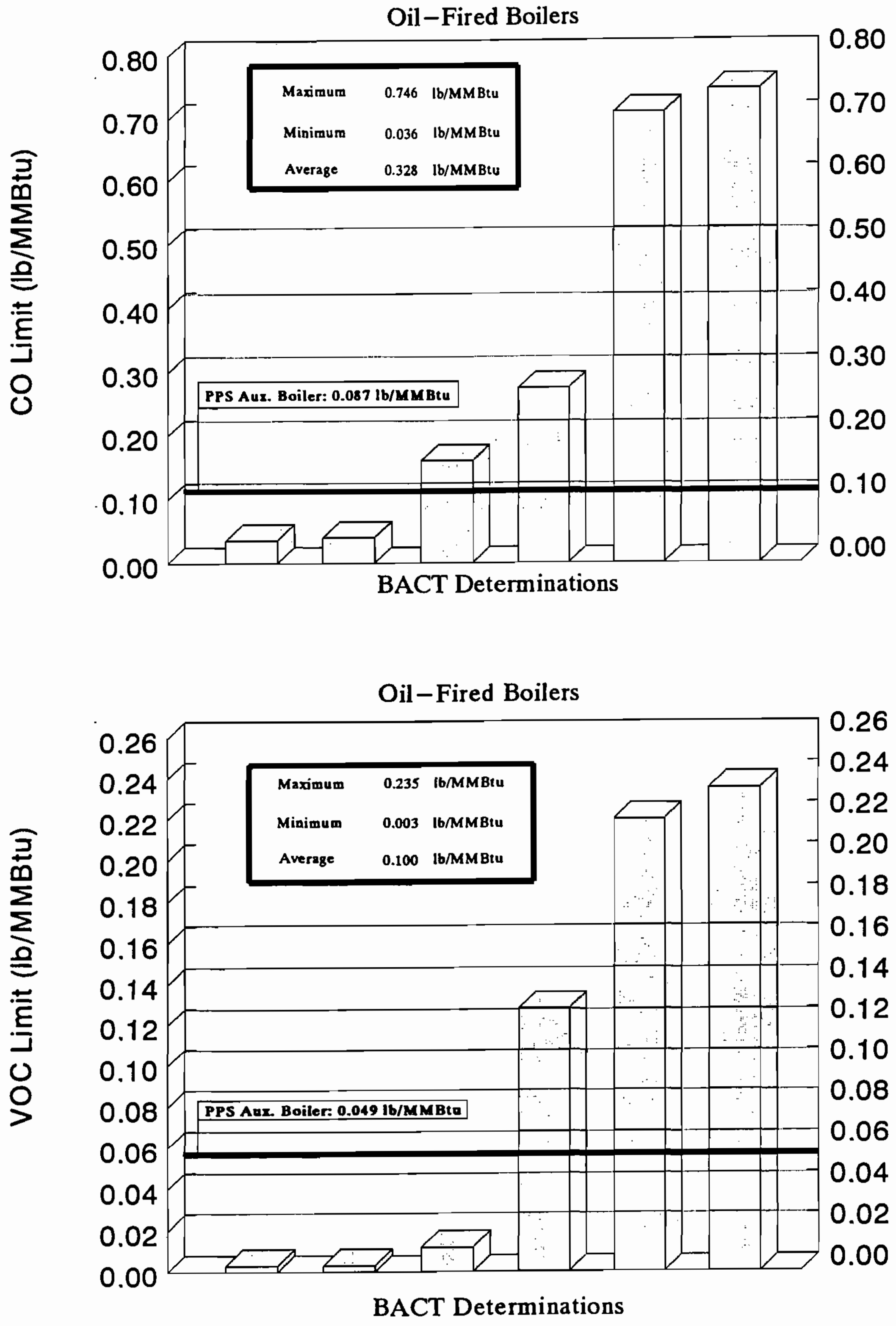

FIGURE 4-6.

SUMMARY OF CO AND VOC BACT DETERMINATIONS: OIL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

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Table 4-18. Proposed CO and VOC BACT Emission Limits for the IGCC Facility

Process	Proposed BACT Emission Limits lb/hr	 lb/MMBtu	 ppmvd	 lb/MW
CO				
CT, Simple-Cycle No. 2 fuel oil (50 percent load)	99.0	0.086	25.0	1.320
IGCC, HRSG				
100 percent CGCU	98.0	0.044*	25.0	0.382†
50 percent CGCU/50 percent HGCU	99.0	0.044*	25.0	0.386†
No. 2 fuel oil	83.0	0.044	25.0	0.377
(50 percent load)	99.0	0.086	40.0	~~0.450~~ 0.900
IGCC, auxiliary boiler	4.3	0.087	108.0	N/A
~~IGCC, tail gas treating unit thermal oxidizer~~	~~1.4~~	~~N/A~~	~~29.0~~	~~N/A~~
IGCC, ~~HGCU~~ H2SO4 plant thermal oxidizer	~~0.61~~ 1.4	N/A	~~29.0~~ 15.1	N/A
VOC				
CT, Simple-Cycle No. 2 fuel oil (50 percent load)	32.0	0.028	20.0	0.427
IGCC, HRSG				
100 percent CGCU	3.0	~~0.0013~~ 0.0017*	1.0	~~0.012~~ 0.015†
50 percent CGCU/50 percent HGCU	3.0	~~0.0013~~ 0.0017*	1.0	~~0.012~~ 0.015†
No. 2 fuel oil	11.0	0.0058	5.0	~~0.063~~ 0.050
(50 percent load)	32.0	0.0277	20.0	~~0.368~~ 0.291
IGCC, auxiliary boiler	2.4	0.0485	27.0	N/A

Table 4-18. Proposed CO and VOC BACT Emission Limits for the IGCC Facility (Continued, Page 2 of 2)

Process	Proposed BACT Emission Limits			
	lb/hr	lb/MMBtu	ppmvd	lb/MW
~~IGCC, tail gas treating unit thermal oxidizer~~	~~0.80~~	~~N/A~~	~~37.0~~	~~N/A~~
IGCC, ~~HGCU~~ H_2SO_4 plant thermal oxidizer	~~0.35~~ 0.80	N/A	~~29.0~~ 15.1	N/A

*Based on heat input (HHV) to coal gasifier and includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.
†Includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.

Sources: GE, 1992.
Texaco, 1992.
ECT, 199~~2~~ 3.
Bechtel, 1993.

4.6.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing sulfur. Since CO and VOC emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in air quality improvements well below the defined PSD significant impact levels for CO and negligible reductions in ambient VOC levels. As has been mentioned, the location of the Polk Power Station project (Polk County, Florida) is classified attainment for all criteria pollutants. From an air quality perspective, the only benefit of CO oxidation catalysts is to prevent localized CO hot spots since the catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of CO emissions from the Polk Power Station indicate that maximum impacts will be insignificant.

The application of oxidation catalyst technology to a gas turbine will result in an increase in backpressure on the CT due to pressure drop across the catalyst bed. The increased backpressure will result in reducing turbine output power while increasing the unit's heat rate. A catalyst system for the Polk Power Station CTs is projected to have a pressure drop across the catalyst bed of 2.0 inches of water. This pressure drop will result in an energy penalty of 5,827,082 kilowatt-hours (kwh) (19,882 MMBtu) per year for the two 220-MW CC units based on 100-percent load, gas-firing, 59°F ambient temperature, and 100-percent capacity factor. The energy penalty is equivalent to the use of 19.94 million cubic feet (MMcf) of gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3). The energy penalty for the six 75 MW simple-cycle CTs is estimated to be 4,370,311 kwh (14,912 MMBtu) per year based on 100-percent load, gas-firing, 59°F ambient temperature, and 50-percent capacity factor. This energy penalty is equivalent to the use of 14.20 MMcf of gas annually based on a natural gas heating value of 1,050 Btu/ft^3.

4.6.3 ECONOMIC IMPACTS

The Polk Power Station stand-alone CC units and CTs will use natural gas as the primary fuel with low sulfur distillate fuel oil as a backup fuel source. Maximum distillate oil annual capacity factors for the stand-alone CC units and CTs are 25 and 10 percent, respectively. Maximum natural gas annual capacity factors for the stand-alone CC units and CTs are 100 and 50 percent, respectively.

An economic evaluation of an oxidation catalyst system was performed for the future Polk Power Station CTs using the OAQPS factors previously summarized in Table 4-1 and project-specific economic factors provided in Table 4-19. Specific capital and annual operating costs for oxidation catalyst control systems for the two CC units are summarized in Tables 4-20 and 4-21, respectively. Capital and annual operating costs for oxidation catalyst control systems for the six simple-cycle CTs are summarized in Tables 4-22 and 4-23, respectively.

Base case CO emissions are estimated to be 25 ppmv. Controlled emissions, consistent with the limit typically required for oxidation catalyst systems located in non-attainment areas, are assumed to be 10.0 ppm. Base case and controlled emission rates are summarized in Table 4-24 for the future Polk Power Station CTs. It is noted that base case CO emission levels are representative of the performance of the advanced dry low-NO_x burners planned for the Polk Power Station future stand-alone CC units and CTs. The advanced low-NO_x burners, which can attain a NO_x exhaust concentration of 9 ppmvd when fired with natural gas, produce slightly higher CO emissions in comparison to conventional burner technology.

Cost effectiveness of oxidation catalyst for CO emissions is determined to be $5,158 per ton of CO removed for the CC units. For the simple-cycle CTs, cost effectiveness of CO oxidation catalyst was found to be $5,643 per ton. Based on the high control costs, use of oxidation catalyst technology to control CO and VOC emissions is not considered to be economically feasible. The slightly higher CO emissions which result from the use of advanced dry low-NO_x burners is felt to be an

Table 4-19. Economic Cost Factors for Polk Power Station

Factor	Units	Value
Interest rate	%	10.06
Construction interest	%	10.0
	Years	1.5
	Payments	3
Control system life	Years	15
Catalyst life	Years	
Oxidation, CC		3
Oxidation, simple-cycle		6
SCR		3
Electricity cost		
1996 to 2011	$/kwh	0.0332
2000 to 2014	$/kwh	0.0428
Ammonia cost	$/ton	85
System downtime	Days	
Oxidation catalyst replacement		4
SCR catalyst replacement		5
Labor costs	$/hour	
Operator		16.80
Maintenance		12.50

Sources: Tampa Electric Company, 1992.
GE, 1992.
UEC, 1992.

Table 4-20. Capital Costs for Oxidation Catalyst Stand-Alone CC Units

Item	$		OAQPS Factor
<u>Direct Costs</u>			
Purchased equipment	3,706,500	(A)	
Installation			
Foundations and supports	296,520		0.08 x A
Handling and erection	518,910		0.14 x A
Electrical	148,260		0.04 x A
Piping	74,130		0.02 x A
Insulation for ductwork	37,065		0.01 x A
Painting	37,065		0.01 x A
Subtotal Installation Cost	**1,111,950**		
Site preparation	80,000		
Subtotal Direct Costs	**4,898,450**		
<u>Indirect Costs</u>			
Engineering	370,650		0.10 x A
Construction and field expenses	185,325		0.05 x A
Contractor fees	370,650		0.10 x A
Startup	74,130		0.02 x A
Performance test	37,065		0.01 x A
Contingency	926,625		0.25 x A
Subtotal Indirect Costs	**1,964,445**		
Interest during construction	686,290		
TOTAL CAPITAL INVESTMENT	**7,549,185**	(TCI)	

Sources: GE, 1992.
ECT, 1992.

Table 4-21. Annual Operating Costs for Oxidation Catalyst for Stand-Alone CC Units

Item	$		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	18,400	(A)	
Supervisor	2,760		0.15 x A
Maintenance			
Labor	13,700	(B)	
Materials	13,700		1.00 x B
Subtotal Labor, Material, and Maintenance Costs	**48,560**	(C)	
Catalyst costs			
Replacement (materials and labor)	2,771,655		
Disposal	40,000		
Credit for used catalyst	-415,750		
Subtotal Catalyst Costs	2,395,905		
Annualized Catalyst Costs	**964,445**		
Energy Penalties			
Turbine backpressure	329,935		
Downtime for catalyst replacement (annualized)	431,715		
Subtotal Energy Penalties Costs	**761,650**		
Subtotal Direct Costs	**1,774,655**	(TDC)	
Contingency	443,665		0.25 x TDC
Indirect Costs			
Overhead	29,135		0.60 x C
Administrative charges	150,985		0.02 x TCI
Property taxes	75,490		0.01 x TCI
Insurance	75,490		0.01 x TCI
Capital recovery	630,275		
Subtotal Indirect Costs	**961,375**		
TOTAL ANNUAL COST	**3,179,695**		

Sources: GE, 1992.
ECT, 1992.

Table 4-22. Capital Costs for Oxidation Catalyst for Stand-Alone Simple-Cycle CTs

Item	$		OAQPS Factor
<u>Direct Costs</u>			
Purchased equipment	5,559,500	(A)	
Installation			
Foundations and supports	444,760		0.08 x A
Handling and erection	778,330		0.14 x A
Electrical	222,380		0.04 x A
Piping	111,190		0.02 x A
Insulation for ductwork	55,595		0.01 x A
Painting	55,595		0.01 x A
Subtotal Installation Cost	**1,667,850**		
Site preparation	150,000		
Subtotal Direct Costs	**7,377,350**		
<u>Indirect Costs</u>			
Engineering	555,950		0.10 x A
Construction and field expenses	277,975		0.05 x A
Contractor fees	555,950		0.10 x A
Startup	111,190		0.02 x A
Performance test	55,595		0.01 x A
Contingency	1,389,875		0.25 x A
Subtotal Indirect Costs	**2,946,535**		
Interest during construction	1,032,390		
TOTAL CAPITAL INVESTMENT	**11,356,275**	(TCI)	

Sources: GE, 1992.
ECT, 1992.

Table 4-23. Annual Operating Costs for Oxidation Catalyst for Stand-Alone Simple-Cycle CTs

Item	$		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	13,800	(A)	
Supervisor	2,070		0.15 x A
Maintenance			
Labor	10,265	(B)	
Materials	10,265		1.00 x B
Subtotal Labor, Material, and Maintenance Costs	**36,400**	(C)	
Catalyst costs			
Replacement (materials and labor)	4,157,484		
Disposal	120,000		
Credit for used catalyst	-623,620		
Subtotal Catalyst Costs	3,653,865		
Annualized Catalyst Costs	**840,430**		
Energy Penalties			
Turbine backpressure	168,718		
Downtime for catalyst replacement (annualized)	252,285		
Subtotal Energy Penalties Costs	**421,000**		
Subtotal Direct Costs	**1,297,830**	(TDC)	
Contingency	324,460		0.25 x TDC
Indirect Costs			
Overhead	21,840		0.60 x C
Administrative charges	227,125		0.02 x TCI
Property taxes	113,565		0.01 x TCI
Insurance	113,565		0.01 x TCI
Capital recovery	949,695		
Subtotal Indirect Costs	**1,425,790**		
TOTAL ANNUAL COST	**3,048,080**		

Sources: GE, 1992.
ECT, 1992.

Table 4-24. Summary of CO BACT Analysis for Stand-Alone CC Units and CTs

	Emission Impacts			Economic Impacts				Environmental Impacts	
Control Option	Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impact Increase Over Baseline (MMBtu/yr)	Toxic Impact?	Adverse Environmental Impact?
CC Units*									
Oxidation catalyst	86.3	377.8	616.5	7,549,185	3,179,695	5,158	19,882	Yes	Yes
Baseline	227.0	994.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Simple-Cycle CTs†									
Oxidation catalyst	77.7	340.2	540.2	11,356,275	3,048,080	5,643	14,912	Yes	Yes
Baseline	201.0	880.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A

*Basis: two CC units, 100-percent load, 59°F ambient temperature, 75 percent natural gas-firing annual capacity factor, 25 percent distillate fuel oil annual capacity factor.

†Basis: six simple cycle CTs, 100-percent load, 59°F ambient temperature, 50 percent natural gas-firing annual capacity factor, 10 percent distillate fuel oil annual capacity factor.

Source: ECT, 1992.

acceptable compromise with respect to overall NO_x and CO emission rates. Results of the oxidation catalyst economic analysis for the CC units and simple-cycle CTs are summarized in Table 4-24.

4.6.4 PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY EMISSION LIMITATIONS

BACT emission limitations for CO and VOCs obtained from the BLIS database for CT facilities are summarized in Table 4-25 and shown graphically in Figures 4-7 and 4-8. Data shown in Table 4-25 represents recent BACT/LAER determinations, i.e., those entered into BLIS from January 1986 through May 1992. CO emission limits range from 0.020 to 0.605 lb/MMBtu with an average rate of 0.103 lb/MMBtu. BACT CO determinations expressed as a concentration (corrected to 15 percent oxygen) range from 2 to 60 ppmv with an average of 26.2 ppmv. VOC emission limits range from 0.002 to 0.080 lb/MMBtu with an average rate of 0.023 lb/MMBtu. BACT VOC determinations expressed as a concentration (corrected to 15 percent oxygen) range from 4 to 19 ppmv with an average of 7.8 ppmv.

The BLIS database for entries made after January 1986 contains eight CT installations which employ oxidation catalyst technology. Four of these projects employed oxidation catalyst due to nonattainment area considerations (three in California and one in New York). The other four projects installed oxidation catalyst controls to avoid PSD review for either CO or VOCs. The remaining CT BACT determinations are all based on the use of good combustion techniques.

Recent Florida BACT determinations for gas turbines are summarized in Table 4-26. All of these determinations are also based on the use of good combustion techniques. Application of current turbine combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs. Specific BACT emission limits proposed for the Polk Power Station stand-alone CC units and CTs are summarized in Table 4-27. The proposed BACT technology and emission limits are consistent with previous determinations both within Florida and elsewhere in the country.

Table 4-25. BLIS CO and VOC Emission Limitation Summary for CTs

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size		Fuel	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr	Type	ppmv	lb/MMBtu	ppmv	lb/MMBtu	
Alaska	0012	03/18/87	Alaska Electrical Generation and Transmission	80.0	N/A	Gas	N/A	0.114	N/A	N/A	N/A
Alabama	0040	11/30/88	Champion International	35.0	N/A	Gas	9.0 lb/hr	N/A	4.0 lb/hr	N/A	N/A
Arizona	0012	10/18/91	El Paso Natural Gas	N/A	400.0	Gas	60.0	N/A	N/A	N/A	Lean burn
	0010	10/25/91	El Paso Natural Gas	N/A	184.0	Gas	10.5	N/A	N/A	N/A	Lean fuel mix
	0011	10/25/91	El Paso Natural Gas	N/A	184.0	Gas	10.5	N/A	N/A	N/A	Lean fuel mix
California	0112	04/30/85	Shell California Production	22.0	N/A	Gas	10.0	N/A	N/A	N/A	Proper combustion
	0067	06/07/85	Proctor & Gamble	N/A	217.0	Gas Oil	32.0 lb/hr 22.0 lb/hr	0.147 0.101	N/A N/A	N/A N/A	N/A N/A
	0147	06/28/85	Sunlaw/Industrial Park 2	N/A	412.3	Gas	10.0	N/A	N/A	N/A	Mfg. guarantee
	0155	01/17/86	Union Cogeneration	16.0	N/A	Gas	39.0 lb/hr	N/A	8.0 lb/hr	N/A	Oxidation catalyst (CO eff. = 80%, VOC eff. = 7%)
	0221	03/10/86	AES Placerita, Inc.	N/A	519.0	Gas	2.0	N/A	N/A	N/A	Oxidation catalyst
	0186	02/20/87	U.S. Borax & Chemical Corp.	45.0	N/A	Gas Oil	23.0 lb/hr 30.0 lb/hr	N/A N/A	N/A N/A	N/A N/A	Proper combustion techniques Proper combustion techniques
	0196	03/06/87	Sycamore Cogeneration Co.	75.0	N/A	Gas	10.0	N/A	N/A	N/A	Oxidation catalyst
	0251	06/19/87	San Joaquin Cogen Limited	48.6	N/A	Gas	55.0	N/A	N/A	N/A	Combustion controls
	0262	01/27/88	Midway-Sunset Cogeneration	75.0	N/A	Gas/Oil	94.0 lb/hr	N/A	N/A	N/A	Proper combustion
	0179	02/26/88	Combined Energy Resources	25.94	268.5	Gas	N/A	N/A	7.95 lb/hr	0.030	Oxidation catalyst (44% VOC eff.)
	0296	11/01/88	Texaco-Yokum Cogeneration	24.50	N/A	Gas	N/A	0.022	N/A	N/A	N/A

Table 4-25. BLIS CO and VOC Emission Limitation Summary for CTs (Continued, Page 2 of 4)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size		Fuel Type	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr		ppmv	lb/MMBtu	ppmv	lb/MMBtu	
Connecticut	0025	10/23/89	Capitol District Energy District	N/A	738.8	Gas	N/A	0.112	N/A	N/A	N/A
						Oil	N/A	0.109	N/A	N/A	N/A
	0054	02/16/88	Downtown Cogeneration Association	N/A	71.9	Gas	N/A	0.048	N/A	N/A	N/A
						Oil	N/A	0.290	N/A	N/A	N/A
	0031	05/18/88	CCF-1	N/A	110.0	Gas	N/A	0.605	N/A	N/A	N/A
						Oil	N/A	1.883	N/A	N/A	N/A
Colorado	0017	02/19/92	Thermo Industries, Ltd.	42.0	246.0	Gas	25	0.120	N/A	0.068	Combustion control
Delaware	0006	08/23/88	Delmarva Power	N/A	100.0	Oil	15	N/A	N/A	N/A	Good combustion
	0008	09/27/90	Delmarva Power	N/A	100.0	Oil	15	N/A	N/A	N/A	Combustion efficiency
Florida	0042	09/01/88	Orlando Utilities	35.0	N/A	Gas	10	N/A	7	N/A	Combustion control
	0043	05/30/89	Tropicana Products	45.4	N/A	Gas	N/A	0.140	N/A	N/A	N/A
Louisiana	0079	08/05/91	Enron Louisiana Energy	N/A	39.1	Gas	5.8 lb/hr	0.148	N/A	N/A	No controls (CO = 60 ppm)
Michigan	0054	02/16/88	Midland Cogeneration Venture	N/A	984.2	Gas	26.0 lb/hr	0.026	N/A	N/A	Turbine design
	0082	06/21/88	Ada Cogeneration	N/A	245.0	Gas	N/A	0.100	N/A	N/A	Turbine design
						Oil	N/A	0.350	N/A	N/A	Water injection
	0206	12/03/91	Kalamazoo Power Limited	234.0	1805.9	Gas	20	N/A	N/A	N/A	Dry, low NO_x turbines
North Carolina	0051	09/06/89	Panda-Rosemary Corp.	N/A	499.0	Gas	10.8 lb/hr	0.022	4.8 lb/hr	0.009	Combustion control
					509.0	Oil	10.9 lb/hr	0.021	4.7 lb/hr	0.009	Combustion control
					1047.0	Gas	23.1 lb/hr	0.022	10.2 lb/hr	0.010	Combustion control
					1060.0	Oil	23.0 lb/hr	0.022	10.1 lb/hr	0.010	Combustion control
New Jersey	0006	01/03/85	Ciba-Geigy Corp.	3.0	N/A	Gas	9.4 lb/hr	N/A	N/A	0.009	N/A
	0008	06/03/87	Cogen Technologies	40.0	N/A	Gas	50.0	N/A	N/A	N/A	N/A

Table 4-25. BLIS CO and VOC Emission Limitation Summary for CTs (Continued, Page 3 of 4)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size		Fuel Type	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr		ppmv	lb/MMBtu	ppmv	lb/MMBtu	
New York	0013	03/10/88	TBG/Grumman	16.0	N/A	Gas	N/A	0.181	N/A	N/A	Oxidation catalyst; 80% eff. (CO nonattainment area)
	0022	09/01/88	Kamine South Glen Falls	40.0	N/A	Gas	N/A	0.021	N/A	0.009	Combustion control
	0024	11/01/88	Long Island Lighting Co.	75.0	N/A	Gas	10	N/A	N/A	0.006	Combustion control
	0026	07/01/88	Kamine Carthage	40.0	N/A	Gas	N/A	0.022	N/A	0.080	Combustion control
	0027	07/01/88	Trigen	40.0	N/A	Gas	N/A	0.023	N/A	0.011	Combustion control
	0029	02/07/89	Indec/Oswego Hill	40.0	N/A	Gas	N/A	0.022	N/A	N/A	Combustion control
	0033	09/01/89	Kamine Syracuse	79.0	N/A	Gas	N/A	0.028	N/A	0.028	Combustion control
	0036	02/26/90	Oneida Cogeneration	54.0	417.0	Gas	40	N/A	N/A	0.013	Combustion control
	0037	03/06/89	Megan-Racine Associates	N/A	430.0	Gas	N/A	0.026	N/A	N/A	Combustion control
						Oil	N/A	0.150	N/A	N/A	Combustion control (Includes duct burner)
	0038	05/02/89	Empire Energy - Niagara	N/A	416.0	Gas	N/A	0.024	N/A	0.012	Combustion control
	0039	01/29/90	Fulton Cogeneration	N/A	500.0	Gas	N/A	0.020	5.0	0.010	Combustion control
	0040	11/21/89	JMC Selkirf, Inc.	N/A	416.0	Gas	N/A	0.024	N/A	0.012	Combustion control
Oregon	0006	05/19/87	Pacific Gas Transmission	10.4	N/A	Gas	6.0 lb/hr	N/A	N/A	N/A	N/A
Pennsylvania	0052	10/12/88	Amtrak	20.0	N/A	Gas	30.8 lb/hr	N/A	N/A	N/A	N/A
	0083	05/03/91	Northern Consolidated Power	34.6	N/A	Gas	110 tpy		105	N/A	Oxidation catalyst (Not PSD affected)
Rhode Island	0004	12/13/88	Ocean State Power	125.0	1059.0	Gas	25	N/A	4.1	N/A	N/A
	0008	01/30/89	Pawtucket Power	N/A	533.0	Gas	23	N/A	19.0	N/A	N/A
						Oil	10	N/A	8.0	N/A	N/A

Table 4-25. BLIS CO and VOC Emission Limitation Summary for CTs (Continued, Page 4 of 4)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size		Fuel Type	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr		ppmv	lb/MMBtu	ppmv	lb/MMBtu	
South Carolina	0021	09/23/91	Carolina Power and Light	80.0	N/A	Gas/Oil	60.0 lb/hr	N/A	N/A	N/A	N/A
Texas	0178A	03/05/85	Champion International	30.6	1342.0	Gas	70.1 tpy	N/A	N/A	N/A	N/A
	0048A	05/29/86	Formosa Plastic Corp.	38.4	N/A	Gas	32.4 tpy	N/A	N/A	N/A	N/A
Virginia	0175	03/05/91	Commonwealth Atlantic Ltd. Partnership	100.0	1533.0	Gas	30	N/A	4.0	N/A	Combustion controls
					1400.0	Oil	30	N/A	16.0	N/A	Combustion controls
	0177	05/04/90	Doswell Limited Partnership	N/A	1261.0	Gas	25.0 lb/hr	0.020	4.4 lb/hr	0.004	Combustor design & operation
	0184	03/03/92	Bermuda Hundred Energy Limited Partners	N/A	1175.0	Gas	62.0 lb/hr	0.053	2.3 lb/hr	0.002	Furnace design
					1117.0	Oil	62.0 lb/hr	0.056	5.8 lb/hr	0.005	Furnace design
Vermont	0005	12/20/89	Arrowhead Cogeneration Co.	N/A	282.0	Gas	50	N/A	N/A	N/A	Design & good combustion
	0007	08/10/90	East Georgia Cogeneration	28.0	400.0	Gas	57	N/A	30.5 lb/hr	0.076	Gas fuel
						Oil	162	N/A	N/A	N/A	Oil fuel
	0008	07/27/90	Vermont Marble Company	4.0	50.0	Gas	36	N/A	N/A	N/A	Proper CT design & operation
						Oil	83	N/A	N/A	N/A	Proper CT design & operation
Washington	0025	10/26/90	March Point Cogeneration	80.0	N/A	Gas	37	N/A	N/A	N/A	Good combustion
	0026	12/01/90	Sumas Energy Inc.	67.0	N/A	Gas	15	N/A	N/A	N/A	Oxidation catalyst (To avoid PSD review)
	0027	06/25/91	Sumas Energy Inc.	88.0	N/A	Gas	6	N/A	N/A	N/A	Oxidation catalyst-80% CO eff. (To avoid PSD review)

Source: EPA, 1992a.

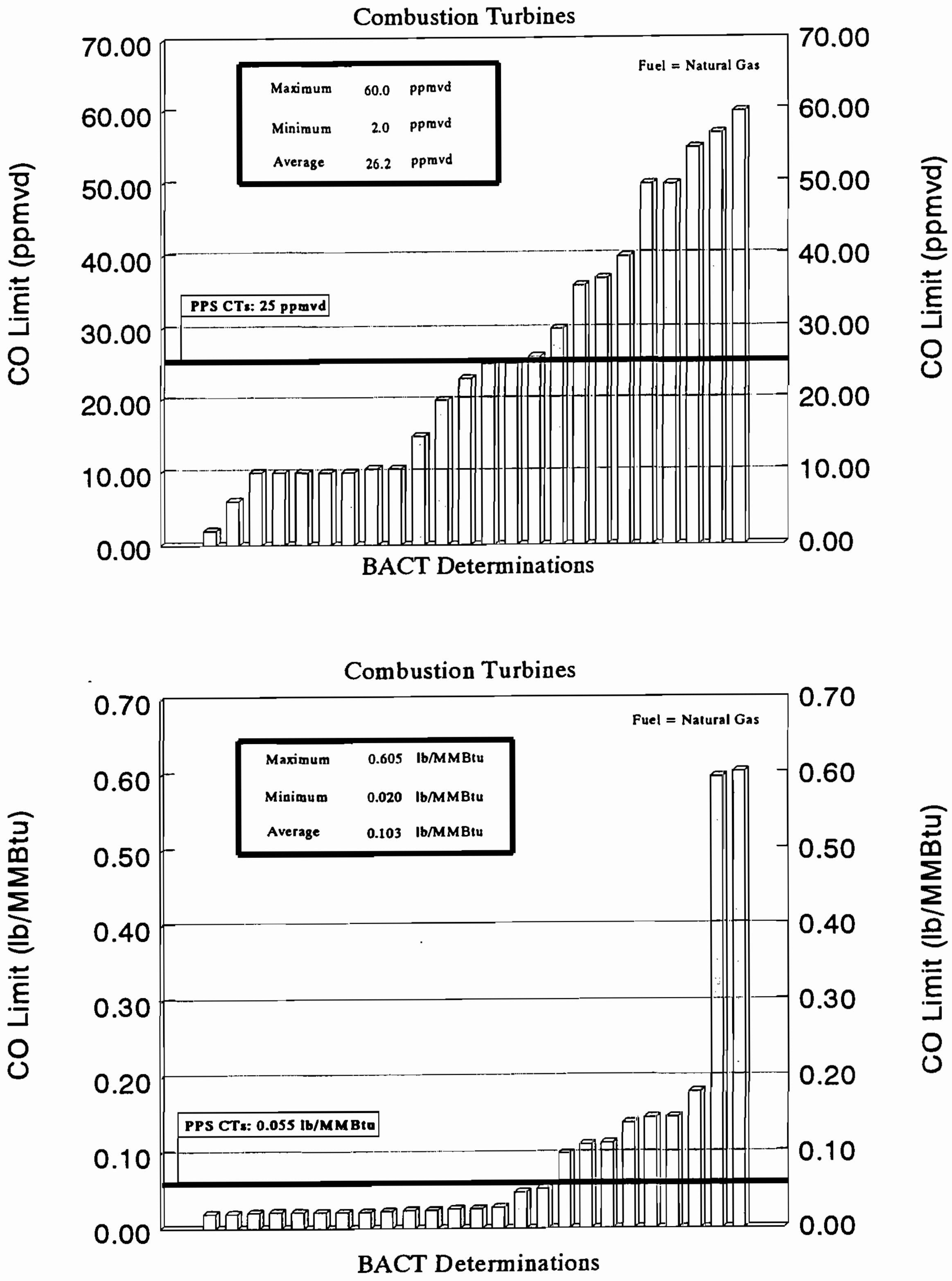


FIGURE 4-7.

SUMMARY OF CO BACT DETERMINATIONS: GAS-FIRED CTs

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

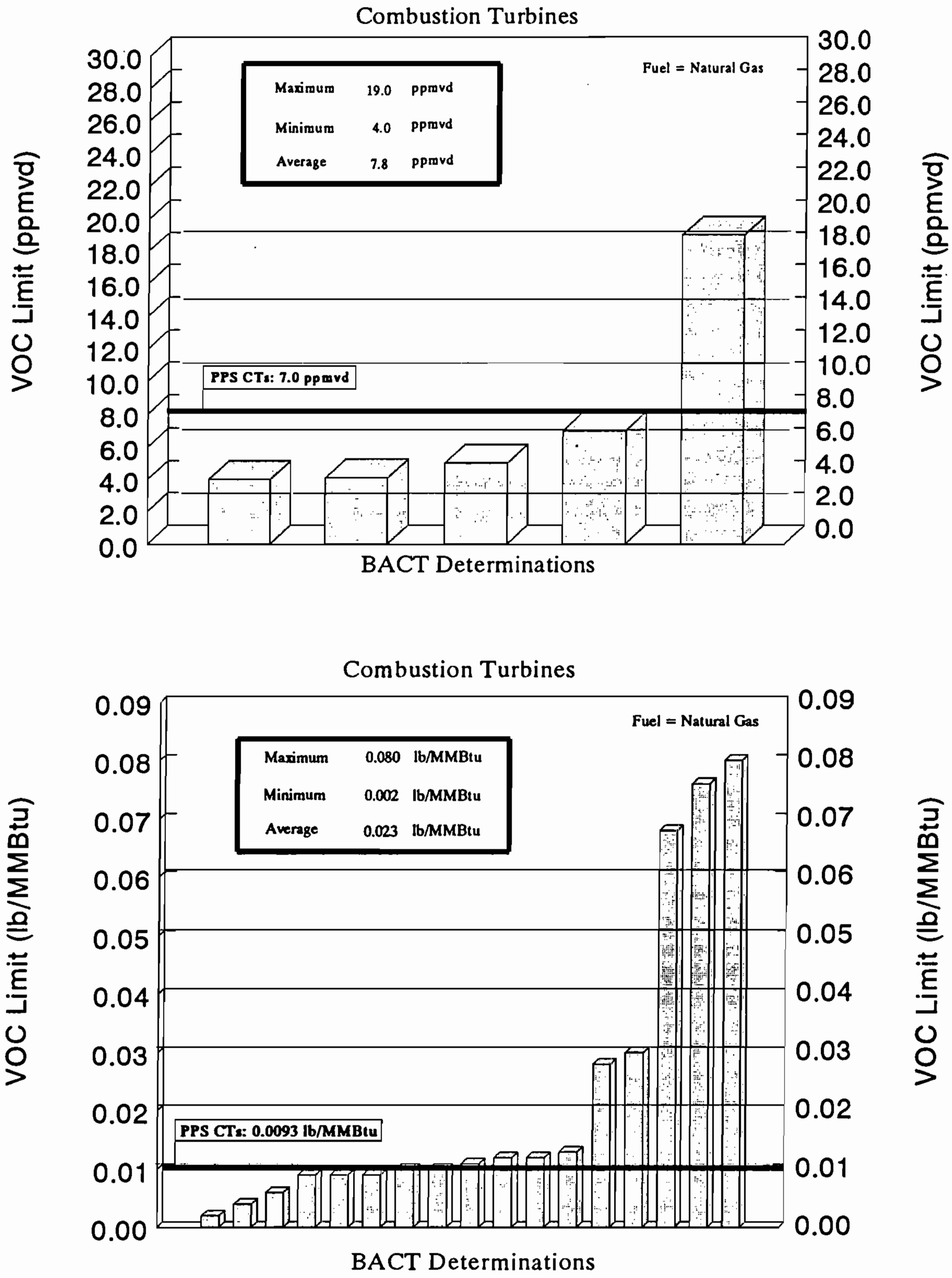


FIGURE 4-8.

SUMMARY OF VOC BACT DETERMINATIONS:
GAS-FIRED CTs

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

Table 4-26. Florida BACT CO and VOC Emission Limitation Summary for CTs

Permit		Turbine Size		Fuel	CO Emission Limit		VOC Emission Limit		
Date	Source Name	MW	MMBtu/hr	Type	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	Control Technology
05/31/91	Florida Power & Light Martin Expansion Project	150.0	1,966	Gas	94.3 (based on 30 ppmvd)	0.048	3.0 (based on 1.6 ppmvd)	0.0015	Combustion design and clean fuels
			1,846	Oil	105.8 (based on 33 ppmvd)	0.057	11.0 (based on 6 ppmvd)	0.0060	Combustion design and clean fuels
10/18/91	Florida Power Corporation Debary Facility	92.9	1,114	Oil	54.0 (based on 25 ppmvd)	0.049	5.0	0.004	Combustion design and clean fuels
07/26/91	City of Lakeland Charles Larsen Plant	80.0	1,055	Gas	232.0 tpy (based on 25 ppm)			9.0 tpy	Combustion design and clean fuels
			1,040	Oil	79.0 tpy (based on 25 ppm)			6.7 tpy	Combustion design and clean fuels
01/04/91	TECO Power Services Hardee Power Station	75.0	1,268.4	Gas	31.3	0.025	3.6	0.003	Combustion design and clean fuels
			1,312.3	Oil	93.4	0.071	10.3	0.008	Combustion design and clean fuels
11/20/91	Pasco Cogen Limited	42.0	384	Gas	80.6 (based on 42 ppmvd)	0.210	3.3	0.009	Combustion design and clean fuels
			387	Oil	151.0 (based on 78 ppmvd)	0.390	8.3	0.021	Combustion design and clean fuels

Source: FDER, 1991a.

Table 4-27. Proposed CO and VOC BACT Emission Limits for Stand-Alone CC Units and CTs

Process	Proposed BACT Emission Limits			
	lb/hr	lb/MMBtu	ppmvd	lb/MW
<u>CO</u>				
CC units (per unit)				
Natural gas	118.0	0.055	25.0	0.536
No. 2 fuel oil	142.0	0.064	30.0	0.645
CTs (per CT)				
Natural gas	59.0	0.055	25.0	0.787
No. 2 fuel oil	71.0	0.064	30.0	0.945
<u>VOC</u>				
CC units (per unit)				
Natural gas	20.0	0.0093	7.0	0.091
No. 2 fuel oil	20.0	0.0090	7.0	0.091
CTs (per CT)				
Natural gas	10.0	0.0093	7.0	0.133
No. 2 fuel oil	10.0	0.0090	7.0	0.133

Sources: GE, 1992.
ECT, 1992.

4.7 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR ACID GASES--INTEGRATED GASIFICATION COMBINED CYCLE FACILITY

BACT evaluations for sulfur compounds and NO_x are discussed in the following sections.

4.7.1 SULFUR OXIDES AND SULFURIC ACID MIST

SO_2, SO_3, and H_2SO_4 mist emissions arise from the combustion of fuels containing sulfur. H_2SO_4 emissions result from the reaction of SO_3 and water in the exhaust gas stream. The conversion rate of SO_2 to SO_3 depends on combustion parameters, e.g., temperature and excess oxygen levels, as well as fuel characteristics.

4.7.1.1 Control Technologies

Removal and recovery of sulfur contained in the inlet coal are integral components of the Texaco CG process. The CG process is highly efficient which results in a low rate of SO_2 emitted per MW of electricity produced in comparison to conventional coal-fired power plants. The CG process removes and recovers sulfur compounds, primarily H_2S, from the high pressure syngas generated by the gasifier. Removal and recovery of sulfur compounds from the syngas stream is much more efficient than removing the same compounds from the post-combustion, highly dilute, low-pressure exhaust streams generated by conventional coal combustion in a steam boiler. The IGCC sulfur recovery process results in a saleable by-product ~~streams, liquid sulfur and~~ H_2SO_4, in contrast to the vast quantities of solid waste materials typically generated by conventional wet or dry FGD systems.

The CG process converts coal to a synthetic gas consisting of CO_2, CO, H_2, water, COS, and H_2S. Using CGCU technology, acid gases (CO_2, H_2S, and COS) present in the syngas are removed using a promoted amine process in the acid gas removal unit. In the acid gas removal unit, syngas is cooled and counter-currently contacted with a promoted amine in the amine absorber. The promoted amine acts as a weak base to selectively absorb the weak H_2S acid while allowing most of the CO_2 to remain in the syngas. CO_2 is a desirable component of syngas since it increases the mass of the syngas stream thereby increasing power production from the downstream

CT. The efficiency of amine absorption increases with increasing inlet gas stream H_2S content and vice versa. Accordingly, reducing the sulfur content of the inlet gas stream will not necessarily result in lower overall plant emissions. The treated syngas stream, containing approximately 0.07 weight percent sulfur, flows from the amine absorber through several coolers and knockout drums for water removal and then is burned in the CT for power production. The rich amine solution containing dissolved acid gases is heated by means of a heat exchanger and then routed to the amine stripper where the acid gases are steam stripped from the rich amine solution. The concentrated acid gas overhead stream from the amine stripper is cooled and routed to the ~~sulfur recovery unit~~ H_2SO_4 plant for processing. Lean amine solution from the amine stripper is cooled and pumped to the amine storage tank for subsequent re-use in the amine absorber.

Amine absorption does not require any refrigeration or compression resulting in a cost effective, energy efficient, and reliable process. Amine treating is the most widely used and efficient process for removing acid gases from sour gas streams.

The concentrated amine stripper overhead stream is routed to the ~~sulfur recovery unit~~ H_2SO_4 plant for conversion of sulfur compounds to H_2SO_4 as described previously. ~~elemental sulfur using gas-phase thermal and catalytic H_2S oxidation. The first step of the process consists of the thermal oxidation of one third of the H_2S to SO_2 in the thermal reactor in accordance with the following reaction:~~

~~$3H_2S + 1.5O_2 \rightarrow SO_2 + H_2O + 2H_2S$~~

~~The thermal reactor is also utilized to oxidize ammonia from the ammonia stripper to nitrogen and water. Pure oxygen will be added as necessary to maintain the temperature of the front chamber of the thermal reactor at approximately 2,200°F. Sufficient air from the thermal reactor air blower and oxygen, as necessary, are supplied to the thermal reactor to: (a) oxidize one-third of the inlet H_2S to SO_2 and water, (b) oxidize ammonia to nitrogen and water, and (c) oxidize any hydrocarbons present in the ammonia stripper stream to CO_2 and water. Hot combustion gases~~

~~from the thermal reactor next flow to a boiler where the gases are cooled and steam is generated. The cooled gas stream then enters the first pass of the primary sulfur condenser where any sulfur produced in the thermal reactor is condensed and drained to a sulfur seal pot via a steam jacketed drain leg. From the seal pot, condensed molten sulfur flows to the sulfur storage pit. The sulfur seal pot provides a liquid seal which prevents process gas from entering the sulfur storage pit via the sulfur drain leg.~~

~~The remaining steps in the catalytic sulfur recovery process involve the catalytic reaction of~~ ~~H_2S~~ ~~to form elemental sulfur in accordance with the following reaction:~~

~~$2H_2S + SO_2 \rightarrow 3S + 2H_2O$~~

~~Uncondensed gas from the first pass of the primary sulfur condenser is reheated and routed to the first catalytic reactor where~~ ~~SO_2~~ ~~reacts with~~ ~~H_2S~~ ~~over a fixed bed of activated alumina catalyst. Sulfur formed in the first catalytic reactor is condensed in the second pass of the primary sulfur condenser. Liquid sulfur condensed in the sulfur condenser is sent to the sulfur storage pit using a steam jacketed drain leg and sulfur seal pot arrangement similar to that employed for the primary sulfur condenser first pass outlet.~~

~~The catalytic oxidation of~~ ~~H_2S~~ ~~is repeated in the second and third stage catalytic reactors. Uncondensed gas from the second pass of the primary sulfur condenser is reheated and routed to the second catalytic reactor. Since the concentration of reactants is lower in the second catalytic reactor than the first, less reaction takes place. Sulfur formed in the second catalytic reactor is condensed in the third pass of the primary sulfur condenser. Again, condensed liquid sulfur flows to the sulfur storage pit via a steam jacketed drain leg and sulfur seal pot. Uncondensed gas from the third pass of the primary sulfur condenser is reheated and routed to the third and final catalytic reactor. Since the concentration of reactants is much lower in the third catalytic reactor, only a relatively small amount of sulfur is formed. Sulfur formed in the third catalytic reactor is condensed in the final sulfur condenser. Condensed~~

~~liquid sulfur from the final condenser flows to the sulfur storage pit via a steam jacketed drain leg and sulfur seal pot.~~

~~The sulfur recovery unit outlet gas stream exhausts to the tail gas treating unit. The three stage catalytic sulfur recovery process will typically convert approximately 96 percent of inlet acid gas H_2S to liquid sulfur. The tail gas treating unit is designed to recover the remaining unreacted H_2S for recycle back to the inlet of the sulfur recovery unit. The tail gas treating unit essentially reverses the sulfur recovery oxidation reactions by reducing the oxidized sulfur species to H_2S. In the first step of the tail gas treating unit process, sulfur recovery plant tail gas is heated and reacted with hydrogen over a cobalt molybdenum catalyst in the tail gas treating unit catalytic reactor. All sulfur compounds, including SO_2, sulfur vapor, COS, and CS_2 are reduced to H_2S by a variety of exothermic reactions. To assure complete reaction of the sulfur compounds to H_2S, a minimum of approximately 50 percent of the stoichiometric requirement of hydrogen rich gas is fed to the catalytic reactor. The second stage of the tail gas treating unit process consists of the cooling of the catalytic reactor overhead stream in a waste heat boiler followed by a direct contact water quench. In the final step of the tail gas treating unit process, the cooled overhead stream flows to an amine absorber where H_2S is selectively removed from the gas stream. The tail gas treating unit amine absorption process is similar to that which is employed to remove acid gases from the coal gasifier syngas stream. H_2S absorbed in the rich amine solution is removed by steam stripping and recycled to the inlet of the sulfur recovery unit. The amine stripper overhead stream, containing less than 260 ppmvd H_2S, is routed to the tail gas treating unit thermal oxidizer for oxidation of any remaining reduced sulfur compounds to SO_2.~~

~~The catalytic sulfur recovery process is the most widely used commercial process for treating sour gas streams. The process generates a saleable liquid sulfur by product while reducing SO_2 emissions to very low levels. The Polk Power Station IGCC will include a sulfur recovery unit consisting of a thermal reactor following by three stages~~

~~of catalytic reactors. The tail gas from the final catalytic stage will be further treated in the tail gas treating unit prior to being oxidized and discharged to the atmosphere.~~

The sulfur removal and recovery process which is integral to the IGCC facility will achieve an overall sulfur removal efficiency of 95.6 percent. *This removal efficiency is higher than the highest efficiency listed in BLIS for large, coal-fired power plants and exceeds that required for recently permitted Florida CG and coal-fired boiler facilities.* Sulfur content of the treated syngas is projected to be less than 0.07 weight percent.

The demonstration HGCU system removes H_2S from the coal gasifier syngas stream at elevated temperatures by reacting the gas stream with zinc titanate sorbent in a moving bed absorber according to the following reaction:

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

The zinc titanate sorbent is regenerated by controlled temperature, multi-stage oxidation in a regenerator. Chemical reactions occurring in the regenerator are:

$$2ZnS + 2O_2 \rightarrow ZnO + SO_2$$

$$2ZnO + 2SO_2 + O_2 <==> 2ZnSO_4$$

Regenerated sorbent is then returned to the absorber for reuse. The concentrated SO_2 stream from the regenerator is routed to a H_2SO_4 plant for conversion to H_2SO_4 as follows:

~~$SO_2 + 2H_2O \rightarrow H_2SO_4 + H_2$~~

$$SO_2 + \frac{1}{2}O_2 \rightarrow SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

The treated syngas is sent to a high temperature barrier filter, which will remove greater than 99.5 percent of the residual PM, prior to entering the IGCC CT. A commercial grade sodium bicarbonate will be injected upstream of the barrier filter to react with and remove chloride and fluoride species from the syngas stream.

The high temperature zinc titanate absorption system has the potential to achieve sulfur removals approximately an order of magnitude greater than conventional

CGCU technology while improving the overall efficiency of the IGCC facility. At a minimum, sulfur removal efficiency for the HGCU technology will equal that of conventional CGCU. The purpose of the 2-year HGCU demonstration period is to demonstrate the overall system performance with respect to emissions and operability which can be obtained from this technology in a commercial facility.

4.7.1.2 Energy and Environmental Impacts

As previously noted, the sulfur removal and recovery processes that are integral to the CG process are highly efficient resulting in low SO_2 emissions per MW of power produced in comparison to conventional coal-fired power plants. In addition, the IGCC sulfur recovery process generates a saleable ~~liquid sulfur and~~ H_2SO_4 by-product~~s~~ instead of the large volumes of solid waste that are typically generated from conventional wet or dry FGD systems. Low sulfur distillate oil will serve as a back-up fuel for IGCC CT. Ambient SO_2 impacts due to combustion of the treated low sulfur syngas and back-up distillate fuel oil in the IGCC CT will meet all applicable air quality standards.

4.7.1.3 Proposed Best Available Control Technology Emission Limitations

BACT emission limitations for SO_2 obtained from the BLIS database for CG facilities are summarized in Table 4-28.

A summary of BLIS SO_2 determinations for coal-fired boilers is provided in Table 4-29 and shown graphically in Figure 4-9. Data shown in Table 4-29 represents recent BACT/LAER determinations, i.e., those entered into BLIS from January 1986 through May 1992. SO_2 BACT determinations range from 0.036 to 1.670 lb/MMBtu with an average of 0.543 lb/MMBtu. Recent FDER SO_2 BACT decisions for coal-fired power plants are summarized in Table 4-30.

Use of the integral acid gas removal and recovery processes is proposed as BACT for the IGCC facility. *Overall sulfur recovery efficiency is 95.6 percent, which surpasses prior CG BACT determinations and exceeds the highest efficiency contained in BLIS for large, coal-fired power plants.* Use of low sulfur distillate oil is proposed as BACT for the ancillary IGCC combustion sources, i.e., auxiliary boiler and thermal oxidizers. Specific BACT emission limits proposed for the IGCC facility are summarized in Table 4-31. The proposed BACT technology and emission limits are consistent with previous determinations both within Florida and elsewhere in the country.

Table 4-28. SO$_2$ Emission Limitation Summary for CG Facilities

State	BLIS I.D. Number	Permit Date	Source Name	Heat Input (MMBtu/hr)	SO$_2$ Emission Limits			Control Technology
					lb/hr	lb/MMBtu	Wt% S	
California	0027	12/09/81	Southern CA Edison Coolwater Station SCOT unit thermal oxidizer	N/A	9.4	N/A	N/A	
					(up to 0.7% S Coal)			
				N/A	65.0	N/A	N/A	
					(0.7% to 3.5% S Coal)			
			CT	842.0	35.0	0.042	N/A	
					(up to 0.7% S Coal)			
				842.0	175.0	0.208	N/A	
					(0.7% to 3.5% S Coal)			
Florida	N/A	05/31/91	FP&L Martin County (per CT)	2,100.0	834.0	0.397	0.3	
Virginia	0098	04/15/88	Virginia Power	1,875.0	572.0	0.330	0.3	Sulfur limit on fuel

Note: Wt%S = weight percent sulfur.

Sources: EPA, 1992a.
FDER, 1991a.
SBCAPCD, 1989.

Table 4-29. BLIS SO_2 Emission Limitation Summary for Coal-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	SO_2 Emission Limits				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
California	0120	04/26/85	SCF - Ridgen Power Project	16.5	212.0	9.4	0.044	23.0	0.570	92.0	Limestone injection
	0128A	10/29/85	Corn Products	N/A	620.0	59.2	0.095	N/A	N/A	90.0	Limestone injection
	0129	12/13/85	Cogeneration National Corp.	49.0	300.0	26.0	0.086	N/A	0.531	95.0	Recir. fluid. bed
	0129A	12/13/85	Cogeneration National Corp.	N/A	279.6	13.0	0.046	N/A	N/A	95.0	Limestone injection
	0128	12/16/85	Corn Products	49.0	N/A	59.0	N/A	N/A	N/A	90.0	Limestone injection
	0158	06/20/86	BMCP	N/A	N/A	N/A	0.039	N/A	N/A	96.0	Limestone injection
	0092B	10/22/86	Rio Bravo Refining Co.	26.0	389.0	14.0	0.036	20.0	0.538	95.0	Limestone injection
	0178	01/12/87	Mount Poso Cogeneration Co.	50.0	N/A	N/A	0.040	N/A	N/A	90.0	Limestone in bed
	0180	01/28/87	GWF Power Systems Co.	25.0	274.0	N/A	N/A	20.2	N/A	N/A	Limestone injection
	0282	02/11/88	GWF Power Systems Co., Inc.	N/A	202.0	22.0	0.109	N/A	N/A	N/A	Sorbent injection system
Connecticut	0067	08/09/89	AES Thames, Inc.	N/A	923.0	295.4	0.320	N/A	N/A	70.0	Limestone injection
Georgia	0030	09/21/90	Thomaston Mills, Inc.	N/A	214.76	49.4	0.230	N/A	N/A	90.0	Spray dryer, 1.5% S coal
Hawaii	0009	01/25/90	Applied Energy Services	N/A	2,150.0	645.0	0.300	48.0	N/A	90.0	Limestone bed
Kentucky	0007B	12/13/85	Tennessee Valley Authority	N/A	200.0	240.0	1.200	N/A	N/A	83.9	Limestone injection
	0007A	04/15/86	Tennessee Valley Authority	N/A	1,430.0	1,229.8	0.860	N/A	N/A	90.0	Limestone injection
	0007C	05/04/88	Tennessee Valley Authority	N/A	1,579.0	1,894.8	1.200	N/A	N/A	90.0	Limestone injection
Michigan	0048	07/31/87	Cogentrix Michigan Leasing	N/A	214.0	101.7	0.475	N/A	N/A	90.0	Lime spray dryer, 3% S (30 day rolling average)
				N/A	214.0	357.4	1.670	N/A	N/A	90.0	Lime spray dryer, 3% S (24 hour rolling average)
	0051	12/07/87	City of Wyandotte	N/A	369.0	183.0	0.496	N/A	N/A	90.0	Limestone injection

Table 4-29. BLIS SO_2 Emission Limitation Summary for Coal-Fired Boilers (Continued, Page 2 of 3)

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	SO_2 Emission Limits				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
North Carolina	0037	05/28/86	Cogentrix Carolina Leasing	53.0	606.0	993.8	1.640	N/A	18.75	N/A	1% S coal
	0039	07/07/86	Cogentrix Carolina Leasing	106.0	1,212.0	1,987.7	1.640	N/A	18.75	N/A	1% S coal
	0050	07/20/89	Cogentrix of Rocky Mount	N/A	1,500.0	465.0	0.310	N/A	N/A	N/A	Dry lime FGD
	0054	01/24/91	Roanoke Valley Project	N/A	1,700.0	362.1	0.213	N/A	N/A	92.0	Dry lime FGD
New Jersey	-	Draft	Keystone Cogeneration	224.0	2,116.0	342.1	0.160	75.0	1.527	93.0	Lime spray dryer FGD
	-	Draft	Chambers Works Cogeneration	250.0	2,778.0	611.2	0.220	100.0	2.445	93.0	Lime spray dryer FGD
New York	0014	04/01/87	Fort Drum Heating Plant	N/A	190.0	228.0	1.200	N/A	N/A	90.0	Limestone in bed
	0030	09/25/88	United Development Group	N/A	577.0	288.5	0.500	N/A	N/A	90.0	Limestone injection
Ohio	0145	02/05/87	Wm. H. Zimmer Gener. Station	N/A	11,968.0	6,558.5	0.548	N/A	N/A	91.0	Magesium-enhanced lime FGD
Pennsylvania	0047	12/02/85	Signal Frackville Energy	40.0	N/A	N/A	0.210	N/A	N/A	N/A	Limestone injection
	0046	01/06/86	Westwood Energy Properties	30.0	425.0	85.0	0.200	N/A	2.833	93.6	Limestone injection
	0035	11/01/86	J. Pagnotti Enterprises	80.0	1,082.0	238.0	0.220	N/A	2.976	N/A	Limestone injection
	0034	12/01/86	Sheridan Coal Co.	40.0	550.0	137.5	0.250	N/A	3.438	N/A	Limestone injection
	0036	12/29/86	Foster Wheeler Power	77.0	566.0	135.8	0.240	N/A	1.764	N/A	Limestone injection
	0045	01/16/87	Archbald Power Corp.	20.0	240.0	36.0	0.150	N/A	1.800	90.0	Limestone injection
	0042	02/17/88	Panther Creek Energy	80.0	1,170.0	386.1	0.330	N/A	4.826	85.0	
	0049	06/06/88	Edensburg Power Co.	N/A	617.0	617.0	1.000	N/A	N/A	90.0	Limestone injection
	0044A	06/17/88	Northeastern Power Co.	49.0	513.0	164.2	0.320	N/A	3.350	N/A	Limestone injection
	0057	01/18/89	Scrubgrass Power Corp.	80.0	1,198.0	539.1	0.450	N/A	6.739	95.0	Limestone injection

Table 4-29. BLIS SO_2 Emission Limitation Summary for Coal-Fired Boilers (Continued, Page 3 of 3)

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	SO_2 Emission Limits				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
	0062	05/26/89	Cambria Cogen, Inc.	79.8	1,118.0	556.0	0.497	N/A	6.967	90.0	Limestone injection
	0058	09/26/88	North Branch Energy Partners	90.0	1,126.0	1,024.7	0.910	N/A	11.385	90.0	Limestone injection
	0072	06/08/90	Panther Creek Partners	80.0	1,228.0	191.6	0.156	N/A	2.395	95.0	Limestone injection
	0073	07/23/90	MidAtlantic Energy of PA	30.0	392.0	392.0	1.000	N/A	13.067	90.0	Limestone injection
Rhode Island	0009	03/11/91	East Providence Cogeneration	72.0	856.5	256.9	0.300	N/A	3.569	90.0	Limestone injection
Utah	0034	10/01/86	Utah Power & Light Co.	400.0	N/A	N/A	1.200	N/A	N/A	80.0	
Virginia	0034	06/12/86	Cogentrix of Virginia, Inc.	N/A	200.0	304.0	1.520	N/A	N/A	N/A	
	0044	12/18/86	Tultex Corp.	N/A	12.0	12.36	1.030	N/A	N/A	N/A	0.9% S coal
	0178	01/02/91	Cogentrix of Richmond	304.0	3,000.0	390.0	0.130	N/A	1.283	90.0	Dry scrubber
	0181	04/29/91	Old Dominion Electric Coop.	786.0	8,170.0	817.0	0.100	N/A	1.039	94.0	FGD (annual avg)
				786.0	8,170.0	1,274.5	0.156	N/A	1.622	94.0	FGD (30-day avg)
Wisconsin	0036	N/A	Wisconsin Electric Power Co.	80.0	825.0	990.0	1.200	N/A	12.375	90.0	Dolemite injection
	0041	09/21/88	Fort Howard Corp.	N/A	505.0	353.5	0.700	N/A	N/A	90.0	Limestone injection
	0061	01/01/92	Milwaukee Co. Power Plant	N/A	157.0	122.5	0.780	N/A	N/A	90.0	Lime injection

Source: EPA, 1992a.

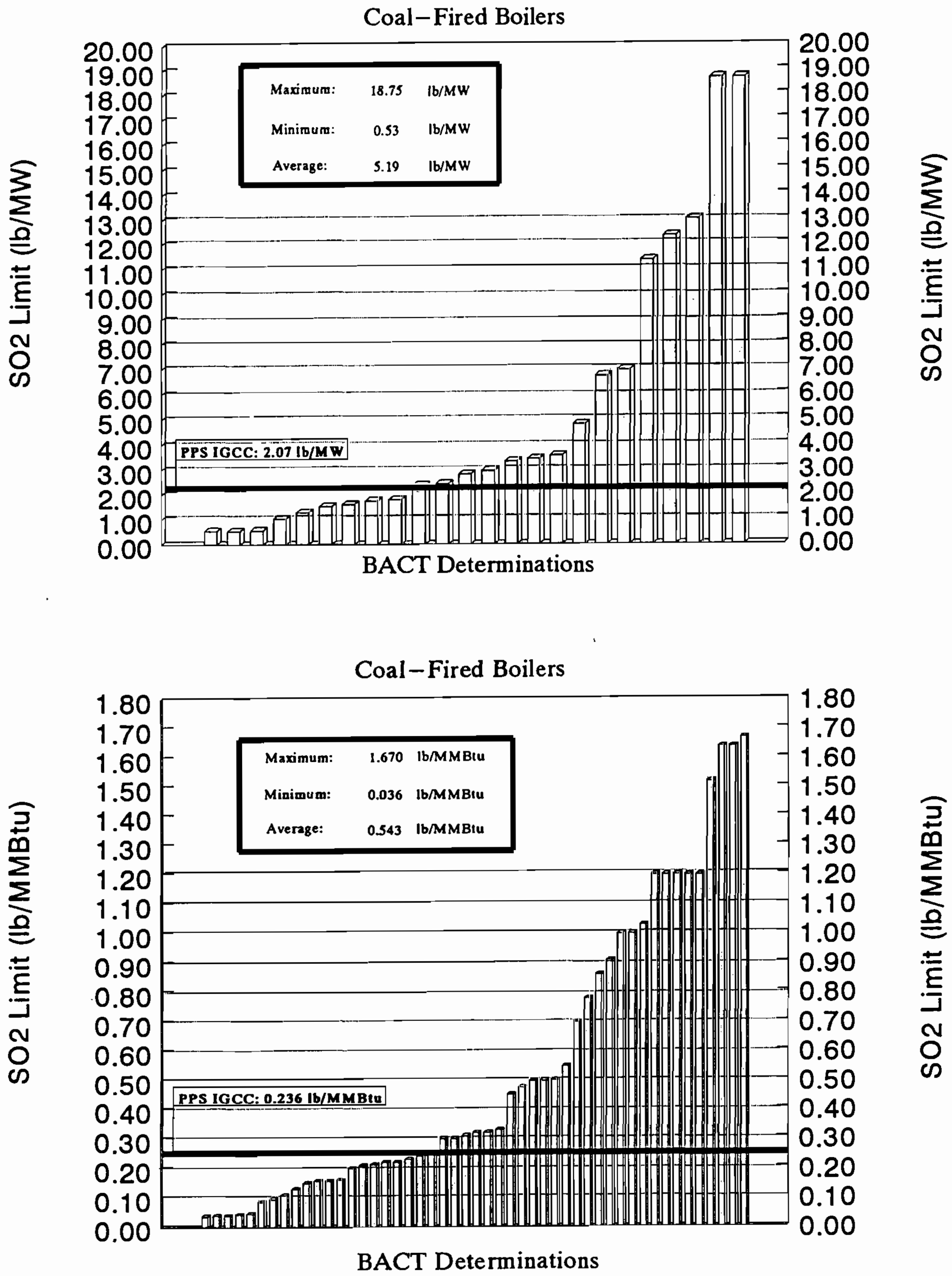


FIGURE 4-9.

SUMMARY OF SO_2 BACT DETERMINATIONS: COAL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

Table 4-30. Florida BACT SO_2 Emission Limitation Summary for Coal-Fired Boilers

Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	SO_2 Emission Limits lb/hr	lb/MMBtu	lb/MW	Control Efficiency	Control Technology
12/31/91	Orlando Utilities Stanton Unit No. 2	465.0	4,286	728.5	0.170	1.567	N/A	FGD
03/25/92	Indiantown cogeneration	330.0	3,422	581.7	0.170	1.763	95.0	Dry scrubber FGD

Source: FDER, 1991a.

Table 4-31. Proposed SO_2 and H_2SO_4 BACT Emission Limits for the IGCC Facility

Process	Proposed BACT Emission Limits		
	lb/hr	lb/MMBtu	lb/MW
SO_2			
CT, Simple-Cycle No 2 fuel oil	92.2	0.048	0.615
IGCC, CT/HRSG			
100 percent CGCU	518.0	~~0.236~~ 0.247*	~~2.073~~ 2.167†
50 percent CGCU/50 percent HGCU	518.0	~~0.236~~ 0.247*	~~2.073~~ 2.167†
No. 2 fuel oil	92.2	0.048	0.419
IGCC, auxiliary boiler	2.6	0.053	N/A
~~IGCC, tail gas treating unit thermal oxidizer~~	~~52.0~~	~~N/A~~	~~N/A~~
IGCC, ~~HGCU~~ H_2SO_4 plant thermal oxidizer	~~10.1~~ 45.3	N/A	N/A
H_2SO_4			
CT, Simple-Cycle No. 2 fuel oil	9.7	0.005	0.065
IGCC, CT/HRSG			
100 percent CGCU	55.0	0.024*	0.212
50 percent CGCU/50 percent HGCU	55.0	0.024*	0.212
No. 2 fuel oil	9.7	0.005	~~0.055~~ 0.044
IGCC, auxiliary boiler	0.0	N/A	N/A
~~IGCC, tail gas treating unit thermal oxidizer~~	~~0.0~~	~~N/A~~	~~N/A~~
IGCC, ~~HGCU~~ H_2SO_4 plant thermal oxidizer	0.0	N/A	N/A

*Based on heat input (HHV) to coal gasifier and includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.

†Includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.

Sources: GE, 1992.
Texaco, 1992.
Bechtel, 1993.
ECT, 199~~2~~3.

4.7.2 NITROGEN OXIDES

NO_x emissions from combustion sources consist of two components: thermal and fuel NO_x. Thermal NO_x results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio and, to a lesser extent, combustion pressure. Fuel NO_x arises from the oxidation of non-elemental nitrogen contained in the fuel. The conversion of fuel-bound nitrogen to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and fuel-bound nitrogen contents; natural gas typically contains a negligible amount of fuel-bound nitrogen.

IGCC facility NO_x emission sources include the CT (using syngas or distillate oil), auxiliary boiler, ~~SRU/TGTU~~ and H_2SO_4 plant thermal oxidizers.

4.7.2.1 Control Technologies

Theoretically available technologies for controlling NO_x emissions from combustion sources include combustion process modifications and post-combustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications

- Flue gas recirculation (FGR),
- Low excess air (LEA),
- Low-NO_x burners,
- Water/steam/diluent injection and standard combustor design,
- Water/steam/diluent injection and advanced combustor design,
- Dry low-NO_x combustor design,

Post-Combustion Exhaust Gas Treatment Systems

- Selective non-catalytic reduction (SNCR),
- Non-selective catalytic reduction (NSCR), and
- SCR.

The first three combustion modifications previously listed would be applicable to boilers and heaters while the last three are pertinent to CTs. The post-combustion control systems would potentially be applicable to both types of combustion sources. A description of each of the listed control technologies is provided in the following sections.

Flue Gas Recirculation

FGR reduces peak combustion flame temperature and thermal NO_x formation by recycling a portion of the cooled flue gas back to the primary combustion zone. Peak flame temperatures are lowered due to the absorption of heat by the inert flue gas. FGR also reduces thermal NO_x by lowering the oxygen content in the primary flame zone. FGR has minimal effect on fuel NO_x and therefore is applied primarily to natural gas or distillate oil combustion sources. Due to flame stability considerations, FGR rates are typically limited to no more than 20 percent.

Low Excess Air

LEA technology for NO_x control lowers both thermal and fuel NO_x. Using LEA, less excess air than normal is supplied to the combustor. The decrease in oxygen in the burner zone reduces the flame temperature and thermal NO_x. Fuel NO_x is also reduced in the oxygen deficient flame zone by converting fuel bound nitrogen to elemental nitrogen. In addition to the environmental benefits, LEA also provides an economic incentive by increasing fuel efficiency. LEA operation requires continuous oxygen monitoring and close operator attention to ensure safe and efficient operation. The extent of LEA firing is limited by flame stability considerations and excessive formation of CO and visible emissions. LEA can be used as the primary

NO_x control technique or in conjunction with other controls such as low-NO_x burners and FGR.

Low-NO_x Burners

Low-NO_x burners reduce both thermal and fuel NO_x by staged combustion. Design features of the burners control the mixing of air and fuel which stage and delay the combustion process. The result is a reduction in peak flame temperature, reducing thermal NO_x, and an oxygen deficient primary combustion zone which reduces fuel NO_x. Low-NO_x burners are of two types: staged air burners and staged fuel burners. Staged air burners reduce flame temperature, delay fuel/air mixing, and result in fuel-rich initial combustion zones. Staged air burners produce long, less intense flames which lower flame temperatures and thermal NO_x. Due to the increase in flame length, staged air burners are applicable to combustion units which are sufficiently large so that flame impingement on internal surfaces does not occur.

Staged fuel burners represent a newer, more effective approach to reducing NO_x from gaseous fuels. Staged fuel burners mix a portion of the fuel and all of the air in the primary combustion zone. The resulting high excess air levels reduce peak flame temperatures and thermal NO_x formation. Secondary fuel is injected at high pressure into the combustion zone from nozzles located on the perimeter of the burner. The high pressure secondary fuel injection promotes FGR. While staged fuel burners produce a more intense, compact flame and thus can be used on different size combustion units, the burners are only applicable to gaseous fuels.

Water/Steam/Diluent Injection and Standard Combustor Design

Injection of steam, water, or another inert diluent such as nitrogen into the primary combustion zone of a CT reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (1) vaporize the water (latent heat of vaporization) and, (2) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required a achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel. Injection of other inert diluents, such as nitrogen, will function in the same manner as steam in reducing flame temperatures and NO_x formation. Water/steam/nitrogen injection will not reduce the formation of fuel NO_x.

The maximum amount of steam/water/diluent that can be injected depends on the CT combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam/water/diluent injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water/diluent to fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely effect safe, efficient, and reliable operation of the turbine.

The use of steam/water/diluent injection and standard turbine combustor design can generally achieve NO_x exhaust concentrations of 42 and 65 ppmvd for gas and oil-firing, respectively.

Water/Steam/Diluent Injection and Advanced Combustor Design

Water/steam/diluent injection functions in the same manner for advanced combustor designs as described previously for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO_x and to tolerate greater amounts of water/steam/diluent injection. The use of wet/diluent injection and advanced turbine combustor design can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd for gas and oil-firing, respectively.

Dry Low-NO_x Combustor Design

A number of turbine vendors have recently developed dry low-NO_x combustors which premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperature are the same causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical dry low-NO_x combustor incorporates fuel staging using several operating modes as follows:

1. Primary Mode--Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation;
2. Lean-Lean Mode--Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 70 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel/air ratio is reached when transfer to premix operation occurs;
3. Secondary Mode (transfer to premix)--At 70-percent load, all fuel is supplied to second stage; and
4. Premix Mode--Fuel is provided to both stages with approximately 80 percent furnished to the first stage at turbine loads from 70 to 100 percent. Flame is present in the second stage only.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 40 percent of baseline due to flame stability considerations. During oil-firing and low loads, wet injection is employed to control NO_x emissions.

Use of dry low-NO_x combustor technology can typically achieve a NO_x exhaust concentration of 25 ppmvd or less using natural gas fuel. Dry low-NO_x combustor technology has not been developed for synthetic coal gas.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's (EPRI) NO_xOUT and Exxon's Thermal DeNO_x® processes. The two processes are similar in that either ammonia (Thermal DeNO_x®) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x® process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6\,H_2O \tag{1}$$

$$4\,NH_3 + 5\,O_2 \rightarrow 4NO + 6\,H_2O \tag{2}$$

The NO_xOUT process is similar with the exception that urea is used in place of ammonia. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Reaction (1), resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Non-Selective Catalytic Reduction

The NSCR process uses a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3 percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (3)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (4)$$

The catalyst serves to lower the activation energy of these reactions which allows the NO_x conversions to take place at a lower temperature; i.e., in the range of 600 to 750°F. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted ammonia (ammonia slip) emissions. As was the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for SCR operation is 600 to 750°F. Below this temperature range, reduction Reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions. NO_x removal efficiencies for SCR systems typically range from 70 to 90 percent.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principle poisons include arsenic, sulfur, potassium, sodium, and calcium. All of these are present in the flyash from coal and oil combustion. Decreased SCR catalyst activity after only a few hundred hours of operation was observed in European tests for certain coals and firing modes. The decrease in catalyst performance was subsequently attributed to arsenic poisoning of the catalyst. Gaseous arsenic trioxide, formed by the oxidation of elemental arsenic in coal, was found to condense on the SCR catalyst preventing the adsorption of NO_x and ammonia.

Of particular concern is the use of SCR catalyst on fuels containing sulfur. SCR catalyst will promote the oxidation of flue gas SO_2 to SO_3 which will then combine with water vapor to form H_2SO_4. Accordingly, corrosion of downstream piping and heat transfer equipment (which would operate at temperatures below the H_2SO_4 dew point) would be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted ammonia to form ammonium bisulfate and ammonium sulfate. Ammonium bisulfate is a hygroscopic solid at approximately 380°F and will deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate would be expected to deposit on HRSG heat transfer equipment where temperatures below 380°F will occur. Since ammonium bisulfate is hygroscopic, the material will absorb water forming a sticky substance which can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown would be required to clean fouled equipment. Formation of ammonium salts will also result in a significant increase in PM emissions.

Application of SCR to CTs has been primarily limited to natural gas fired units. Information provided by GE on emission controls for gas turbine applications indicates that, in California, out of 41 permitted SCR facilities only 11 have been permitted to fire oil as a backup fuel. Of these 11, only 3 are in operation and only one (United Airlines) has ever fired oil. Several units which are permitted to fire oil have regulatory approval to by-pass the SCR unit when using fuel oil.

The one United States CT installation equipped with SCR controls having significant experience with firing fuel oil is the United Airlines cogeneration plant located in San Francisco. This facility, which has a NO_x limitation of 16 ppmvd, is fired with natural gas with very low sulfur Jet-A fuel as backup. During the first year of operations, the catalyst failed and was replaced three times. Catalyst failure was attributed both to poisoning of the catalyst by ammonium bisulfate, and to gas pressure surges which caused automatic switching to jet fuel and consequent temperature excursions. Based on the unsatisfactory performance, United Airlines no longer operates the cogeneration plant on liquid fuels.

The technical difficulties associated with SCR and sulfur bearing fuels have been documented for fuels having relatively low sulfur contents; e.g., as low as 50 to 100 ppm (0.005 to 0.01 percent) sulfur. Although the fuels planned for the Polk Power Station IGCC CT (syngas and back-up distillate fuel oil) are low in sulfur content, the sulfur levels are more than sufficient to cause problems with operation of a SCR control system. Problems associated with ammonium salt deposition can be ameliorated to some extent by reducing the ammonia/NO_x molar ratio when firing sulfur-containing fuels. However, all known successful applications of SCR for CTs are on natural gas-fired units. There are no applications of SCR to CTs fired with synthetic coal gas.

Due to thermal degradation and chemical poisoning, catalyst vendors typically assign a 3-year lifetime to SCR catalyst systems.

Technical Feasibility

The NO_x control technologies previously described were reviewed for technical feasibility with respect to the Polk Power Station project. The IGCC CT will use syngas fuel with low sulfur distillate fuel oil serving as a back-up fuel source. There are two major differences between synthetic coal gas and natural gas with respect to CT emissions: composition and heat content. In contrast to natural gas which is predominately methane, syngas is composed of a variety of constituents including CO, hydrogen, CO_2, nitrogen, and water. The combustible components of syngas are primarily CO and hydrogen instead of methane. CO and hydrogen burn at a higher adiabatic flame temperature than methane and therefore can produce approximately three times as much NO_x as natural gas. This NO_x increase is offset somewhat by other syngas components since these components (CO_2, water, and nitrogen) act as diluents to reduce flame temperature and NO_x formation in the same fashion as steam/water injection or lean dry low-NO_x combustors.

The other major difference between natural gas and syngas is the fuel heating value. Syngas has a substantially lower heating value [approximately 250 British thermal units per standard cubic foot (Btu/scf)] in comparison to natural gas (approximately 1,050 Btu/scf). One consequence of this difference is that significantly higher mass flows are required to maintain a specified heat consumption rate. This has a beneficial impact since turbine power output is increased due to the higher mass flow rate through the turbine. However, there are turbine stress and high temperature limitations which constrain the maximum mass flow rate through the unit.

The GE CT planned for the Polk Power Station IGCC facility is a 7F unit. Operation of a GE 7E turbine was demonstrated at the Texaco Cool Water project. The Polk Power Station IGCC CT differs from the Cool Water unit in that the 7F operates with significantly higher firing temperature (2,300 versus 1,950°F) and output (190 versus 60 MW) than the Cool Water 7E unit. In addition, the Polk Power Station IGCC CT will employ nitrogen as a diluent versus steam injection at Cool Water.

An evaluation of control technology feasibility was conducted with consideration given to the unique characteristics of syngas fuel and specifics of the Polk Power

Station IGCC facility. Water/steam/diluent injection with either standard or advanced combustor technology would be feasible for the IGCC CT. Dry low-NO_x burner technology is not feasible since this technology has not yet been developed for synthetic coal gas fuels. A test program sponsored by EPRI, GE, and Shell Oil Company was conducted in 1990 at GE's Gas Turbine Development Laboratory in Schenectady, New York. The purpose of the program was to evaluate the performance of advanced turbine combustors fueled with low-Btu synthetic coal gas. A portion of the test program was devoted to the evaluation of a two-stage premixed dry low-NO_x combustor. The test program found NO_x emissions from the dry low-NO_x combustor to be essentially the same as from the conventional multi-nozzle combustor. Further research is planned on the potential application of dry low-NO_x combustor technology to syngas fueled CTs.

The IGCC CT will use nitrogen injection to reduce NO_x emissions. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection. Nitrogen used for injection is provided by the air separation plant used to generate oxygen for the IGCC gasification process. Nitrogen addition also is beneficial in increasing turbine power output due to an increase in mass flow rates. Use of nitrogen as a diluent results in lower NO_x emissions per unit of power produced since nitrogen addition serves both to decrease NO_x formation and provide power augmentation. Nitrogen power augmentation replaces power that otherwise would be generated by fossil fuel combustion. The savings in fuel consumption resulting from nitrogen addition translates to a reduction in combustion-related emissions. The maximum amount of nitrogen diluent will be injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. As mentioned previously, maximum mass flow rates through the turbine are constrained by high temperature and equipment stress considerations.

Of the post-combustion stack gas treatment technologies, SNCR is not feasible since the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CT exhaust gas streams (approximately 1,000°F). NSCR was also determined to be technically infeasible since the process must take place in a fuel rich (less than 3 percent oxygen) environment. Due to high excess air rates, the oxygen content of CT exhaust gases is typically 13 percent.

Accordingly, BACT analysis for NO_x for the IGCC CT was confined to nitrogen injection with advanced combustor technology and the application of post-combustion SCR control technology. Steam/water injection technology was not reviewed since it results in the same level of NO_x emissions in comparison to nitrogen injection. In addition, the water consumption and treatment/disposal requirements associated with water/steam injection do not exist for nitrogen addition making nitrogen diluent preferable to wet injection. SCR has been evaluated although there are a number of concerns regarding the technical feasibility of SCR to CTs fueled with synthetic coal gas as previously discussed. BACT analysis for the remaining NO_x emission sources was based on consideration of the combustion modification technologies listed previously.

4.7.2.2 Energy and Environmental Impacts

The use of maximum nitrogen injection and advanced combustor technology will not have a significant impact on turbine heat rate.

The installation of SCR technology will cause an increase in backpressure on the CT due to pressure drop across the catalyst bed. Additional energy will be needed for the pumping of aqueous ammonia from storage to the injection nozzles and generation of steam for ammonia vaporization. Total energy penalty is projected to be 7,235,396 kilowatt-hours per year (kwh/yr) (24,688 MMBtu/yr). The total SCR energy penalty of 24,688 MMBtu/yr is equivalent to the use of 23.5 million cubic feet (ft^3) of natural gas annually based on a gas heating value of 1,050 Btu/ft^3.

There are no significant adverse environmental effects due to the use of nitrogen injection and advanced combustor technology. In contrast, application of SCR technology will result in the following adverse environmental impacts:

- Ammonia emissions due to ammonia slip: ammonia emissions are estimated to total 98 tpy (at base load and 59°F ambient temperature) for a typical SCR design ammonia slippage rate of 10 ppmv;
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of ammonia with SO_3 present in the exhaust gases: total particulate emissions would increase by approximately 50 percent;
- A public risk due to potential leaks from the storage of large quantities of ammonia: ammonia has been designated an Extraordinarily Hazardous Substance under the Federal Superfund Amendments and Reauthorization Act (SARA) Title III regulations; and
- Disposal of spent catalyst which may be considered hazardous due to heavy metal contamination: vanadium pentoxide is an active component of a typical SCR catalyst and is listed as a hazardous chemical waste under Resource Conservation and Recovery Act (RCRA) Regulations 40 CFR 261.30.

4.7.2.3 Economic Impacts

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced combustion and nitrogen injection and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 25 and 42 ppmvd at 15-percent oxygen for syngas and oil-firing, respectively. Due to the problems associated with the application of SCR to exhaust streams containing sulfur, ammonia addition must be reduced to prevent formation of ammonium sulfate and subsequent fouling of downstream heat transfer equipment. Based on Japanese experience, SCR technology with reduced ammonia addition was premised to achieve NO_x concentrations of 12.5 and 21 ppmvd at 15-percent oxygen for syngas and oil-firing, respectively, representing a 50-percent NO_x removal efficiency.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 4-1 and project-specific economic factors provided in Table 4-19. Emission reductions were calculated based on the use of syngas with a maximum annual capacity factor of 10 percent for oil-firing. Specific capital and annual operating costs for the SCR control system are summarized in Tables 4-32 and 4-33, respectively.

Cost effectiveness for the application of SCR technology to the Polk Power Station IGCC project was determined to be $6,272 per ton of NO_x removed. The economic evaluation did not include the increased costs that would accrue due to downtime required for cleaning of fouled heat transfer equipment. This control cost is greater than those previously considered to be reasonable for BACT NO_x determinations. Results of the NO_x BACT analysis are summarized in Table 4-34.

4.7.2.4 Proposed Best Available Control Technology Emission Limitations

CG facility BACT emission limitations for NO_x are summarized in Table 4-35.

A summary of BLIS NO_x determinations for coal-fired boilers is provided in Table 4-36 and shown graphically in Figure 4-10. NO_x BACT determinations range from 0.039 to 0.600 lb/MMBtu with an average of 0.392 lb/MMBtu. Recent FDER NO_x BACT decisions for coal-fired power plants are summarized in Table 4-37.

A summary of BLIS NO_x determinations for oil-fired boilers is provided in Table 4-38 and shown graphically in Figure 4-11. NO_x BACT determinations (excluding two high outliers) range from 0.074 to 0.380 lb/MMBtu with an average of 0.173 lb/MMBtu.

NO_x emissions during the 2-year HGCU demonstration period are expected to be higher than for CGCU technology. The primary reason for this increase is the presence of ammonia in the HGCU syngas stream; the ammonia is subsequently oxidized to NO_x in the IGCC CT. Ammonia is removed from the gasifier syngas

Table 4-32. Capital Costs for SCR Catalyst for the IGCC CT

Item	$	OAQPS Factor
Direct Costs		
Purchased equipment	3,081,500 (A)	
Installation		
Foundations and supports	246,520	0.08 x A
Handling and erection	431,410	0.14 x A
Electrical	123,260	0.04 x A
Piping	61,630	0.02 x A
Insulation for ductwork	30,815	0.01 x A
Painting	30,815	0.01 x A
Subtotal Installation Cost	**924,450**	
Site preparation	163,000	
Subtotal Direct Costs	**4,168,950**	
Indirect Costs		
Engineering	308,150	0.10 x A
Construction and field expenses	154,075	0.05 x A
Contractor fees	308,150	0.10 x A
Startup	61,630	0.02 x A
Performance test	30,815	0.01 x A
Contingency	770,375	0.25 x A
Subtotal Indirect Costs	**1,633,195**	
Interest during construction	580,215	
TOTAL CAPITAL INVESTMENT	**6,382,360** (TCI)	

Sources: GE, 1992.
ECT, 1992.
UEC, 1992.

Table 4-33. Annual Operating Costs for SCR Catalyst for the IGCC CT

Item	$		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	18,400	(A)	
Supervisor	2,760		0.15 x A
Maintenance			
Labor	13,700	(B)	
Materials	13,700		1.00 x B
Subtotal Labor, Material, and Maintenance Costs	**48,560**	(C)	
Catalyst costs			
Inventory (annualized)	279,030		
Replacement (materials and labor)	2,119,570		
Disposal	32,575		
Annualized replacement and disposal costs	866,325		
Annualized Catalyst Costs	**1,145,355**		
Utilities and raw materials			
Electricity	18,170		
Ammonia	52,305		
Subtotal Utilities and Raw Materials	**70,475**		
Energy Penalties			
Turbine backpressure	302,465		
Downtime for catalyst replacement (annualized)	178,715		
Subtotal Energy Penalties Costs	**481,180**		
Subtotal Direct Costs	**1,745,570**	(TDC)	
Contingency	436,390		0.25 x TDC
Indirect Costs			
Overhead	29,135		0.60 x C
Administrative charges	127,645		0.02 x TCI
Property taxes	63,825		0.01 x TCI
Insurance	63,825		0.01 x TCI
Capital recovery	562,365		
Subtotal Indirect Costs	**846,795**		
TOTAL ANNUAL COST	**3,028,755**		

Sources: GE, 1992.
ECT, 1992.
UEC, 1992.

Table 4-34. Summary of NO_x BACT Analysis for the IGCC Unit

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
Control Option	Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost-Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact	Adverse Environmental Impact
SCR	110.3	482.9	482.9	6,382,360	3,028,755	6,272	24,688	Yes	Yes
Baseline	220.5	965.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Basis--IGCC unit, 100-percent CGCU, 100-percent load, 59°F ambient temperature, 90 percent annual capacity factor for natural gas-firing, 10 percent annual capacity factor for distillate fuel oil-firing.

Source: ECT, 1992.

Table 4-35. NO_x Emission Limitation Summary for CG Facilities

State	BLIS I.D. Number	Permit Date	Source Name	Heat Input (MMBtu/hr)	NO_x Emission Limits lb/hr	lb/MMBtu	ppmvd	Control Technology
California	0027	12/09/81	Southern California Edison Coolwater Station SCOT unit thermal oxidizer	20.9	7.0	0.335	N/A	
			CT	842.0	129.1	0.153	80.0 (3% oxygen)	Wet injection
Florida	N/A	05/31/91	FP&L Martin County (per CT)	2,100.0	392.1	0.189	42.0 (15% oxygen)	Wet injection
Virginia	0098	04/15/88	Virginia Power	1,875.0	490.0	0.261	42.0	Steam injection

Sources: EPA, 1992a.
FDER, 1991a.
SBCAPCD, 1989.

Table 4-36. BLIS NO_x Emission Limitation Summary for Coal-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	NO_x Emission Limits lb/hr	lb/MMBtu	ppmvd	lb/MW	Control Efficiency (%)	Control Technology
California	0120	04/26/85	SCF - Ridgen Power Project	16.5	212.0	9.2	0.043	34.0	0.558	80.0	SNCR
	0128A	10/29/85	Corn Products	N/A	620.0	59.2	0.095	30.0	N/A	N/A	NSCR, staged combustion
	0129	12/13/85	Cogeneration National Corp.	49.0	300.0	N/A	N/A	30.0	N/A	80.0	SNCR
	0129A	12/13/85	Cogeneration National Corp.	N/A	279.6	12.0	0.043	30.0	N/A	N/A	NSCR
	0128	12/16/85	Corn Products	49.0	N/A	42.0	N/A	50.0	N/A	60.0	Staged combustion, ammonia injection
	0158	06/20/86	BMCP	N/A	N/A	N/A	0.039	N/A	N/A	80.0	Low temp, staged comb., ammonia injection
	0092B	10/22/86	Rio Bravo Refining Co.	26.0	389.0	38.9	0.100	78.0	1.496	50.0	Ammonia injection
	0178	01/12/87	Mount Poso Cogeneration Co.	50.0	N/A	N/A	0.100	N/A	N/A	50.0	Ammonia injection
	0180	01/28/87	GWF Power Systems Co.	25.0	274.0	N/A	N/A	28.0	N/A	N/A	Staged comb., ammonia injection
	0282	02/11/88	GWF Power Systems Co., Inc.	N/A	202.0	15.0	0.074	N/A	N/A	N/A	Ammonia injection
Connecticut	0067	08/09/89	AES Thames, Inc.	N/A	923.0	332.3	0.360	N/A	N/A	70.0	Fluidized bed comb.
Georgia	0030	09/21/90	Thomaston Mills, Inc.	N/A	214.76	128.9	0.600	N/A	N/A	N/A	Combustion controls
Hawaii	0009	01/25/90	Applied Energy Services	N/A	2,150.0	236.5	0.110	25.0	N/A	62.0	SNCR
Kentucky	0007B	12/13/85	Tennessee Valley Authority	N/A	200.0	112.0	0.560	N/A	N/A	N/A	
	0007A	04/15/86	Tennessee Valley Authority	N/A	1,430.0	858.0	0.600	N/A	N/A	N/A	
	0007C	05/04/88	Tennessee Valley Authority	N/A	1,579.0	947.4	0.600	N/A	N/A	N/A	
Michigan	0048	07/31/87	Cogentrix Michigan Leasing	N/A	214.0	128.4	0.600	N/A	N/A	N/A	Design & operating practices
	0051	12/07/87	City of Wyandotte	N/A	369.0	147.6	0.400	N/A	N/A	N/A	Equipment design

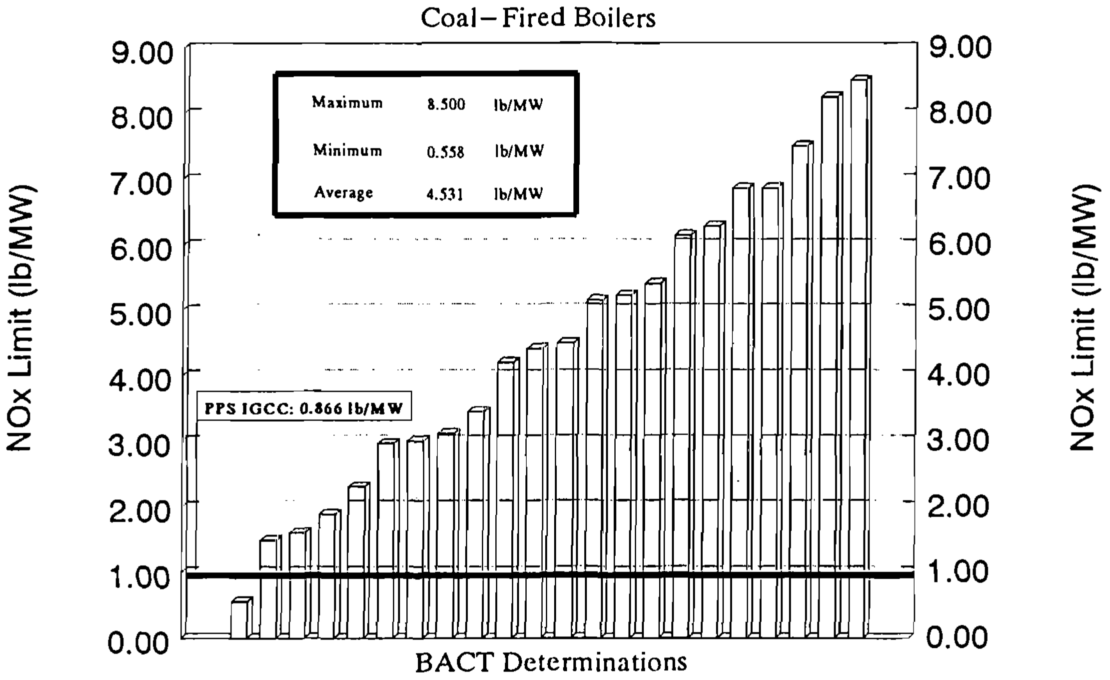
Table 4-36. BLIS NO_x Emission Limitation Summary for Coal-Fired Boilers (Continued, Page 2 of 3)

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	NO_x Emission Limits lb/hr	lb/MMBtu	ppmvd	lb/MW	Control Efficiency (%)	Control Technology
North Carolina	0037	05/28/86	Cogentrix Carolina Leasing	53.0	606.0	363.6	0.600	N/A	6.86	N/A	Excess air control
	0039	07/07/86	Cogentrix Carolina Leasing	106.0	1,212.0	727.2	0.600	N/A	6.86	N/A	Excess air control
	0050	07/20/89	Cogentrix of Rocky Mount	N/A	1,500.0	900.0	0.600	N/A	N/A	N/A	Excess air control
	0054	01/24/91	Roanoke Valley Project	N/A	1,700.0	561.0	0.330	N/A	N/A	N/A	Low NO_x burner
New Jersey	-	Draft	Keystone Cogeneration	224.0	2,116.0	359.7	0.170	100.0	1.606	N/A	SNCR
	-	Draft	Chambers Works Cogeneration	250.0	2,778.0	472.3	0.170	100.0	1.889	N/A	SCR
New York	0014	04/01/87	Fort Drum Heating Plant	N/A	190.0	114.0	0.600	N/A	N/A	N/A	Combustion control
	0030	09/25/88	United Development Group	N/A	577.0	288.5	0.500	N/A	N/A	65.0	Combustion control
Ohio	0145	02/05/87	Wm. H. Zimmer Gener. Station	N/A	11,968.0	7,180.8	0.600	N/A	N/A	35.0	Low NO_x burners
Pennsylvania	0047	12/02/85	Signal Frackville Energy	40.0	N/A	N/A	0.600	N/A	N/A	N/A	
	0046	01/06/86	Westwood Energy Properties	30.0	425.0	255.0	0.600	N/A	8.500	N/A	
	0035	11/01/86	J. Pagnotti Enterprises	80.0	1,082.0	432.8	0.400	N/A	5.410	N/A	
	0034	12/01/86	Sheridan Coal Co.	40.0	550.0	330.0	0.600	N/A	8.250	N/A	
	0036	12/29/86	Foster Wheeler Power	77.0	566.0	339.6	0.600	N/A	4.410	N/A	
	0045	01/16/87	Archbald Power Corp.	20.0	240.0	60.0	0.250	N/A	3.000	N/A	
	0042	02/17/88	Panther Creek Energy	80.0	1,170.0	491.4	0.420	N/A	6.143	N/A	
	0049	06/06/88	Edensburg Power Co.	N/A	617.0	370.2	0.600	N/A	N/A	N/A	
	0044A	06/17/88	Northeastern Power Co.	49.0	513.0	307.8	0.600	N/A	6.282	N/A	
	0057	01/18/89	Scrubgrass Power Corp.	80.0	1,198.0	359.4	0.300	N/A	4.493	N/A	Combustion control

Table 4-36. BLIS NO_x Emission Limitation Summary for Coal-Fired Boilers (Continued, Page 3 of 3)

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	NO_x Emission Limits				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
	0062	05/26/89	Cambria Cogen, Inc.	79.8	1,118.0	335.5	0.284	N/A	4.204	N/A	Combustion control
	0058	09/26/88	North Branch Energy Partners	90.0	1,126.0	675.6	0.600	N/A	7.507	N/A	
	0072	06/08/90	Panther Creek Partners	80.0	1,228.0	184.2	0.150	N/A	2.303	N/A	SNCR
	0073	07/23/90	MidAtlantic Energy of PA	30.0	392.0	156.8	0.400	N/A	5.227	N/A	Combustion control
Rhode Island	0009	03/11/91	East Providence Cogeneration	72.0	856.5	248.4	0.290	N/A	3.450	N/A	Combustion control
Utah	0034	10/01/86	Utah Power & Light Co.	400.0	N/A	N/A	0.490	N/A	N/A	35.0	Low NO_x burners
Virginia	0034	06/12/86	Cogentrix of Virginia, Inc.	N/A	200.0	120.0	0.600	N/A	N/A	N/A	
	0044	12/18/86	Tultex Corp.	N/A	12.0	4.20	0.350	N/A	N/A	N/A	
	0178	01/02/91	Cogentrix of Richmond	304.0	3,000.0	900.0	0.300	N/A	2.961	50.0	SNCR
	0181	04/29/91	Old Dominion Electric Coop.	786.0.	8,170.0	2,451.0	0.300	N/A	3.118	50.0	Low NO_x burners
Wisconsin	0036	N/A	Wisconsin Electric Power Co.	80.0	825.0	412.5	0.500	N/A	5.156	N/A	Proper combustion
	0041	09/21/88	Fort Howard Corp.	N/A	505.0	247.5	0.490	N/A	N/A	N/A	Proper bed operation
	0055	09/05/90	Wisconsin Electric Power Co.	N/A	879.0	351.6	0.400	N/A	N/A	N/A	Good comb. practices
				N/A	873.0	349.2	0.400	N/A	N/A	N/A	Good comb. practices
				N/A	880.0	352.0	0.400	N/A	N/A	N/A	Good comb. practices
				N/A	872.0	348.8	0.400	N/A	N/A	N/A	Good comb. practices
	0061	01/01/92	Milwaukee Co. Power Plant	N/A	157.0	25.1	0.160	N/A	N/A	60.0	Ammonia injection

Source: EPA, 1992a.



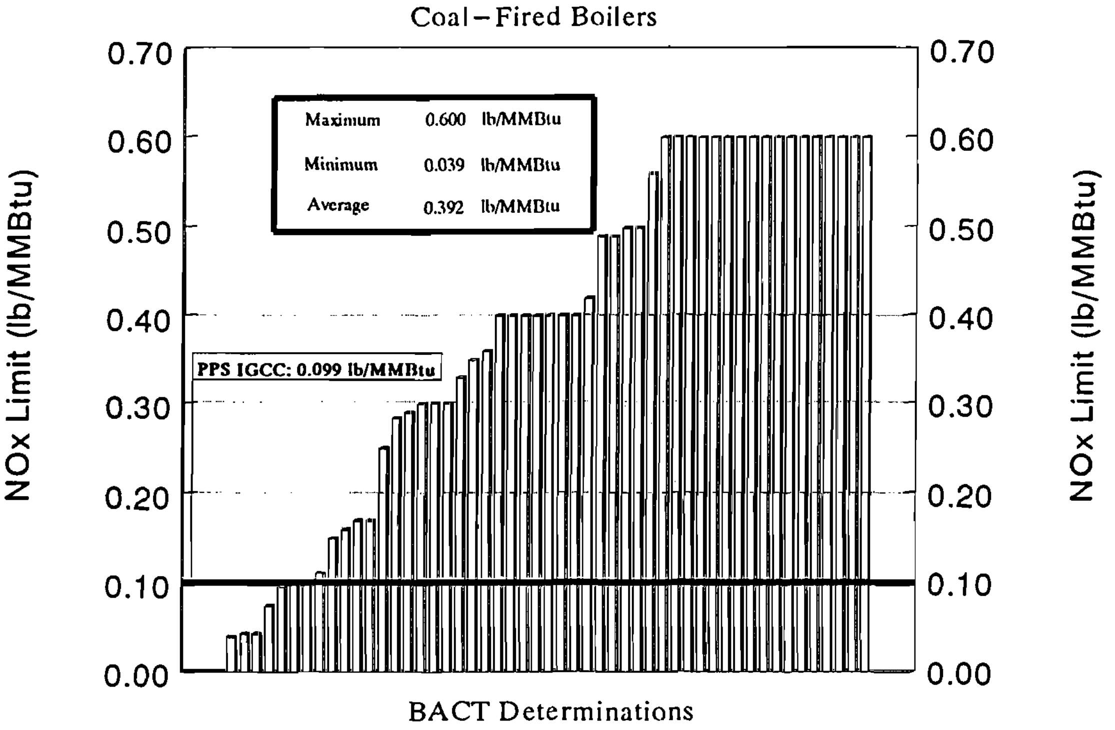


FIGURE 4-10.

SUMMARY OF NOx BACT DETERMINATIONS: COAL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

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Table 4-37. Florida BACT NO_x Emission Limitation Summary for Coal-Fired Boilers

Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	NO_x Emission Limits lb/hr	lb/MMBtu	lb/MW	Control Efficiency	Control Technology
12/31/91	Orlando Utilities Stanton Unit No. 2	465.0	4,286	728.5	0.170	1.567	N/A	SNCR or SCR
03/25/92	Indiantown cogeneration	330.0	3,422	581.7	0.170	1.763	63.0	SNCR

Source: FDER, 1991a.

Table 4-38. BLIS NO_x Emission Limitation Summary for Oil-Fired Boilers

State	BLIS I.D. Number	Permit Date	Source Name	Size (MW)	Heat Input (MMBtu/hr)	NO_x Emission Limits				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
California	0116B	08/07/84	Petro-Lewis Corp.	N/A	50.0	6.3	0.120	N/A	N/A	70.0	Low NO_x burner - LAER
	0113A	10/25/85	Berry Holding Co.	N/A	31.5	6.3	0.200	N/A	N/A	61.8	Low NO_x burner
	0129B	02/25/88	Cogeneration National Corp.	N/A	79.0	5.8	0.074	N/A	N/A	51.0	Low NO_x burner
	0128B	03/02/88	CPC International	N/A	178.0	21.3	0.120	N/A	N/A	56.0	Low NO_x burners
Connecticut	0080	09/23/88	Northeast Utilities, NNECO	N/A	28.3	92.3	3.260	N/A	N/A	N/A	Diesel Fired
	0074	08/28/89	Exeter Energy Limited	N/A	11.2	38.5	3.434	N/A	N/A	N/A	Diesel Fired
North Carolina	0054	01/24/91	Roanoke Valley Project	N/A	19.0	1.9	0.100	N/A	N/A	N/A	Low NO_x burner
Ohio	0094	N/A	Georgia-Pacific Corp.	N/A	118.0	35.4	0.300	N/A	N/A	N/A	Low excess air
	0117	11/26/86	Owens-Illinois Inc.	N/A	10.3	1.5	0.145	N/A	N/A	N/A	Nat Gas/#2 Oil Firing
Virginia	0044	12/18/86	Tultex Corp.	N/A	93.3	13.3	0.140	N/A	N/A	N/A	
	0177	05/04/90	Doswell Limited Partnership	N/A	40.0	4.8	0.120	N/A	N/A	N/A	Burner design
	0181	04/29/91	Old Dominion Elect. Coop.	N/A	213.9	42.8	0.200	N/A	N/A	N/A	
Wisconsin	0037A	10/10/88	Wisconsin Tissue Mills, Inc.	N/A	146.4	55.6	0.380	N/A	N/A	N/A	Low escess air

Source: EPA, 1992a.

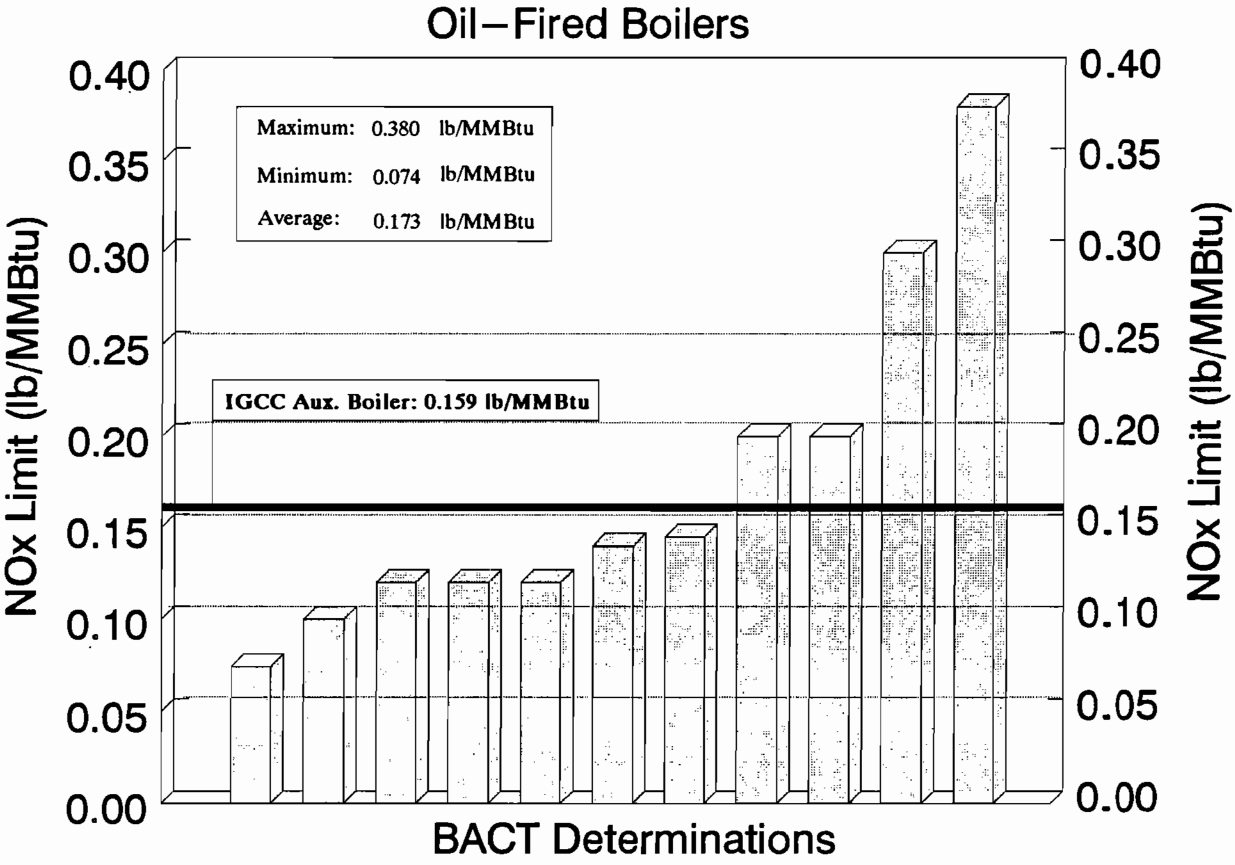

FIGURE 4-11.

SUMMARY OF NOx BACT DETERMINATIONS:
OIL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

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stream as part of the CGCU process and thus CGCU generates syngas with negligible ammonia concentrations. One of the goals of the HGCU demonstration project is to determine the NO_x levels that are generated by the process.

Use of nitrogen diluent injection to achieve NO_x exhaust concentrations of 25 ppmvd at 15-percent oxygen for syngas and water injection to achieve 42 ppmvd at 15-percent oxygen for distillate fuel oil, is proposed as BACT for the IGCC CT. Nitrogen/water injection is considered to represent BACT for the following reasons:

- The CT 25 ppmvd NO_x concentration limit for syngas combustion together with NO_x emissions from the tail gas treating unit thermal oxidizer represents an overall IGCC NO_x emission rate of 0.099 lb/MMBtu. *This rate is among the lowest contained in the BLIS database and is well below the most recent BACT determination of 0.17 lb/MMBtu made in Florida and New Jersey for coal-fired power plants*;
- Overall NO_x emission rate from the IGCC facility in terms of lb NO_x/MW *is approximately 50 percent* of the rates recently approved by FDER for the Stanton and Indiantown coal-fired power plants and, with one exception, *is the lowest in the BLIS database*. Comparison of emissions on a lb/MW basis is believed to be more meaningful than other units such as lb/MMBtu since it reflects the emission reduction benefit of process efficiency;
- The 25-ppmvd NO_x concentration limit proposed for syngas combustion is well below the previous BACT concentration of 42 ppmvd assigned to CG projects in Virginia and Florida;
- Nitrogen injection will achieve the same level of NO_x control as water or steam injection without the water consumption and treatment/disposal requirements associated with wet injection;
- Power augmentation due to nitrogen addition results in lower emissions per unit of power produced since the nitrogen augmentation replaces power that would otherwise be generated by fossil fuel combustion. The

concomitant emissions associated with fuel combustion are therefore avoided;

- Dry low-NO_x burner technology has not yet been developed for syngas fuels; initial research indicated comparable performance to the standard multi-nozzle combustor;
- Cost-effectiveness of SCR was found to be $6,272 per ton of NO_x removed which exceeds values previously considered to be reasonable for NO_x BACT determinations;
- The application of SCR technology to the treatment of exhaust gases generated by the combustion of sulfur-bearing fuels poses a number of technical concerns. These concerns include potential catalyst poisoning from arsenic and sulfur compounds and formation of ammonium salts due to the combination of SO_3 and any unreacted ammonia causing corrosion and reduced efficiency of downstream heat transfer equipment;
- Spent SCR catalyst may require handling and disposal as a hazardous waste due to vanadium pentoxide content. Also, facility workers could be exposed to high levels of vanadium pentoxide particulates during catalyst handling; and
- Emissions of ammonia may occur due to ammonia slip. SCR vendors typically guarantee a maximum ammonia slip rate of 10 ppmv for natural gas fired CTs. Since SCR has not been demonstrated for CTs fired with syngas, vendor guarantees and actual maximum ammonia slip rates are not available. Both NO_x and ammonia participate in the photochemical ozone cycle--the substitution of 10 ppmv ammonia (due to slip) for 12.5 ppmv NO_x (the concentration controlled by SCR) during syngas firing, the fuel which will be employed 90 percent of the time in the IGCC CT, is believed to be problematical from an air quality perspective. In addition, ammonia slip can increase significantly during start-ups, upsets/failures of the ammonia injection system, or due to catalyst degradation. During such instances, ammonia concentrations of 50 ppmv or greater have been measured, which exceeds the odor threshold of approximately 20 ppmv.

Use of low-NO_x burner technology is proposed as BACT for the ancillary IGCC combustion sources. These sources, auxiliary boiler~~, tail gas treating unit thermal oxidizer,~~ and H_2SO_4 plant thermal oxidizer, have NO_x emission rates which are only a small fraction (approximately 5 percent) of the total IGCC facility NO_x emissions. Specific BACT emission limits proposed for the Polk Power Station IGCC facility are summarized in Table 4-39.

4.8 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR ACID GASES--STAND-ALONE COMBINED CYCLE UNITS AND COMBUSTION TURBINES

Acid gas emissions (SO_2, H_2SO_4 mist, and NO_x) from fossil fuel combustion depend on fuel composition and combustion variables. BACT evaluations for sulfur compounds and NO_x are discussed in the following sections.

4.8.1 SULFUR OXIDES AND SULFURIC ACID MIST

As was mentioned in Section 4.7.1, SO_2, SO_3, and H_2SO_4 mist emissions arise from the combustion of fuels containing sulfur. H_2SO_4 emissions result from the reaction of SO_3 and water in the exhaust gas stream. The conversion rate of SO_2 to SO_3 depends on combustion parameters, e.g., temperature and excess oxygen levels, as well as fuel characteristics.

The Polk Power Station combined and simple-cycle CTs will utilize natural gas and low sulfur distillate oil as fuels. Natural gas is the primary fuel with distillate oil serving as a back-up fuel source. Distillate fuel oil annual capacity factors will be 25 and 10 percent for the CC units and simple-cycle CTs, respectively.

4.8.1.1 Control Technologies

Technologies employed to control SO_2 and H_2SO_4 emissions from combustion sources consist of fuel treatment and post-combustion add-on controls, i.e., FGD systems.

FGD systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be

Table 4-39. Proposed NO_x BACT Emission Limits for the IGCC Facility

Process	Proposed BACT Emission Limits lb/hr	lb/MMBtu	ppmvd**	lb/MW
CT, simple-cycle				
No. 2 fuel oil	311.0	0.163	42.0	2.073
IGCC, CT/HRSG				
100 percent CT/HRSG	222.5	0.099*	25.0	0.866†
50 percent CGCU/50 percent HGCU	664.0	0.292*	81.0	2.564†
No. 2 fuel oil††	311.0	0.163	42.0	1.414
IGCC, auxiliary boiler	7.9	0.159	123.0	N/A
~~IGCC, tail gas treating unit thermal oxidizer~~	~~2.6~~	~~N/A~~	~~42.0~~	~~N/A~~
IGCC, ~~HGCU~~ H_2SO_4 plant thermal oxidizer	~~1.14~~ 2.6	N/A	~~33.0~~ 17.1	N/A

*Based on heat input (HHV) to coal gasifier and includes emissions from ~~SRU/TGTU~~ H_2SO_4 plant thermal oxidizer.

†Includes emissions from ~~tail gas treating unit~~ H_2SO_4 plant thermal oxidizer.

**At 15 percent oxygen.

††Emission estimates based on following fuel oil properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum FBN of 0.015 weight percent [for FBN levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the FBN allowance contained in 40 CFR 60(GG)].

Sources: GE, 1992.
Texaco, 1992.
Bechtel, 1993.
ECT, 199~~2~~3.

performed using either a wet or dry contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems typically generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

While FGD technology would be technically feasible, there have been no applications to CTs since low sulfur fuels are used resulting in low exhaust gas SO_2 concentrations. Fuels proposed for the Polk Power Station CTs consist of natural gas and low sulfur (maximum 0.05 weight percent sulfur) distillate oil. The sulfur content of the distillate oil proposed for the Polk Power Station CTs is more than 40 times lower than the fuels employed in coal-fired boilers utilizing FGD systems. In addition, CTs operate with a significant amount of excess air which generates high exhaust gas flow rates. Since FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentrations, application of a FGD system to a CT exhaust stream would result in unreasonably low SO_2 removal efficiencies. Due to low SO_2 exhaust stream concentrations, FGD technology is not considered to be feasible for CTs since removal efficiencies would be unreasonably low and costs would be excessive.

Since post-combustion SO_2 controls are not applicable, use of low sulfur fuels is considered to represent BACT for CTs. The Polk Power Station CTs will use natural gas (containing less than 10 gr/100 scf) and low sulfur distillate oil. NSPS Subpart GG limits the sulfur content of CT fuels to a maximum of 0.8 weight percent sulfur. The use of distillate fuel oil containing no more than 0.05 weight percent sulfur is considered to represent the top or most stringent technology with respect to CT SO_2 emissions. In accordance with the top-down BACT methodology, further analysis of alternative SO_2 control technology is not required.

4.8.1.2 Energy and Environmental Impacts

There are no significant energy impacts associated with the distillate oil planned for the Polk Power Station CTs. Since low sulfur distillate oil will serve as a back-up fuel for both the CC units and simple-cycle CTs, ambient SO_2 impacts resulting from use of the low sulfur distillate oil will be minor.

4.8.1.3 Proposed Best Available Control Technology Emission Limitations

Recent BACT emission limitations for SO_2 obtained from the BLIS database are summarized in Table 4-40 and shown graphically in Figure 4-12. Data shown in Table 4-40 represents BACT/LAER determinations entered into BLIS from January 1986 through May 1992. For distillate oil-firing, fuel sulfur limits range from 0.040 to 0.370 weight percent sulfur with an average limit of 0.205 weight percent sulfur. Recent Florida BACT determinations for CTs are summarized in Table 4-41.

Use of low sulfur fuels, natural gas, and distillate fuel oil is proposed as BACT for SO_2 and H_2SO_4. Natural gas sulfur content will be less than 10 gr/100 scf. Distillate fuel oil will contain a maximum of 0.05 weight percent sulfur. Specific BACT emission limits proposed for the Polk Power Station CTs are summarized in Table 4-42. Use of low sulfur fuels and the proposed emission limits are consistent with previous Florida and national BACT determinations.

4.8.2 NITROGEN OXIDES

The methods of NO_x formation previously described for the IGCC facility in Section 4.7.2 are also applicable to the future stand-alone CC units and simple-cycle CTs.

4.8.2.1 Control Technologies

Theoretically available NO_x control technologies potentially applicable to the combined and simple-cycle CTs include the following combustion process modifications and post-combustion exhaust gas treatment systems:

Table 4-40. BLIS SO_2 Emission Limitation Summary for CTs

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	SO_2 Emission Limit % S	lb/MMBtu	Control Technology
Alaska	0012	03/18/87	Alaska Electrical Generation and Transmission	80.0	N/A	Oil	0.060	N/A	N/A
	0018	03/18/87	Alaska Electrical Generation and Transmission	38.0	N/A	Oil	0.150	N/A	N/A
California	0111A	12/19/84	Witco Chemical Corp.	N/A	350.0	Oil	0.250	N/A	N/A
	0067	06/07/85	Proctor & Gamble	N/A	217.0	Oil	0.300	N/A	N/A
	0147	06/28/85	Sunlaw/Industrial Park 2	N/A	412.3	Oil	0.050	N/A	Limit fuel S content
	0122	08/01/85	Gilroy Energy Co.	60.0	N/A	Oil	0.120	N/A	N/A
	0249A	10/26/87	BAF Energy	N/A	887.2	Oil	0.050	N/A	Type of standby fuel
	0274	01/12/89	Mojave Cogeneration Co.	45.0	490.0	Oil	0.200	N/A	Low sulfur fuel
Connecticut	0027	08/19/87	Downtown Cogeneration Association	N/A	71.9	Oil	(0.330)	0.341	Low sulfur oil
	0031	05/18/88	CCF-1	N/A	110.0	Oil	(0.300)	0.306	Low sulfur oil
	0022	08/08/88	O'Brien Cogeneration	N/A	499.9	Oil	(0.180)	0.190	Low sulfur oil
	0025	10/23/89	Capital District Energy Center	N/A	738.8	Oil	(0.300)	0.306	Low sulfur oil
Delaware	0006	08/23/88	Delmarva Power	N/A	100.0	Oil	0.300	N/A	Low sulfur fuel
	0008	09/27/90	Delmarva Power	N/A	100.0	Oil	0.040	N/A	Low sulfur fuel

Table 4-40. BLIS SO_2 Emission Limitation Summary for CTs (Continued, Page 2 of 3)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	SO_2 Emission Limit % S	lb/MMBtu	Control Technology
Florida	0042	09/01/88	Orlando Utilities	35.0	N/A	Oil	0.300	N/A	Low sulfur fuel
Kentucky	0048	02/26/88	Texas Gas Transmission	35.0	N/A	Oil	0.127	N/A	N/A
Michigan	0082	06/21/88	Ada Cogeneration	N/A	245.0	Oil	(0.240)	0.250	Low sulfur fuel
North Carolina	0051	09/06/89	Panda-Rosemary Corp.	N/A	499.0	Oil	(0.203)	0.210	Low sulfur fuel
New Jersey	0008	06/03/87	Cogen Technologies	40.0	N/A	Oil	0.150	N/A	Fuel analysis
Nevada	0013	10/18/90	Las Vegas Cogeneration	N/A	397.0	Oil	0.050	N/A	N/A
New York	0013	03/10/88	TBG/Grumman	16.0	N/A	Oil	0.370	N/A	N/A
	0027	07/01/88	Trigen	40.0	N/A	Oil	0.270	N/A	Low sulfur fuel
	0026	07/01/88	Kamine Carthage	40.0	N/A	Oil	0.100	N/A	Low sulfur fuel
	0022	09/01/88	Kamine South Glen Falls	40.0	N/A	Oil	0.200	N/A	Low sulfur fuel
	0024	11/01/88	Long Island Lighting Co.	75.0	N/A	Oil	0.250	N/A	Low sulfur fuel
	0031	11/04/88	Indeck-Yerks Energy Services, Inc.	40.0	N/A	Oil	0.300	N/A	Low sulfur fuel
	0032	01/15/89	L & J Energy System Cogeneration	40.0	N/A	Oil	0.100	N/A	Low sulfur fuel
	0029	02/07/89	Indec/Oswego Hill	40.0	N/A	Oil	0.270	N/A	Low sulfur fuel oil

Table 4-40. BLIS SO_2 Emission Limitation Summary for CTs (Continued, Page 3 of 3)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	SO_2 Emission Limit % S	lb/MMBtu	Control Technology
	0037	03/06/89	Megan-Racine Associates	N/A	430.0	Oil	0.200	N/A	Low sulfur fuel
	0038	05/02/89	Empire Energy - Niagara Cogeneration	N/A	416.0	Oil	0.250	N/A	Low sulfur fuel
	0033	09/01/89	Kamine Syracuse	79.0	N/A	Oil	0.150	N/A	Low sulfur fuel
	0040	11/21/89	JMC Selkirk, Inc.	80.0	N/A	Oil	0.200	N/A	Low sulfur fuel
	0039	01/29/90	Fulton Cogeneration Associates	N/A	500.0	Oil	0.300	N/A	Low sulfur fuel
Pennsylvania	0052	10/12/88	Amtrak	20.0	N/A	Oil	0.200	N/A	N/A
Virginia	0177	05/04/90	Doswell Limited Partnership	N/A	1261.0	Oil	(0.213)	0.221	Use of #2 oil
	0175	03/05/91	Commonwealth Atlantic Ltd. Partnership	100.0	1400.0	Oil	0.200	N/A	Low sulfur fuel
Vermont	0005	12/20/89	Arrowhead Cogeneration Company	N/A	282.0	Oil	0.300	N/A	N/A

Note: ( ) = calculated from lb/MMBtu SO_2 emission limit.
%S = percent sulfur.

Source: EPA, 1992a.

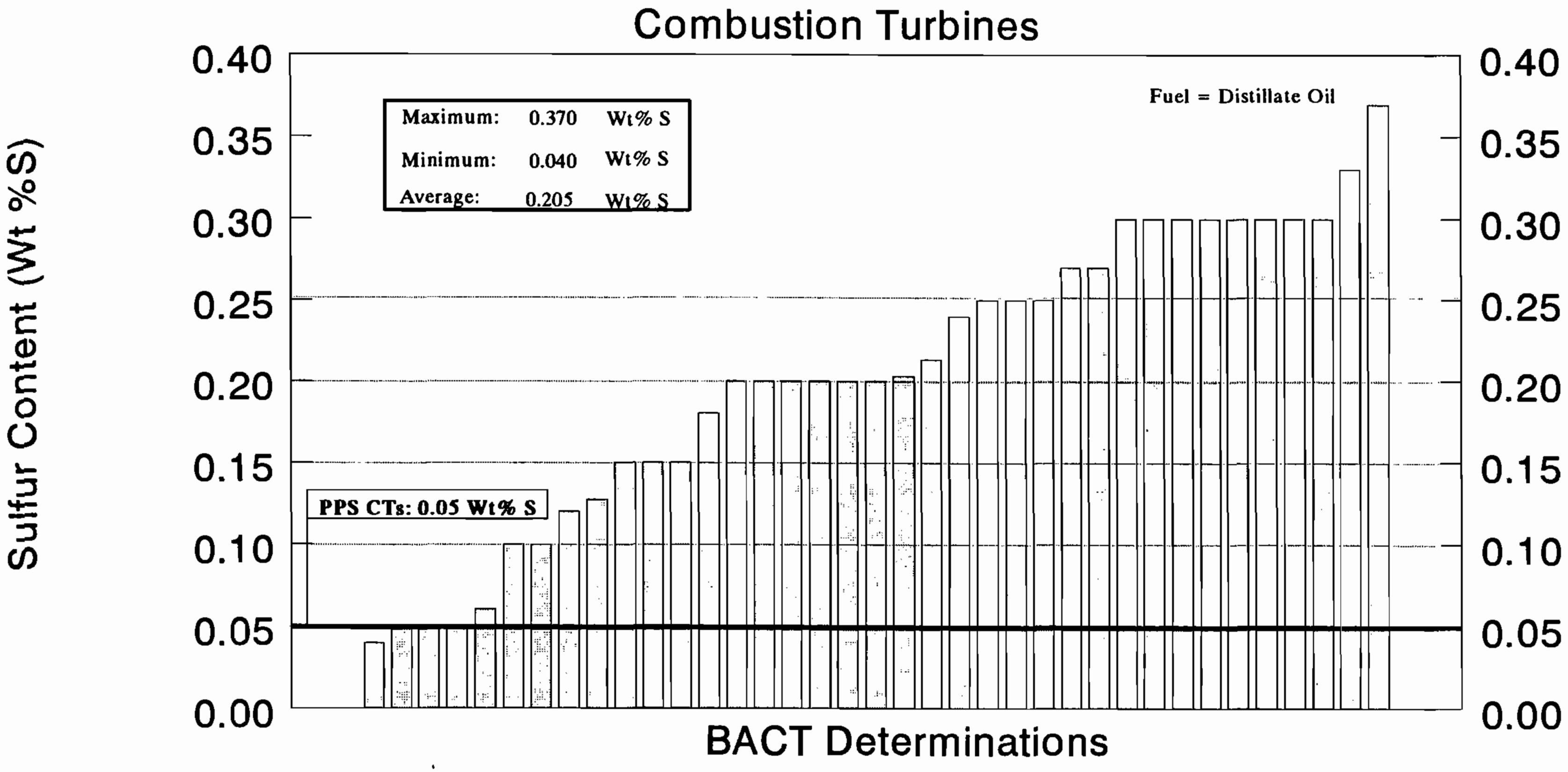

FIGURE 4-12.

SUMMARY OF SO_2 BACT DETERMINATIONS: OIL-FIRED CTs

Sources: EPA, 1992a; ECT, 1992.

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Table 4-41. Florida BACT SO_2 Emission Limitation Summary for CTs

Permit Date	Source Name	Turbine Size MW	Turbine Size MMBtu/hr	Fuel Type	SO_2 Emission Limit lb/hr	SO_2 Emission Limit Average	SO_2 Emission Limit Maximum	Control Technology
05/31/91	Florida Power & Light Martin Expansion Project	150.0	1,846	Oil	920	0.5	0.3	No. 2 fuel oil
10/18/91	Florida Power Corporation Debary Facility	92.9	1,144	Oil	555	0.3	0.5	No. 2 fuel oil
07/26/91	City of Lakeland Charles Larsen Plant	80.0	1,040	Oil	307 tpy	N/A	0.2	No. 2 fuel oil
01/04/91	TECO Power Services Hardee Power Station	75.0	1,312.3	Oil	734.4	0.3	0.5	No. 2 fuel oil
11/20/91	Pasco Cogen Limited	42.0	387	Oil	80	N/A	0.1	No. 2 fuel oil

Source: FDER, 1991a.

Table 4-42. Proposed SO_2 and H_2SO_4 BACT Emission Limits for Stand-Alone CC Units and CTs

Process	Proposed BACT Emission Limits lb/hr	lb/MMBtu	lb/MW
$\underline{SO_2}$			
CC units (per unit)			
Natural gas	72.0	0.034	0.327
No. 2 fuel oil	105.4	0.047	0.479
CTs (per CT)			
Natural gas	36.0	0.034	0.480
No. 2 fuel oil	52.7	0.047	0.703
$\underline{H_2SO_4}$			
CC units (per unit)			
Natural gas	8.0	0.0037	~~0.026~~ 0.036
No. 2 fuel oil	11.0	0.0049	0.050
CTs (per CT)			
Natural gas	4.0	0.0037	0.053
No. 2 fuel oil	5.5	0.0049	0.073

Sources: GE, 1992.
ECT, 199~~2~~3.

Combustion Process Modifications

- Water/steam injection and standard combustor design,
- Water/steam injection and advanced combustor design,
- Dry low-NO_x combustor design,

Post-Combustion Exhaust Gas Treatment Systems

- SNCR,
- NSCR, and
- SCR.

Detailed descriptions of each of these technologies were previously provided in Section 4.7.2.1.

Technical Feasibility

The future combined and simple-cycle CTs will use natural gas as a primary fuel source with low sulfur (maximum 0.05 weight percent sulfur) distillate fuel oil as a backup fuel. All of the combustion process modification technologies listed would be feasible for the combined and simple-cycle CTs. Of the post-combustion stack gas treatment technologies, SNCR is not feasible since the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CT exhaust gas streams (approximately 1,000°F). NSCR was also determined to be technically infeasible since the process must take place in a fuel rich (less than 3 percent oxygen) environment. Due to high excess air rates, the oxygen content of CT exhaust gases is typically 13 percent. Also, SCR technology is not considered to be applicable to simple-cycle CTs due to temperature constraints; i.e., the CT exhaust temperature of approximately 1,000°F exceeds the maximum temperature required for successful SCR operation.

Use of dry low-NO_x burner technology will achieve lower NO_x emission rates in comparison to wet injection based on vendor data. The CTs are projected to attain NO_x exhaust concentrations of 9 and 42 ppmvd at 15 percent oxygen for gas and oil-firing, respectively. Dry low-NO_x burner technology employs conventional wet injection when distillate oil is used as the turbine fuel source.

4.8.2.2 Proposed BACT Emission Limitations

BACT emission limitations for NO_x obtained from the BLIS database for CTs are summarized in Table 4-43 and shown graphically in Figure 4-13. Data shown in Table 4-43 represents recent BACT/LAER determinations; i.e., those entered into BLIS from January 1986 through May 1992. NO_x emission limits range from 0.013 to 0.260 lb/MMBtu with an average rate of 0.099 lb/MMBtu. BACT NO_x determinations expressed as a concentration (corrected to 15 percent oxygen) range from 4.5 to 75 ppmv with an average of 28.9 ppmv.

Recent Florida BACT determinations for gas turbines are summarized in Table 4-44. All of these determinations are based on the use of wet injection technology.

The use of dry low-NO_x burner technology is considered to represent BACT for the future combined and simple-cycle CTs for the following reasons:

- Dry low-NO_x burner technology will achieve NO_x concentrations of 9 and 42 ppmvd for gas and oil-firing, respectively. *An NO_x exhaust concentration of 9 ppmvd is generally considered to represent BACT for CTs equipped with SCR control technology.* The proposed NO_x concentration is also below the current FDER BACT guideline of 15 ppmvd for natural gas-fired CTs using dry low-NO_x burners;
- Dry low-NO_x burner technology will achieve comparable emission rates as SCR for gas-firing without the adverse impacts associated with SCR technology; i.e., ammonia emissions due to ammonia slip, potential of ammonium salt particulate formation with subsequent downstream corrosion and reduced efficiency of heat transfer equipment, hazards associated with the storage of ammonia and disposal of spent catalyst, and energy penalties due to increased turbine backpressure and additional system downtime for catalyst replacement;

Table 4-43. BLIS NO$_x$ Emission Limitation Summary for CTs

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	NO$_x$ Emission Limit ppmvd	lb/MMBtu	Control Technology
Arkansas	0012	03/18/87	Alaska Generation & trans	80.0	N/A	Gas	75.0	N/A	Water injection
	0018	03/18/87	Alaska Generation & trans	38.0	N/A	Gas	75.0	N/A	Water injection
Alabama	0040	11/30/88	Champion International	35.0	N/A	Gas	42.0	N/A	Steam injection, eff. = 70%
Arizona	0012	10/18/91	El Paso Natural Gas	N/A	401.7	Gas	42.0	N/A	Dry Low NO$_x$ combustor; Eff. = 80.0
	0010	10/25/91	El Paso Natural Gas	N/A	184.1	Gas	42.0	N/A	Dry Low NO$_x$ combustor; Eff. = 51.0
	0011	10/25/91	El Paso Natural Gas	N/A	184.1	Gas	42.0	N/A	Dry Low NO$_x$ combustor; Eff. = 51.0
California	0011A	12/19/84	Witco Chemical Corp.	N/A	350.0	Gas Oil	N/A N/A	0.200 0.180	
	0139	04/01/85	Northern California Power	25.8	N/A	Gas Oil	42.0 65.0	N/A N/A	Water injection Water injection
	0144	04/26/85	Willamette Industries	N/A	230.0	Gas	15.0	N/A	Water injection & SCR, eff. = 92%
	0112	04/30/85	Shell California Production	22.0	N/A	Gas	42.0	N/A	Water injection
	0067	06/07/85	Proctor & Gamble	N/A	217.0	Gas Oil	62.0 75.0	N/A N/A	Water injection Water injection
	0147	06/28/85	Sunlaw/Industrial Park 2	N/A	412.3	Gas	9.0	N/A	SCR & steam injection, eff. = 80.0%
	0122	08/01/85	Gilroy Energy Co.	60.0	N/A	Gas	25.0	N/A	Steam injection, quiet combustor
	0155	01/17/86	Union Cogeneration	16.0	N/A	Gas	25.0	N/A	SCR & water injection
	0221	03/10/86	AES Placerita, Inc.	N/A	519.0	Gas	7.0	N/A	Water injection & SCR
	0167	03/15/86	Western Power System, Inc.	26.5	N/A	Gas	9.0	N/A	Water injection & SCR, eff. = 80.0%
	0288	04/18/86	Monarch Cogeneration	N/A	92.2	Gas	22.0	N/A	SCR
	0138	04/18/86	Moran Power, Inc.	8.0 MMcf/day		Gas	N/A	0.020	SCR, steam injection, eff. = 87%

Table 4-43. BLIS NO_x Emission Limitation Summary for CTs (Continued, Page 2 of 6)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	NO_x Emission Limit		Control Technology
							ppmvd	lb/MMBtu	
	0136	04/18/86	Kern Energy Corp.	8.8 MMcf/day		Gas	N/A	0.023	SCR, eff. = 87%
	0137	04/18/86	Southeast Energy, Inc.	8.0 MMcf/day		Gas	N/A	0.023	SCR, eff. = 87%
	0162	08/25/86	PG & E, Station T	N/A	396.0	Gas	25.0	N/A	Steam injection, eff. = 75%
	0163	11/04/86	Double 'C' Limited	25.0	N/A	Gas	N/A	193.98 lb/day	Water injection & SCR, eff. = 95.8%
	0164	11/04/86	Kern Front Limited	25.0	N/A	Gas	4.5	N/A	Water injection & SCR, eff. = 95.8%
	0189	12/30/86	O'Brien Systems/Merchants	N/A	359.5	Gas	15.0	N/A	Water injection & SCR
	0192	01/05/87	City of Santa Clara	N/A	N/A	Gas	42.0	N/A	Water injection
	0177	01/06/87	Midway - Sunset Project	N/A	973.0	Gas	16.3	N/A	Water injection, eff. = 73.0%
	0159	02/19/87	Sierra, Ltd.	11.34 MMcf/day		Gas	N/A	0.016	SCR & steam injection, eff. = 95.86%
	0186	02/20/87	U.S. Borax & Chemical	45.0	N/A	Gas	25.0	N/A	Water/steam injection & SCR
	0251	06/19/87	San Joaquin Cogen Limited	48.6	N/A	Gas	6.0	N/A	Water injection & SCR, eff. = 76.0%
	0230	06/22/87	Power Development Co.	N/A	49.0	Gas	9.0	N/A	Water injection & SCR
	0221A	07/02/87	AES Placerita, Inc.	N/A	530.0	Gas	9.0	N/A	Steam injection & SCR
	0221B	07/02/87	AES Placerita, Inc.	N/A	530.0	Gas	9.0	N/A	Steam injection & SCR
	0249	07/08/87	BAF Energy	N/A	887.2	Gas	9.0	N/A	Steam injection & SCR, eff. = 80.0%
	0262	01/27/88	Midway-Sunset Cogen Co.	75.0	N/A	Gas Oil	N/A N/A	85.0 lb/hr 140.0 lb/hr	Water injection & quiet combustor Water injection & quiet combustor
	0179	02/26/88	Combined Energy Resources	25.94	N/A	Gas	N/A	199 lb/day	Water injection, low NO_x design
	0179A	02/26/88	Combined Energy Resources	2.0	N/A	Gas	N/A	199 lb/hr	Water injection & SCR, eff. = 81.0%
	0297	09/27/88	Mobil Oil	N/A	81.4	Gas	N/A	0.047	Molecular sieve catalyst, H_2O injection

Table 4-43. BLIS NO_x Emission Limitation Summary for CTs (Continued, Page 3 of 6)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	NO_x Emission Limit ppmvd	NO_x Emission Limit lb/MMBtu	Control Technology
	0293	09/27/88	Mobil Exploration & Prod.	3.11	N/A	Gas	N/A	0.047	SCR catalyst, eff. = 65%
	0296	11/01/88	Texaco-Yokum Cogeneration	24.50	N/A	Gas	N/A	0.031	
	0273	01/12/89	Mojave Cogeneration Co.	N/A	490.0	Gas	10.0	N/A	SCR/steam injection
	0335	09/15/89	City of Anaheim Gas Turbine	N/A	442.0	Gas	N/A	0.013	SCR, steam injection, eff. = 69.6%
	0437	09/28/89	Kingsburg Energy Systems	34.5	N/A	Gas	6.0	6.2 lb/hr	SCR, steam injection, eff. = 90.0%
	0320	10/30/89	Badger Creek Limited	N/A	457.8	Gas	N/A	0.013	SCR, steam injection
	0318	01/04/90	O'Brien California Cogen	49.5	N/A	Gas	N/A	14.6 lb/hr	SCR, dry type
	0399	11/19/90	Sargent Canyon Cogen Co.	42.5	N/A	Gas	6.0	10.0 lb/hr	Dry low NO_x and SCR
	0400	11/19/90	Salinas River Cogen Co.	43.2	N/A	Gas	6.0	10.0 lb/hr	Dry low NO_x and SCR
	0441	05/06/91	Granite Road Limited	N/A	N/A	Gas	6.0	0.013	SCR, steam injection; eff. = 97.0
Colorado	0015	08/01/89	Cimarron Chemical Inc.	N/A	271.0	Gas	65.0	N/A	Steam injection
Colorado	0017	02/19/92	Thermo Industries, Ltd.	272.0	246.0	Gas	25.0	0.984	Dry Low NO_x combustors
Connecticut	0027	08/19/87	Downtown Cogeneration Assoc.	N/A	71.9	Gas Oil	42.0 62.0	N/A N/A	Water injection Water injection
	0031	05/18/88	CCF-1	N/A	110.0	Gas Oil	36.0 63.0	N/A N/A	Water injection Water injection
	0022	08/08/88	O'Brien Cogeneration	N/A	499.9	Gas Oil	39.0 40.0	N/A N/A	Water injection Water injection
	0025	10/23/89	Capitol District Energy	N/A	738.8	Gas Oil	42.0 62.0	N/A N/A	Steam injection Steam injection
Delaware	0006	08/23/88	Delmarva Power	100.0	N/A	Gas	42.0	N/A	Water injection & low NO_x burner
	0008	09/27/90	Delmarva Power	100.0	N/A	Gas	25.0	N/A	Low NO_x burner

Table 4-43. BLIS NO$_x$ Emission Limitation Summary for CTs (Continued, Page 4 of 6)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	NO$_x$ Emission Limit ppmvd	NO$_x$ Emission Limit lb/MMBtu	Control Technology
Florida	0042	09/01/88	Orlando Utilities Comm.	35.0	N/A	Gas	42.0	N/A	Steam injection
						Oil	65.0	N/A	Steam injection
	0043	05/30/89	Tropicana Products, Inc.	45.4	N/A	Gas	42.0	N/A	Steam injection
Kentucky	0048	02/26/88	Texas Gas Transmission Corp	N/A	36.4	Gas	150.0	N/A	
Louisiana	0079	08/05/91	Enron Louisiana Energy	N/A	39.1	Gas	40.0	N/A	Water injection, eff. = 71.0%
Michigan	0054	02/16/88	Midland Cogeneration Vent.	N/A	984.2	Gas	42.0	N/A	Steam injection
	0082	06/21/88	Ada Cogeneration	N/A	245.0	Gas	42.0	N/A	Water injection
	0206	12/03/91	Kalamazoo Power Limited	468.0	1805.9	Gas	15.0	N/A	Dry Low NO$_x$ turbines
North Carolina	0051	09/06/89	Panda-Rosemary Corp.	N/A	499.0	Gas	N/A	0.170	Water injection
					509.0	Oil	N/A	0.260	Water injection
					1,047.0	Gas	N/A	0.170	Water injection
					1,060.0	Oil	N/A	0.260	Water injection
New Jersey	0006	01/03/85	Ciba-Geigy Corp.	3.0	N/A	Gas	N/A	11.06 lb/hr	Water injection, eff. = 55.0%
	0008	06/03/87	Cogen Technologies	40.0	N/A	Gas	9.6	N/A	Water injection & SCR, eff. = 95.0%
Nevada	0013	10/18/90	Las Vegas Cogeneration Ltd.	N/A	397.0	Gas	10.0	N/A	Water injection & SCR
New York	0013	03/10/88	TBG/Grumman	16.0	N/A	Gas	75.0	0.200	Water injection & combustion controls
	0026	07/01/88	Kamine Carthage	40.0	N/A	Gas	42.0	N/A	Steam injection
						Kerosine	65.0	N/A	Steam injection
	0027	07/01/88	Trigen	40.0	N/A	Gas	60.0	N/A	Steam injection
						Oil	65.0	N/A	Steam injection
	0022	09/01/88	Kamine South Glen Falls	40.0	N/A	Gas	42.0	N/A	Steam injection
						Oil	65.0	N/A	Steam injection
	0024	11/01/88	Long Island Lighting Co.	75.0	N/A	Gas	55.0	N/A	Water injection

Table 4-43. BLIS NO_x Emission Limitation Summary for CTs (Continued, Page 5 of 6)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	NO_x Emission Limit ppmvd	NO_x Emission Limit lb/MMBtu	Control Technology
	0031	11/04/88	Indek-Yerks Energy Services	40.0	N/A	Gas Oil	42.0 65.0	N/A N/A	Steam injection Steam injection
	0032	01/15/89	L & J Energy System Cogen	40.0	N/A	Gas Oil	42.0 65.0	N/A N/A	Steam injection Steam injection
	0029	02/07/89	Indec/Oswego Hill Cogen	40.0	N/A	Gas Oil	42.0 65.0	N/A N/A	Water injection Water injection
	0037	03/06/89	Megan-Racine Associates	N/A	430.0	Gas Oil	42.0 65.0	N/A N/A	Water injection Water injection
	0038	05/02/89	Empire Energy - Niagara	N/A	416.0	Gas Oil	42.0 65.0	N/A N/A	Steam injection Steam injection
	0033	09/01/89	Kamine Syracuse Cogen. Co.	79.0	N/A	Gas Oil	36.0 65.0	N/A N/A	Steam injection Steam injection
	0040	11/21/89	JMC Selkirk, Inc.	80.0	N/A	Gas Oil	25.0 42.0	N/A N/A	Steam injection Steam injection
	0039	01/29/90	Fulton Cogen. Associates	N/A	500.0	Gas Oil	36.0 65.0	N/A N/A	Water injection Water injection
	0036	02/26/90	Oneida Cogen. Facility	N/A	417.0	Gas	32.0	N/A	Combustion control
Oregon	0006	05/19/87	Pacific Gas Transmission	N/A	35.6	Gas	154.0	N/A	Combustion controls
Pennsylvania	0052	10/12/88	Amtrak	N/A	90.0	Gas	N/A	0.100	Low NO_x burner
	0083	05/03/91	Northern Consolidated	34.6	N/A	Gas	25.0	N/A	Steam injection, eff. = 85%
Rhode Island	0004	12/13/88	Ocean State Power	N/A	1,059.0	Gas	9.0	N/A	SCR & water injection
	0008	01/30/89	Pawtucket Power	N/A	533.0	Gas Oil	9.0 18.0	N/A N/A	SCR SCR

Table 4-43. BLIS NO_x Emission Limitation Summary for CTs (Continued, Page 6 of 6)

State	BLIS I.D. Number	Permit Date	Source Name	Turbine Size (MW)	Heat Input (MMBtu/hr)	Fuel Type	NO_x Emission Limit		Control Technology
							ppmvd	lb/MMBtu	
South Carolina	0021	09/23/91	Carolina Power and Light Co.	80.0	N/A	Gas	N/A	292.0 lb/hr	Water injection, eff. = 50%
Virginia	0161	12/12/89	Richmond Power Enterprise	N/A	1,163.5	Gas	8.2	N/A	SCR & steam injection
						Oil	11.7	N/A	SCR & steam injection
	0177	05/04/90	Doswell Ltd. Partnership	N/A	1,261.5	Gas	9.0	N/A	SCR & dry combustor
	0175	03/05/91	Commonwealth Atlantic Ltd.	N/A	1,533.5	Gas	25.0	N/A	Water injection & low NO_x combustion
						Oil	42.0	N/A	Water injection & low NO_x combustion
	0184	03/03/92	Bermuda Hundred Energy	N/A	1,175.0	Gas	9.0	N/A	SCR & steam injection, eff. = 91%
					1,117.0	Oil	15.0	N/A	SCR & steam injection, eff. = 91%
Vermont	0007	08/10/90	East Georgia Cogen Project	N/A	400.0	Gas	9.0	N/A	SCR & water injection
	0008	07/27/90	Vermont Marble Company	N/A	50.0	Gas	42.0	N/A	Water injection
Washington	0025	10/26/90	March Point Cogeneration	80.0	N/A	Gas	25.0	N/A	Massive steam injection
	0026	12/01/90	Sumas Energy, Inc.	67.0	N/A	Gas	9.0	N/A	SCR, eff. = 90.0%
	0027	06/25/91	Sumas Energy, Inc.	88.0	N/A	Gas	6.0	N/A	SCR, eff. = 90.0%

Source: EPA, 1992a.

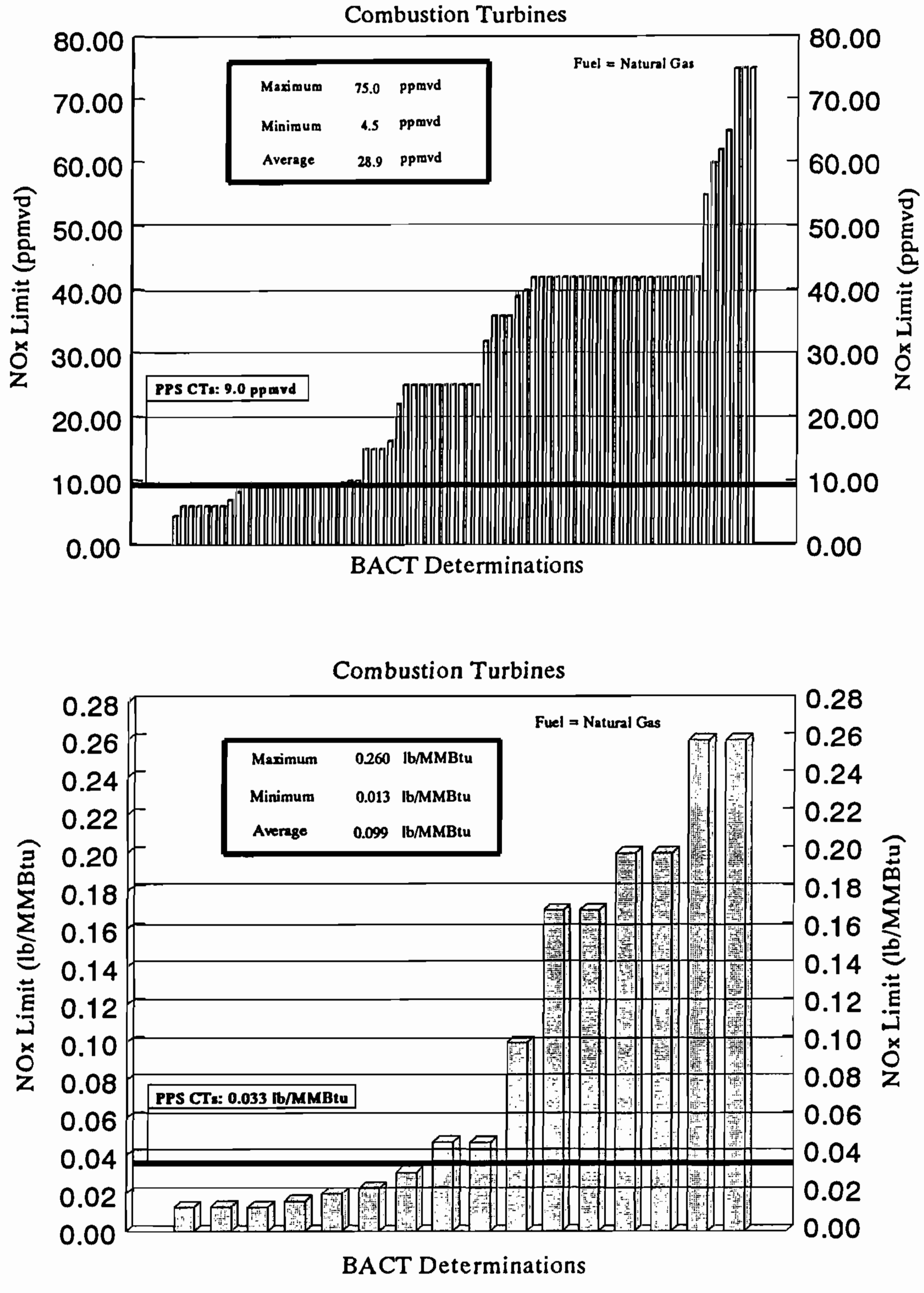

FIGURE 4-13.

SUMMARY OF NOx BACT DETERMINATIONS: COMBUSTION TURBINES

Sources: EPA, 1992a; ECT, 1992.

TAMPA
ELECTRIC
A TECO ENERGY COMPANY

**POLK
POWER
STATION**

Table 4-44. Florida BACT NO_x Emission Limitation Summary for CTs

Permit Date	Source Name	Turbine Size		Fuel Type	NO_x Emission Limit (ppmvd at 15% oxygen)	Control Technology
		MW	MMBtu/hr			
01/04/91	TECO Power Services	75.0	1,268.4	Gas	42	Wet injection
	Hardee Power Station		1,312.3	Oil	65	Wet injection
05/31/91	Florida Power & Light	150.0	1,966	Gas	25	Wet injection
	Martin Expansion project		1,846	Oil	65	Wet injection
07/26/91	City of Lakeland	80.0	1,055	Gas	25	Wet injection
	Charles Larsen Plant		1,040	Oil	42	Wet injection
10/18/91	Florida Power Corporation Debary Facility	92.9	1,114	Oil	42	Wet injection
11/20/91	Pasco Cogen Limited	42.0	384	Gas	25	Wet injection
			387	Oil	42	Wet injection

Source: FDER, 1991a.

- Use of backup distillate fuel oil will be limited to annual capacity factors of 25 and 10 percent, respectively, for the combined and simple-cycle CTs; and
- Application of SCR to the simple-cycle CTs is considered to be infeasible due to the substantial cost required to reduce CT exhaust temperatures to levels consistent with successful SCR operation, low backup fuel oil capacity factor, and relatively minor reduction in NO_x emissions that would result from applying SCR to CTs equipped with dry low-NO_x burners.

Specific BACT emission limits proposed for the Polk Power Station stand-alone CC units and CTs are summarized in Table 4-45.

Table 4-45. Proposed NO_x BACT Limits for Stand-Alone CTs

Process	Proposed BACT Emission Limits			
	lb/hr	lb/MMBtu	ppmvd*	lb/MW
CC units (per unit)				
Natural gas	70.0	0.033	9.0	0.318
No. 2 fuel oil†	362.0	0.162	42.0	1.645
CTs (per CT)				
Natural gas	35.0	0.033	9.0	0.467
No. 2 fuel oil†	181.0	0.162	42.0	2.413

*At 15 percent oxygen.

†Emission estimates based on following fuel oil properties: (1) maximum ash content of 0.01 weight percent, (2) maximum sulfur content of 0.05 weight percent, and (3) maximum FBN of 0.015 weight percent [for FBN levels greater than 0.015 weight percent, emission limits are adjusted in accordance with the FBN allowance contained in 40 CFR 60(GG)].

Sources: GE, 1992.
ECT, 1992.

APPENDIX A

EMISSION RATE CALCULATIONS

APPENDIX A.1
BASIS FOR 7F CT EMISSION RATES

7F CT FIRING NO. 2 FUEL OIL

Emission rates were based on data received from the CT vendor and on fuel specifications, as summarized below:

Pollutant	Basis
TSP/PM_{10}	Non-sulfate PM provided by vendor, based on fuel ash content of 0.01 weight percent. Added to H_2SO_4 provided by vendor, based on 0.05 weight percent S.
SO_2	Provided by vendor, based on 0.05 weight percent S.
NO_x	Provided by vendor, based on 42 ppmvd.
CO	Provided by vendor, based on 25 ppmvd, except for 50 percent CT load (based on 40 ppmvd).
VOC	NMHC provided by vendor, based on 5 ppmvd at 100 percent CT load, 7 ppmvd at 75 percent CT load, and 20 ppmvd at 50 percent CT load.
Pb	Calculated from fuel specification of 1 ppm (equivalent to 53 lb/10^{12} Btu).
H_2SO_4	Provided by vendor, based on 0.05 weight percent S.
F	Calculated from worst-case emission factor given in Table A.1-1.
Hg	Calculated from worst-case emission factor given in Table A.1-1.
Be	Calculated from worst-case emission factor given in Table A.1-1.
As	Calculated from worst-case emission factor given in Table A.1-1.
Cd	Calculated from worst-case emission factor given in Table A.1-1.
Cr	Calculated from worst-case emission factor given in Table A.1-1.

7F CT FIRING SYNGAS

All emission rates were based on data received from vendors.

Table A.1-1. Worst-Case Emission Factors for Non-Criteria Pollutants: No. 2 Fuel Oil

Pollutant	Emission Factor ($lb/10^{12}$ Btu)	Reference
Arsenic	20*	NJDEP, 1982
Beryllium	2.5	EPA, 1989
Cadmium	10.5	EPA, 1989
Chromium	89†	NJDEP, 1982
Fluorides	32.5	EPA, 1981
Mercury	3.0	EPA, 1989

*Based on fuel oil analyses performed by the New Jersey Department of Environmental Protection (NJDEP) in a special study conducted in the summer and fall of 1982. This emission factor is significantly higher than the EPA (1989) factor, which is 4.2 $lb/10^{12}$ Btu.

†Based on fuel oil analyses performed by NJDEP in a special study conducted in the summer and fall of 1982. This emission factor is significantly higher than the EPA (1989) factor, which is 48 $lb/10^{12}$ Btu.

Source: ECT, 1992.

APPENDIX A.2
PARTICULATE MATTER EMISSIONS FROM COAL HANDLING SOURCES

COAL HANDLING BAGHOUSE

The coal handling baghouse filters air from the coal unloading area, the transfer between the feeder belts and conveyors 1A and 1B, and the transfer between conveyors 1A, 1B, and 2.

The short-term emissions are calculated using the equation:

$$A_s = V \times Q \times c_1 \times c_3$$

where: A_S = short-term emissions [pounds per hour (lb/hr)];
V = volume of air through baghouse [standard cubic foot per minute (scfm)] = 30,000 scfm;
Q = allowable emission concentration [grains per standard cubic foot (gr/scf)] = 0.02 gr/scf;
c_1 = conversion constant = 1 pound per 7,000 grains (lb/7,000 gr); and
c_3 = conversion constant = 60 minutes per hour (min/hr).

Substituting, the short-term emissions are:

$$A_s = 30{,}000\ scfm \times 0.02\ gr/scf \times (1\ lb/7{,}000\ gr) \times (60\ min/hr);$$
$$A_s = 5.14\ lb/hr;\ and$$
$$A_s = 0.65\ g/\mathrm{sec}.$$

The annual emissions are calculated using the equation:

$$A_L = V \times Q \times H \times D \times c_1 \times c_2 \times c_3$$

where: A_L = annual emissions [tons per year (tpy)];
V = volume of air through baghouse (scfm) = 30,000 scfm;
Q = allowable emission concentration (gr/scf) = 0.02 gr/scf;
H = operating hours per coal delivery (hr/delivery) = 10 hr/delivery;
D = coal deliveries per year (delivery/yr) = 200 deliveries/yr;
c_1 = conversion constant = 1 lb/7,000 gr;
c_2 = conversion constant = 1 ton per 2,000 pounds (t/2,000 lb); and
c_3 = conversion constant = 60 min/hr.

Substituting, the annual emissions are:

$$A_L = 30{,}000\ scfm \times 0.02\ gr/scf \times 10\ hr/delivery \times 200\ delivery/yr \times (1\ lb/7{,}000\ gr) \times (1\ t/2{,}000\ lb) \times (60\ \text{min}/hr);$$

$$A_L = 5.14\ tpy;\ and$$

$$A_L = 0.15\ g/\text{sec}.$$

COAL TRANSFER BAGHOUSE

Coal transfer baghouse filters air from the transfer between conveyors 2 and 3.

The short-term emissions are calculated using the equation:

$$A_s = V \times Q \times c_1 \times c_3$$

where: A_S = short-term emissions (lb/hr);
V = volume of air through baghouse (scfm) = 12,500 scfm;
Q = allowable emission concentration (gr/scf) = 0.02 gr/scf;
c_1 = conversion constant = 1 lb/7000 gr; and
c_3 = conversion constant = 60 min/hr.

Substituting, the short-term emissions are:

$$A_s = 12{,}500\ scfm \times 0.02\ gr/scf \times (1\ lb/7{,}000\ gr) \times (60\ \text{min}/hr);$$

$$A_s = 2.14\ lb/hr;\ and$$

$$A_s = 0.27\ g/\text{sec}.$$

The annual emissions are calculated using the equation:

$$A_L = V \times Q \times H \times D \times c_1 \times c_2 \times c_3$$

where: A_L = annual emissions (tpy);
V = volume of air through baghouse (scfm) = 12,500 scfm;
Q = allowable emission concentration (gr/scf) = 0.02 gr/scf;
H = operating hours per coal delivery = 10 hr/delivery;
D = coal deliveries per year = 200 deliveries/yr;
c_1 = conversion constant = 1 lb/7000 gr;
c_2 = conversion constant = 1 t/2,000 lb; and
c_3 = conversion constant = 60 min/hr.

Substituting, the annual emissions are:

$$
\begin{aligned}
A_L &= 12{,}500\ scfm \times 0.02\ gr/scf \times 10\ hr/delivery \times \\
&\quad 200\ delivery/yr \times (1\ lb/7{,}000\ gr) \times \\
&\quad (1\ t/2{,}000\ lb) \times (60\ \mathrm{min}/hr); \\
A_L &= 2.14\ tpy;\ and \\
A_L &= 0.27\ g/\mathrm{sec}.
\end{aligned}
$$

TRANSFER BETWEEN STACKER AND STOCKPILE

Coal will be transferred in the open between the stacker and the stockpile. The emission factor for this operation, from AP-42, Section 11.2.3, Aggregate Handling and Storage (EPA, 1991b), is:

$$E = [0.0032 \times k \times (u/5)^{1.3}]\ /\ (M/2)^{1.4}$$

where E = emission factor (lb/t);
k = particulate size coefficient (dimensionless) = 0.74;
u = annual average windspeed (mph) = 8.6 mph (NWS meteorological data for Tampa); and
M = moisture content of the coal (%) = 7%.

Substituting, the emission factor is:

$$
\begin{aligned}
E &= [0.0032 \times 0.74 \times (8.6/5)^{1.3}]\ /\ (7/2)^{1.4}; \\
E &= 0.000830\ lb/t.
\end{aligned}
$$

The short-term emissions are calculated using the equation:

$$A_s = E \times H$$

where A_S = short-term emissions (lb/hr);
E = emission factor = 0.000830 lb/t; and
H = hourly coal transfer = 3,000 t/hr.

Substituting, the short-term emissions are

$$
\begin{aligned}
A_s &= 0.000830\ lb/t \times 3{,}000\ t/hr; \\
A_s &= 2.49\ lb/hr;\ and \\
A_s &= 0.31\ g/\mathrm{sec}.
\end{aligned}
$$

The annual emissions are calculated using the equation:

$$A_L = E \times T \times c_2$$

where:A_L = annual emissions (tpy);
E = emission factor = 0.000830 lb/t;
T = annual coal usage = 952,020 tpy; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are

$$A_L = 0.000830\ lb/t \times 952{,}020\ tpy \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.395\ tpy;\ and$$
$$A_L = 0.011\ g/\text{sec}.$$

RECLAIM TRANSFER ONTO CONVEYOR 4

Coal will be reclaimed by dropping onto conveyor 4 (below grade). The emission factor for this operation, from AP-42, Section 11.2.3, Aggregate Handling and Storage (EPA, 1991b), is:

$$E = [0.0032 \times k \times (u/5)^{1.3}] / (M/2)^{1.4}$$

where:E = emission factor (lb/t);
k = particulate size coefficient (dimensionless) = 0.74;
u = annual average windspeed (mph) = 8.6 mph (NWS meteorological data for Tampa); and
M = moisture content of the coal (%) = 7%.

Substituting, the emission factor is:

$$E = [0.0032 \times 0.74 \times (8.6/5)^{1.3}] / (7/2)^{1.4};$$
$$E = 0.000830\ lb/t.$$

The short-term emissions are calculated using the equation:

$$A_s = E \times H$$

where:A_S = short-term emissions (lb/hr);
E = emission factor = 0.000830 lb/t; and
H = hourly coal transfer = 775 t/hr.

Substituting, the short-term emissions are

$$A_s = 0.000830\ lb/t \times 775\ t/hr;$$
$$A_s = 0.64\ lb/hr;\ and$$
$$A_s = 0.08\ g/\text{sec}.$$

The annual emissions are calculated using the equation:

$$A_L = E \times T \times c_2$$

where: A_L = annual emissions (tpy);
E = emission factor = 0.000830 lb/t;
T = annual coal usage = 952,020 tpy; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are

$$A_L = 0.000830\ lb/t \times 952{,}020\ tpy \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.395\ tpy;\ and$$
$$A_L = 0.011\ g/\text{sec}.$$

BULLDOZER OPERATIONS ON STOCKPILE

A bulldozer will move coal into the reclaim feeder and will occasionally redistribute coal within the stockpile. The emission factor for this operation, from AP-42, Section 11.2.1, Unpaved Roads (EPA, 1991b), is:

$$E = 5.9 \times k \times (s/12) \times (S/30) \times (W/3)^{0.7} \times (w/4)^{0.5} \times [(365 - P)/365]$$

where: E = emission factor [pound per vehicle mile travelled (lb/VMT)];
k = particulate size coefficient (dimensionless) = 0.80;
s = material silt content (%) = 8.6%;
S = average vehicle speed (mph) = 3.0 mph;
W = vehicle weight (t) = 48 t;
w = number of vehicle wheels (dimensionless) = 6 (assumes a rubber tire dozer); and
P = annual number of days with rain (dimensionless) = 107 (NWS meteorological data for Tampa).

Substituting, the emission factor is:

$$E = 5.9 \times 0.80 \times (8.6/12) \times (3.0/30) \times (48/3)^{0.7} \times (6/4)^{0.5} \times [(365 - 107)/365];$$
$$E = 2.03\ lb/VMT.$$

The short-term emissions are calculated using the equation:

$$A_s = E \times S$$

where: A_S = short-term emissions (lb/hr);
E = emission factor = 2.03 lb/VMT; and
S = average vehicle speed (mph) = 3.0 mph.

Substituting, the short-term emissions are (with 50 percent control by water sprays):

$$A_s = 2.03\ lb/VMT \times 3.0\ mph \times 0.5;$$
$$A_s = 3.05\ lb/hr;\ and$$
$$A_s = 0.38\ g/\text{sec}.$$

The annual emissions are calculated using the equation:

$$A_L = [E \times S \times H_1 \times D_1 \times c_2] + [E \times S \times H_2 \times D_2 \times c_2]$$

where: A_L = annual emissions (tpy);
E = emission factor = 2.03 lb/VMT;
S = average vehicle speed (mph) = 3.0 mph;
H_1 = daily operating time (hr/day) = 3 hr/day;
D_1 = annual operating days (day/yr) = 365 day/yr;
c_2 = conversion constant = 1 t/2,000 lb;
H_2 = daily maintenance (hr/day) = 8 hr/day; and
D_2 = annual maintenance days (day/yr) = 105 day/yr.

Substituting, the annual emissions are (with 50 percent control by water sprays):

$$A_L = 0.5 \times [2.03\ lb/VMT \times 3.0\ mph \times 3\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb]; + 0.5 \times [2.03\ lb/VMT \times 3.0\ mph \times 8\ hr/day \times 105\ day/yr \times 1\ t/2{,}000\ lb];$$
$$A_L = 2.95\ tpy;\ and$$
$$A_L = 0.085\ g/\text{sec}.$$

WIND-CAUSED COAL STOCKPILE EMISSIONS

Coal stockpile emissions were calculated following the procedure outlined in AP-42, Section 11.2.7, Industrial Wind Erosion (EPA, 1991b). The analysis was based on 1986 NWS meteorological data for Tampa.

As a first step, 1986 was divided into 91 periods of 4 days each. Period 91 contained 5 days. A 4-day period was selected because coal will be delivered to the short-term area of the stockpile at approximately this frequency. The Tampa meteorological data was then examined to determine the fastest mile windspeed for each period. These windspeeds were measured at 7 meters (m), so were adjusted to the standard 10-m height using:

$$u_{10}^{+} = u_{7}^{+} \times [\ln (10/0.005)/\ln (7/0.005)]$$

where: u_{10}^{+} = windspeed [meters per second (m/sec)] at 10 m; and
u_{7}^{+} = windspeed (m/sec) at 7 m.

The fastest mile windspeed was then used to calculate the friction velocity for the coal stockpile, using:

$$u^{*} = 0.1 \times u_{10}^{+} \times (u_s/u_r)$$

where: u^{*} = friction velocity (m/sec);
u_{10}^{+} = windspeed (m/sec) at 10 m; and
u_s/u_r = friction velocity coefficient (dimensionless), derived from Pile B3 (Figure A.2-1).

The results of each of these calculations for the 91 periods are presented in Table A.2-1. Comparing the friction velocities to the 1.12-m/sec threshold friction velocity for an uncrusted coal pile demonstrates that Periods 7, 15, 19, 33, 39, and 45 are the only times fugitive emission may be expected. Additionally, emissions during these periods are expected only from the most exposed portion of the stockpile (Figure A.2-1).

The calculated emissions are a function of the exposure potential and the exposed area. The exposure potential is:

$$P = [58 \times (u^{*} - u_{T}^{*})^2] + [25 \times (u^{*} - u_{T}^{*})]$$

where: P = emission potential [grams per square meter (g/m^2)];
u_T^{*} = threshold friction velocity = 1.12 m/sec; and
u^{*} = friction velocity for a specific period.

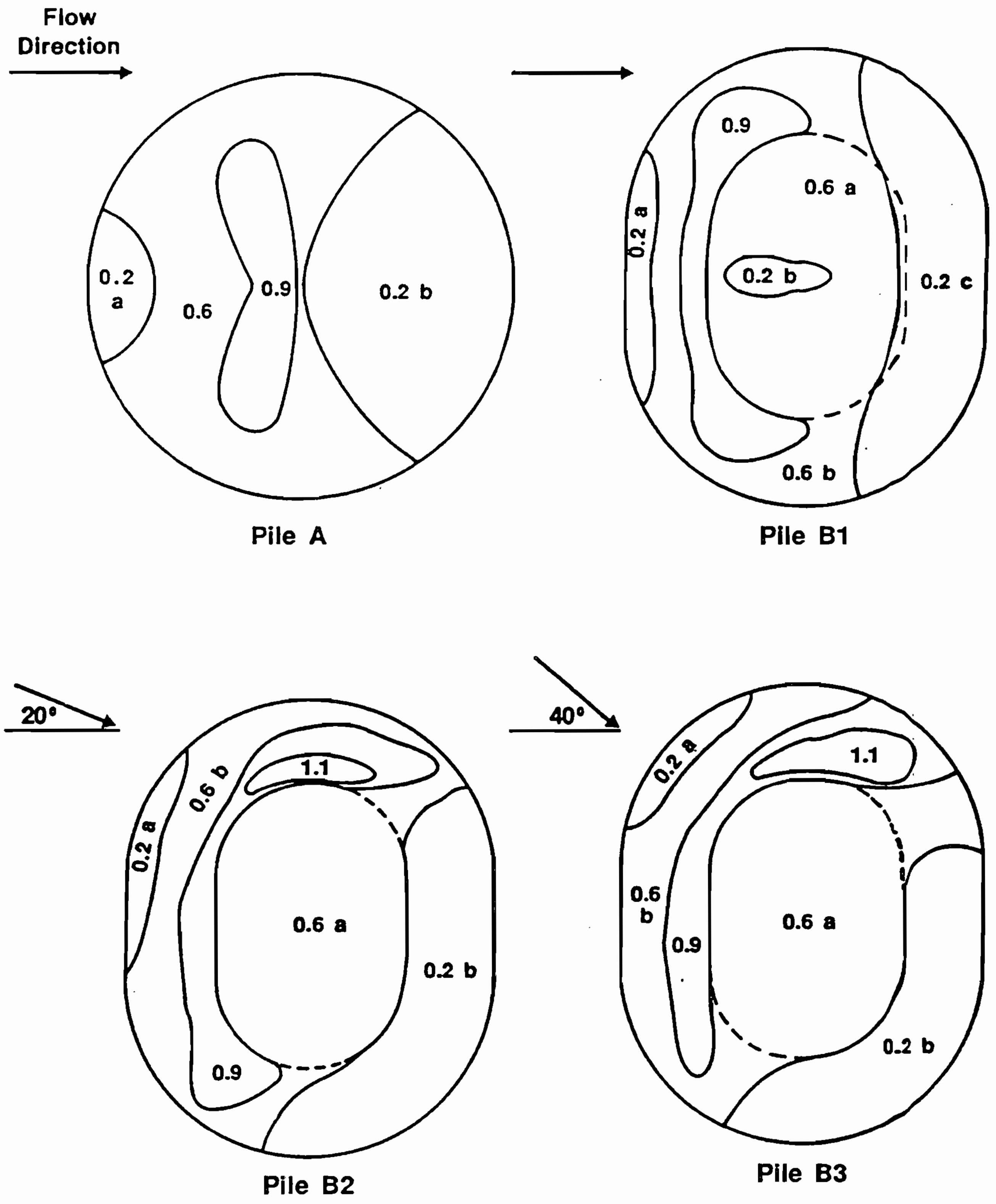

FIGURE A.2-1.

CONTOURS OF NORMALIZED SURFACE WINDSPEEDS, U_S/U_R

Source: EPA, 1991b.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

Table A.2-1. Summary of Friction Velocity Calculations

Period	Windspeed at 7 m (m/sec)	Windspeed at 10 m (m/sec)	Friction Velocity (m/sec)			
			u_s/u_r 0.2	u_s/u_r 0.6	u_s/u_r 0.9	u_s/u_r 1.1
1	7.6	8.0	0.16	0.48	0.72	0.88
2	8.0	8.4	0.17	0.50	0.76	0.92
3	8.0	8.4	0.17	0.50	0.76	0.92
4	6.7	7.0	0.14	0.42	0.63	0.77
5	7.6	8.0	0.16	0.48	0.72	0.72
6	5.8	6.1	0.12	0.37	0.55	0.67
7	11.2	11.8	0.24	0.71	1.06	1.30
8	5.8	6.1	0.12	0.37	0.55	0.67
9	5.8	6.1	0.12	0.37	0.55	0.67
10	7.2	7.6	0.15	0.46	0.68	0.84
11	6.3	6.6	0.13	0.40	0.59	0.73
12	6.3	6.6	0.13	0.40	0.59	0.73
13	8.9	9.3	0.19	0.56	0.84	1.02
14	7.2	7.6	0.15	0.46	0.68	0.84
15	9.8	10.3	0.21	0.62	0.93	1.13
16	5.4	5.6	0.11	0.34	0.50	0.61
17	6.7	7.0	0.14	0.42	0.63	0.77
18	7.2	7.6	0.15	0.46	0.68	0.84
19	11.6	12.1	0.24	0.73	1.09	1.33
20	8.0	8.4	0.17	0.50	0.76	0.92
21	6.7	7.0	0.14	0.42	0.63	0.77
22	6.3	6.6	0.13	0.40	0.59	0.73
23	6.3	6.6	0.13	0.40	0.59	0.73
24	6.7	7.0	0.14	0.42	0.63	0.77
25	7.6	8.0	0.16	0.48	0.72	0.88
26	5.4	5.6	0.11	0.34	0.50	0.62
27	7.6	8.0	0.16	0.48	0.72	0.88
28	6.7	7.0	0.14	0.42	0.63	0.77
29	5.4	5.6	0.11	0.34	0.50	0.62
30	5.8	6.1	0.12	0.37	0.55	0.67
31	6.3	6.6	0.13	0.40	0.59	0.73
32	6.3	6.6	0.13	0.40	0.59	0.73
33	15.6	16.4	0.33	0.98	1.48	1.80
34	5.8	6.1	0.12	0.37	0.55	0.67
35	6.3	6.6	0.13	0.40	0.59	0.73
36	5.4	5.6	0.11	0.34	0.50	0.62
37	6.3	6.6	0.13	0.40	0.59	0.73
38	6.7	7.0	0.14	0.42	0.63	0.77
39	11.2	11.8	0.24	0.71	1.06	1.30
40	6.3	6.6	0.13	0.40	0.59	0.73
41	6.7	7.0	0.14	0.42	0.63	0.77
42	7.6	8.0	0.16	0.48	0.72	0.88
43	5.4	5.6	0.11	0.34	0.50	0.62
44	7.6	8.0	0.16	0.48	0.72	0.88
45	11.6	12.1	0.24	0.72	1.09	1.33
46	7.2	7.6	0.15	0.46	0.68	0.84
47	8.0	8.4	0.17	0.50	0.76	0.92

Table A.2-1. Summary of Friction Velocity Calculations (Continued, Page 2 of 2)

Period	Windspeed at 7 m (m/sec)	Windspeed at 10 m (m/sec)	Friction Velocity (m/sec)			
			u_*/u_r 0.2	u_*/u_r 0.6	u_*/u_r 0.9	u_*/u_r 1.1
48	8.9	9.3	0.19	0.56	0.84	1.02
49	5.4	5.6	0.11	0.34	0.50	0.62
50	7.2	7.6	0.15	0.46	0.68	0.84
51	7.2	7.6	0.15	0.46	0.68	0.84
52	7.6	8.0	0.16	0.48	0.72	0.88
53	8.0	8.4	0.17	0.50	0.76	0.92
54	6.7	7.0	0.14	0.42	0.63	0.77
55	7.6	8.0	0.16	0.48	0.72	0.88
56	6.3	6.6	0.13	0.40	0.59	0.73
57	8.0	8.4	0.17	0.50	0.76	0.92
58	7.6	8.0	0.16	0.48	0.72	0.88
59	6.7	7.0	0.14	0.42	0.63	0.77
60	6.3	6.6	0.13	0.40	0.59	0.73
61	7.2	7.6	0.15	0.46	0.68	0.84
62	6.3	6.6	0.13	0.40	0.59	0.73
63	8.0	8.4	0.17	0.50	0.76	0.92
64	5.4	5.6	0.11	0.34	0.50	0.62
65	7.6	8.0	0.16	0.48	0.72	0.88
66	6.3	6.6	0.13	0.40	0.59	0.73
67	6.3	6.6	0.13	0.40	0.59	0.73
68	4.5	4.7	0.09	0.28	0.42	0.52
69	6.3	6.6	0.13	0.40	0.59	0.73
70	5.4	5.6	0.11	0.34	0.50	0.62
71	5.4	5.6	0.11	0.34	0.50	0.62
72	4.0	4.2	0.08	0.25	0.38	0.46
73	6.3	6.6	0.13	0.40	0.59	0.73
74	6.3	6.6	0.13	0.40	0.59	0.73
75	6.3	6.6	0.13	0.40	0.59	0.73
76	6.7	7.0	0.14	0.42	0.63	0.77
77	4.5	4.7	0.09	0.18	0.42	0.52
78	5.4	5.6	0.11	0.34	0.50	0.62
79	6.3	6.6	0.13	0.40	0.59	0.73
80	7.6	8.0	0.16	0.48	0.72	0.88
81	5.4	5.6	0.11	0.34	0.50	0.62
82	5.8	6.1	0.12	0.37	0.55	0.67
83	6.3	6.6	0.13	0.40	0.59	0.73
84	7.6	8.0	0.16	0.48	0.72	0.88
85	6.7	7.0	0.14	0.42	0.63	0.77
86	5.8	6.1	0.12	0.37	0.55	0.67
87	7.6	8.0	0.16	0.48	0.72	0.88
88	4.5	4.7	0.09	0.28	0.42	0.52
89	7.2	7.6	0.15	0.46	0.68	0.84
90	6.7	7.0	0.14	0.42	0.63	0.77
91	6.7	7.0	0.14	0.42	0.63	0.77

Source: ECT, 1992.

Substituting, the emission potentials are given in Table A.2-2.

The coal stockpile is divided into two adjacent areas: short- and long-term storage. The long-term storage area will be turned over once or twice per year. The short-term area will be turned over more frequently and will receive a coal delivery approximately every fourth day. The surface areas covered by the short-term stockpile is:

$$R_S = c_4 \times [L \times W]$$

where: R_S = short-term affected area (m^2);
L = ~~length~~ radius of the pile (m) = ~~100.6~~ 33.25 m; and
~~W = width of the pile (m) = 34.5 m; and~~
c_4 = the affected fraction of the storage area (dimensionless, from Figure A.2-1) = 0.14 or 0.4.

Substituting, the size of the short-term affected areas are:

$$R_{S1} = 0.14 \times \cancel{100.6\ m}\ (33.25\ m)^2 \times \cancel{34.5\ m}\ 3.14;$$
$$R_{S1} = 485.9\ m^2;$$
$$R_{S2} = 0.04 \times \cancel{100.6\ m}\ (33.25\ m)^2 \times \cancel{34.5\ m}\ 3.14;\ and$$
$$R_{S2} = 138.8\ m^2.$$

The surface area covered by the long-term stockpile is:

$$R_L = c_4 \times (L \times W)$$

where: R_L = long-term affected area (m^2);
L = length of the pile (m) = 134.8 m;
W = width of the pile (m) = 100.6 m;
C_4 = the affected fraction of the storage area (dimensionless, from Figure A.2-1) = 0.14 or 0.04.

Substituting, the size of the long-term affected areas are:

$$R_{L1} = 0.14 \times 134.8\ m \times 100.6\ m$$
$$= 1{,}898.5\ m^2;$$
$$R_{L2} = 0.04 \times 134.8\ m \times 100.6\ m;\ and$$
$$= 542.4\ m^2.$$

Table A.2-2. Summary of Emission Potential

Period	Calculated Emission Potential (g/m²)	Area Effected (percent)
7	6.38	4
15	0.26	4
19	7.81	4
33	16.52	4
	43.82	14
39	6.38	4
45	7.81	4

Source: ECT, 1992.

Water sprays will be used to control dust on the short-term stockpile. Water spraying is assumed to be 50 percent efficient. Chemical suppressants will be used to control dust from the long-term stockpile. Chemical control is assumed to be 90 percent efficient. Conservatively assuming that Period 33 is the highest short-term emission case and that particulate matter could be released during any single 4-hour period, the worst-case, short-term emission rate from the short-term pile is:

$$\begin{aligned}
A_s &= 0.5 \times [(485.9\ m^2 \times 16.52\ g/m^2) + (138.8\ m^2 \times 43.82\ g/m^2)];\\
A_s &= 3.89\ lb/hr;\ and\\
A_s &= 0.49\ g/\mathrm{sec}.
\end{aligned}$$

The short-term emission rate from the long-term pile is:

$$\begin{aligned}
A_S &= 0.1\ [(1{,}898.5\ m^3 \times 16.52\ g/m^3) + (542.4\ m^2 \times 43.82\ g/m^2)];\\
A_S &= 3.04\ lb/hr;\\
A_S &= 0.38\ g/\mathrm{sec}.
\end{aligned}$$

The annual emission from the stockpiles can be calculated by adding the short-term emissions during the periods of high windspeed.

For the short-term stockpile, this calculation is:

$$\begin{aligned}
A_L = {} & 0.5\ [138.8\ m^2 \times 6.38\ g/m^2) + (138.8\ m^2 \times 0.24) + (138.8\ m^2 \times 7.81\ g/m^2);\\
& + (138.8\ m^2 \times 43.82\ g/m^2) + (485.9\ m^2 \times 16.52\ g/m^2) + (138.8\ m^2 \times 6.38\ g/m^2);\\
& + (138.8\ m \times 7.81\ g/m^2)] \times (1\ lb/453.6\ g) \times (1\ t/2{,}000\ lb);\\
A_L = {} & 0.01\ tpy;\ and\\
= {} & 0.0003\ g/\mathrm{sec}.
\end{aligned}$$

For the long-term stockpile, this calculation is:

$$\begin{aligned}
A_L = {} & 0.1\ [(542.4\ m^2 \times 6.38\ g/m^2) + (542.4\ m^2 \times 0.26\ g/m^2)\\
& + (542.4\ m^2 \times 7.81\ g/m^2) + (542.4\ m^2 \times 43.82\ g/m^2)\\
& + (1{,}898.5\ m^2 \times 16.52\ g/m^2) + (542.4\ m^2 \times 6.38\ g/m^2) + (542.4\ m^2 \times 7.81\ g/m^2)]\\
& \times (1\ lb/453.6\ g) \times 1\ t/2{,}000\ lb;\\
A_L = {} & 0.09\ tpy;\ and\\
= {} & 0.0025\ g/\mathrm{sec}.
\end{aligned}$$

APPENDIX A.3
PARTICULATE MATTER EMISSIONS FROM IGCC PROCESS SOURCES

COAL STORAGE BIN

The coal storage bin receives coal from the stockpile and stores the coal until needed in the grinding circuit. A baghouse filters ventilation air from the bin. The short-term emission rate (Texaco, 1992) is:

$A_S = 3.8\ lb/hr$; *and*
$A_S = 0.48\ g/\text{sec}.$

The annual emissions are calculated using the equation:

$$A_L = A_S \times H \times D \times c_2$$

where: A_L = annual emission rate (tpy);
A_S = emission rate (lb/hr) = 3.8 lb/hr;
H = operating hours per day = 8 hr/day;
D = operating days per year = 365 days/yr; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are:

$A_L = 3.8\ lb/hr \times 8\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$
$A_L = 5.54\ tpy$; *and*
$A_2 = 0.16\ g/\text{sec}.$

GRINDING TOWER BAGHOUSE

The grinding tower baghouse filters ventilation air from the grinding tower. The short-term emission rate (Texaco, 1992) is:

$A_s = 3.4\ lb/hr$; *and*
$A_s = 0.43\ g/\text{sec}.$

The annual emissions are calculated using the equation:

$$A_L = A_S \times H \times D \times c_2$$

where: A_L = annual emission (tpy);
A_S = emission rate (lb/hr) = 3.4 lb/hr;
H = operating hours per day = 8 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are:

$$A_L = 3.4\ lb/hr \times 8\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 4.96\ tpy;\ and$$
$$A_L = 0.14\ g/\text{sec.}$$

ROD MILL DISCHARGE

The rod mill grinds the coal into a fine powder. The short-term emission rate (Texaco, 1992) is:

$$A_s = 1.6\ lb/hr;\ and$$
$$A_s = 0.20\ g/\text{sec.}$$

The annual particulate matter emissions from the rod mill discharge are calculated using the equation:

$$A_L = A_S \times H \times D \times c_2$$

where: A_L = annual emission (tpy);
A_S = emission rate (lb/hr) = 1.6 lb/hr;
H = operating hours per day = 8 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are:

$$A_L = 1.6\ lb/hr \times 8\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 2.34\ tpy;\ and$$
$$A_L = 0.07\ g/\text{sec.}$$

AIR SEPARATION UNIT

The air separation unit is regenerated approximately 30 minutes every 4 weeks. The short-term emission rate (Texaco, 1992) is:

A_s = 100 *lb/hr; and*
A_s = 12.6 *g/*sec.

The annual particulate matter emissions from the air separation unit are calculated using the equation:

$$A_L = A_S \times H \times D \times c_2$$

where: A_L = annual emission (tpy);
A_S = emission rate (lb/hr) = 100 lb/hr;
H = operating hours per day = 0.5 hr/day;
D = operating days per year = 13 day/yr; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are:

A_L = 100 *lb/hr* × 0.5 *hr/day* × 13 *day/yr* × 1 *t/*2,000 *lb*;
A_L = 0.33 *tpy*; *and*
A_L = 0.009 *g/*sec.

FILTER UNIT

The short-term emission rate (Texaco, 1992) is:

A_s = 0.5 *lb/hr; and*
A_s = 0.06 *g/*sec.

The annual particulate matter emissions from the filter unit are calculated using the equation:

$$A_L = A_S \times H \times D \times c_2$$

where: A_L = annual emission (tpy);
A_S = emission rate (lb/hr) = 0.5 lb/hr;
H = operating hours per day = 24 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are:

A_L = 0.5 *lb/hr* × 24 *hr/day* × 365 *day/yr* × 1 *t*/2,000 *lb*;
A_L = 2.19 *tpy*; *and*
A_L = 0.06 *g*/sec.

APPENDIX A.4
H_2S, NH_3, AND CO EMISSIONS FROM IGCC PROCESS VENTS AND FUGITIVE SOURCES

HYDROGEN SULFIDE

GRINDING SUMP

Hydrogen sulfide (H_2S) will be discharged intermittently from the grinding sump, after control with carbon canister (90 percent control assumed). The short-term emission rate is (Texaco, 1992):

$$A_s = 0.48\ lb/hr;\ and$$
$$A_s = 0.06\ g/\text{sec.}$$

The annual emissions are calculated using the equation:

$$A_L = A_s \times H \times D \times c_2$$

where: A_L = annual emissions (tpy);
A_S = short-term emission rate (lb/hr) = 0.48 lb/hr;
H = operating hours per day = 24 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = 1 t/2,000 lb.

Substituting, the annual emissions are:

$$A_L = 0.48\ lb/hr \times 24\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 2.1\ tpy;\ and$$
$$A_L = 0.06\ g/\text{sec.}$$

SECONDARY SUMP

H_2S will be discharged intermittently from the secondary sump. The short-term emission rate is (Texaco, 1992):

$$A_s = 0.21\ lb/hr;\ and$$
$$A_s = 0.03\ g/\text{sec.}$$

The annual emissions are calculated using the equation:

$$A_L = A_s \times H \times D \times c_2$$

where: A_L = annual emissions (tpy);
A_S = short-term emission rate (lb/hr) = 0.21 lb/hr;
H = operating hours per day 1 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = 1 t/2,000 lb.

Substituting, the annual emissions are:

$$A_L = 0.21\ lb/hr\ 1\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.038\ tpy;\ and$$
$$A_L = 0.001\ g/\mathrm{sec}.$$

~~SULFUR PIT~~

~~H_2S will be discharged from the sulfur pit during loading/unloading, sampling, and metering operations. The short term emission rate is (Texaco, 1992):~~

~~$A_s = 0.5\ lb/hr;\ and$~~
~~$A_s = 0.06\ g/sec.$~~

~~The annual emissions are calculated using the equation:~~

~~$A_L = A_s \times H \times D \times c_2$~~

~~where: A_L = annual emissions (tpy);~~
~~A_S = short-term emission rate (lb/hr) = 0.5 lb/hr;~~
~~H = operating hours per day = 1 hr/day~~
~~D = operating days per year = 365 day/yr; and~~
~~c_2 = 1 t/2,000 lb.~~

~~Substituting, the annual emissions are:~~

~~$A_L = 0.5\ lb/hr \times 1\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$~~
~~$A_L = 0.09\ tpy;\ and$~~
~~$A_L = 0.003\ g/sec.$~~

FUGITIVE SOURCES

H_2S will be discharged via routine leakage from valves, flanges, and other piping equipment. Table A.4-1 summarizes the estimated numbers and types of fugitive sources associated with the IGCC unit. Table A.4-2 provides data on the composition of IGCC process streams [i.e., percentages of H_2S, NH_3, and carbon monoxide (CO)] and on the location of the emission sources given in Table A.4-1. Based on these data, emissions are calculated using emission factors provided in Table A.4-3. A control efficiency of 50 percent is assumed based on a quarterly program to inspect piping equipment and repair leaks. Therefore, for each emission point, the short-term H_2S emissions are calculated as follows:

$$A_s = \sum_{i,j} TP_{i,j} \times EF_{i,j} \times Conc_{H_2S_j} \times c_4 \times c_5$$

where:
A_s = short-term emissions (lb/hr);
$TP_{i,j}$ = total population of source type i in service category j;
$EF_{i,j}$ = emission factor for source type i in service category j [kilograms per hour per source (kg/hr/source)];
$Conc_{H2Sj}$ = concentration of H_2S in service category j (percent per 100);
c_4 = 0.50 (50 percent control efficiency); and
c_5 = 2.2 pounds per kilogram (lb/kg).

As an example calculation, for EP 32, AGR fugitives, substituting into the previous equation:

$$\begin{aligned} A_s &= \{0.70\ [(40 \times 0.00083) + (2 \times 0.228) + (12 \times 0.0017) + (16 \times 0.0494) + \\ &\quad (2 \times 0.104) + (261 \times 0.0056)] \times 0.1202 \times 0.50 \times 2.2\} + \\ &\quad \{0.10\ [(1{,}750 \times 0.00083) + (2 \times 0.228) + (8 \times 0.0017) + (10 \times 0.0494) + \\ &\quad (4 \times 0.104) + (460 \times 0.0056)] \times 0.015 \times 0.50 \times 2.2\} \\ &= 0.284\ lb/hr \\ &= 0.036\ g/sec \end{aligned}$$

Annual emissions are calculated using the following equation, which assumes continuous leakage:

$$A_L = A_s \times c_2 \times c_6$$

where: A_L = annual emissions (tpy);
A_s = short-term emission rate (lb/hr);
c_2 = 1 t/2,000 lb; and
c_6 = 8,760 hr/yr.

Table A.4-1. Summary of IGCC Fugitive Emissions Sources

Service Category*	Source Type†	Total Source Population
AG	CN	40
AG	CO	2
AG	OE	12
AG	PU	16
AG	RV	2
AG	VA	261
GWL	CN	1,928
GWL	CO	2
GWL	OE	30
GWL	PU	20
GWL	RV	2
GWL	VA	420
HL	PU	30
HL	VA	260
SG	CN	1,750
SG	CO	2
SG	OE	8
SG	PU	10
SG	RV	4
SG	VA	460
WWL	CN	132
WWL	CO	2
WWL	OE	40
WWL	PU	35
WWL	RV	2
WWL	VA	300

* AG = acid gas.
GWL = grey/black water.
HL = hydrocarbon liquid.
SG = syngas.
WWL = wastewater liquid.

† CN = connection (flange).
CO = compressor.
OE = open-ended line.
PU = pump.
RV = relief valve.
VA = valve.

Source: Texaco, 1992.

Table A.4-2. Composition of IGCC Process Streams and Location of Emission Sources

Service Category	Composition (percent)		Source Location(s)	Average Height(s) (ft)
AG	H_2S	12.02	70 percent in acid gas removal unit	12
	CO	0.02	10 percent in pipe rack between acid gas Removal unit and ~~sulfur recover unit~~ H_2SO_4 plant	20
	NH_3	0.00		
			20 percent in ~~sulfur recover unit~~ H_2SO_4 plant	12
GWL	H_2S	0.4	100 percent in gasification unit	12
	CO	0.1		
	NH_3	0.1		
HL	H_2S	0.5*	20 percent in fuel storage area	5
	CO	0.0	40 percent in pipe rack between fuel and CCs	20
	NH_3	0.0		
			20 percent in gasification unit	12
			10 percent in pipe rack from fuel to ~~sulfur removal unit~~ H_2SO_4 plant	20
			10 percent in pipe rack from fuel to flare	20
SG	H_2S	1.5	60 percent in gasification unit	12
	CO	47.0	10 percent in pipe rack from gas to acid gas removal unit	20
	NH_3	0.2		
			10 percent in acid gas removal unit	12
			10 percent in pipe rack from acid gas removal unit to CC	20
WWL	H_2S	0.1	40 percent in gasification unit	12
	CO	0.1	30 percent in pipe rack from gas to brine	20
	NH_3	0.1	30 percent in brine treating unit	12

*There is no H_2S in the hydrocarbon stream. However, sulfur bonded to the hydrocarbon registers as H_2S in the monitors so a level is detected.

Source: Texaco, 1992.

Table A.4-3. Average Emission Factors for Fugitive Emissions

Equipment	Service	Emission Factor (kg/hr/source)
Valves	Gas	0.0056
	Light liquid	0.0071
	Heavy liquid	0.00023
Pump seals	Light liquid	0.0494
	Heavy liquid	0.0214
Compressor seals	Gas/vapor	0.228
Pressure relief seals	Gas/vapor	0.104
Flanges	All	0.00083
Open-ended lines	All	0.0017
Sampling connections	All	0.0150

Source: EPA, 1988c.

Substituting, the annual emissions are:

$$\begin{aligned} A_L &= 0.284\ lb/hr \times 1\ t/2{,}000\ lb \times 8{,}760\ hr/yr \\ &= 1.24\ tpy \\ &= 0.036\ g/\text{sec} \end{aligned}$$

AMMONIA

MILL DISCHARGE TANK VENTS

Ammonia (NH_3) will be discharged intermittently from the mill discharge tank vents. The discharge gas will be passed through a carbon canister for treatment prior to release. The short-term emission rate is (Texaco, 1992):

$$A_s = 19\ lb/hr;\ and$$
$$A_s = 2.39\ g/\text{sec}.$$

The annual emissions are calculated using the equation:

$$A_L = A_s \times H \times D \times c_2$$

where: A_L = annual emissions (tpy);
A_S = short-term emission rate (lb/hr) = 19 lb/hr;
H = operating hours per day = 1 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = 1 t/2,000 lb.

Substituting, the annual emissions are:

$$A_L = 19\ lb/hr \times 1\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 3.47\ tpy;\ and$$
$$A_L = 0.099\ g/\text{sec}.$$

SLURRY TANK VENTS

NH_3 will be discharged intermittently from the slurry tank vents. The discharge gas will be passed through a carbon canister for treatment prior to release. The short-term emission rate is (Texaco, 1992):

A_s = 19 *lb/hr; and*
A_s = 2.39 *g/*sec.

The annual emissions are calculated using the equation:

$$A_L = A_s \times H \times D \times c_2$$

where: A_L = annual emissions (tpy);
A_S = short-term emission rate (lb/hr) = lb/hr;
H = operating hours per day = 1 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = 1 t/2,000 lb.

Substituting, the annual emissions are:

A_L = 19 *lb/hr* × 1 *hr/day* × 365 *day/yr* × 1 *t/*2,000 *lb*;
A_L = 3.47 *tpy; and*
A_L = 0.099 *g/*sec.

DEAERATOR VENT

NH_3 will be discharged as part of the steam stream released through the deaerator vent. The short-term emission rate is (Texaco, 1992):

A_s = 13 *lb/hr; and*
A_s = 1.64 *g/*sec.

The annual emissions are calculated using the equation:

$$A_L = A_s \times H \times D \times c_2$$

where: A_L = annual emissions (tpy);
A_S = short-term emission rate (lb/hr) = 13 lb/hr;
H = operating hours per day = 1 hr/day;
D = operating days per year = 365 day/yr; and
c_2 = 1 t/2,000 lb.

Substituting, the annual emissions are:

$$A_L = 13\ lb/hr \times 1\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 2.37\ tpy;\ and$$
$$A_L = 0.068\ g/\text{sec}.$$

FUGITIVE SOURCES

Procedures for calculating NH_3 fugitive emissions are provided under **HYDROGEN SULFIDE**.

CARBON MONOXIDE

FUGITIVE SOURCES

Procedures for calculating CO fugitive emissions are provided under **HYDROGEN SULFIDE**.

APPENDIX A.5
BASIS FOR STAND-ALONE CT EMISSION RATES

CT FIRING NATURAL GAS

Emission rates were based on data received from the CT vendor and on fuel specifications, as summarized below:

Pollutant	Basis
TSP/PM_{10}	Non-sulfate PM provided by vendor. Added to H_2SO_4 provided by vendor, based on 10 gr S/100 scf.
SO_2	Provided by vendor, based on 10 gr S/100 scf.
NO_x	Provided by vendor, based on 9 ppmvd.
CO	Provided by vendor, based on 25 ppmvd.
VOC	NMHC provided by vendor, based on 7 ppmvd.
H_2SO_4	Provided by vendor, based on 10 gr S/100 scf.
Hg	Calculated from worst-case emission factor, based on CCAP (1991)*.

*Data presented by CCAP (1991) on the range of Hg in natural gas provides a range of emission factors from a low value of less than 0.1 lb/10^{12} Btu to a high value of 12 lb/10^{12} Btu. Use of a median emission factor would reduce calculated Hg emissions by approximately half.

CT FIRING NO. 2 FUEL OIL

Emission rates were based on data received from the CT vendor and on fuel specifications, as summarized below:

Pollutant	Basis
TSP/PM_{10}	Non-sulfate PM provided by vendor, based on fuel ash content of 0.01 weight percent. Added to H_2SO_4 provided by vendor, based on 0.05 weight percent S.
SO_2	Provided by vendor, based on 0.05 weight percent S.
NO_x	Provided by vendor, based on 42 ppmvd.

CO	Provided by vendor, based on 30 ppmvd.
VOC	NMHC provided by vendor, based on 7 ppmvd.
Pb	Calculated from fuel specification of 1 ppm (equivalent to 53 lb/10^{12} Btu).
H_2SO_4	Provided by vendor, based on 0.05 weight percent S.
F	Calculated from worst-case emission factor (see Table A.1-1).
Hg	Calculated from worst-case emission factor (see Table A.1-1).
Be	Calculated from worst-case emission factor (see Table A.1-1).
As	Calculated from worst-case emission factor (see Table A.1-1).
Cd	Calculated from worst-case emission factor (see Table A.1-1).
Cr	Calculated from worst-case emission factor (see Table A.1-1).

LIST OF ACRONYMS

7Q10	7-day, 10-year flow rate
AADT	average annual daily trips
AAQS	ambient air quality standard
ACSR	aluminum conductor steel reinforced
Agrico	Agrico Chemical Company
AM	amplitude modulation
A/RR	Agricultural/Residential Rural
ASTM	American Society for Testing and Materials
BACT	best available control technology
BEBR	Bureau of Economic and Business Research
BLIS	BACT/LAER information system
BOCC	Board of County Commissioners
BOD	biochemical oxygen demand
Btu	British thermal unit
Btu/ft^3	British thermal units per cubic foot
Btu/gal	British thermal units per gallon
Btu/lb	British thermal units per pound
°C	degree Celsius
$CaCO_3$	calcium carbonate
CC	combined cycle
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CFRPC	Central Florida Regional Planning Council
cfs	cubic foot per second
CG	coal gasification
CGCU	cold gas cleanup
CITES	Convention on International Trade in Endangered Species
cm	centimeter
cm/sec	centimeter per second

LIST OF ACRONYMS
(Continued, Page 2 of 8)

CO	carbon monoxide
CO_2	carbon dioxide
COD	chemical oxygen demand
COS	carbonyl sulfide
CPT	cone penetration test
CR	County Road
CS_2	carbon disulfide
CSM	cubic foot per second per square mile
CT	combustion turbine
CUP	Conditional Use Permit
CWA	Clean Water Act
°	degree
d	Shannon Weaver diversity index
dBA	A-weighted decibel
dbh	diameter at breast height
DO	dissolved oxygen
DOE	U.S. Department of Energy
DSM	demand-side management
ECT	Environmental Consulting & Technology, Inc.
EEI	Edison Electric Institute
EIS	environmental impact statement
EIV	Volume of Environmental Information
EMF	electromagnetic field
EMS	emergency medical services
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
°F	degree Fahrenheit
F.A.C.	Florida Administrative Code
FCC	Federal Communications Commission

LIST OF ACRONYMS
(Continued, Page 3 of 8)

FCG	Florida Electric Power Coordinating Group
FCREPA	Florida Committee on Rare and Endangered Plants and Animals
FDACS	Florida Department of Agriculture and Consumer Services
FDCA	Florida Department of Community Affairs
FDER	Florida Department of Environmental Regulation
FDER/PSES	FDER Point Source Evaluation Section
FDHR	Florida Division of Historical Resources
FDLES	Florida Department of Labor and Employment Security
FDNR	Florida Department of Natural Resources
FDOT	Florida Department of Transportation
FEECA	Florida Energy Efficiency and Conservation Act
FEMA	Federal Emergency Management Agency
FEPPSA	Florida Electrical Power Plant Siting Act
FGD	flue gas desulfurization
FGFWFC	Florida Game and Fresh Water Fish Commission
FGS	Florida Geological Survey
FGT	Florida Gas Transmission Company
FLUCCS	Florida Land Use and Cover Classification System
FLUCFS	FDOT Land Use, Cover, and Forms Classification System
FM	frequency modulation
FNAI	Florida Natural Areas Inventory
FPC	Florida Power Corporation
FPSC	Florida Public Service Commission
FR	Federal Register
F.S.	Florida Statutes
FSRI	Florida Sinkhole Research Institute
ft	foot
ft bls	foot below land surface
ft/day	foot per day

LIST OF ACRONYMS
(Continued, Page 4 of 8)

ft^2/day	square foot per day
ft^3/day	cubic foot per day
ft^3/day/ft^3	cubic foot per day per cubic foot
ft/ft	foot per foot
ft^3/hr	cubic foot per hour
ft-msl	foot above mean sea level
ft-NGVD	foot national geodetic vertical datum
FTE	full-time equivalent
GE	General Electric Company
GEESI	General Electric Environmental Systems, Inc.
gpd	gallon per day
gpm	gallon per minute
gpm/ft	gallon per minute per foot
gpm/ft^2	gallon per minute per square foot
gr/scf	grains per standard cubic foot
gr/100 scf	grains per 100 standard cubic feet
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HGCU	hot gas cleanup
HHV	higher heating value
HRSG	heat recovery steam generator
HUD	Housing Urban Development
IGCC	integrated coal gasification combined cycle
IWTP	industrial wastewater treatment plant
kg	kilogram
km	kilometer
kV	kilovolt
kV/m	kilovolt per meter
kw	kilowatt

LIST OF ACRONYMS
(Continued, Page 5 of 8)

kwh	kilowatt hour
LAER	lowest achievable emission rate
lb/day	pound per day
lb/ft^3	pound per cubic foot
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
L_{dn}	day-night sound level
L_{eq}	equivalent noise level
$L_{eq}(24)$	equivalent sound level for 24-hour periods
LHV	lower heating value
LOLP	loss of load probability
LOS	level of service
LRU	logical reclamation unit
m	meter
m^2	square meter
MCR	maximum current rating
mG	milligauss
mg/L	milligram per liter
MGD	million gallons per day
mi^2	square mile
mL	milliliter
mph	miles per hour
MVA	megavolt amperes
MW	megawatt
NAS	National Audubon Society
NEPA	National Environmental Policy Act of 1969
NESC	National Electrical Safety Code
NESHAPS	National Emission Standard for Hazardous Air Pollutants
NGVD	National Geodetic Vertical Datum

LIST OF ACRONYMS
(Continued, Page 6 of 8)

NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSCR	non-selective catalytic reduction
NSPS	new source performance standards
NSR	New Source Review
NTU	nephelometric turbidity unit
NWS	National Weather Service
O_3	ozone
OAQPS	Office of Air Quality Planning and Standards
organisms/m^2	organisms per square meter
PCB	polychlorinated biphenyl
pCi/L	picoCurie per liter
persons/mi_2	persons per square mile
PHX	primary heat exchanger
PM	particulate matter
PM_{10}	particulate matter less than or equal to 10 micrometers aerodynamic diameter
POS	plan of study
POTW	publicly owned treatment works
ppb	part per billion
ppm	part per million
ppmv	part per million volumetric
ppmvd	dry volume parts per million
PRECO	Peace River Electric Cooperative
PSD	prevention of significant deterioration
psia	pound per square inch absolute
psig	pound per square inch gauge

LIST OF ACRONYMS
(Continued, Page 7 of 8)

Pt-Co	platinum-cobalt
PVC	polyvinyl chloride
QA/QC	quality assurance/quality control
R-1	Residence
RC	Rural Conservation
RCC	Rural-Cluster Center
R.O.	reverse osmosis
RCRA	Resource Conservation and Recovery Act
RMD	Rural Mixed-Use Development
rpm	revolutions per minute
RRD	Rural Residential
RV	recreational vehicle
SARA	Superfund Amendment and Reauthorization Act
SCA	Site Certification Application
scf	standard cubic foot
SCR	selective catalytic reduction
SCS	Soil Conservation Services
SF-1M	Single Family-Mixed
SIC	Standard Industrial Classification
SMSA	Standard Metropolitan Statistical Area
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SOP	standard operating procedure
SPCC	Spill Prevention, Control, and Countermeasure
SPT	standard penetration test
SR	State Road
ST	steam turbine
stpd	short-tons per day

LIST OF ACRONYMS
(Continued, Page 8 of 8)

SUS	Saybolt Universal seconds
SWFWMD	Southwest Florida Water Management District
TCLP	toxicity characteristic leaching procedure
TDS	total dissolved solids
Texaco	Texaco, Inc.
tpd	ton per day
tpy	ton per year
TSP	total suspended particulate
TSS	total suspended solids
UE&C	United Engineers & Constructors
μg/L	microgram per liter
μg/m^3	microgram per cubic meter
μmhos/cm	micromhos per centimeter
U.S.C.	United States Code
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compound
WUP	water use permit