TAMPA ELECTRIC COMPANY

POLK POWER STATION
Polk County, Florida

SITE CERTIFICATION APPLICATION

VOLUME 4

TAMPA ELECTRIC
A TECO ENERGY COMPANY

July 1992

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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

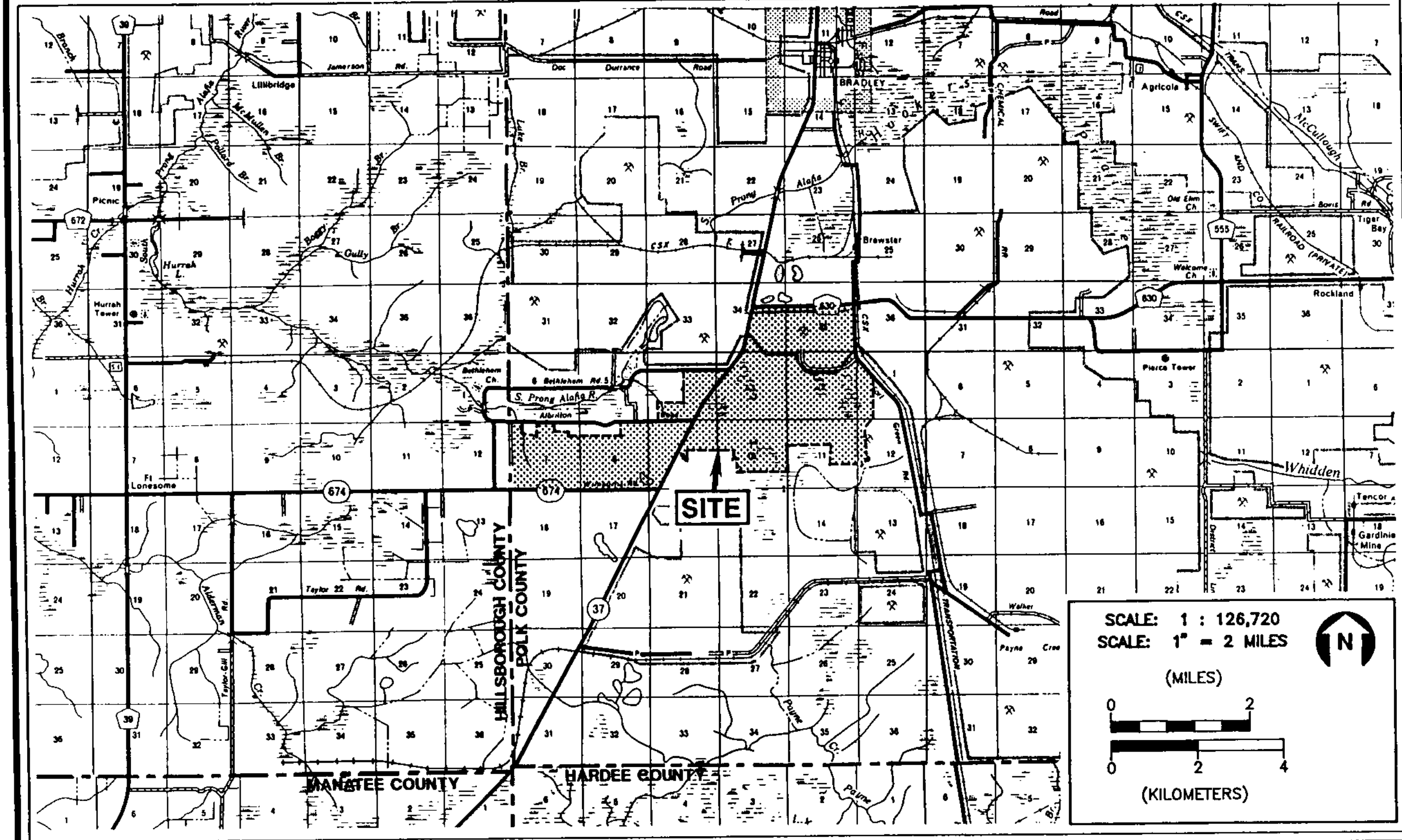

FIGURE 2-1.

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 and H_2SO_4 by-product 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

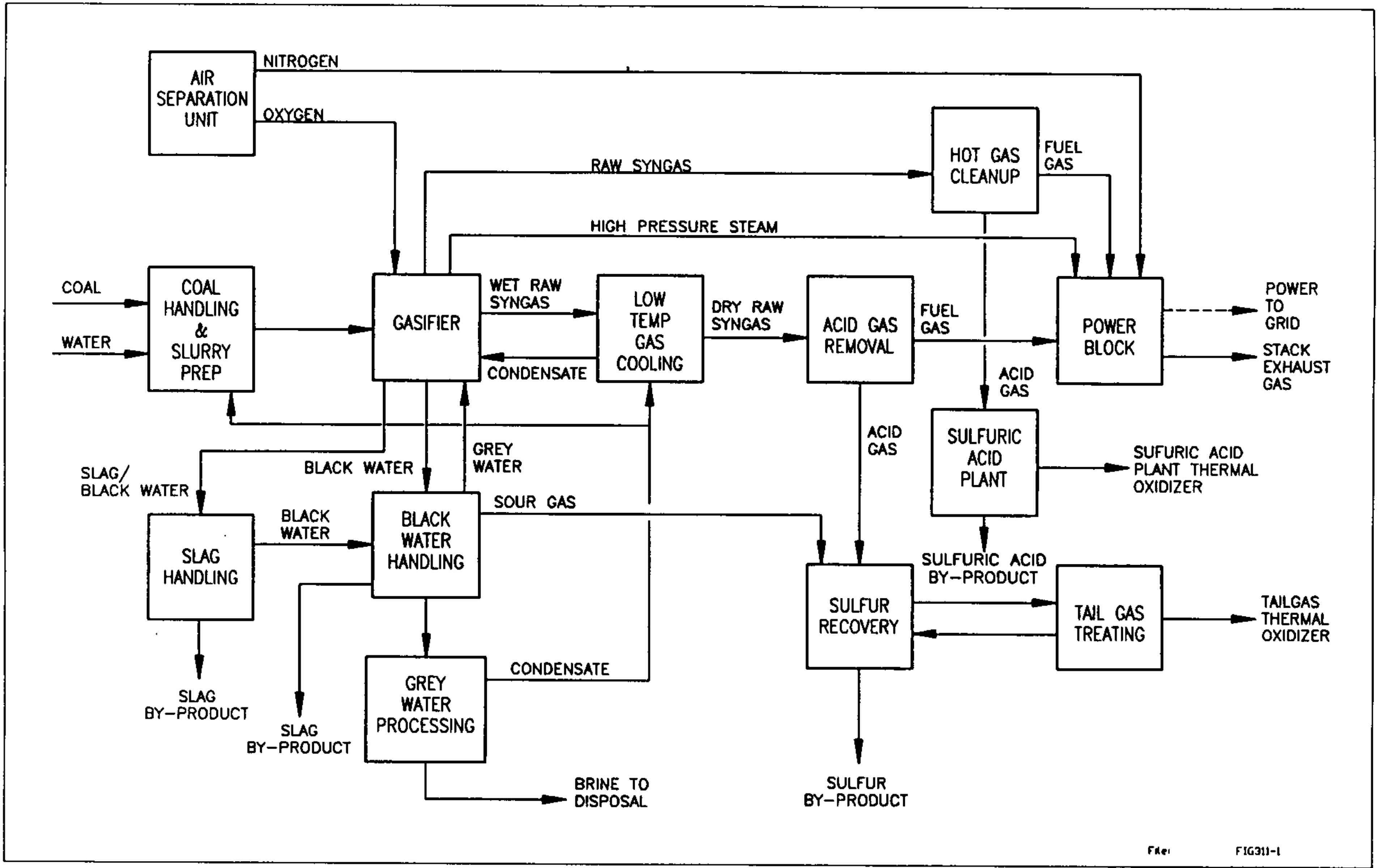

FIGURE 2-2.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1992.

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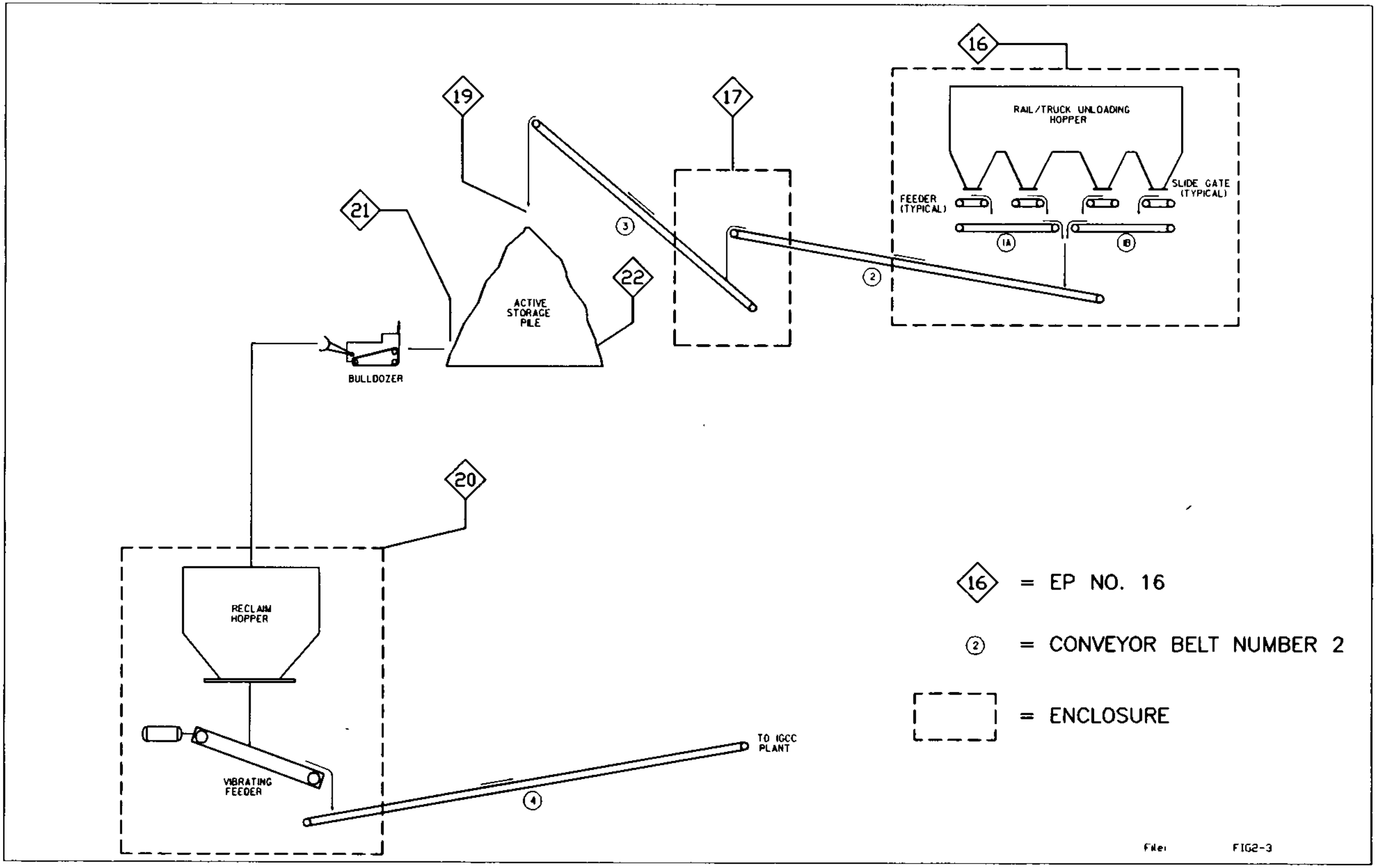

FIGURE 2-3.

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.

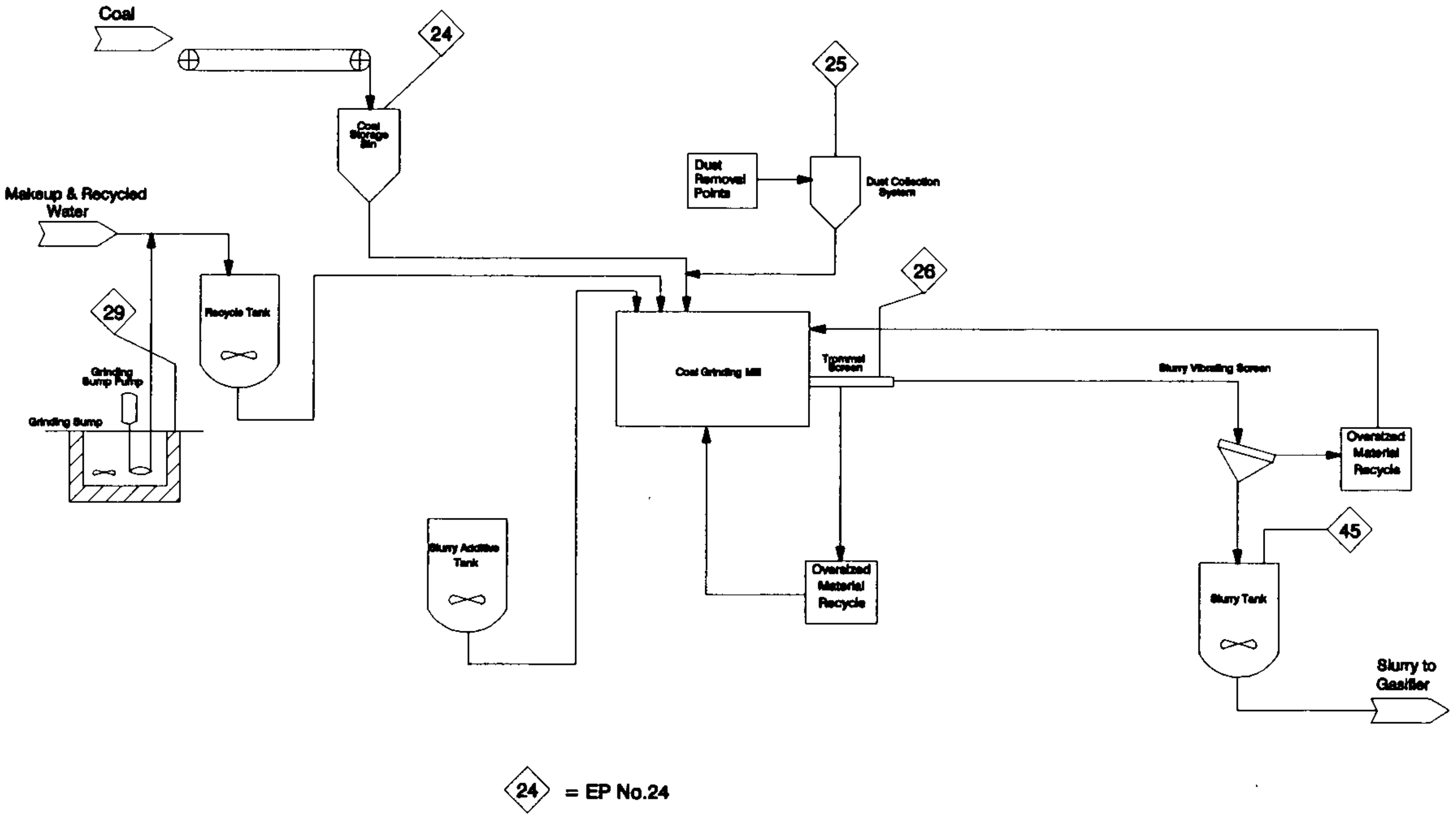

FIGURE 2-4.

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.

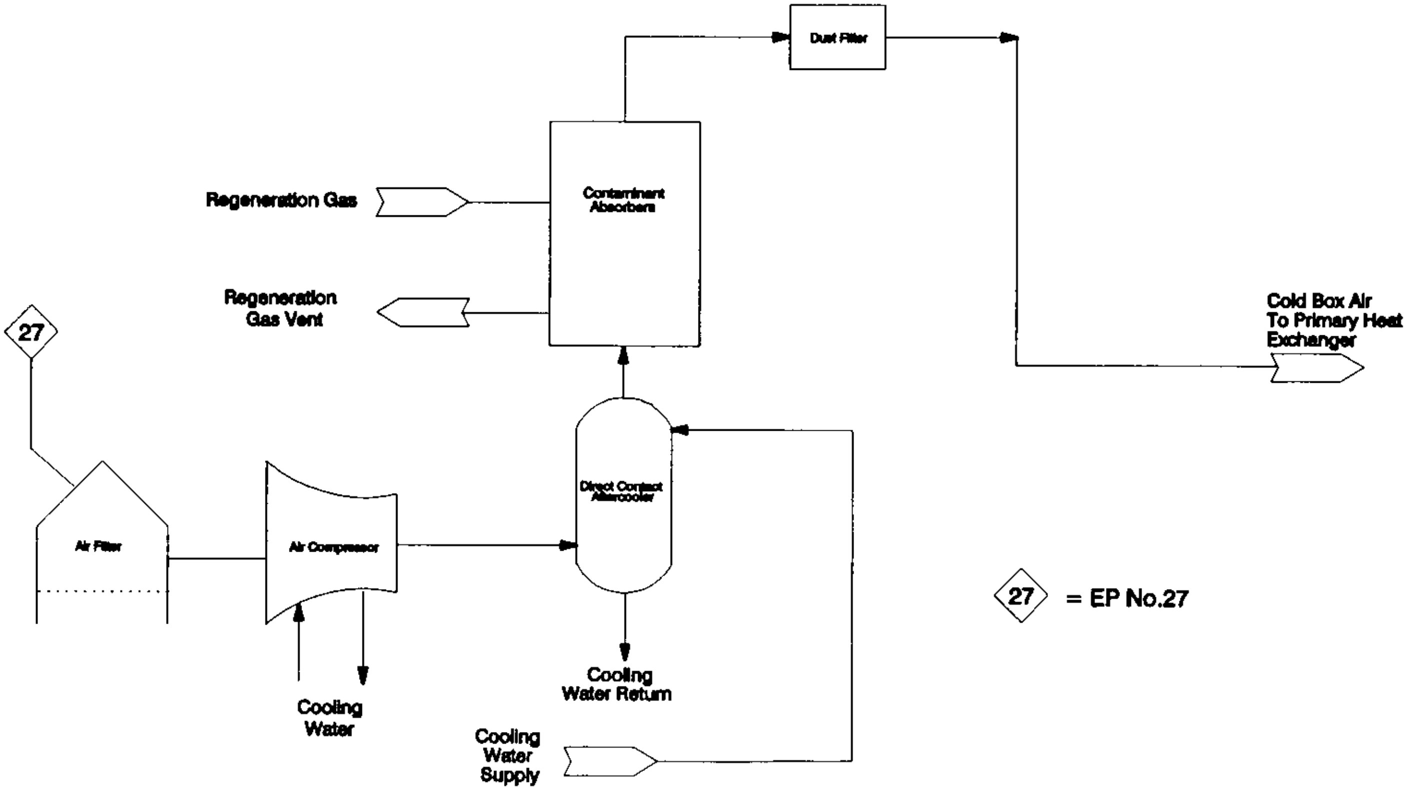

FIGURE 2-5.

AIR SEPARATION UNIT SCHEMATIC (PAGE 1 OF 2)

Source: Texaco, 1992.

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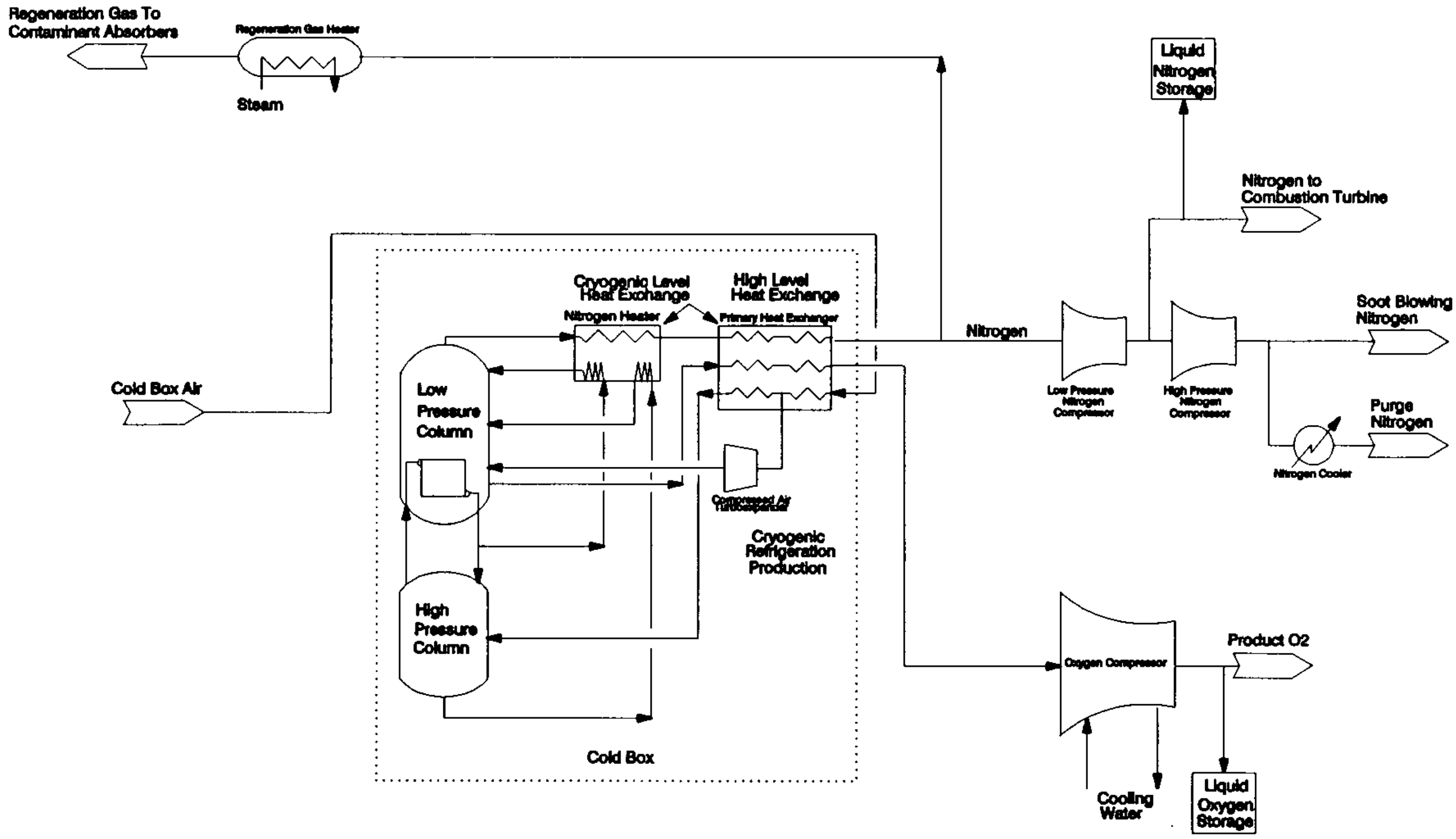

FIGURE 2-5.

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

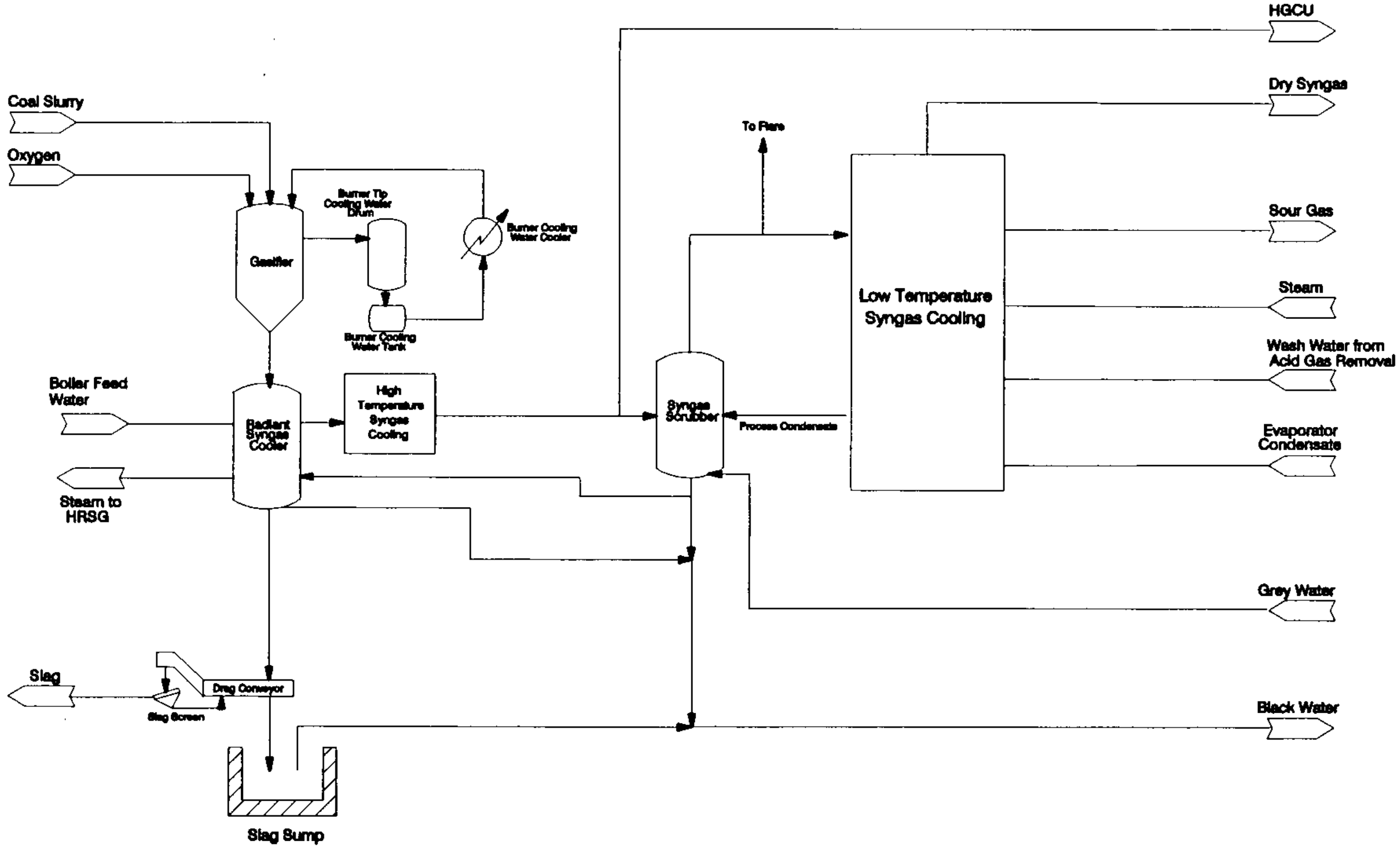

FIGURE 2-6.

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), 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

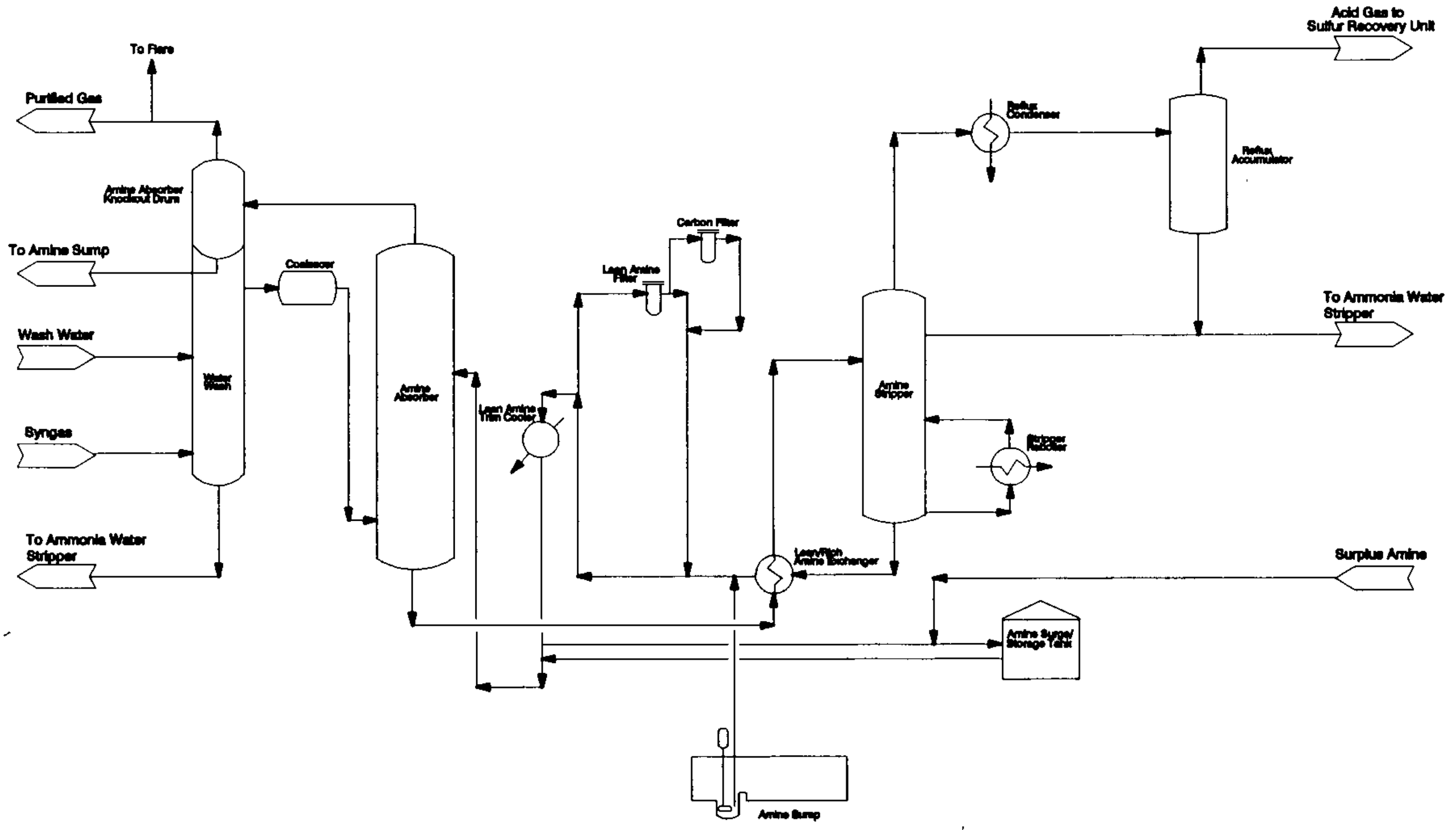

FIGURE 2-7.

ACID GAS REMOVAL UNIT SCHEMATIC

Source: ECT, 1992.

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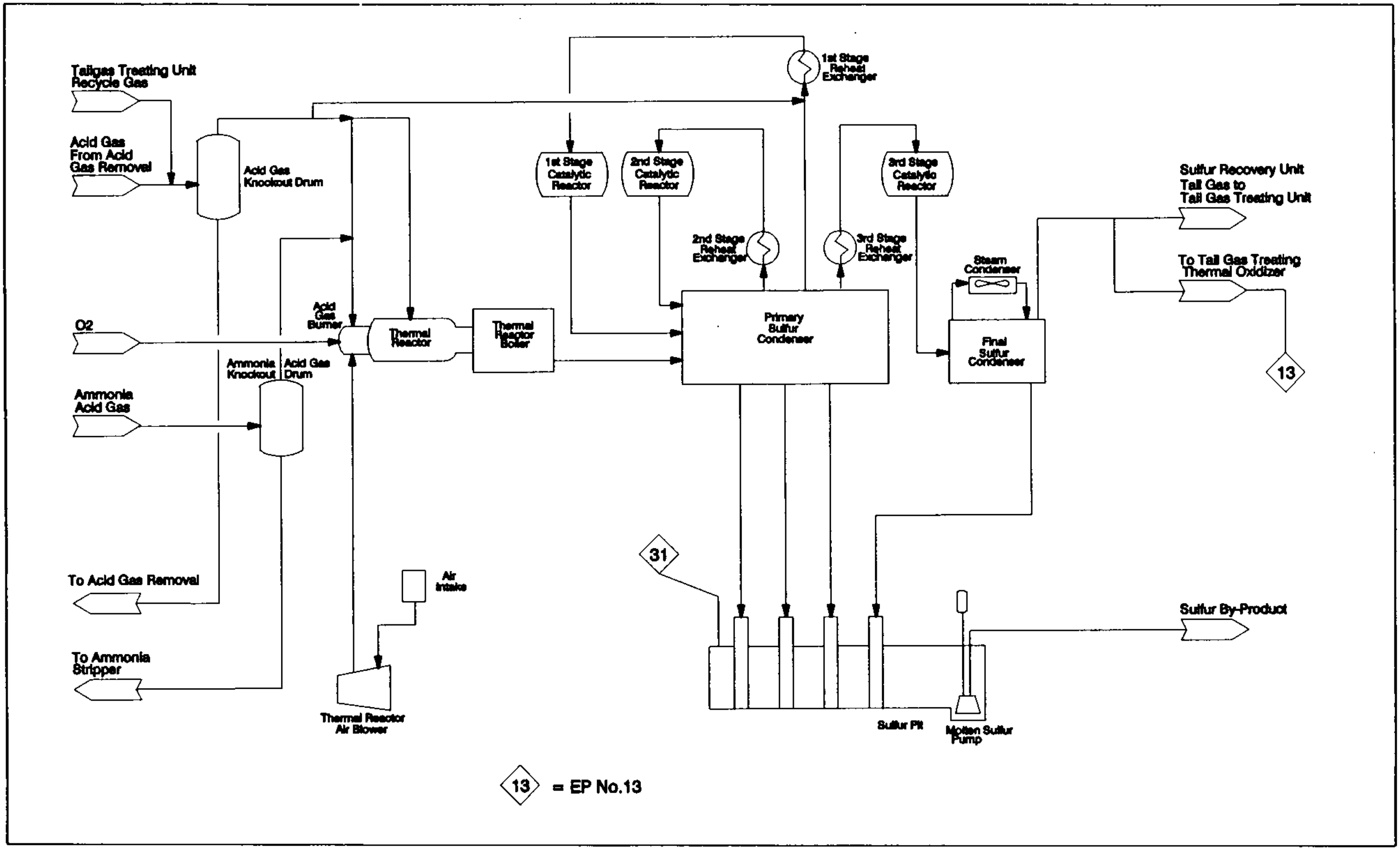

FIGURE 2-8.

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

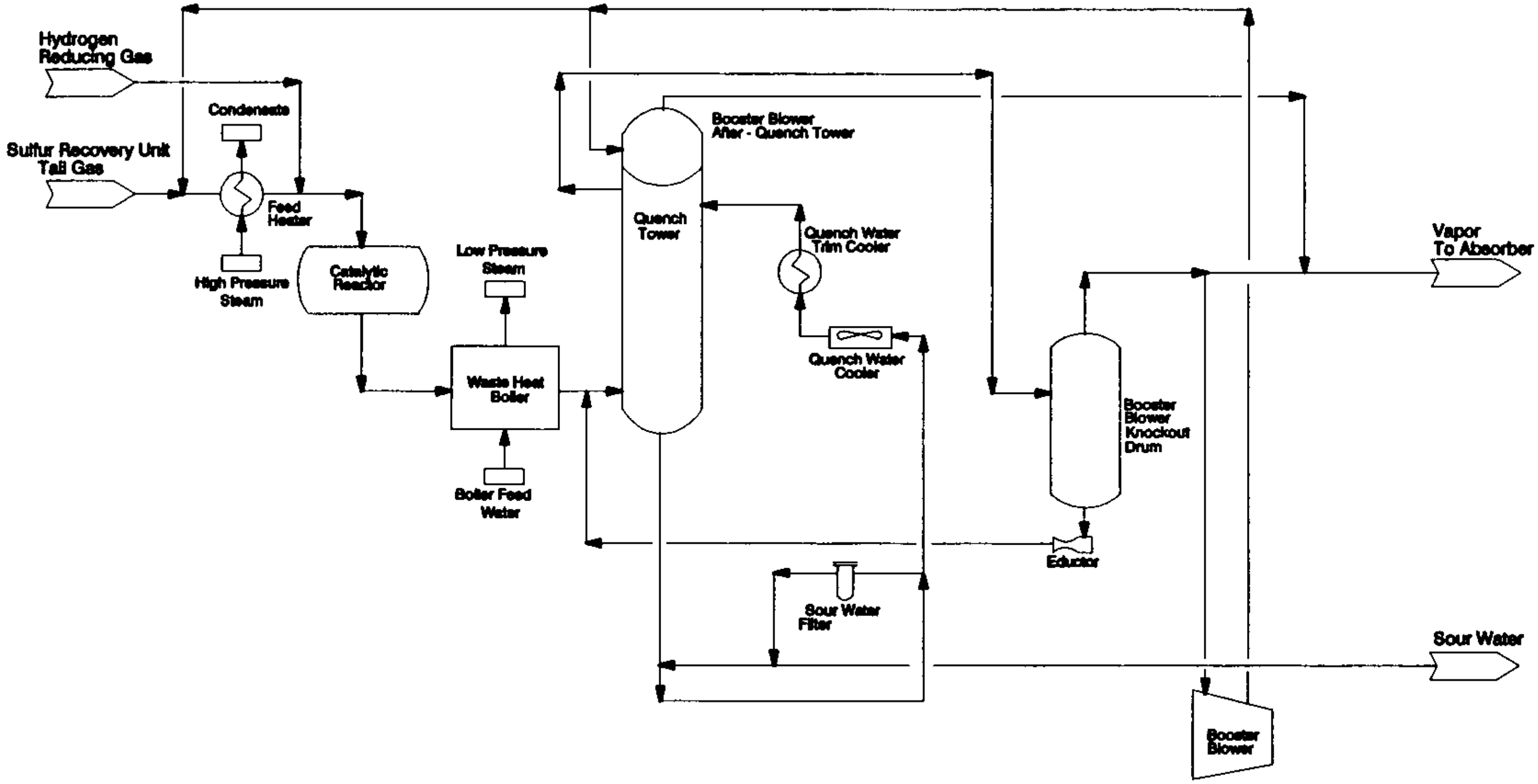

FIGURE 2-9.

TAIL GAS TREATING UNIT REACTION SECTION SCHEMATIC

Source: Texaco, 1992.

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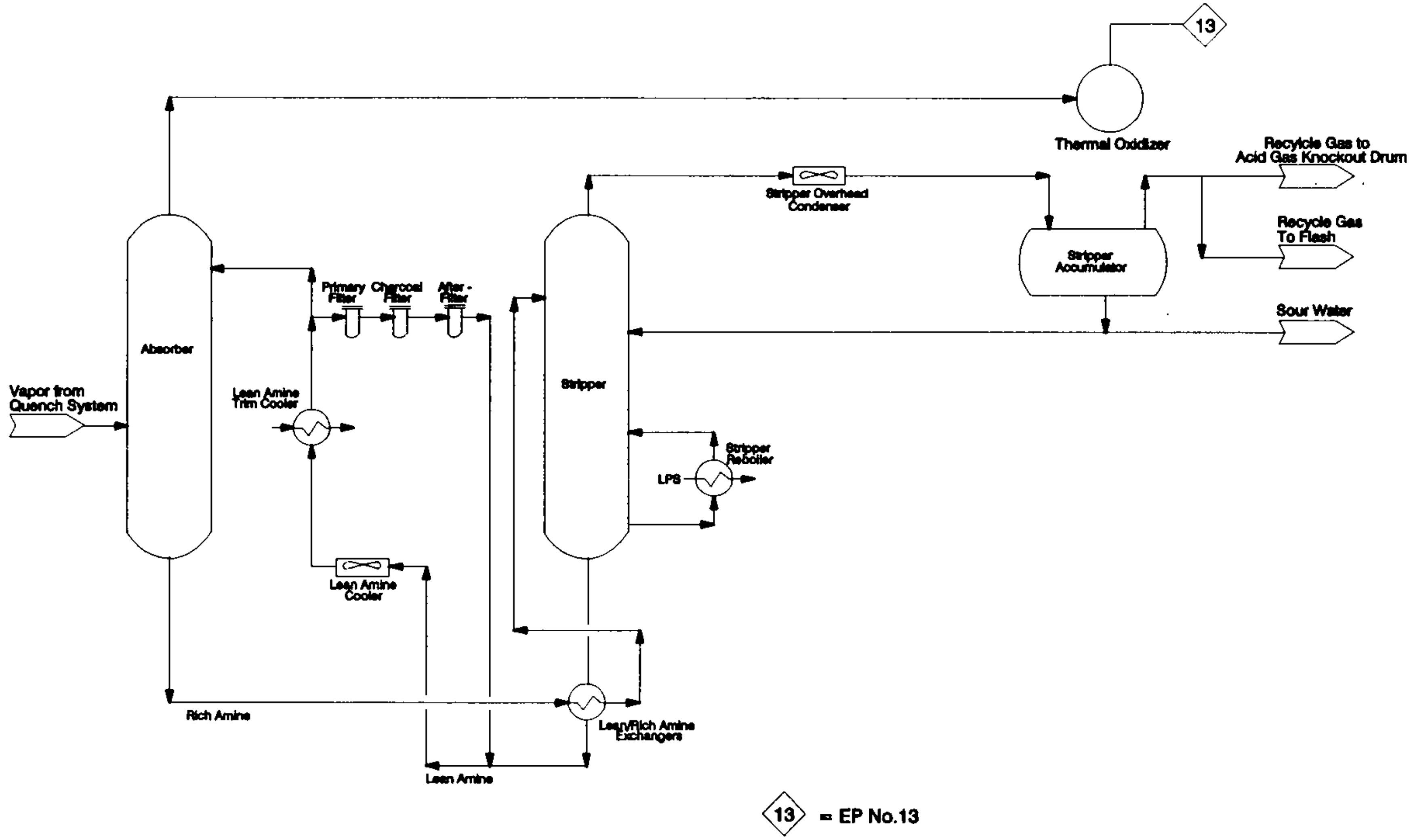

FIGURE 2-10.

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

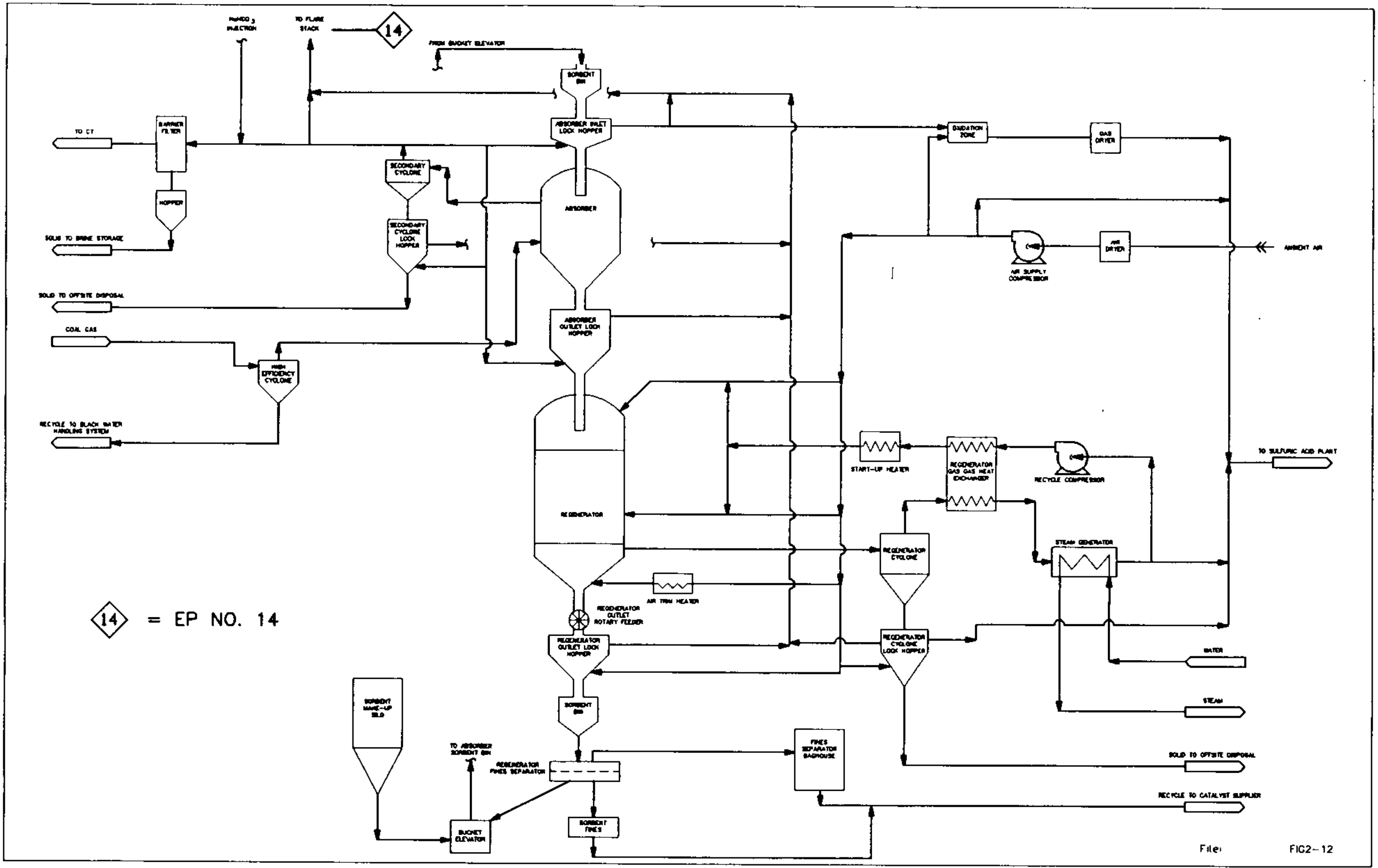

FIGURE 2-11.

HOT GAS CLEAN UP 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.

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 lock-hopper, 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, the reactor is divided into up to three zones. 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:

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

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

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.

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

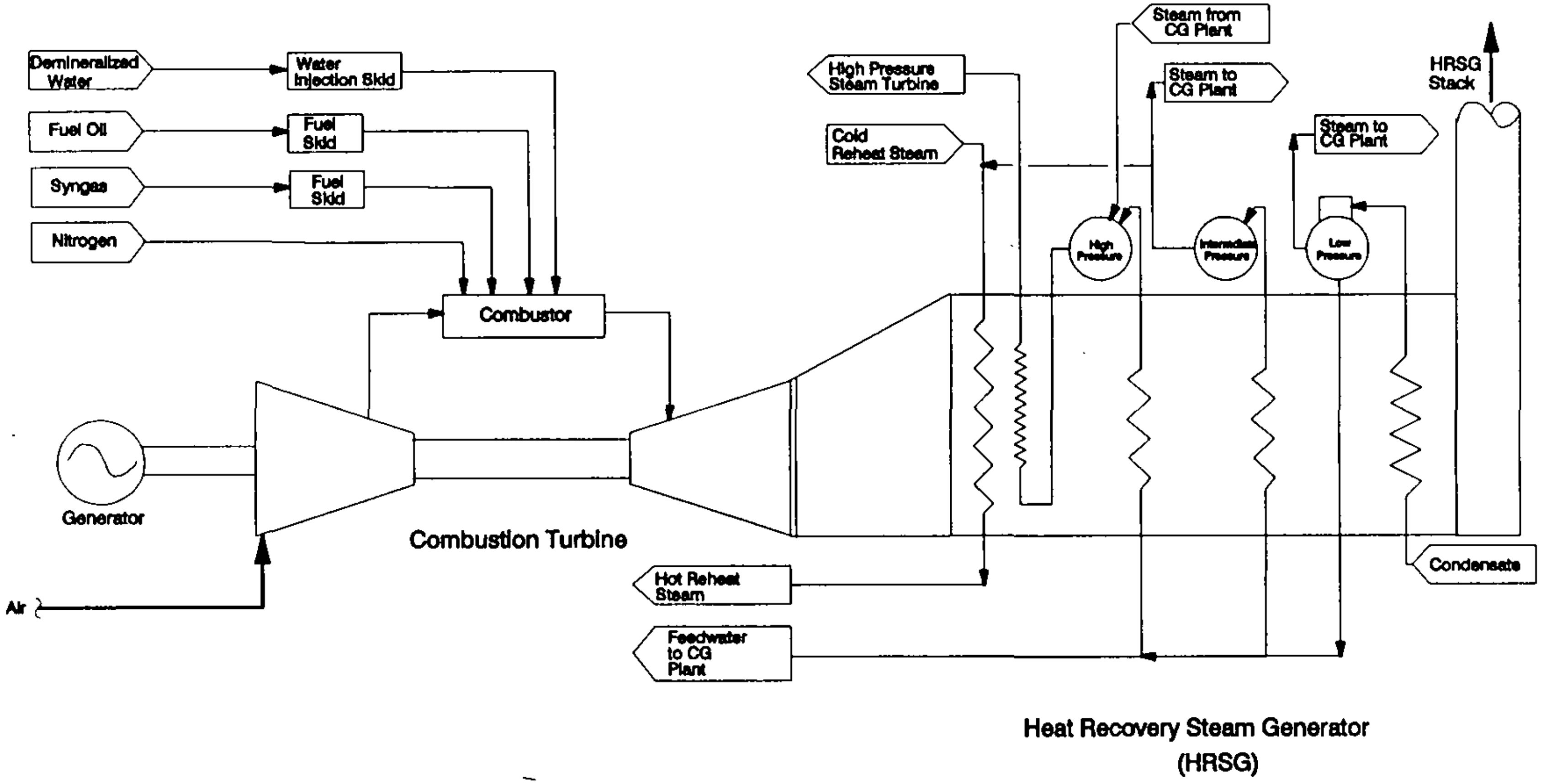

FIGURE 2-12.

COMBUSTION TURBINE PROCESS FLOW SCHEMATIC

Source: GE, 1992.

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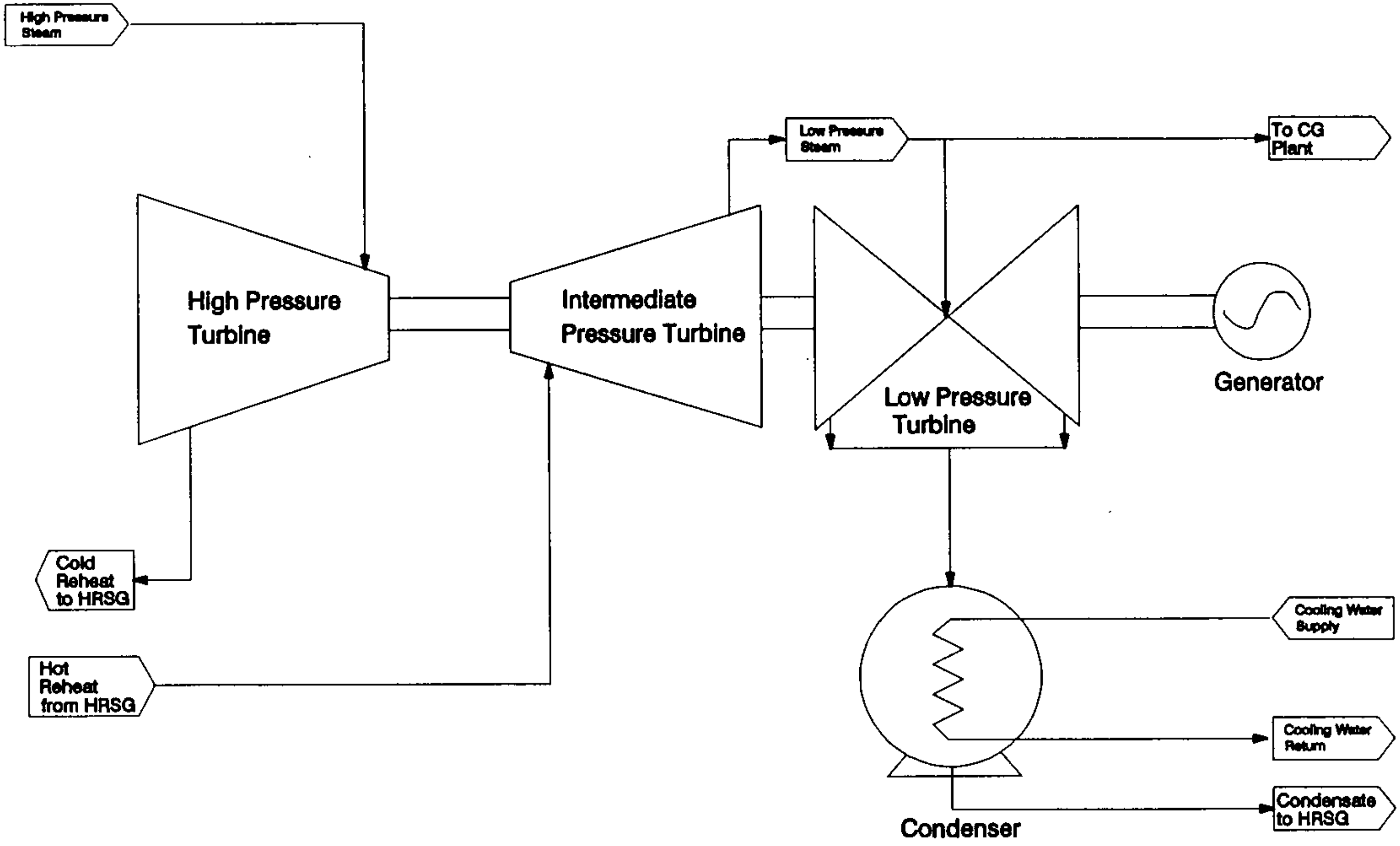

FIGURE 2-13.

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

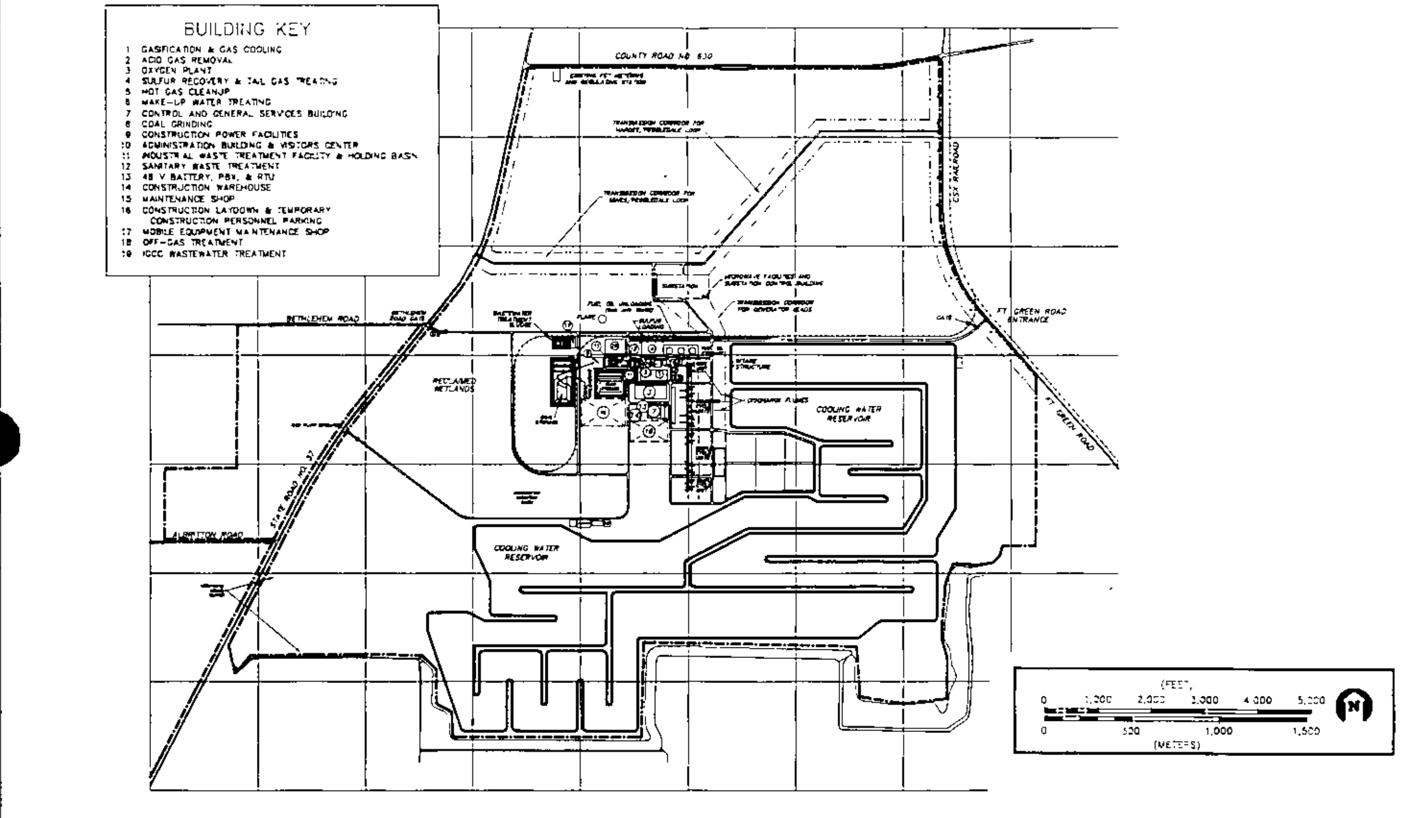

FIGURE 2-14.

CONCEPTUAL POWER BLOCK AND DIRECTLY ASSOCIATED FACILITIES LAYOUT

Source: ECT, 1992.

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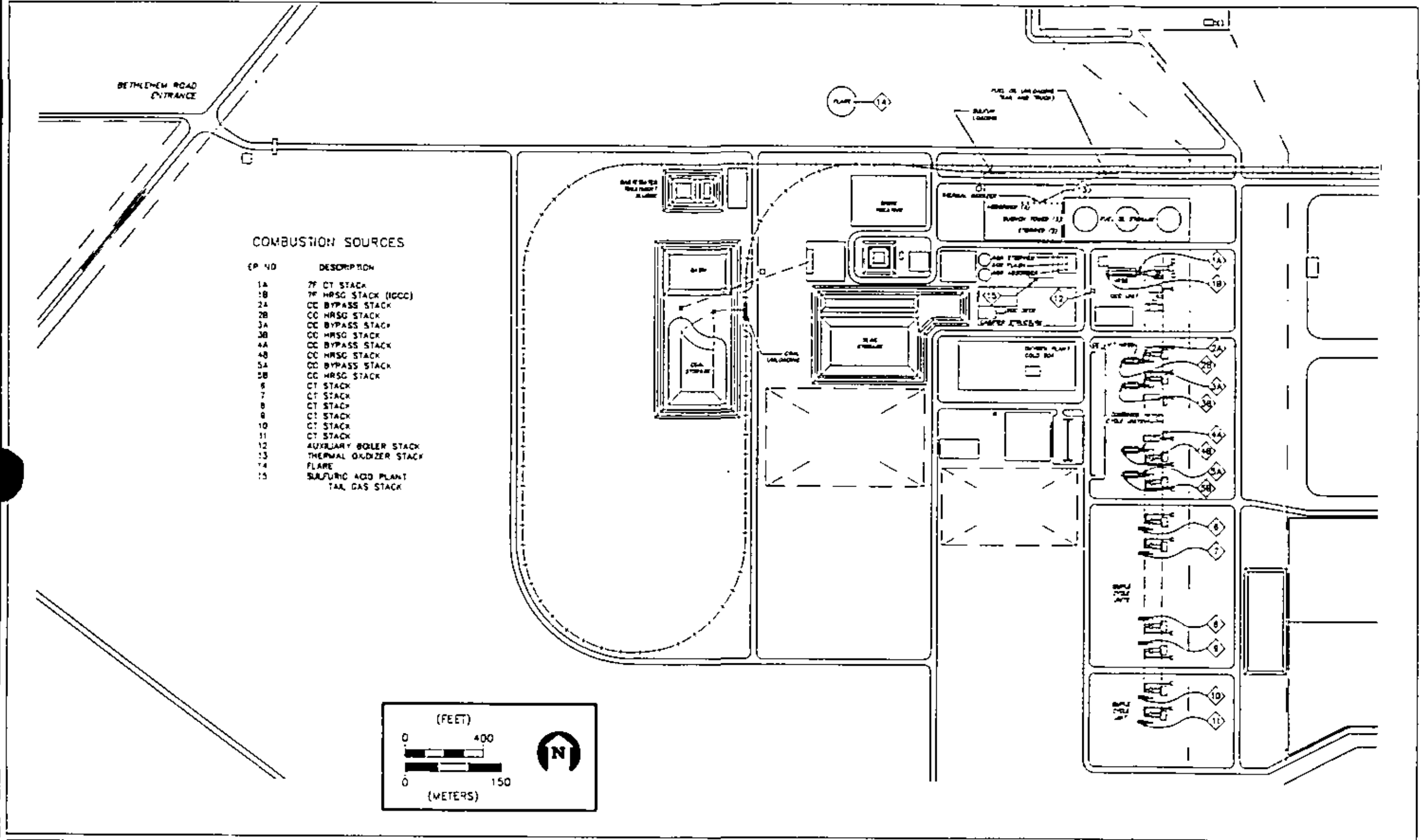
1 mile from offsite properties. Tampa Electric Company is planning to provide vegetative visual buffers along SR 37 and Fort Green Road so that only the tallest structures on the site (e.g., CG facilities and exhaust stacks) are potentially visible from roadways or offsite property.

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
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
13	THERMAL OXIDIZER STACK
14	FLARE
15	SULFURIC ACID PLANT TAIL GAS STACK

FIGURE 2-15.

LOCATION OF COMBUSTION SOURCES

Source: ECT, 1992

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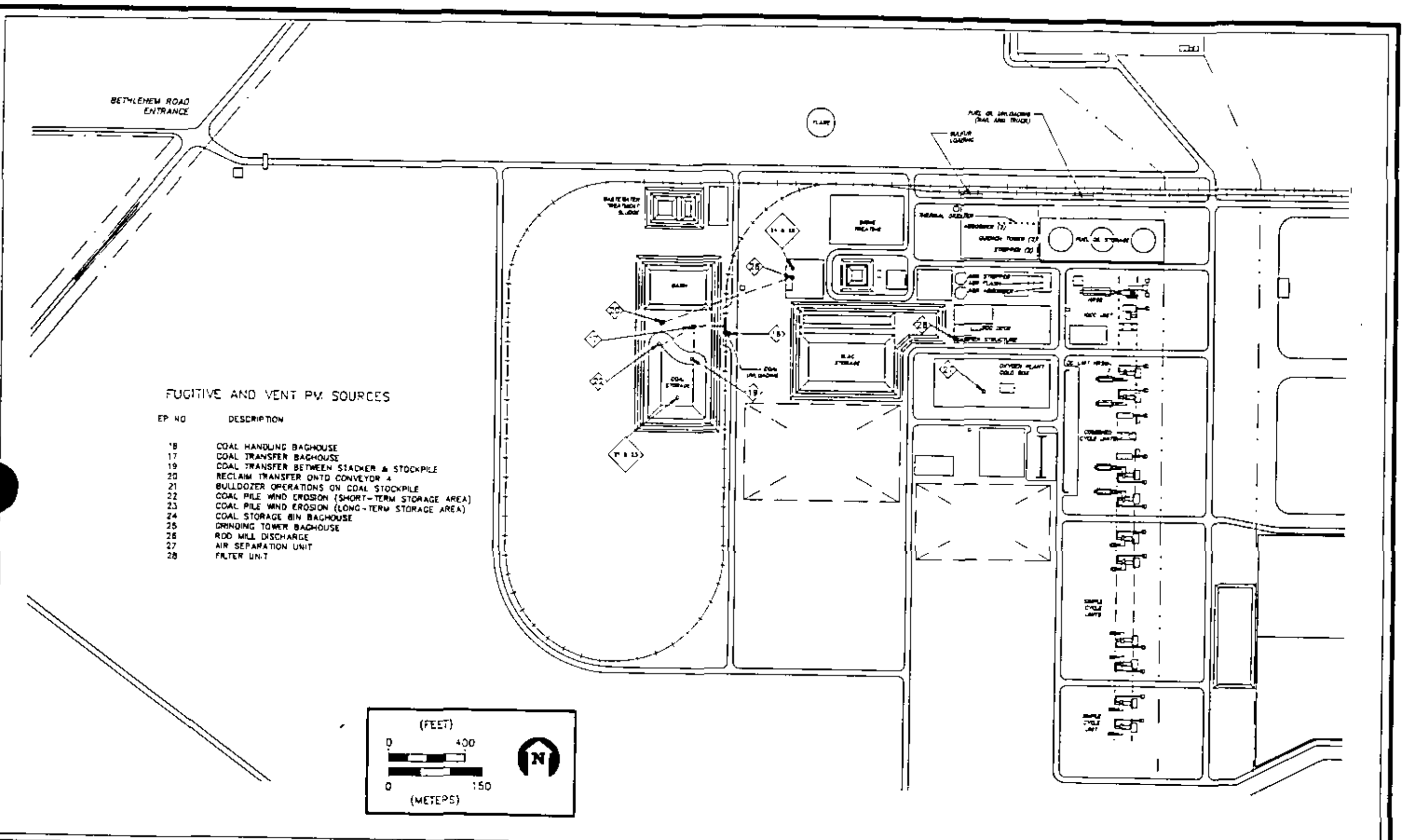

FUGITIVE AND VENT PM SOURCES

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 PM SOURCES

Source: ECT, 1992

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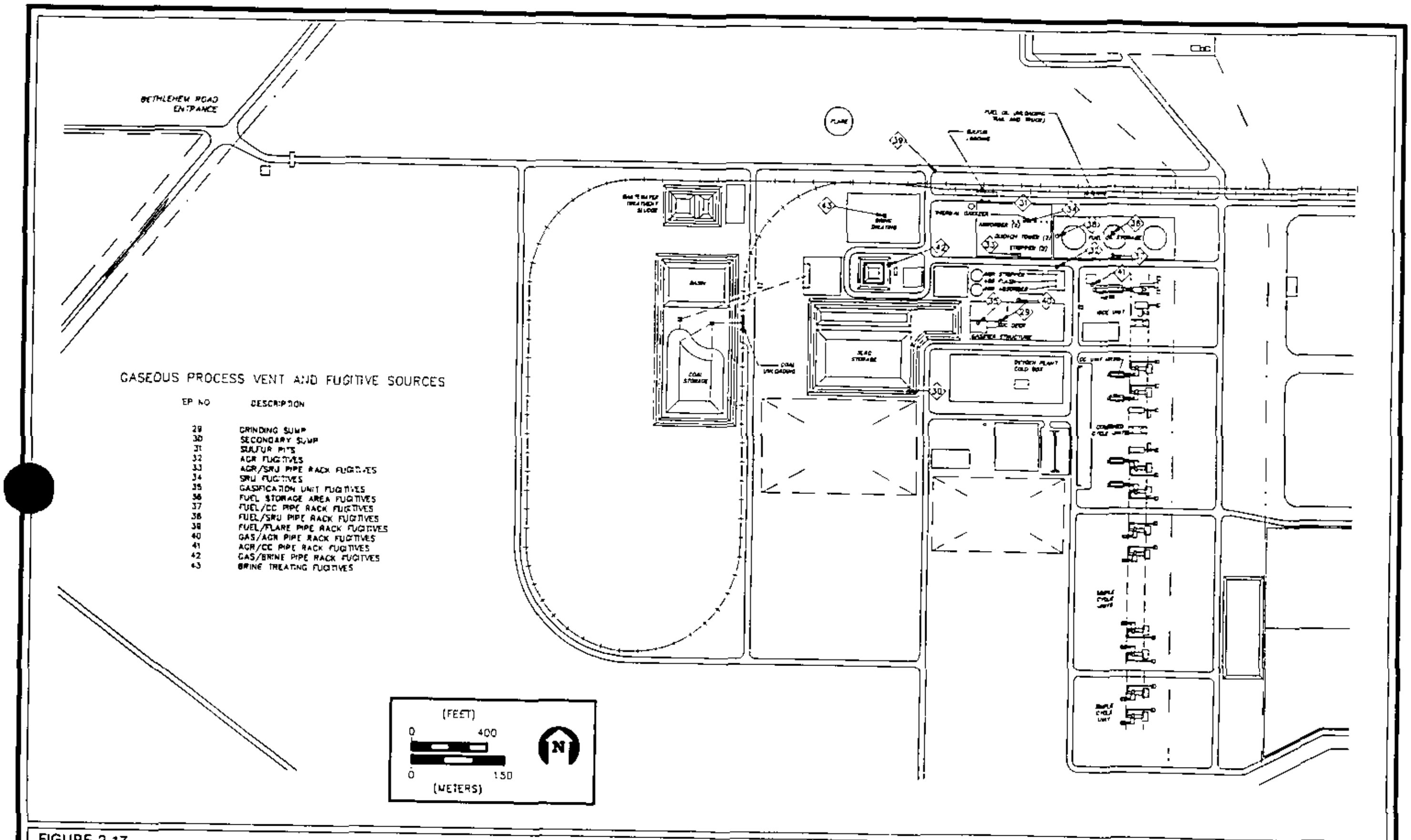

GASEOUS PROCESS VENT AND FUGITIVE SOURCES

EP NO	DESCRIPTION
29	GRINDING SUMP
30	SECONDARY SUMP
31	SULFUR PITS
32	AGR FUGITIVES
33	AGR/SRU PIPE RACK FUGITIVES
34	SRU FUGITIVES
35	GASIFICATION UNIT FUGITIVES
36	FUEL STORAGE AREA FUGITIVES
37	FUEL/CC PIPE RACK FUGITIVES
38	FUEL/SRU 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 FUCITVES
43	BRINE TREATING FUGITIVES

FIGURE 2-17.

LOCATION OF GASEOUS PROCESS VENT AND FUGITIVE SOURCES

Source: ECT, 1992

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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 (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	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
(%)	(°F)	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	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
(%)	(°F)	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 present 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	11.4	0.33
SO_2	10.1	44.2	1.27
NO_x	1.14	5.0	0.14
CO	0.61	2.7	0.08
VOC	0.35	1.5	0.04
Lead	0.001	0.004	0.0001
H_2SO_4	0	0	0
Fluorides	0	0	0
Mercury	0.001	0.004	0.0001
Beryllium	0.001	0.004	0.0001
Arsenic	0.001	0.004	0.0001
Cadmium	0.001	0.004	0.0001
Chromium	0.052	0.23	0.0066
H_2S	0.23	1.0	0.03
Stack Parameters			
Stack height	199 ft		60.7 m
Stack exit temperature	1,400°F		1,033 K
Stack exit velocity	30 ft/sec		9.1 m/sec
Stack diameter	3.5 ft		1.1 m

Sources: Texaco, 1992.
ECT, 1992.

Table 2-16. PM Emission Rates and Stack Parameters for Coal Handling 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
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	0.86	0.11	0.14	0.004	35	10.7	Ambient		NA	0.01*	NA	1.0*
20	Reclaim transfer onto conveyor 4	0.22	0.03	0.14	0.004	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 pipe rack fugitives	0.04	0.005	0.2	0.005	20	6.1	Ambient		NA	0.01*	NA	1.0*
34	SRU 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 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.
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		Annualized NH_3 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	0.001	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 lb/hr	g/sec	Annualized CO 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	0.28	0.04	1.23	0.04	12	3.7	Ambient		NA	0.01*	NA	1.0*
33	AGR/SRU pipe rack fugitives	negl.	negl.	negl.	negl.	20	6.1	Ambient		NA	0.01*	NA	1.0*
34	SRU 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.
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*		CC†	
	tpy	g/sec	tpy	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.

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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

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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

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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

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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

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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

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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

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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
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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

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

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ECT
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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

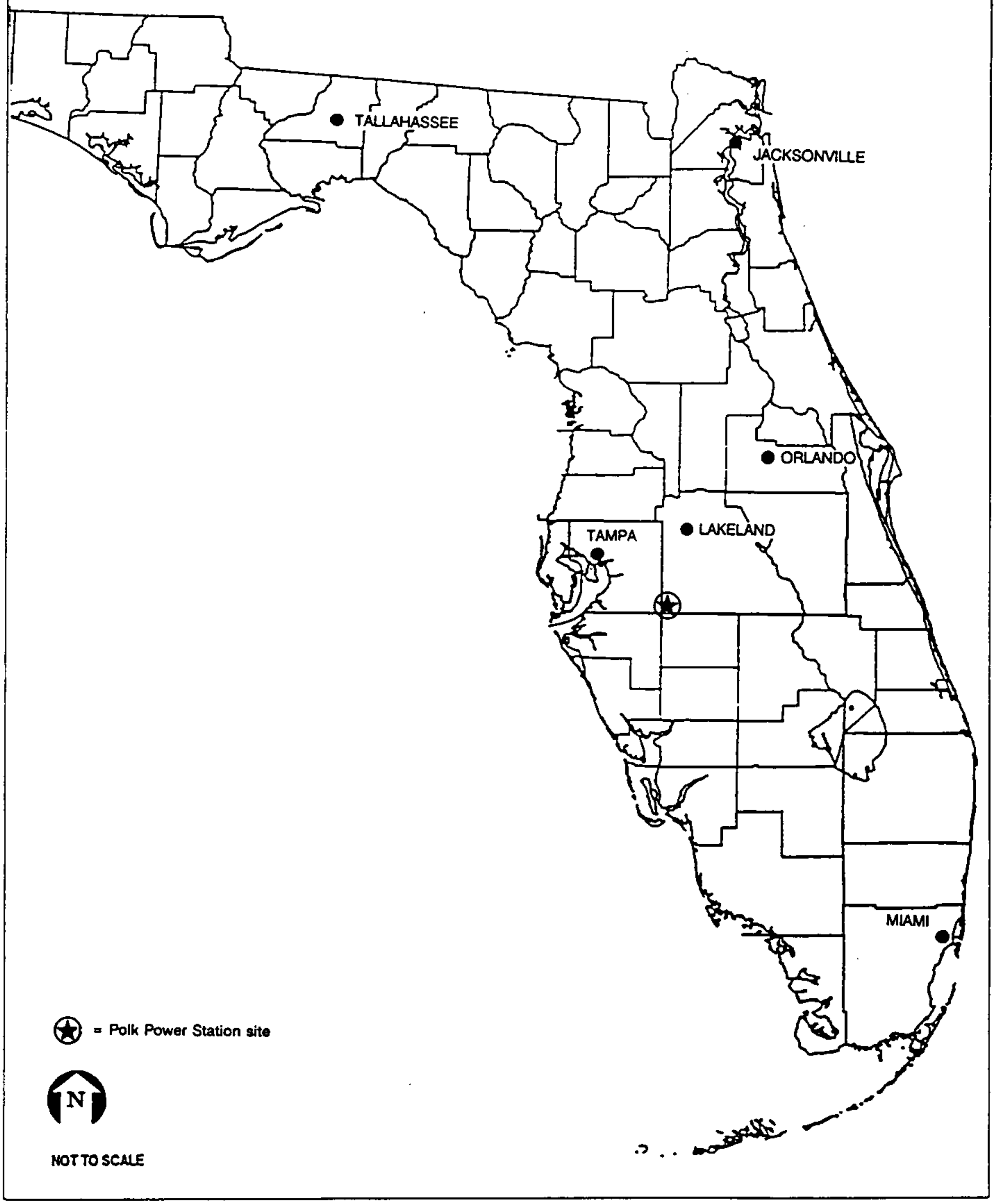

FIGURE 1-1.

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

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

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 tons per year (tpy) of sulfur dioxide (SO_2) and 5,250 tpy of nitrogen oxides (NO_x). Regarding other criteria pollutants, the facility will potentially emit 917 tpy of particulate matter (PM), 2,526 tpy of carbon monoxide (CO), 394 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 processes to recover sulfur from the inlet coal. *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 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.

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

Pollutant	Projected Maximum Annual Emissions (tpy)				Significance Rate (tpy)	Subject to PSD Review?
	IGCC*	+ CCs†	+ CTs**	= Total		
PM (TSP)	411	260	246	917	25	Yes
PM (PM_{10})	411	260	246	917	15	Yes
SO_2	2,543	720	654	3,917	40	Yes
NO_x	2,928	1,308	1,014	5,250	40	Yes
CO	456	1,092	978	2,526	100	Yes
Ozone/VOC	46	180	168	394	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	0.013	0.008	0.03	0.0004	Yes
Total reduced sulfur (including H_2S)	7.1	0	0	7.1	10	No
Reduced sulfur compounds (including H_2S)	7.1	0	0	7.1	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: ECT, 1992.

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.

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.

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 includes a skid-mounted H_2SO_4 plant to convert HGCU purge gas 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)].

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 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 = $\leq$0.015 percent by volume at 15 percent oxygen and on a dry basis; or fuel sulfur content $\leq$0.8 weight percent.

B. NSPS Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units $\geq$10 MMBtu/hr and $\leq$ 100 MMBtu/hr Heat Input

Pollutant	Emission Limitation*
SO_2	$\leq$0.50 lb/MMBtu heat input (HHV); or fuel sulfur content $\leq$0.5 weight percent.
PM	$\leq$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	$\leq$4 lb/ton of 100-percent H_2SO_4 produced
• H_2SO_4 mist	$\leq$ 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. Chapter 17-2.610(2), F.A.C.: General Visible Emissions Standard	
• Visible emissions	<20 percent opacity
E. 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				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	gr/dscf	lb/MW		
	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.

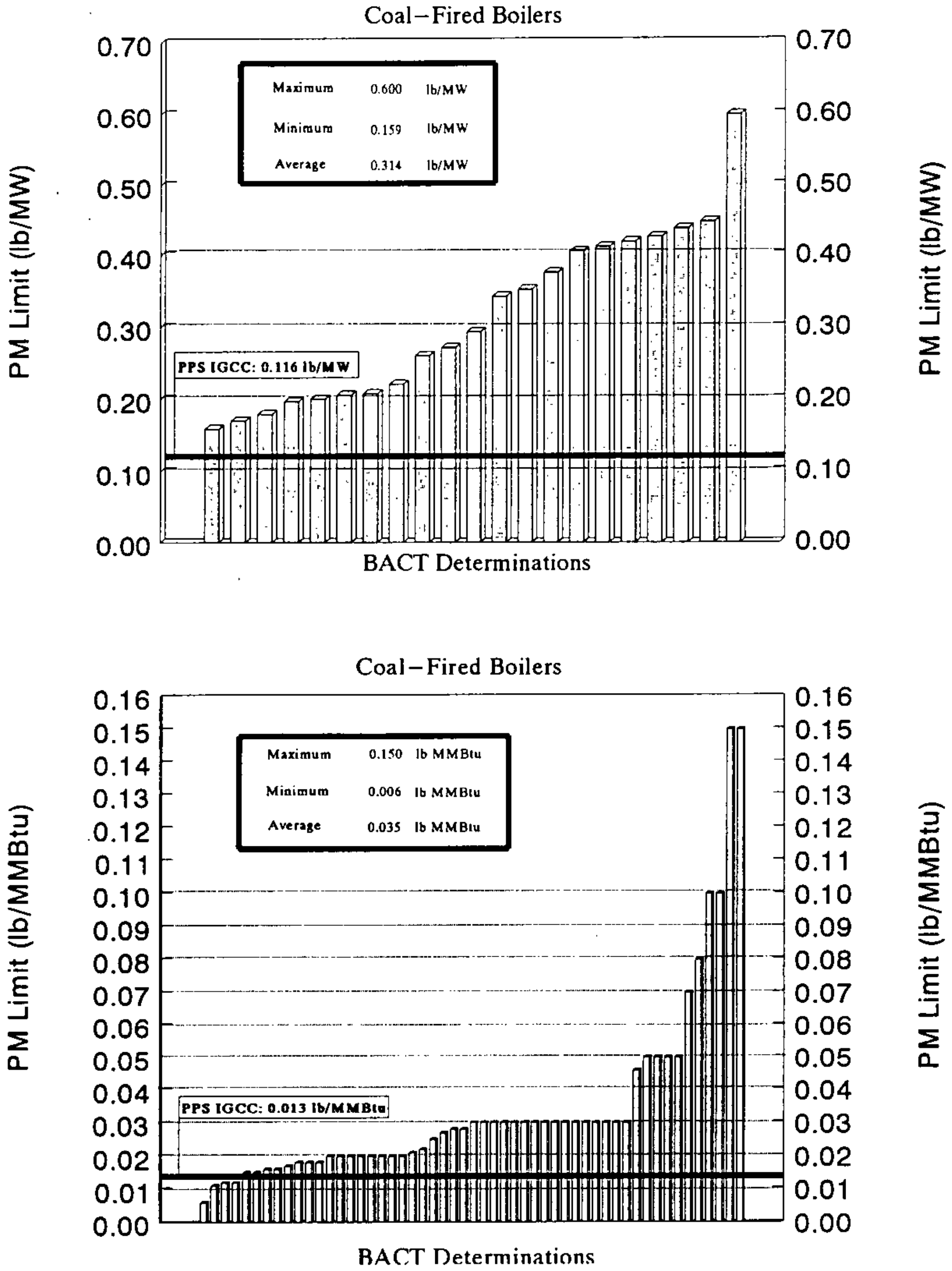

FIGURE 4-1.

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.

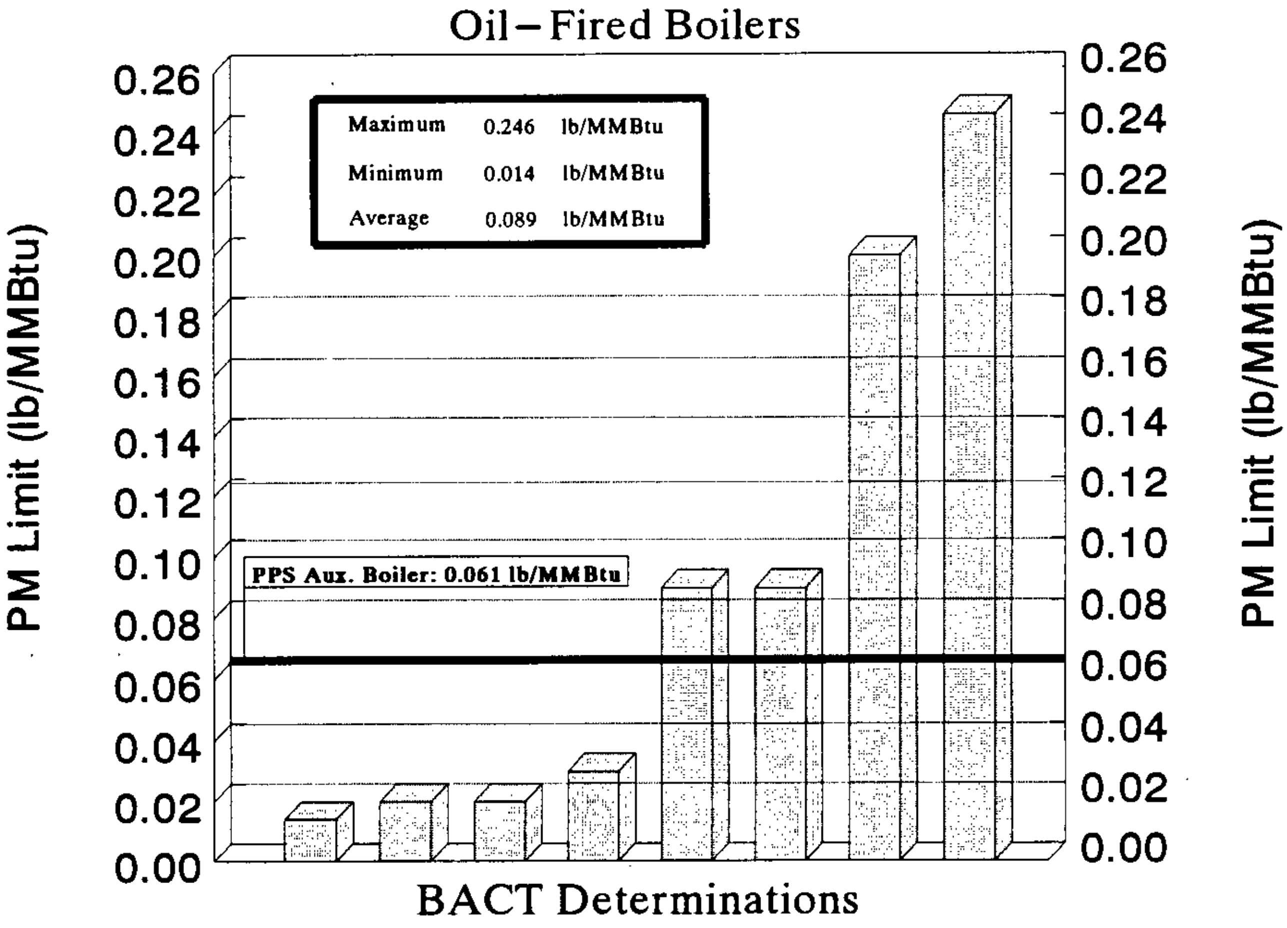

FIGURE 4-2.

SUMMARY OF PM BACT DETERMINATIONS:
OIL-FIRED BOILERS
Sources: EPA, 1992a; ECT, 1992.

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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 †
50 percent CGCU/50 percent HGCU	72.0	0.037 *	0.296 †
No. 2 fuel oil	26.7	0.014	0.152
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	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 †
50 percent CGCU/50 percent HGCU	17.0	0.013 *	0.116 †
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	N/A	N/A

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

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

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		Technology
							lb/hr	lb/MMBtu	
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	PM Emission Limit 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.

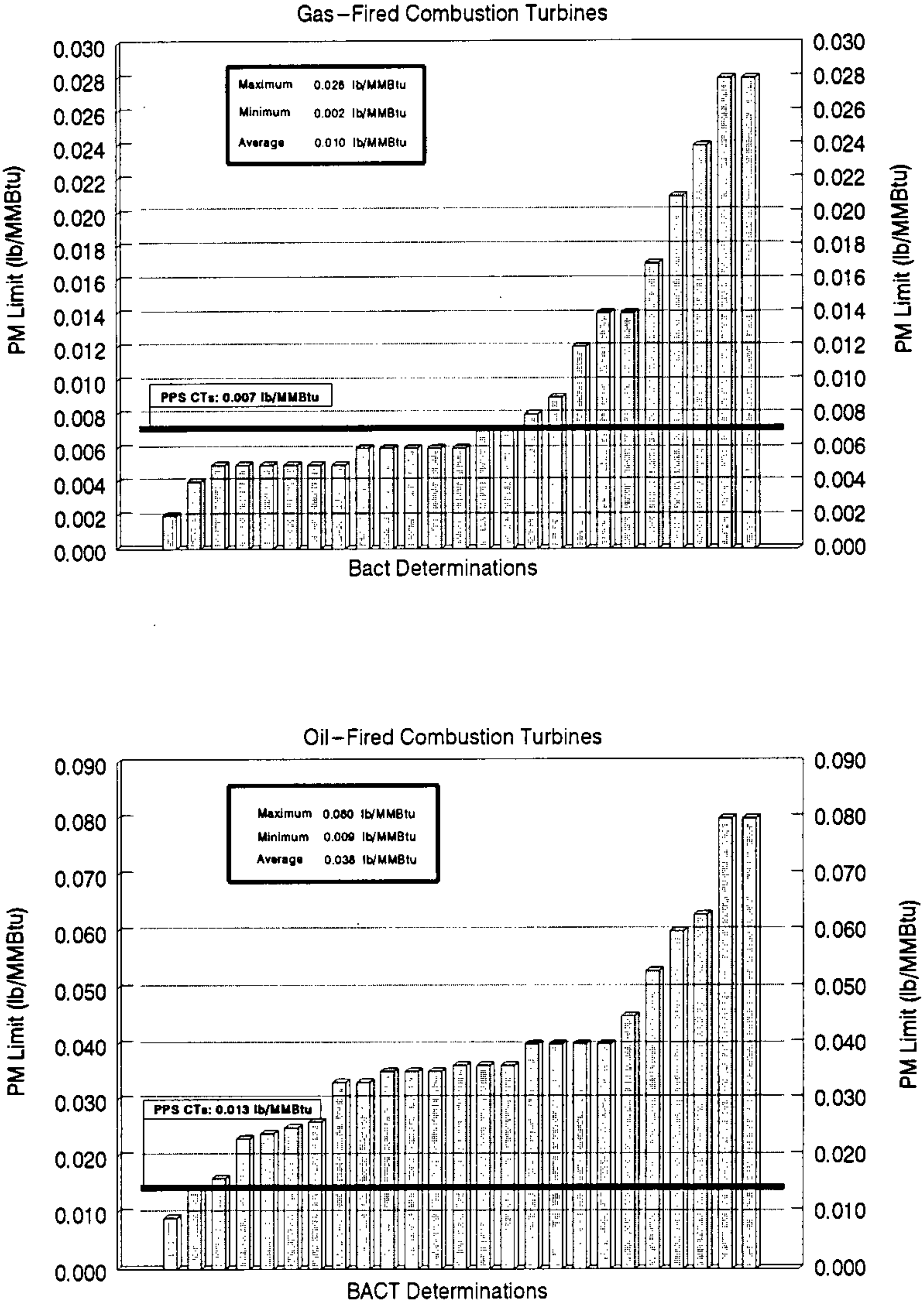

FIGURE 4-3.

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 MW	Turbine Size MMBtu/hr	Fuel Type	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Control Technology
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 combustion sources: (a) CT, (b) auxiliary boiler, (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	
<u>CO</u>								
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
<u>VOC</u>								
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	9.0	Good combustion
						(Excluding background)		
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 lb/hr	CO Emission Limit lb/MMBtu	CO Emission Limit ppmvd	CO Emission Limit lb/MW	Control Efficiency (%)	Control Technology
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.

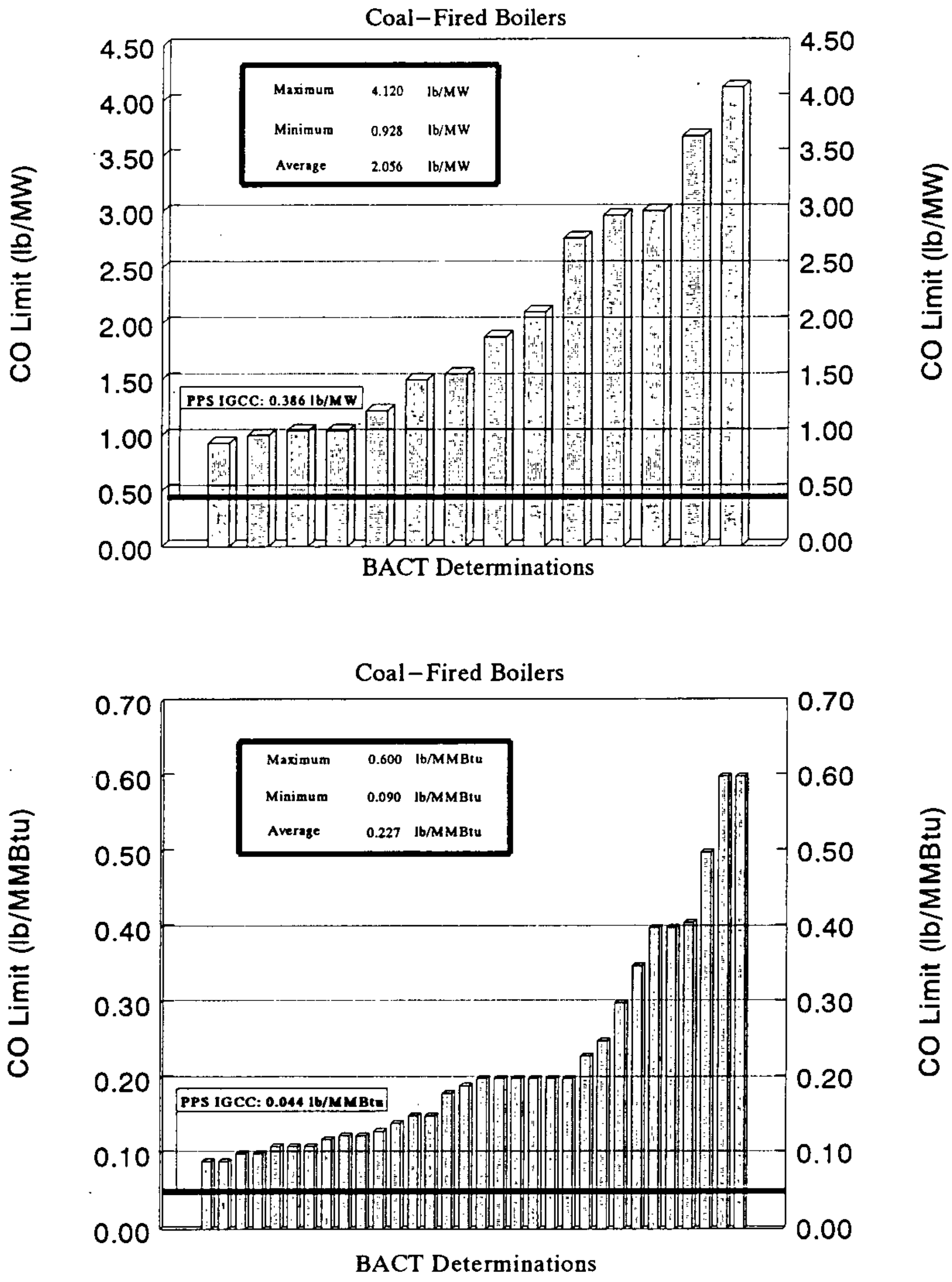

FIGURE 4-4.

SUMMARY OF CO BACT DETERMINATIONS: COAL-FIRED BOILERS

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

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.

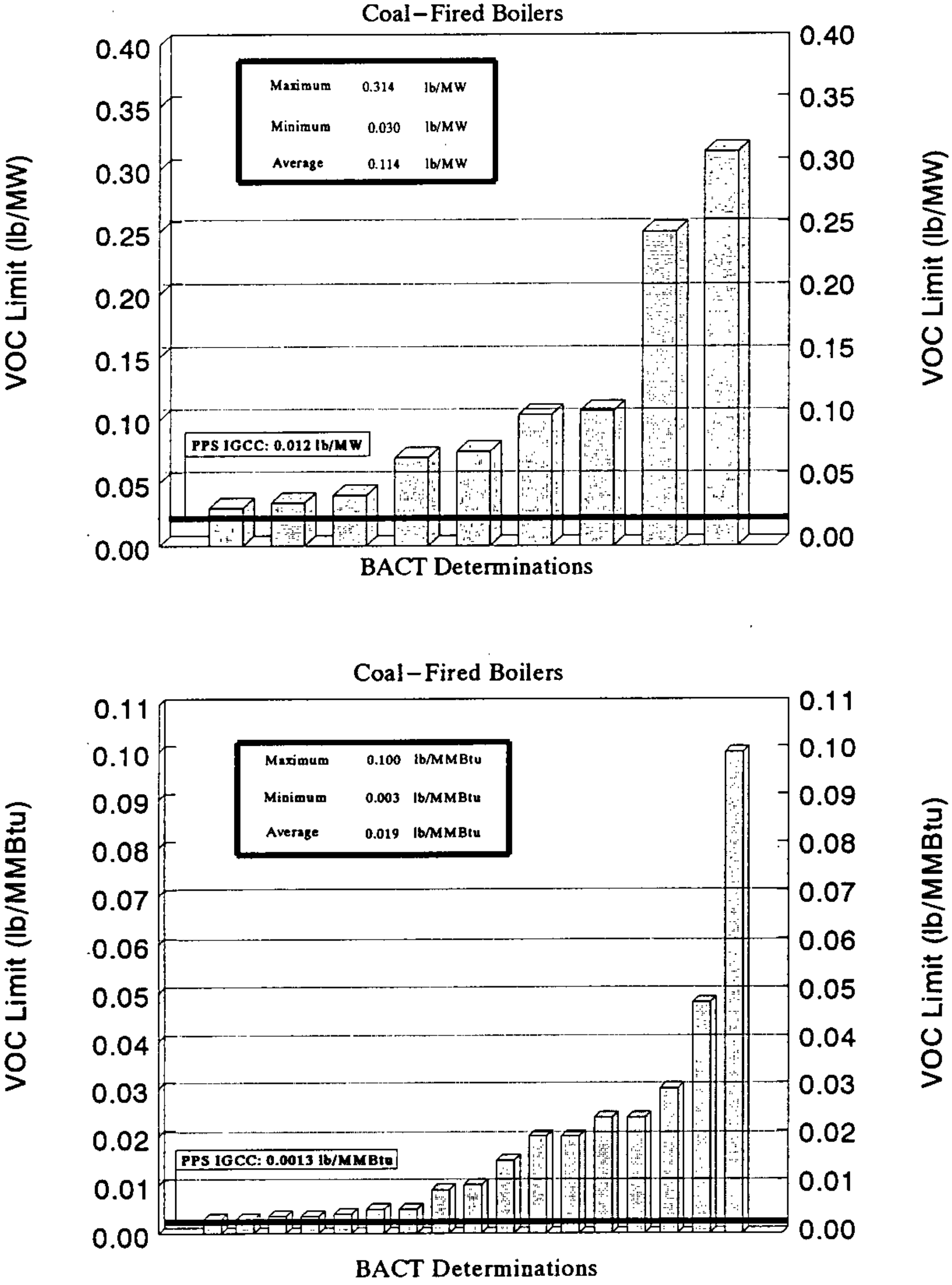

FIGURE 4-5.

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			Control Technology
				lb/hr	lb/MMBtu	lb/MW	
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	Emission Limit lb/MMBtu	Emission Limit ppmvd	Emission Limit 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.

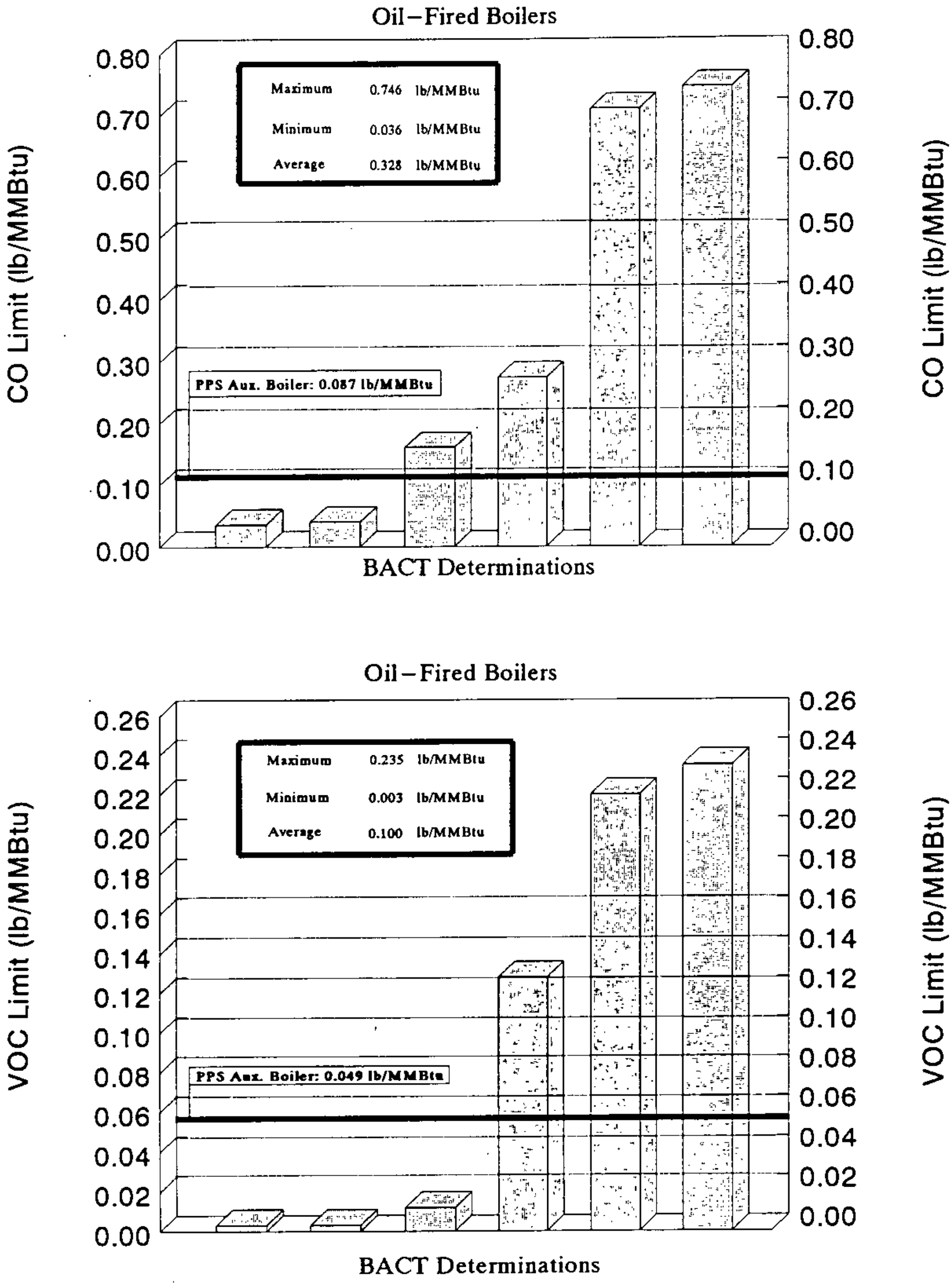

FIGURE 4-6.

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
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 H_2SO_4 plant	0.61	N/A	29.0	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 *	1.0	0.012 †
50 percent CGCU/50 percent HGCU	3.0	0.0013 *	1.0	0.012 †
No. 2 fuel oil	11.0	0.0058	5.0	0.063
(50 percent load)	32.0	0.0277	20.0	0.368
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	N/A	29.0	N/A

* Based on heat input (HHV) to coal gasifier and includes emissions from tail gas treating unit thermal oxidizer.

† Includes emissions from tail gas treating unit thermal oxidizer.

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

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 nonattainment 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
Direct Costs			
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**		
Indirect Costs			
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
Direct Costs			
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**		
Indirect Costs			
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	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	164,970		
Downtime for catalyst replacement (annualized)	431,715		
Subtotal Energy Penalties Costs	**596,685**		
Subtotal Direct Costs	**1,609,690**	(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	**3,014,730**		

Sources: GE, 1992.
ECT, 1992.

Table 4-24. Summary of CO BACT Analysis for Stand-Alone CC Units and CTs

	Emission Impacts			Economic Impacts			Energy Impact	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?
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	704.3	11,356,275	3,014,730	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 Type	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr		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	32.0 lb/hr	0.147	N/A	N/A	N/A
						Oil	22.0 lb/hr	0.101	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	23.0 lb/hr	N/A	N/A	N/A	Proper combustion techniques
						Oil	30.0 lb/hr	N/A	N/A	N/A	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	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr	Type	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	CO Emission Limit		VOC Emission Limit		Control Technology
				MW	MMBtu/hr	Type	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	100.0	1533.0	Gas	30	N/A	4.0	N/A	Combustion controls
			Ltd. Partnership		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	N/A	1175.0	Gas	62.0 lb/hr	0.053	2.3 lb/hr	0.002	Furnace design
			Limited Partners		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.

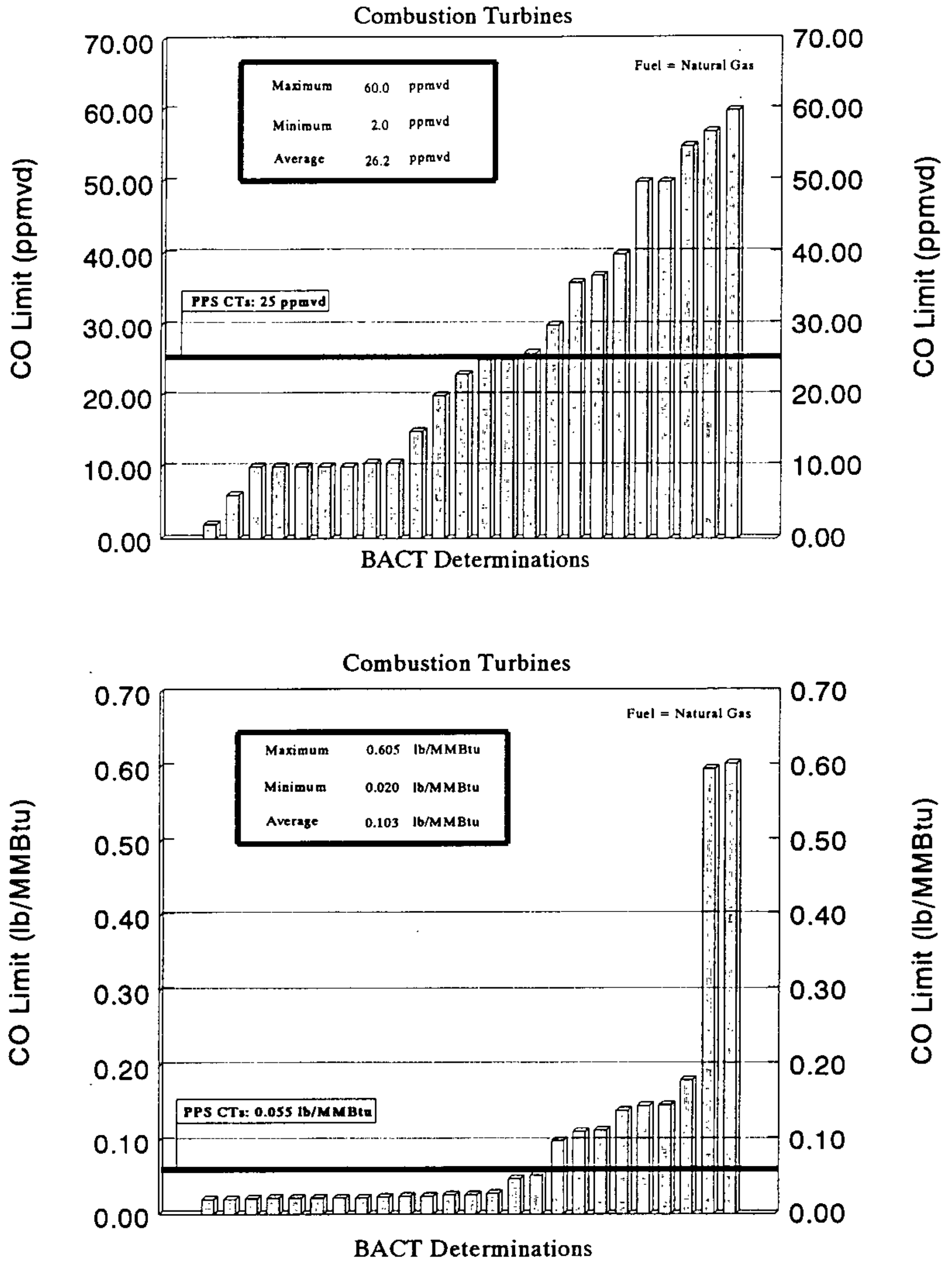

FIGURE 4-7.

SUMMARY OF CO BACT DETERMINATIONS: GAS-FIRED CTs

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

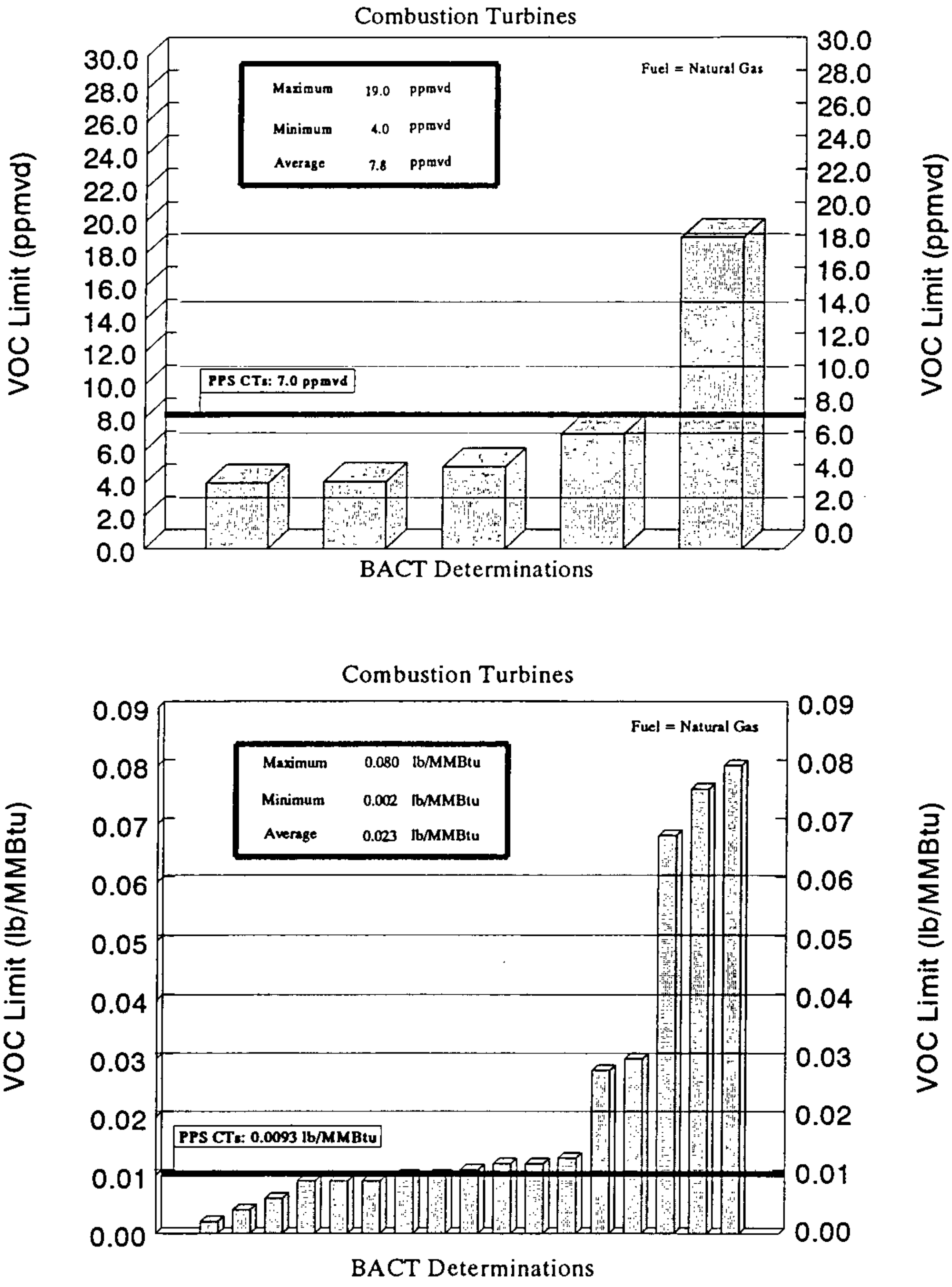

FIGURE 4-8.

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 Date	Source Name	Turbine Size		Fuel Type	CO Emission Limit		VOC Emission Limit		Control Technology
		MW	MMBtu/hr		lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	
05/31/91	Florida Power & Light	150.0	1,966	Gas	94.3	0.048	3.0	0.0015	Combustion design and clean fuels
	Martin Expansion Project				(based on 30 ppmvd)		(based on 1.6 ppmvd)		
			1,846	Oil	105.8	0.057	11.0	0.0060	Combustion design and clean fuels
					(based on 33 ppmvd)		(based on 6 ppmvd)		
10/18/91	Florida Power Corporation	92.9	1,114	Oil	54.0	0.049	5.0	0.004	Combustion design and clean fuels
	Debary Facility				(based on 25 ppmvd)				
07/26/91	City of Lakeland	80.0	1,055	Gas	232.0 tpy (based on 25 ppm)			9.0 tpy	Combustion design and clean fuels
	Charles Larsen Plant		1,040	Oil	79.0 tpy (based on 25 ppm)			6.7 tpy	Combustion design and clean fuels
01/04/91	TECO Power Services	75.0	1,268.4	Gas	31.3	0.025	3.6	0.003	Combustion design and clean fuels
	Hardee Power Station		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	0.210	3.3	0.009	Combustion design and clean fuels
					(based on 42 ppmvd)				
			387	Oil	151.0	0.390	8.3	0.021	Combustion design and clean fuels
					(based on 78 ppmvd)				

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
CO				
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
VOC				
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 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 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 for conversion of sulfur compounds to 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:

$$SO_2 + 2H_2O \rightarrow H_2SO_4 + H_2$$

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 saleable liquid sulfur and sulfuric acid by-products 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 lb/hr	lb/MMBtu	Wt% S	Control Technology
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 lb/hr	lb/MMBtu	ppmvd	lb/MW	Control Efficiency (%)	Control Technology
California	0120	04/26/85	SCF - Ridgen Power Project	16.5	212.0	9.4	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.

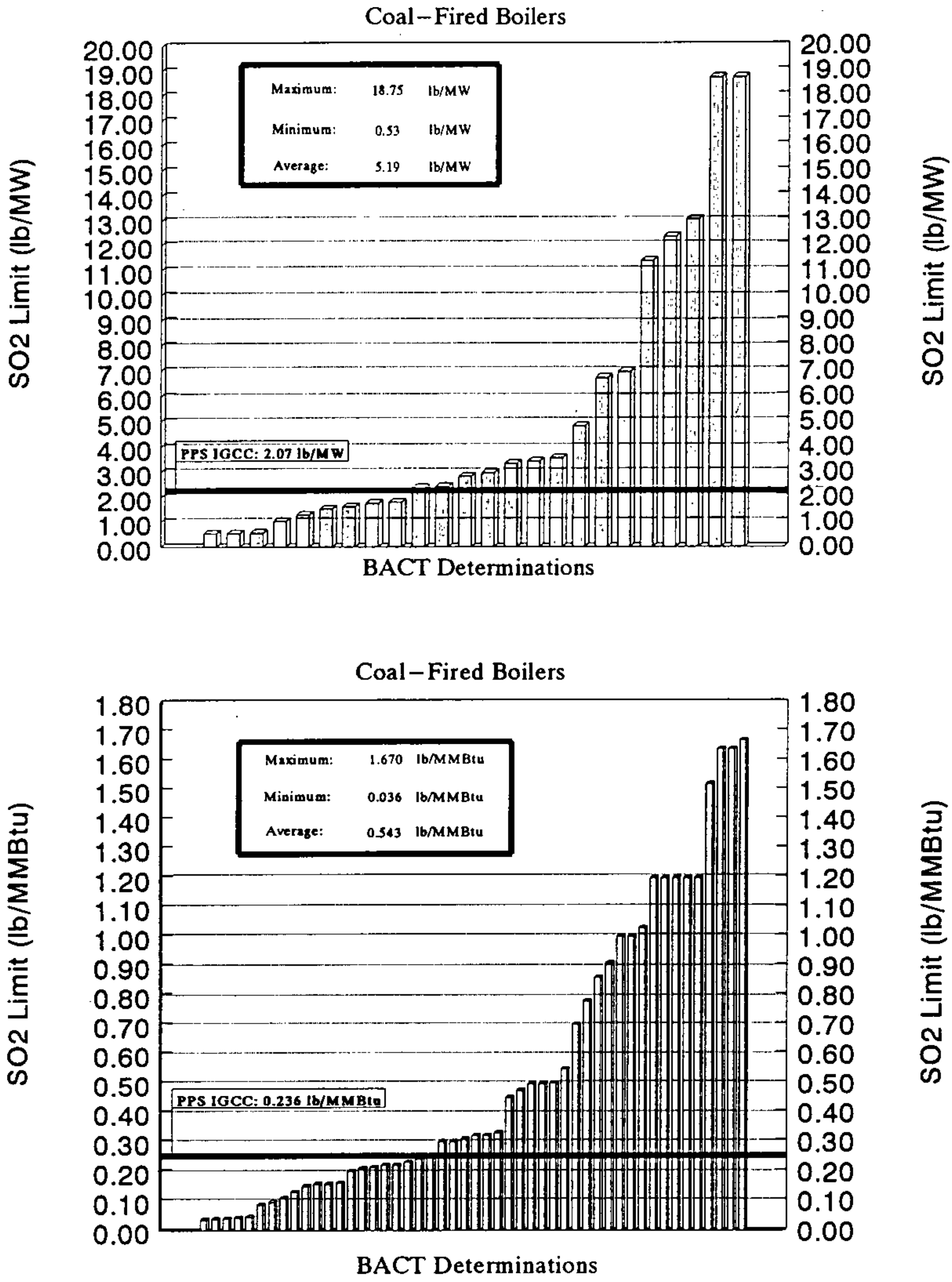

FIGURE 4-9.

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			Control Efficiency	Control Technology
				lb/hr	lb/MMBtu	lb/MW		
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

	Proposed BACT Emission Limits		
Process	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 *	2.073 †
50 percent CGCU/50 percent HGCU	518.0	0.236 *	2.073 †
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	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	0.0005	0.055
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	0.0	N/A	N/A

* Based on heat input (HHV) to coal gasifier and includes emissions from tail gas treating unit thermal oxidizer.

† Includes emissions from tail gas treating unit thermal oxidizer.

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

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:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \tag{3}$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \tag{4}$$

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 <u>Proposed Best Available Control Technology Emission Limitations</u>

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

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Impacts: Emission Rates tpy	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost-Effectiveness Over Baseline ($/ton)	Energy Impacts Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact	Environmental Impacts: 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				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
California	0120	04/26/85	SCF - Ridgen Power Project	16.5	212.0	9.2	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				Control Efficiency (%)	Control Technology
						lb/hr	lb/MMBtu	ppmvd	lb/MW		
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.

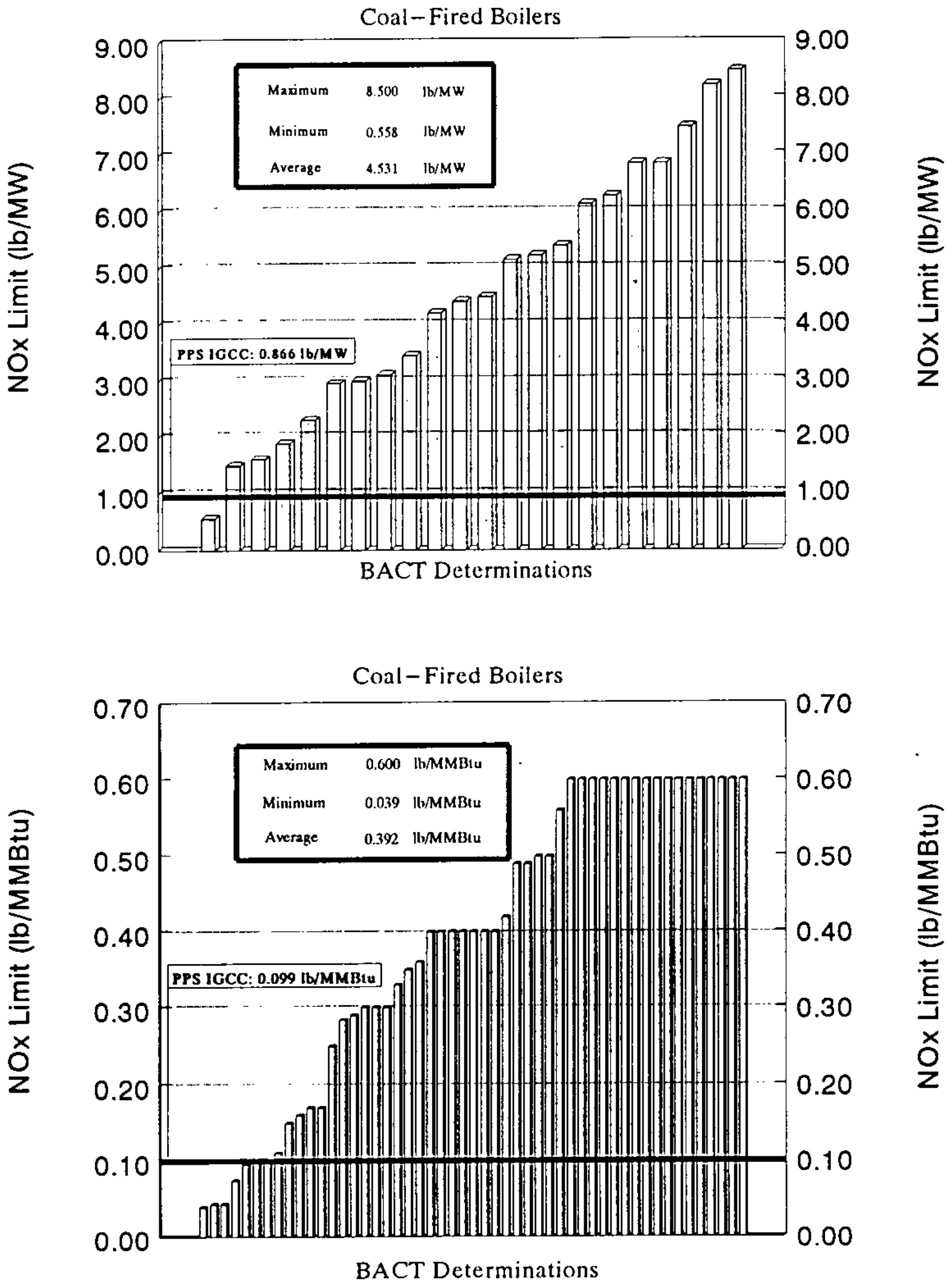

FIGURE 4-10.

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			Control Efficiency	Control Technology
				lb/hr	lb/MMBtu	lb/MW		
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.

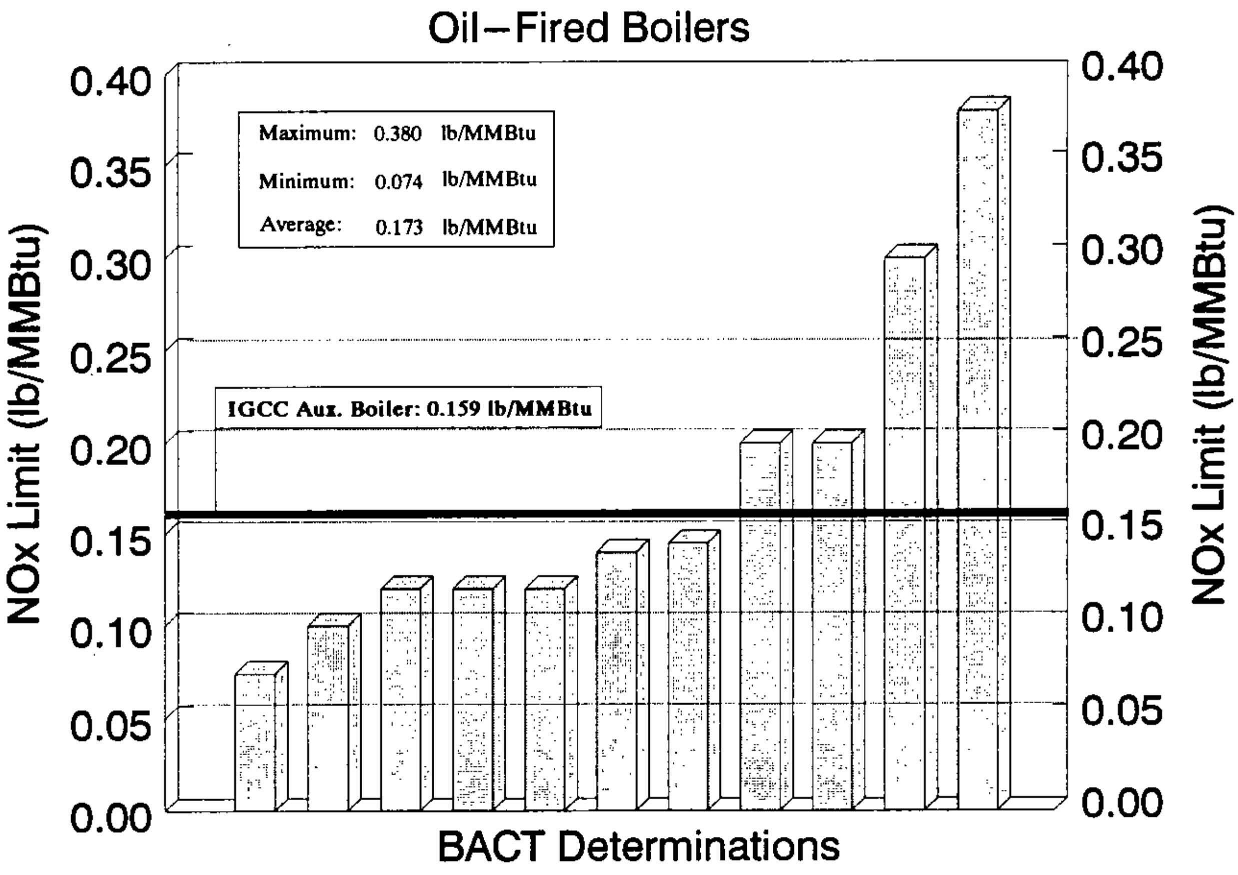

FIGURE 4-11.

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, 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
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	N/A	33.0	N/A

*Based on heat input (HHV) to coal gasifier and includes emissions from SRU/TGTU thermal oxidizer.

†Includes emissions from tail gas treating unit 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.
ECT, 1992.

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		Control Technology
							% S	lb/MMBtu	
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		Control Technology
							% S	lb/MMBtu	
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.

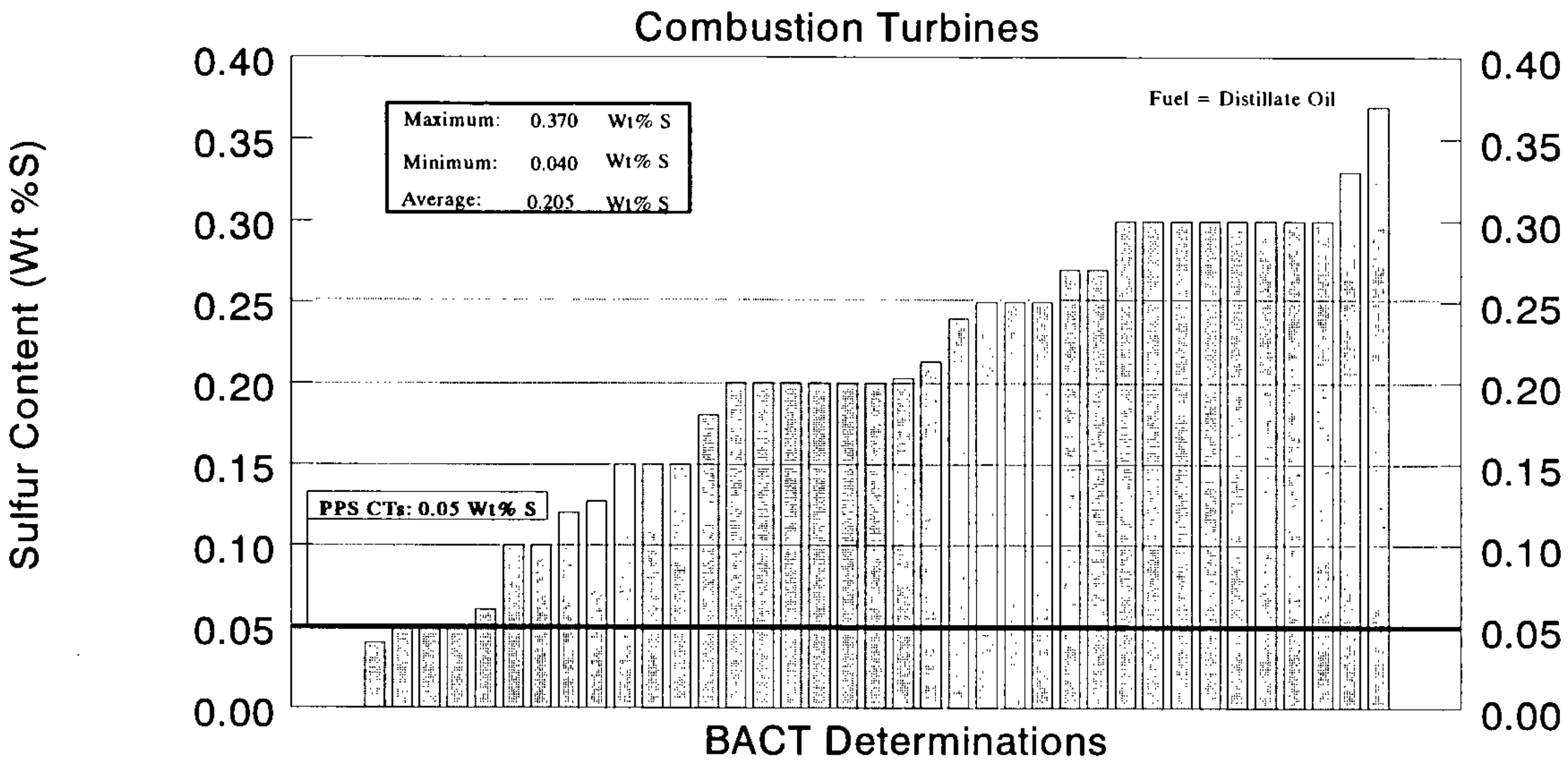

FIGURE 4-12.

SUMMARY OF SO_2 BACT DETERMINATIONS: OIL-FIRED CTs

Sources: EPA, 1992a; ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

Table 4-41. Florida BACT SO_2 Emission Limitation Summary for CTs

Permit Date	Source Name	Turbine Size		Fuel Type	SO_2 Emission Limit			Control Technology
		MW	MMBtu/hr		lb/hr	Average	Maximum	
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
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
H_2SO_4			
CC units (per unit)			
Natural gas	8.0	0.0037	0.026
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, 1992.

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		Control Technology
							ppmvd	lb/MMBtu	
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 ppmvd	NO_x Emission Limit lb/MMBtu	Control Technology
	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	N/A	85.0 lb/hr	Water injection & quiet combustor
						Oil	N/A	140.0 lb/hr	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.

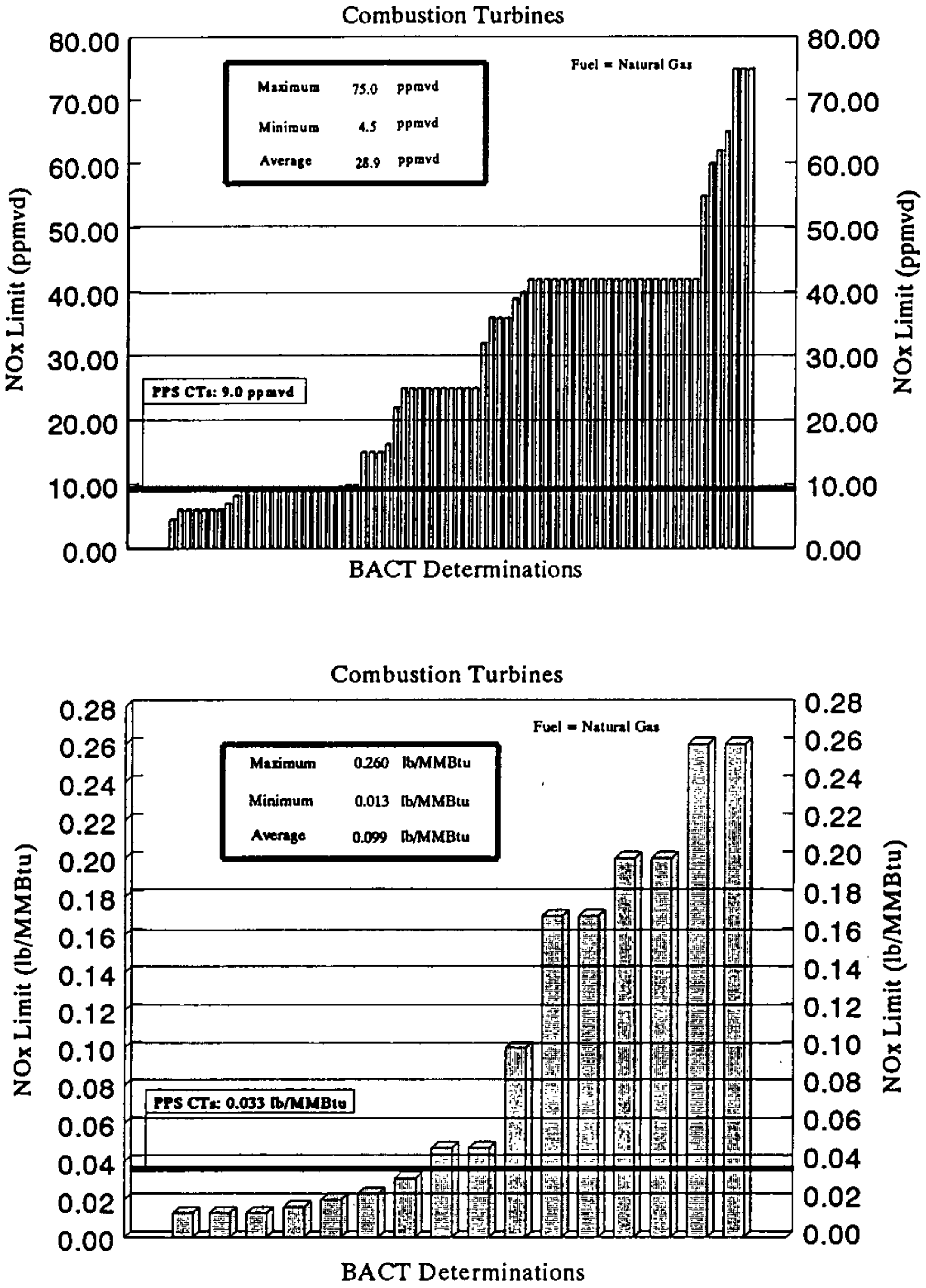

FIGURE 4-13.

SUMMARY OF NOx BACT DETERMINATIONS:
COMBUSTION TURBINES
Sources: EPA, 1992a; ECT, 1992.

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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 Hardee Power Station	75.0	1,268.4 1,312.3	Gas Oil	42 65	Wet injection Wet injection
05/31/91	Florida Power & Light Martin Expansion project	150.0	1,966 1,846	Gas Oil	25 65	Wet injection Wet injection
07/26/91	City of Lakeland Charles Larsen Plant	80.0	1,055 1,040	Gas Oil	25 42	Wet injection 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	384 387	Gas Oil	25 42	Wet injection 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.

5.0 AIR QUALITY ANALYSES

5.1 OVERVIEW

As mentioned in Section 3.2.3, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Since several PSD pollutants are projected to be emitted from Polk Power Station in excess of their significance levels, preconstruction monitoring is required. However, the PSD regulations [see Chapter 17-2.500(3)(e)1., F.A.C.] provide for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. (The *de minimis* levels were first presented in Table 3-3.)

To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the proposed facility. The results of these analyses are presented in detail in Section 7.2. Table 5-1 presents a summary of the highest projected facility impacts relative to the *de minimis* concentrations. As shown, impacts for several pollutants were predicted to be below the monitoring thresholds; for others, greater than *de minimis* impacts were shown. Therefore, as presented in the following subsection, monitoring exemptions are appropriate for some pollutants. For PM_{10}, SO_2, and ozone, however, monitoring exemptions were not appropriate. The remainder of this section, therefore, describes the monitoring program completed for this project and presents analyses of background concentrations for the monitored pollutants. Complete monitoring data are included in Appendix 11.11 of the SCA.

5.2 RATIONALE FOR MONITORING EXEMPTIONS

5.2.1 NITROGEN OXIDES

The maximum annual NO_x impact due to emissions from Polk Power Station sources was predicted to be 2.26 $\mu g/m^3$. This concentration is well below the *de minimis*

Table 5-1. Summary of Projected Facility Impacts Compared to *De Minimis* Levels

Pollutant	Averaging Time	Impact ($\mu g/m^3$) High	Impact ($\mu g/m^3$) HSH	*De Minimis* Level ($\mu g/m^3$)
NO_x	Annual	2.26	NA	14
Lead	Quarterly	0.0014	NA	0.1
SO_2	24-hour	19.0	18.1	13
TSP/PM_{10}	24-hour	27.9	23.2	10
Mercury	24-hour	0.005	0.004	0.25
Beryllium	24-hour	0.00075	0.00069	0.001
CO	8-hour	67.1	63.3	575

Source: ECT, 1992.

level. Therefore, a monitoring exemption is appropriate in accordance with the PSD regulations.

5.2.2 LEAD

The maximum 3-month lead impact due to emissions from Polk Power Station sources was predicted to be 0.0014 $\mu g/m^3$. This concentration is well below the *de minimis* level. Therefore, a monitoring exemption is appropriate in accordance with the PSD regulations.

5.2.3 PARTICULATE MATTER (TOTAL SUSPENDED PARTICULATE)

For all impact analyses presented in this report, all PM emissions were conservatively assumed to be both TSP and PM_{10}. The predicted TSP/PM_{10} concentrations shown in Table 5-1 were above the TSP *de minimis* level of 10 $\mu g/m^3$. However, no state ambient air quality standards addressing TSP remain in Florida. Consistent with the changes in federal regulations which took place in 1987, TSP standards in Florida have been replaced with standards for PM_{10}. Therefore, the need for background data for TSP no longer exists, and an exemption from preconstruction monitoring for TSP is appropriate.

5.2.4 MERCURY

The highest and HSH 24-hour mercury impacts due to emissions from Polk Power Station sources were predicted to be 0.005 and 0.004 $\mu g/m^3$, respectively. These concentrations are well below the *de minimis* level. Therefore, a monitoring exemption is appropriate in accordance with the PSD regulations.

5.2.5 BERYLLIUM

The highest and HSH 24-hour beryllium impacts due to emissions from Polk Power Station sources were predicted to be 0.00075 and 0.00069 $\mu g/m^3$, respectively. These concentrations are well below the *de minimis* level. Therefore, a monitoring exemption is appropriate in accordance with the PSD regulations.

5.2.6 CARBON MONOXIDE

The highest and HSH 8-hour CO impacts due to emissions from Polk Power Station sources were predicted to be 67.1 and 63.3 $\mu g/m^3$, respectively. These concentrations are well below the *de minimis* level. Therefore, a monitoring exemption is appropriate in accordance with the PSD regulations.

5.3 ANALYSES FOR MONITORED POLLUTANTS

5.3.1 MONITORING PROGRAM

5.3.1.1 Program Objectives and Design

Impacts of SO_2 and PM emissions from Polk Power Station sources were projected to exceed the *de minimis* criteria, as indicated previously. In addition, VOC emissions will exceed the ozone monitoring *de minimis* level. In such cases, air quality monitoring data should be collected:

> "To establish background air quality concentrations in the vicinity of the proposed source or modification. These background levels are important in determining whether the air quality before or after construction are or will be approaching or exceeding the [AAQS]." (EPA, 1987a)

Following EPA guidance, a monitoring plan for PSD ambient monitoring at the Polk Power Station site, dated March 26, 1991 (ECT, 1991a), was prepared, submitted, and approved by FDER. Based on the results of modeling analyses described in the monitoring plan, a two-station air quality monitoring network was proposed to satisfy the preconstruction requirements mandated by the PSD regulations. This monitoring approach was accepted by FDER. Ambient levels of SO_2 and ozone were monitored continuously at one location. PM_{10} was monitored at two locations, with collocated samplers at one location. The PM_{10} samples were collected on a 6-day schedule, concurrent with the national sampling schedule. Basic meteorological information was collected at one monitoring location. The parameters measured were windspeed and wind direction at 10 m, and ambient temperature and precipitation (collected at approximately 2 m). A summary of the ambient monitoring network configuration is provided in Table 5-2. Station locations in Universal Transverse Mercator (UTM) coordinates are provided in this table. The station locations are shown in Figure 5-1.

Table 5-2. Polk Power Station Site Ambient Air Monitoring Station Configurations and Locations

Station Number	SO_2	Ozone	PM_{10}	PM_{10} Col-located	Wind Velocity	Ambient Temper-ature	Precipi-tation	UTM Location East	UTM Location North
AQ-1	✓	✓	✓		✓	✓	✓	400.1	3,066.2
AQ-2			✓	✓				401.1	3,067.4

Note: ✓ = this parameter measured at this station.

Source: ECT, 1991a.

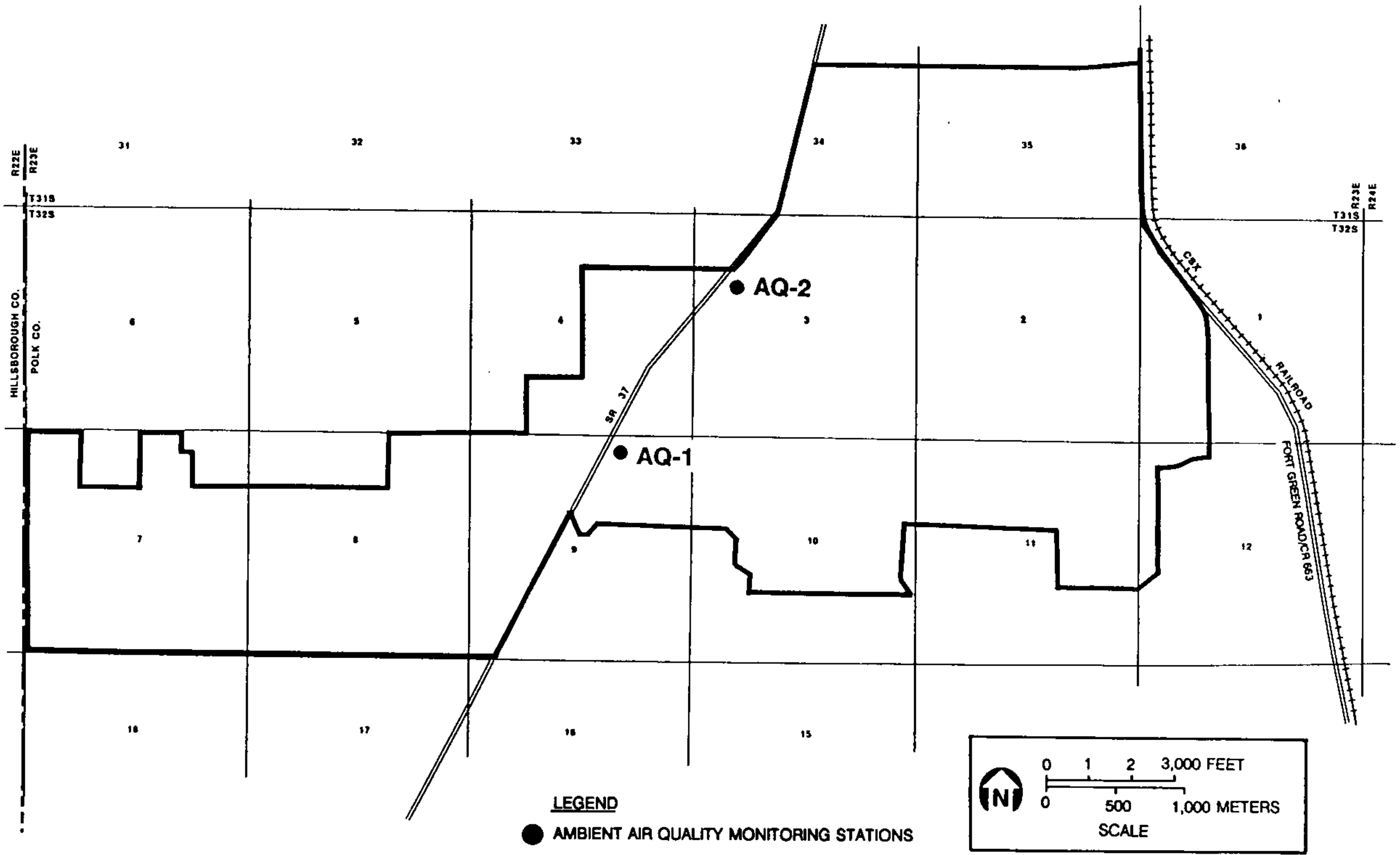

FIGURE 5-1.

AMBIENT AIR MONITORING STATIONS

Source: ECT, 1991.

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A list of the sampling equipment used to monitor each parameter is presented in Table 5-3. Ambient concentrations of SO_2 and ozone were measured continuously using monitoring equipment manufactured by Thermo Environmental Instruments, Inc. Thermo Environmental calibration systems for the gas analyzers were used. The air sampling probe heights were approximately 4 m aboveground. The PM_{10} samplers chosen for this monitoring network were manufactured by Sierra-Andersen, Inc. Meteorological instrumentation (manufactured by R.M. Young Company and Climatronics Corporation) meeting PSD measurement specifications was used. The outputs of the continuous monitoring devices (i.e., SO_2 and ozone monitors) and the meteorological sensors were connected directly to the data acquisition system inside the adjacent air quality monitoring shelter. The data acquisition system chosen for the project was manufactured by Odessa Engineering.

The equipment shelter chosen for the project was designed with no windows and sufficient insulation to maintain the conditioned environment required for proper operation of the monitoring equipment. The shelter was equipped with electric heaters and an air conditioner to maintain a temperature between 20 and 30 degrees Celsius (°C).

5.3.1.2 Program Operations and Performance

The operation of the network was consistent with detailed standard operating procedures (SOPs) (ECT, 1991b). The SOP manual provided detailed descriptions of all monitoring equipment, specific procedures for their normal operation, quality assurance/quality control (QA/QC) procedures, and procedures for performance auditing.

The monitoring program was initiated in late March 1991 and ran through the end of March 1992. The 1-year program duration was consistent with PSD requirements. The monitoring results were reported on a quarterly basis. Each quarterly report included both summarized and detailed results for each monitored parameter, as well as results of QA activities.

Table 5-3. Monitoring Equipment List for Polk Power Station Ambient Air Monitoring Program

Model Description	Manufacturer	Model Number
SO_2 analyzer	Thermo Environmental, Inc.	43A
Ozone analyzer	Thermo Environmental, Inc.	49
PM_{10} samplers	Sierra-Andersen, Inc.	SAUV-15H
Meteorological equipment	R.M. Young and Climatronics	Various
Data acquisition system	Odessa Engineering	DSM-3260
Gas calibration system	Thermo Environmental, Inc.	146
Three-pen chart recorder	Esterline-Angus	MS-413C
Two-pen chart recorder	Esterline-Angus	MS-412C

Source: ECT, 1991a.

The QA program was designed to conform with the PSD regulations as set forth in 40 CFR 58, Appendix B, QA Requirements for PSD Air Monitoring, and with FDER's State-Wide QA Air Program Plan. The five important elements that provided the basis for the QA program were:

1. Equipment calibration--calibration procedures and complete recordkeeping;
2. Independent audit program--independent performance and system audits as required and/or needed;
3. Data handling--field assessment and chain-of-custody procedures for transfer of samples and records between individuals and from the sampling site to the Project Data Manager;
4. Data reduction--editing and digitizing of data tapes and strip charts as well as data interpretation; and
5. Preparation and filing of data report--proper report preparation, thorough documentation, and retention of records.

QA procedures were implemented in accordance with the FDER approved SOP Manual and QA Plan. The QA Plan addressed QA requirements specified by Appendix B, CFR Part 58 and the FDER State-Wide QA Air Program Plan. Major components of the QA program included:

- Daily automated zero, span, and precision checks for the ozone and SO_2 continuous monitors;
- Quarterly multipoint calibrations of the ozone, SO_2, and PM_{10} analyzers, strip chart recorders, and data acquisition system;
- Quarterly multipoint audits of the ozone, SO_2, and PM_{10} analyzers;
- Audit of the ozone, SO_2, and PM_{10} analyzers using EPA-furnished audit equipment (National Performance Audit Program);
- Monthly one-point flow rate checks of the PM_{10} samplers;
- Biannual calibration of the meteorological sensors; and
- Systems audit conducted by FDER personnel.

Four quarterly performance audits were conducted, the first by ECT and the last three by FDER personnel. An additional performance audit, using EPA furnished test equipment in accordance with the National Performance Audit Program, was performed by ECT. All audit results met the required accuracy criteria. A summary of the performance audits is shown on Table 5-4.

A systems audit was conducted by FDER personnel on August 13 and 14, 1991, at ECT's offices in Gainesville, Florida. FDER personnel also performed a systems audit of the PM_{10} filter processing procedures performed by PACE, Inc. on November 13, 1991, in Charlotte, North Carolina. Corrective action was taken to satisfactorily resolve all audit findings. FDER issued a final audit report on January 10, 1992, which stated: (a) an overall rating of satisfactory, (b) that all findings were properly addressed, and (c) that the audit was formally closed (FDER, 1992a).

For the monitored pollutants, data capture percentages were above the EPA data recovery requirement of 80 percent. Table 5-5 summarizes data capture percentages. Therefore, based on the results of QA/QC activities and the data completeness, the monitoring program produced data of sufficient quality and quantity to adequately establish background concentrations in the vicinity of the Polk Power Station site.

5.3.2 ANALYSIS FOR SULFUR DIOXIDE

The results of the SO_2 monitoring effort are presented in summary form in Table 5-6 and Figures 5-2 and 5-3. Table 5-6 presents the mean and maximum 3- and 24-hour SO_2 concentrations on a monthly basis. The maximum 3-hour concentration was 78 parts per billion (ppb), which is equal to approximately 204 $\mu g/m^3$. The highest 24-hour concentration was 17 ppb, or approximately 44.5 $\mu g/m^3$. Figures 5-2 and 5-3 present plots of concentration versus time for the 3- and 24-hour averages, respectively.

Table 5-4. Summary of Performance Audit Results

Audit Date	Agency	Pollutant	Audit Parameter	Audit Value (%)
05/21/91	ECT	Ozone	Mean deviation	-4.5
		SO_2	Mean deviation	5.5
		PM_{10} - AQ1	Flow rate deviation	1.2
		PM_{10} - AQ2C	Flow rate deviation	0.8
		PM_{10} - AQ2D	Flow rate deviation	0.5
08/13/91	FDER	Ozone	Mean deviation	13.2
		SO_2	Mean deviation	7.5
		PM_{10} - AQ1	Flow rate deviation	-1.0
		PM_{10} - AQ2C	Flow rate deviation	-1.0
		PM_{10} - AQ2D	Flow rate deviation	-0.6
12/03/91	FDER	Ozone	Mean deviation	1.0
		SO_2	Mean deviation	4.1
		PM_{10} - AQ1	Flow rate deviation	0.5
		PM_{10} - AQ2C	Flow rate deviation	0.5
		PM_{10} - AQ2D	Flow rate deviation	2.8
01/16/92 (EPA equipment)	ECT	PM_{10} - AQ1	Flow rate deviation	-4.0
		PM_{10} - AQ2C	Flow rate deviation	-3.5
		PM_{10} - AQ2D	Flow rate deviation	-2.8
02/13/92 (EPA equipment)	ECT	Ozone	Mean deviation	4.2
		SO_2	Mean deviation	-7.6
02/19/92	FDER	Ozone	Mean deviation	5.0
		SO_2	Mean deviation	-1.1
		PM_{10} - AQ1	Flow rate deviation	0.3
		PM_{10} - AQ2C	Flow rate deviation	-0.7
		PM_{10} - AQ2D	Flow rate deviation	0.4

Source: ECT, 1992.

Table 5-5. Monthly and Annual Percent Data Capture for Monitored Pollutants

Year	Month	Ozone	SO_2	AQ-1 PM_{10}	AQ-2 PM_{10}
1991	April	83.6	87.6	100.0	33.3
	May	94.0	94.5	100.0	100.0
	June	92.2	92.9	100.0	100.0
	July	68.3	68.4	80.0	100.0
	August	94.1	86.8	100.0	100.0
	September	94.0	94.2	100.0	100.0
	October	92.7	93.0	100.0	80.0
	November	95.4	95.4	100.0	100.0
	December	91.8	91.8	100.0	100.0
1992	January	87.6	88.8	100.0	100.0
	February	79.0	78.9	100.0	100.0
	March	95.3	95.4	100.0	100.0
	Annual Average	**89.0**	**89.0**	**98.3**	**92.8**

Source: ECT, 1992.

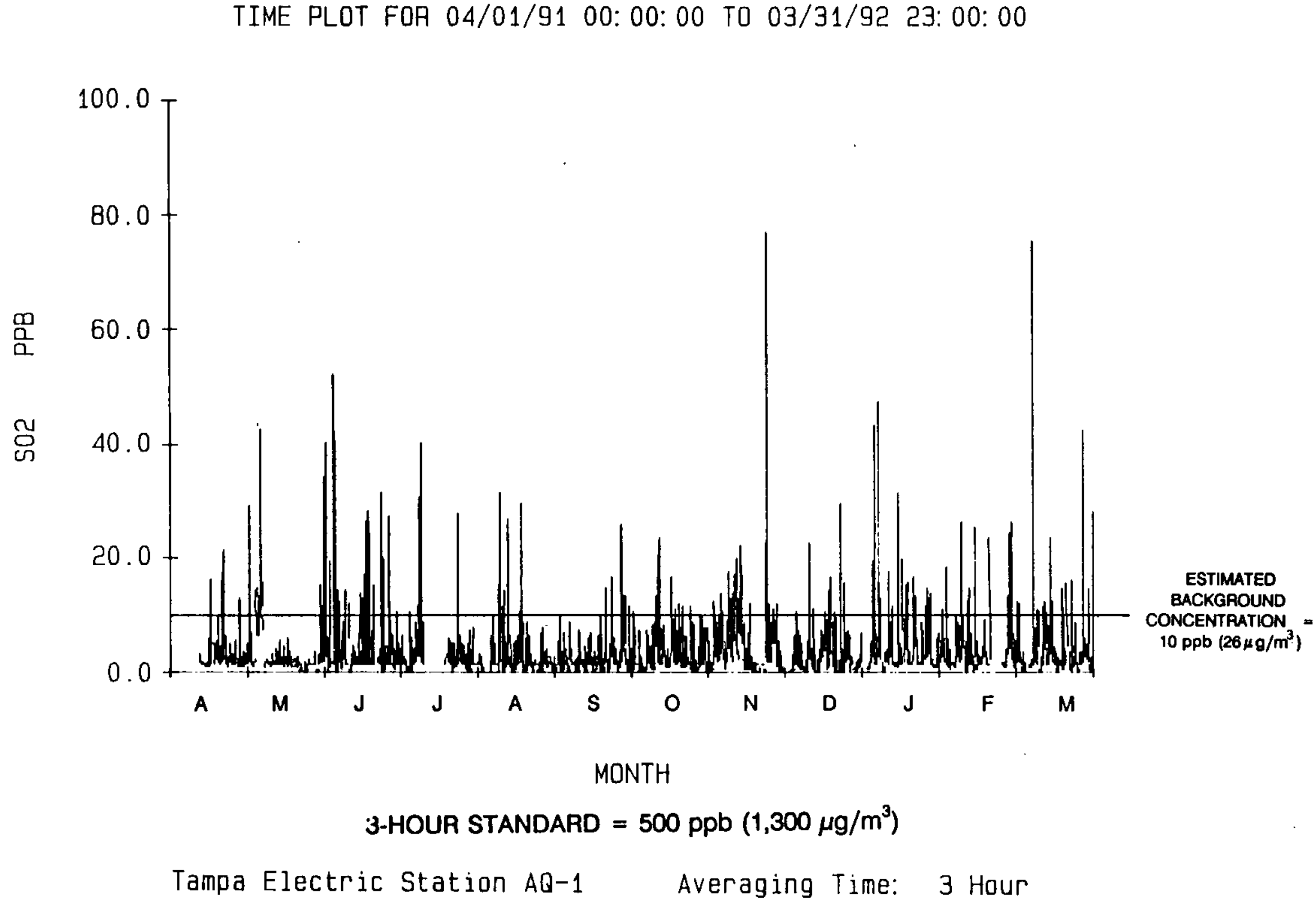

FIGURE 5-2.

MEASURED AMBIENT 3-HOUR SO_2 AVERAGES AT THE POLK POWER STATION SITE

Source: ECT, 1992.

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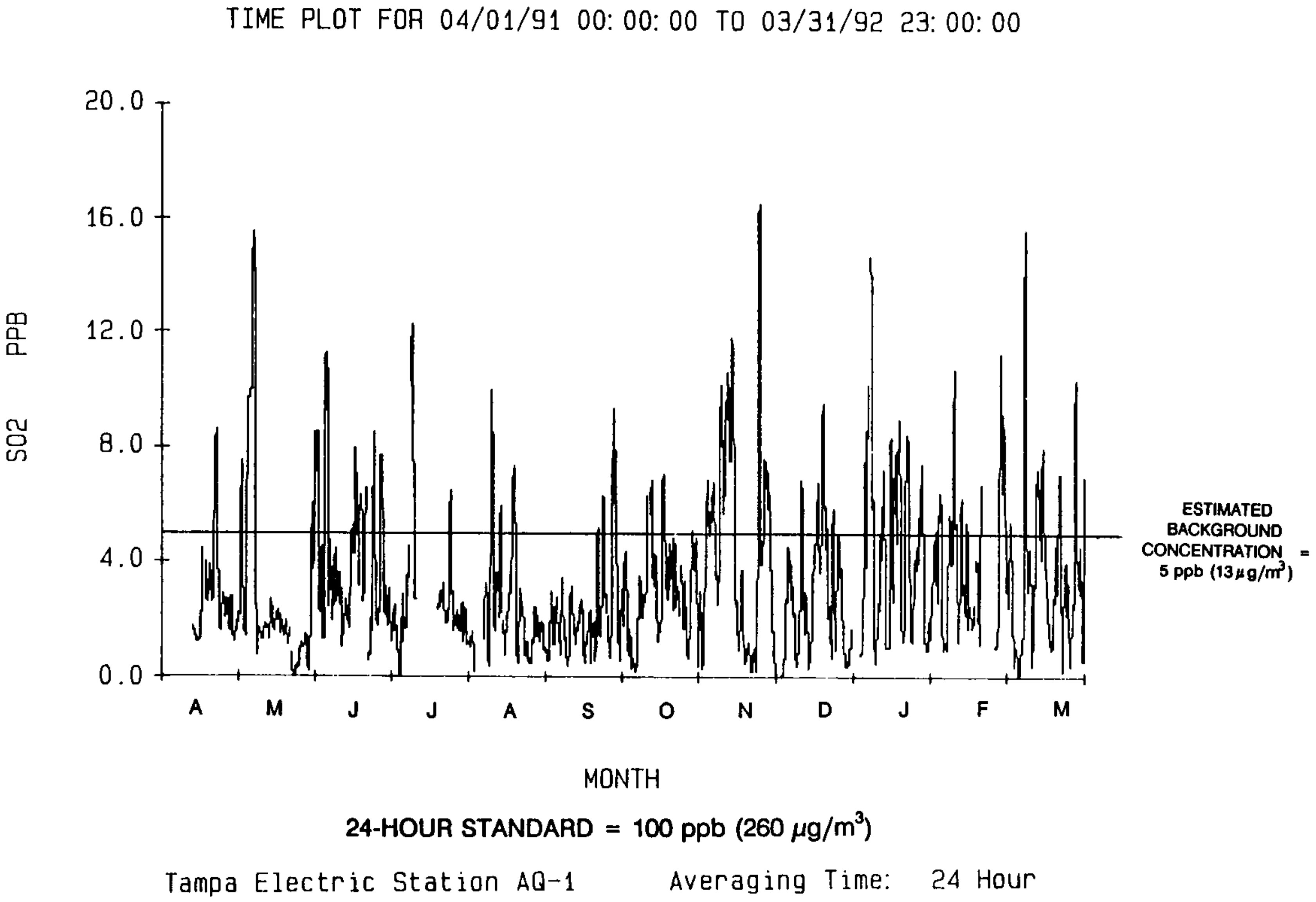

FIGURE 5-3.

MEASURED AMBIENT 24-HOUR SO_2 AVERAGES AT THE POLK POWER STATION SITE

Source: ECT, 1992.

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Table 5-6. Summary of Monthly Mean, Maximum 3-Hour, and 24-Hour SO_2 Concentrations (ppb) at AQ-1 for the Polk Power Station Site (April 1991 through March 1992)

Month	Mean	Maximum 3-Hour*	Ending Date and Time	Maximum 24-Hour*	Ending Date and Time
April	2	21	04/21/91 17:00	9	04/22/91 11:00
May	3	43	05/06/91 17:00	16	05/07/91 14:00
June	4	53	06/04/91 18:00	11	06/04/91 21:00
July	3	40	07/09/91 11:00	12	07/09/91 10:00
August	2	31	08/09/91 13:00	10	08/09/91 17:00
September	2	26	09/26/91 15:00	9	09/27/91 12:00
October	3	23	10/11/91 17:00	7	10/17/91 05:00
November	5	78	11/23/91 17:00	17	11/24/91 04:00
December	3	29	12/22/91 20:00	10	12/19/91 19:00
January	4	48	01/06/92 15:00	15	01/07/92 07:00
February	4	26	02/28/92 19:00	11	02/27/92 17:00
March	4	76	03/07/92 23:00	16	03/08/92 20:00

*Based on a rolling average.

Source: ECT, 1992.

The data plots (Figures 5-2 and 5-3) were used to develop estimates of background concentrations, which should include contributions from natural emission sources, large anthropogenic sources too distant to be included in the modeling inventory, small area sources, and/or other unidentified sources. The peak concentrations shown were attributed to emissions from existing, large SO_2 sources in the vicinity, of which there are many (see Section 6.9). Therefore, superimposed on Figures 5-2 and 5-3 are estimates of background concentrations, which were selected at levels below the concentration spikes. For the 3-hour averaging time, 10 ppb (26 $\mu g/m^3$) was selected. For the 24-hour average, 5 ppb (13 $\mu g/m^3$) was selected. For an annual average background concentration, the lowest monthly mean of 2 ppb (5 $\mu g/m^3$) was selected.

5.3.3 ANALYSIS FOR PARTICULATE MATTER (PM_{10})

Table 5-7 presents the complete set of results for the PM_{10} monitoring program. The highest measured PM_{10} concentration at each site was less than 50 $\mu g/m^3$, versus the 24-hour AAQS of 150 $\mu g/m^3$. The arithmetic mean concentrations were no greater than 18.4 $\mu g/m^3$, versus the annual AAQS of 50 $\mu g/m^3$.

Based on the results presented in Table 5-7, estimates of background PM_{10} concentrations were derived. Unlike SO_2, for which peak monitored concentrations could readily be attributed to large anthropogenic sources, peak PM_{10} concentrations could be due to a combination of point and area sources, some of which would not be accounted for in the modeling analysis. Therefore, for the estimate of a 24-hour PM_{10} background concentration, the HSH value of 45.4 $\mu g/m^3$ was selected. For the annual background concentration, the highest arithmetic mean value of 18.4 $\mu g/m^3$ was chosen.

5.3.4 ANALYSIS FOR OZONE

The results of the ozone monitoring program are summarized in Table 5-8 and Figure 5-4. Table 5-8 presents the monthly mean and maximum hourly concentrations. Figure 5-4 shows hourly concentrations versus time. The program showed that

Table 5-7. Summary of PM$_{10}$ Concentrations ($\mu g/m^3$) at AQ-1 and AQ-2 for the Polk Power Station Site (April 1991 through March 1992)

	PM$_{10}$ Concentration by Site		
Date	AQ-1	AQ-2C	AQ-2D
03/31/91	23.3	28.3	26.9
04/06/91	17.6	*	*
04/12/91	18.9	18.1	18.7
04/18/91	14.3	*	*
04/24/91	19.7	*	*
04/30/91	18.2	*	*
05/06/91	20.5	17.3	19.8
05/12/91	22.5	26.4	22.4
05/18/91	15.4	17.6	16.5
05/24/91	13.8	14.6	14.1
05/30/91	29.3	30.0	33.5
06/05/91	20.9	22.7	21.2
06/11/91	16.4	16.3	15.8
06/17/91	13.3	18.2	12.9
06/23/91	20.6	20.4	21.1
06/29/91	48.3	17.1	29.6
07/05/92	23.4	43.5	†
07/11/91	†	29.6	12.0
07/17/91	45.4	16.7	23.6
07/23/91	29.9	18.8	29.9
07/29/91	42.4	46.9	†
08/04/91	14.6	15.1	13.8
08/10/91	12.3	11.0	†
08/16/91	25.1	27.0	26.5
08/22/91	16.2	9.4	9.4
08/28/91	9.9	8.4	†
09/03/91	14.0	14.5	14.9
09/09/91	10.9	10.5	10.1
09/15/91	16.6	16.8	16.7
09/21/91	16.2	16.4	14.0
09/27/91	25.1	25.0	30.8
10/03/91	26.9	22.5	†
10/09/91	26.3	†	†
10/15/91	23.5	20.0	19.5
10/21/91	10.8	14.4	13.3
10/27/91	11.6	12.1	10.5
11/02/91	14.6	12.6	12.1
11/08/91	45.1	42.7	43.9

Table 5-7. Summary of PM_{10} Concentrations ($\mu g/m^3$) at AQ-1 and AQ-2 for the Polk Power Station Site (April 1991 through March 1992) (Continued, Page 2 of 2)

Date	PM_{10} Concentration by Site		
	AQ-1	AQ-2C	AQ-2D
11/14/91	19.5	22.4	24.0
11/20/91	7.5	7.2	6.8
11/26/91	24.4	20.7	22.7
12/02/91	7.9	8.5	8.7
12/08/91	8.1	8.5	7.4
12/14/91	7.1	8.7	9.0
12/20/91	16.8	17.6	18.3
12/26/91	13.7	14.1	14.0
01/01/92	12.3	11.7	11.6
01/07/92	19.2	19.1	19.3
01/13/92	9.9	10.6	11.4
01/19/92	7.6	8.8	8.3
01/25/92	14.8	16.5	15.8
01/31/92	10.2	11.6	12.1
02/06/92	7.7	7.6	8.2
02/12/92	25.5	27.6	28.1
02/18/92	11.8	11.4	9.0
02/24/92	7.1	8.6	10.0
03/01/92	19.3	19.1	17.6
03/07/92	8.1	7.3	7.7
03/13/92	12.2	12.4	13.6
03/19/92	30.2	18.7	19.6
03/25/92	15.0	14.8	14.9
03/31/92	14.4	12.5	13.4
Highest	48.3	46.9**	43.9
Date	06/29/91	07/29/91	11/08/91
Second highest	45.4	43.5**	33.5
Date	07/17/91	07/05/91	05/30/91
Arithmetic mean	18.4	17.7	17.0
Standard deviation	9.5	8.7	7.8

* Electrical problems.

† Invalid data.

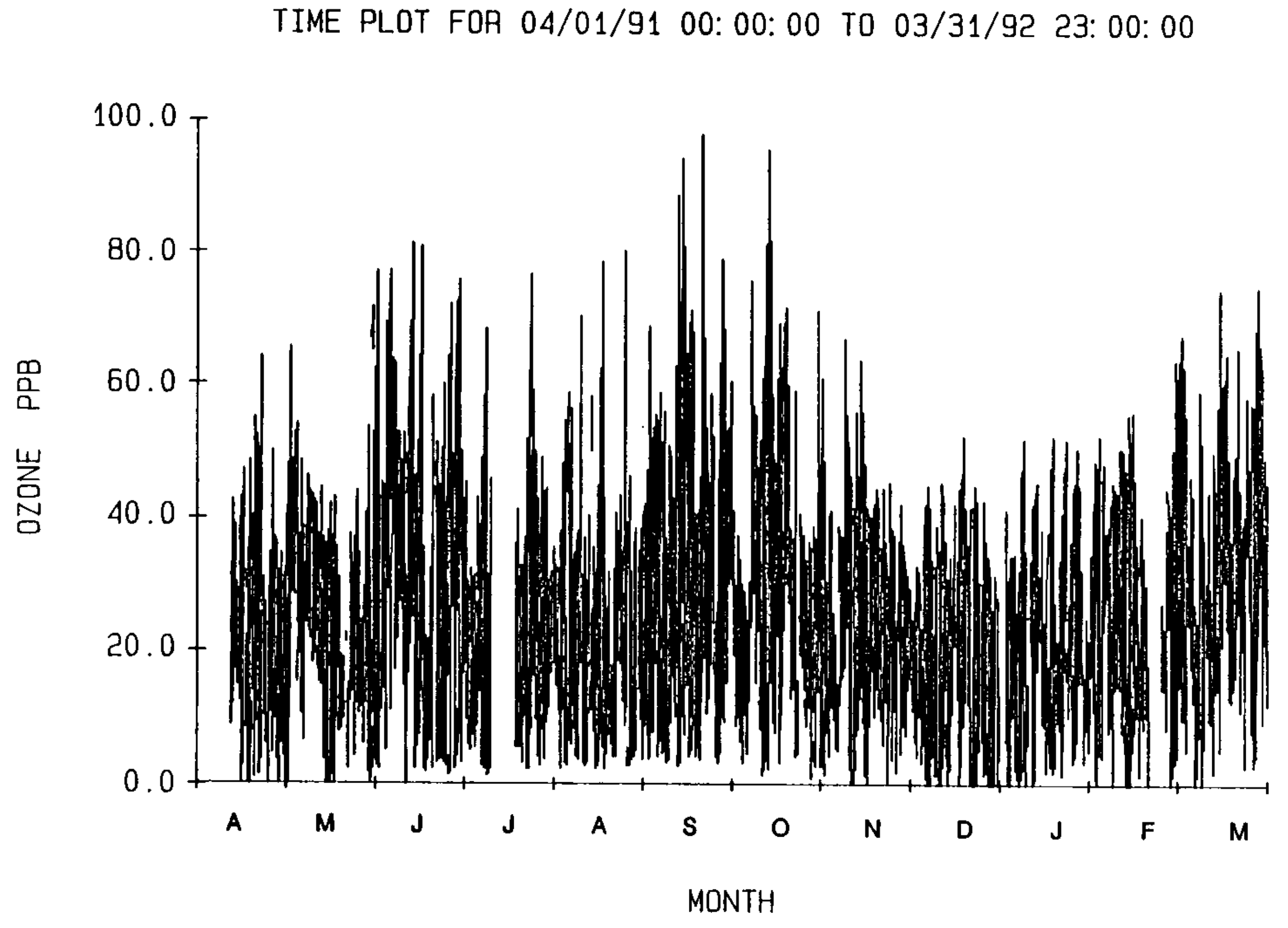
** The data for AQ-2D were not valid on July 5 and 29, 1991.

Source: ECT, 1992.

Table 5-8. Summary of Monthly Mean and 1-Hour Maximum Ozone Concentrations (ppb) at AQ-1 for the Polk Power Station Site (April 1991 through March 1992)

Month	Mean	Maximum 1-Hour	Date and Time
April	24	69	04/02/91 19:00
May	25	72	05/30/91 14:00
June	35	82	06/13/91 16:00
July	24	77	07/23/91 16:00
August	23	81	08/24/91 17:00
September	34	99	09/20/91 14:00
October	31	96	10/13/91 13:00
November	24	67	11/08/91 13:00
December	18	53	12/18/91 15:00
January	21	53	01/18/92 14:00
February	25	64	02/29/92 15:00
March	33	75	03/28/92 16:00

Source: ECT, 1992.



1-HOUR STANDARD = 120 ppb (235 μg/m^3)

Tampa Electric Station AQ-1 Averaging Time: 1 Hour

FIGURE 5-4.

MEASURED AMBIENT 1-HOUR OZONE AVERAGES AT THE POLK POWER STATION SITE

Source: ECT, 1992.

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ambient ozone concentrations in the vicinity of the Polk Power Station site were below the AAQS (120 ppb). Thus, the primary objective of the ozone monitoring effort (i.e., determining whether the existing air quality approaches or exceeds the AAQS) is favorably addressed. However, given the: (1) regional nature of ozone pollution, (2) difficulty in attributing ozone concentrations to individual emissions sources, and (3) fact that no approved modeling technique exists with which to assess the potential of emissions from Polk Power Station sources to affect ozone levels, no further attempt was made to define the background ozone concentration in the area.

6.0 MODELING APPROACH FOR SOURCE IMPACT ANALYSES AND AIR TOXICS ASSESSMENTS

6.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed. In addition, the proposed modeling protocol was presented to FDER as Appendix A of the Environmental Licensing Plan of Study (ECT, 1991c). The general modeling approach outlined in the protocol was accepted by FDER staff. Note that subsequent to the development of the modeling protocol, the need for modeling with the MESOPUFF-II long-range transport model to address impacts at a PSD Class I area was determined. The use of this model is discussed in Section 9.0.

6.2 AREA DESCRIPTION

The area around a proposed facility is important in determining model selection and use. The first consideration is whether the area is rural or urban. For this analysis, the land use of the surrounding area was examined in the context of the Auer classification method (Auer, 1978). EPA (1986) indicates that the Auer method is the preferred land use classification method because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends that, for determining classification, these land use factors be considered within 3 km of the source to be modeled.

The Auer technique recognizes four primary land use types: industrial (I), commercial (C), residential (R), and agricultural (A). Practically all industrial and commercial areas come under the heading of urban while the agricultural areas are considered rural. (However, those portions of generally industrial and commercial areas that are heavily vegetated can be considered rural in character.) In the case of residential areas, the delineation between urban and rural is not as clear. For residential areas, Auer subdivides this land use type into four groupings based on building structures and associated vegetation. It is important to accurately classify the residential areas into proper groupings to determine the most appropriate land use classification for the study area.

Through the use of U.S. Geological Survey topographic maps for the area, recent aerial photographs, and a field visit to the site, the land use types were identified within a 3-km radius of the plant site. Based on this analysis, clearly less than 50 percent of the land use surrounding the plant is urban. Therefore, rural dispersion coefficients and mixing heights were used.

The second modeling consideration associated with site characteristics is terrain. Certain models are appropriate for use only in certain terrain conditions. EPA (1986) has classified terrain as either simple or complex. Simple terrain is where terrain features are all lower in elevation than the top of the stack(s) of the source(s) in question. Complex terrain is defined as terrain exceeding the height of the stack being modeled. Study of the area surrounding the proposed site determined that terrain in any direction from the site would be classified as simple. It was also determined that the use of terrain elevations would not be necessary given the minimal amount of relief in the area.

6.3 MODEL SELECTION AND USE

The region surrounding the site would, for modeling purposes, be classified as rural and as having simple terrain, as discussed previously. For applying dispersion models to this type of situation, EPA has identified several recommended alternatives. First, for screening purposes, the SCREEN model (EPA, 1988a) is recommended. SCREEN is a simple model that calculates 1-hour average concentrations over a range of meteorological conditions. It is appropriate for use in situations where building wake downwash is or is not a concern. Then, as refined models, the

Industrial Source Complex (ISC2) models (EPA, 1992b) are recommended. 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 ISC2 models include a short-term version (ISCST2) and a long-term version (ISCLT2). Both versions are listed by EPA as refined models, and both were used for this study. Consistent with the use of the ISC2 models for regulatory purposes, the default option on each version was employed.

For this study, air quality models were applied at two levels. At the first, or screening, level, models were used to provide conservative estimates of impacts from a specific source. The main purpose of screening modeling was to provide information that was used to guide the more rigorous refined analysis. The second, or refined, level consisted of techniques that provide more detailed treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but provides more accurate estimates of source impacts.

6.4 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISCST2 and ISCLT2 models. ISCST2 requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings. ISCLT2 requires a statistical tabulation of the joint frequency of occurrence of wind speed, wind direction, and atmospheric stability category. These frequency distributions are commonly referred to as STAR data, abbreviated for STability ARray.

For this effort, meteorological data for input to the ISC2 models were selected to be consistent with EPA guidance and FDER practice. For southwest Polk County, surface data from Tampa and mixing height data from Ruskin are appropriate. As recommended by EPA (1986), for full-year refined ISCST2 runs, 5 years of the Tampa/Ruskin meteorological data were obtained from FDER in preprocessed form. The 5 years of data covered the years 1982 through 1986, as required by FDER.

For input to ISCLT2, ECT obtained the Tampa surface data files from FDER. These data were processed into STAR data sets using EPA's PCSTAR program. Values of ambient air temperatures and mixing heights specified by stability class were derived as recommended in the previous version of the ISC User's Guide (EPA, 1987b). Average ambient air temperatures for Bartow were obtained (Gale Research, 1985), along with the mean afternoon mixing height (Holzworth, 1972), from which the specific ISCLT2 model input values were calculated.

6.5 RECEPTOR LOCATIONS

Receptors were placed at locations considered to be *ambient air*, which EPA has defined as "that portion of the atmosphere, external to buildings, to which the general public has access" [40 CFR 50.1(e)]. Portions of the site with restricted access were not considered ambient air. A plot plan showing the plant boundary was provided in Section 2.1.3 (see Figure 2-15). As stated in Section 2.1.3, the entire perimeter of the portion of the plant site east of SR 37 will be fenced. Therefore, the nearest locations considered ambient air were at the property boundaries.

Receptor locations were selected consistent with definition of ambient air. For the SCREEN model, the receptor grid was started at 1,000 m, since this distance approximates the distance between the combustion source stacks and the nearest property line. The SCREEN grid was extended out to 50,000 m.

To determine the maximum impacts and, if applicable, the significant impact areas (SIAs) for the proposed facility, the ISC2 models were used with a polar receptor grid. The grid was centered on the IGCC HRSG stack and extended to distances necessary to determine the maximum impact and define the SIA for each subject pollutant. Discrete receptors were placed at the site property boundary. Table 6-1 provides the polar coordinates for the property line receptors as well as for discrete receptors placed between the property boundary and the closest receptor ring. Receptor rings were placed at distances beginning at 2,000 m; note that for the 2,000-m ring receptors at 40, 100, 110, 120, 140, 190, 200, 210, 220, 230, 240, and

Table 6-1. Polar Coordinates for Property Line and Other Discrete Receptors

Property Line Receptors		Other Discrete Receptors	
Radial (°)	Distance from Center (m)	Radial (°)	Distance from Center (m)
10	1,690	290	1,500
20	1,785	300	1,500
30	1,920	310	1,500
40	2,225	10	1,750
50	1,950	70	1,750
60	1,720	170	1,750
70	1,660	180	1,750
80	1,755	270	1,750
90	1,980	280	1,750
100	2,075	290	1,750
110	2,170	300	1,750
120	2,135	300	1,750
130	1,995	310	1,750
140	2,410	320	1,750
150	1,815	350	1,750
160	1,675	360	1,750
170	1,585		
180	1,560		
190	2,135		
200	2,240		
210	2,410		
220	2,195		
230	2,515		
240	2,895		
250	2,300		
260	1,905		
270	1,600		
280	1,415		
290	1,310		
300	1,295		
310	1,355		
320	1,510		
330	1,770		
340	1,770		
350	1,690		
360	1,660		

Source: ECT, 1992.

250 degree (°) radials fell within the property boundary. Figure 6-1 shows the discrete receptor locations and the close-in polar receptor rings. Receptor rings were placed at distances of 2,000, 2,500, 3,000, 3,500, 4,000, 5,000, 6,000, 7,000, 8,000, 9,000, 10,000, 12,500, 15,000, 17,500, 20,000, 22,500, 25,000, 27,500, 30,000, 32,500, 35,000, 40,000, 45,000, and 50,000 m from the grid center. Figure 6-2 illustrates the full receptor ring configuration. The SIAs were defined per the EPA and FDER modeling significance levels (see Table 3-4), using the highest annual and short-term impacts. For short-term averaging times, the SIAs were also defined by time. That is, a particular location was only included in the SIA during those periods when the facility had a significant impact.

6.6 GOOD ENGINEERING PRACTICE/DOWNWASH CONSIDERATIONS

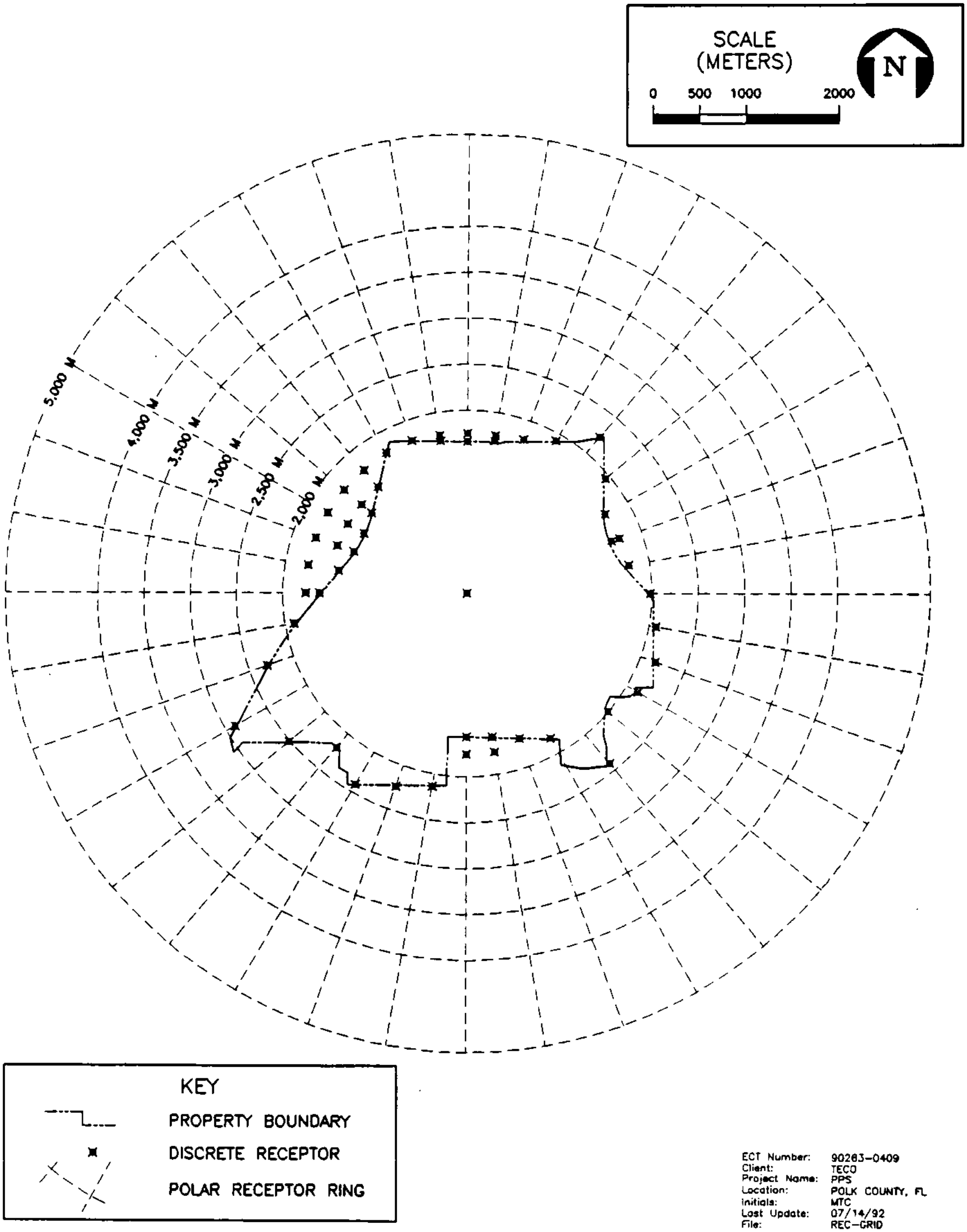
The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds Good Engineering Practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51), in which GEP stack height is defined as the highest of:

1. 65 m, or
2. A height established by applying the formula:

$$Hg = H + 1.5\,L$$

where: Hg = GEP stack height,
H = height of the structure or nearby structure, and
L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While GEP stack height regulations require that a stack height used in modeling for



ECT Number:	90263-0409
Client:	TECO
Project Name:	PPS
Location:	POLK COUNTY, FL
Initials:	MTC
Last Update:	07/14/92
File:	REC-GRID

FIGURE 6-1.

LOCATIONS OF DISCRETE RECEPTORS AND CLOSE-IN RECEPTORS
Source: ECT, 1992.

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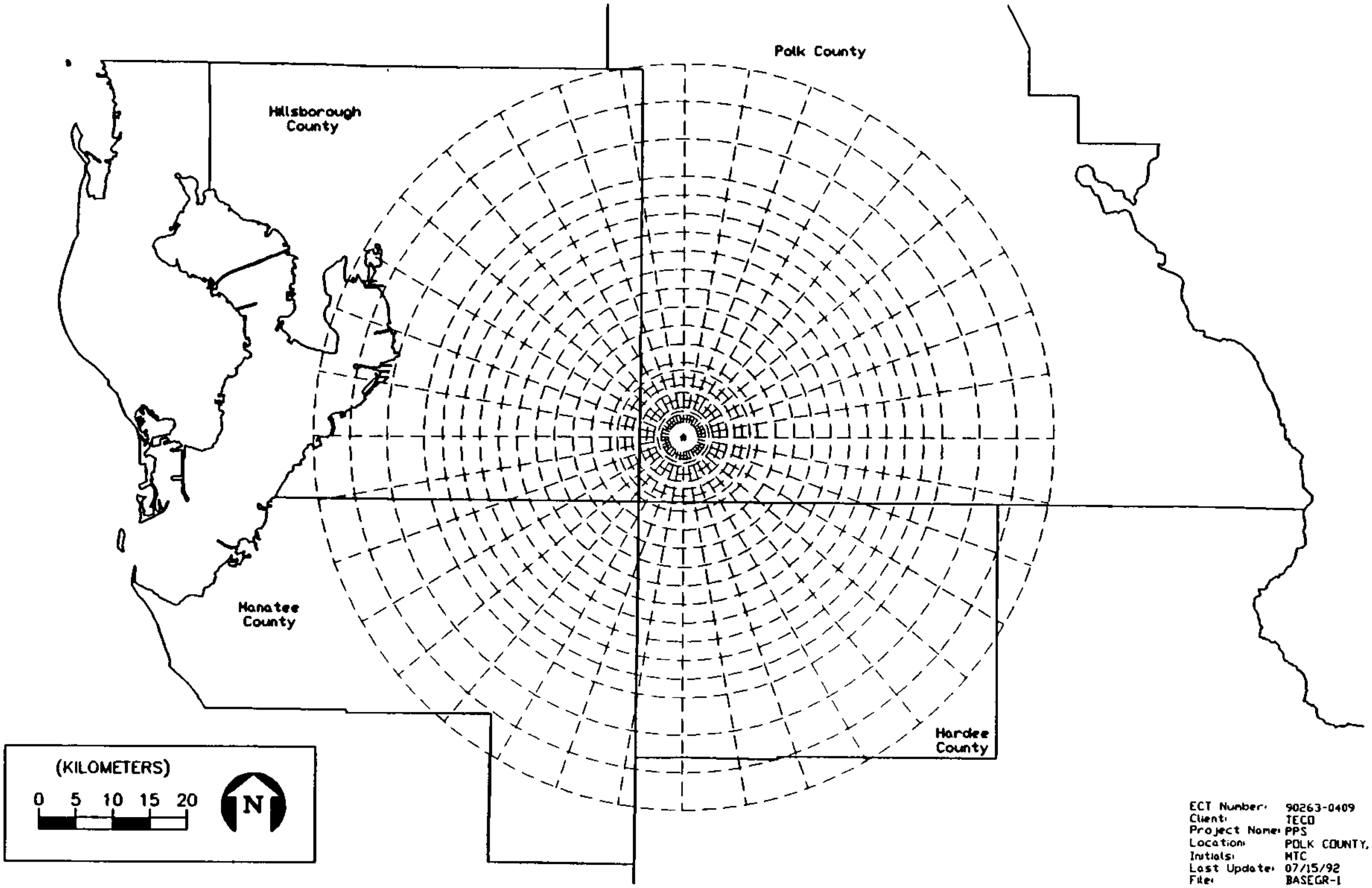

ECT Number:	90263-0409
Client:	TECO
Project Name:	PPS
Location:	POLK COUNTY, FL
Initials:	MTC
Last Update:	07/15/92
File:	BASEGR-1

FIGURE 6-2.

POLAR RECEPTOR RINGS

Source: ECT, 1992.

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determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The guidelines published by EPA (1985) for application of the stack height regulations were followed in determining the GEP stack height for each stack.

The complex downwash analysis was performed using the Bowman GEP program to determine the appropriate downwash parameters for ISCST2 and ISCLT2. The structures that were considered in this analysis are listed in Table 6-2, along with structural dimensions. Figure 6-3 shows the stacks and structures that were evaluated for downwash influences. The results indicated that 16 stacks would be affected by downwash. These results are summarized in Table 6-3.

6.7 CONSIDERATION OF PLANT OPERATING LOADS AND AMBIENT TEMPERATURES

For emissions from CTs and CCs, operating load and ambient temperature can affect plume dispersion, and therefore, ground-level impacts, since exit temperature and velocity change. For each fuel, two or three operating load cases at three ambient temperatures were analyzed at the screening level. Loads were selected to cover the range of normal plant operations, while ambient temperatures were representative of the area (see Section 2.2). The load/temperature case shown in the screening analysis to cause the highest impacts for each source were be used in the refined analyses.

6.8 CONSIDERATION OF PROJECT PHASES AND CAPACITY FACTORS

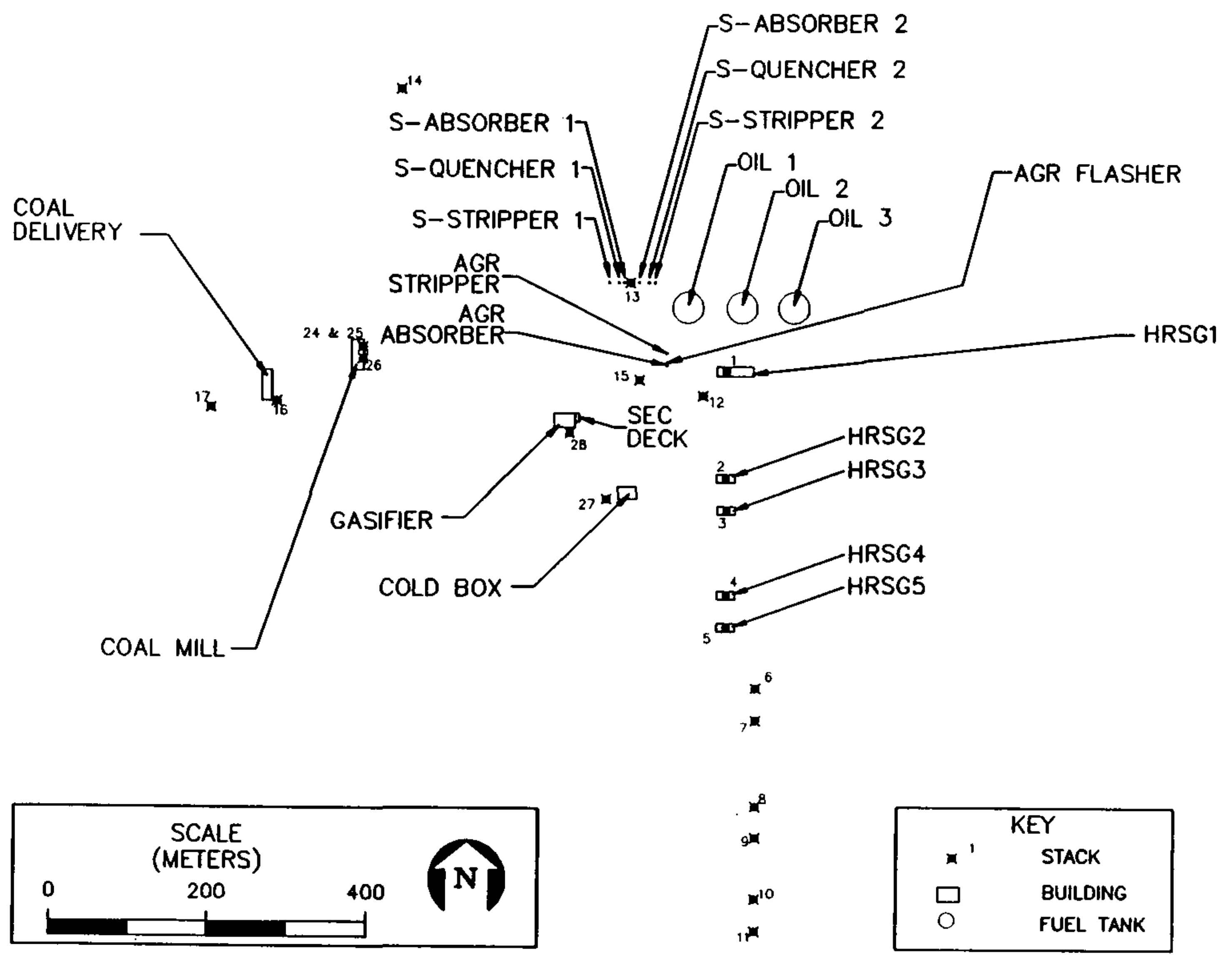
As discussed in Section 2.1.2, the development and installation of power generating facilities at Polk Power Station will occur in phases (see Table 2-1). From the perspective of facility emissions, the two significant project phases are: (1) the IGCC demonstration period, and (2) full buildout. The demonstration phase was considered important due to the higher emission rates that may occur from the 7F CT for some pollutants during this 2-year period as a result of the use of HGCU technology. However, during this period, no other power generating facilities will be

Table 6-2. Dimensions of Downwash Structures

Structure	Height (m)	Length (m)	Width (m)
7F (EP 1B) HRSG enclosure	24.0	46.0	12.0
CC (EP 2B) HRSG enclosure	17.4	23.0	10.0
CC (EP 3B) HRSG enclosure	17.4	23.0	10.0
CC (EP 4B) HRSG enclosure	17.4	23.0	10.0
CC (EP 5B) HRSG enclosure	17.4	23.0	10.0
SGC deck	53.4	11.0	5.0
Gasifier	76.2	27.0	18.0
Cold box	57.9	23.0	15.0
Coal grinding mill	70.1	38.1	15.3
Coal delivery enclosure	12.2	38.5	12.2
Oil storage tank 1	19.5	39.0*	NA
Oil storage tank 2	19.5	39.0*	NA
Oil storage tank 3	19.5	39.0*	NA
AGR stripper	42.7	3.0*	NA
AGR flasher	42.7	3.0*	NA
AGR absorber	42.7	3.0*	NA
Sulfur stripper (two units)	36.6	3.0*	NA
Sulfur quencher (two units)	18.3	3.0*	NA
Sulfur absorber (two units)	21.3	3.0*	NA

*Diameter.

Source: ECT, 1992.



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

FIGURE 6-3.

STRUCTURES INCLUDED IN GEP ANALYSIS

Source: ECT, 1992.

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Table 6-3. Stacks Affected by Downwash

I.D. Number	Stack	Affected by Downwash?
1B	7F, CC mode	Yes
2B	CT, CC mode	Yes
3B	CT, CC mode	Yes
4B	CT, CC mode	Yes
5B	CT, CC mode	Yes
6	CT, simple-cycle mode	Yes
7	CT, simple-cycle mode	No
8	CT, simple-cycle mode	No
9	CT, simple-cycle mode	No
10	CT, simple-cycle mode	No
11	CT, simple-cycle mode	No
12	Auxiliary boiler	Yes
13	TGTU thermal oxidizer	Yes
14	Flare	No
15	H_2SO_4 plant thermal oxidizer	Yes
16	Coal handling baghouse	Yes
17	Coal transfer baghouse	Yes
24	Coal storage bin baghouse	Yes
25	Grinding tower baghouse	Yes
26	Rod mill discharge	Yes
27	Air separation unit	Yes
28	Filter unit	Yes

Source: ECT, 1992.

in place. The full buildout scenario was also considered an obvious choice for impact analyses given the overall worst-case emissions that could occur.

In addition, capacity factors for individual units were considered in the modeling analyses. For short-term impacts, maximum hourly emission rates were used. However, for annual impacts, annualized emission rates, taking annual utilization into account, were used. Utilization rates were discussed in Section 2.1.2.1, and annualized emission rates were presented in Section 2.2.

6.9 CONSIDERATION OF OTHER, OFFSITE EMISSION SOURCES

For three pollutants (SO_2, NO_x, and PM), impacts due to Polk Power Station emission sources were determined to be *significant* (see Section 7.2). For these pollutants, it was therefore necessary to evaluate the impacts of other, offsite sources. Several sources of information were used in assembling the emissions inventories. These were:

1. Data from the FDER Air Pollution Information System (APIS) (FDER, 1991b),
2. Other data received directly from FDER staff, and
3. Information on recently applied-for facilities contained in FDER permit application files.

ECT obtained complete APIS listings for facilities located in the following counties:

- Citrus,
- DeSoto,
- Hardee,
- Hernando,
- Highlands,
- Hillsborough,
- Lake,
- Levy,
- Manatee,
- Marion,
- Orange,
- Osceola,
- Pasco,
- Pinellas,
- Polk, and
- Sarasota.

This inventory was received in September 1991. In addition, ECT received the following data directly from FDER staff (FDER, 1992b):

1. PSD Class I inventory for SO_2,
2. PSD Class I and II inventories for NO_x,
3. PSD Class I and II inventories for PM,
4. Updates to PSD Class I and II inventories for SO_2,
5. Updates to PSD Class I and II inventories for NO_x, and
6. Updates to PSD Class I and II inventories for PM.

ECT conducted a review of FDER permit application files on May 6, 1992, to review any pending permits. Several followup inquiries regarding pending permits were conducted via telephone conversations with FDER.

The AAQS inventory data were assembled by tabulating SO_2-emitting sources located within 75 km of Polk Power Station. NO_x- and PM-emitting sources were tabulated out to 50 km from Polk Power Station. These inventories are provided in Tables 6-4 through 6-6 for SO_2, NO_x, and PM, respectively. From these overall listings, facilities to be included in the AAQS modeling analysis were selected using the 20D method. Following this method, facilities were included in the AAQS inventory if annual emissions (in tpy) for a specific pollutant were greater than 20 times the distance between the facility and Polk Power Station. The results of these analyses are indicated in Tables 6-4 through 6-6. In all cases, the higher of the annualized APIS short-term emission rates or the stated APIS long-term emission rates were used in these comparisons. Figures 6-4 through 6-6 show the locations of the facilities included in AAQS modeling analyses.

For facilities to be included in the modeling analyses, details of maximum emission rates and of stack exhaust parameters were assembled. The specific source emission parameters for each facility included in the AAQS inventory for SO_2 are provided in Appendix B.1. These data were obtained from APIS, reviewed for consistency and gross errors, and updated to include recently permitted sources before use in the AAQS modeling.

Table 6–4. Summary of All SO2 Emitting Facilities Within 75 km

Identi- fication Number	Facility	County	UTM		Distance from Site (km)	SO2 (tpy)	20 x D	Include in AAQS Modeling
			East	North				
	Myakka Processors	DeSoto	409.9	3,010.3	57.4	31.0	1,148.0	No
	Better Roads of Lake Placid	DeSoto	412.0	3,005.0	63.0	59.0	1,260.0	No
	Florida Fence Post	Hardee	409.2	3,039.9	28.3	30.0	566.0	No
	The Mancini Packing Co	Hardee	421.4	3,040.8	33.2	1.0	664.0	No
	Wachula City Power	Hardee	418.4	3,047.0	26.5	180.0	530.0	No
	American Orange Corp	Hardee	429.8	3,047.3	24.9	430.0	698.0	No
100	Hardee Power Station Ft. Green Springs*	Hardee	404.8	3,057.4	10.3	16,080.0	206.0	Yes
	TECO Sebring	Highlands	456.8	3,042.5	60.9	136.0	1,218.0	No
167	TECO Sebring Airport*	Highlands	464.3	3,035.4	70.7	3,864.0	1,414.0	Yes
	Royster Co	Hillsborough	362.8	3,098.4	49.4	32.0	988.0	No
102	C F Industries Inc (Central Phosphate)*	Hillsborough	388.0	3,116.0	50.7	9,035.0	1,014.0	Yes
	The Stroh Brewing Co	Hillsborough	362.0	3,103.2	53.2	15.0	1,064.0	No
104	Cargill Fertilizer Inc (Gardinier)*	Hillsborough	362.9	3,082.2	41.0	5,480.0	820.0	Yes
	Couch Construction Company	Hillsborough	362.1	3,096.7	48.9	75.0	978.0	No
	LaFarge Corp	Hillsborough	357.7	3,090.6	49.3	655.0	986.0	No
	H & S Properties	Hillsborough	360.3	3,093.2	48.4	44.0	968.0	No
	IMC Port Sutton Terminal	Hillsborough	360.1	3,087.5	45.7	48.0	914.0	No
	Gold Bond Building Products	Hillsborough	347.3	3,082.7	55.9	315.0	1,118.0	No
	Stilwell Foods of Florida	Hillsborough	389.8	3,098.9	33.8	22.0	676.0	No
	Cargill/Nutrena Feed Division	Hillsborough	360.8	3,095.8	49.5	2.0	990.0	No
103	TECO Hooker's Point	Hillsborough	358.0	3,091.0	49.2	13,522.0	984.0	Yes
105	TECO Big Bend*	Hillsborough	361.9	3,075.0	39.9	371,760.0	798.0	Yes
106	TECO Gannon	Hillsborough	360.0	3,087.5	45.8	126,940.0	916.0	Yes
	Tampa General Hospital	Hillsborough	356.4	3,091.0	50.6	59.0	1,012.0	No
	Tampa Block Plant	Hillsborough	349.0	3,100.8	62.0	22.0	1,240.0	No
107	Gulf Coast Lead Company	Hillsborough	364.0	3,093.5	45.5	1,709.0	910.0	Yes
	Weyerhaeuser Co	Hillsborough	362.8	3,098.3	49.4	19.0	988.0	No

Table 6–4. Summary of All SO2 Emitting Facilities Within 75 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	SO2 (tpy)	20 x D	Include in AAQS Modeling
108	Consolidated Minerals Inc. Plant City	Hillsborough	393.8	3,096.3	30.2	942.0	604.0	Yes
	Delta Asphalt	Hillsborough	372.1	3,105.4	48.1	131.0	962.0	No
	W R Grace & Co	Hillsborough	360.2	3,093.0	48.4	5.0	968.0	No
	Sulfur Terminals Co	Hillsborough	358.0	3,090.0	48.8	210.0	976.0	No
	Amoco Oil	Hillsborough	357.8	3,092.0	49.9	303.0	998.0	No
	Haley, James A. Veterans Hospital	Hillsborough	359.6	3,104.1	55.6	7.0	1,112.0	No
	St. Josephs Hospital	Hillsborough	353.7	3,095.9	55.4	1.0	1,108.0	No
	Sulphuric Acid Trading	Hillsborough	349.0	3,081.5	54.0	156.0	1,080.0	No
109	IMC Ft. Lonesome	Hillsborough	389.6	3,067.9	11.4	1,717.0	228.0	Yes
110	Mobil Mining & Minerals Big Four Mine*	Hillsborough	394.7	3,069.6	6.8	569.0	136.0	Yes
	Tarmac Florida Hialeah	Hillsborough	362.8	3,097.0	48.6	88.0	972.0	No
	Stauffer Chemical Company	Hillsborough	365.3	3,093.6	44.5	1.0	890.0	No
	Humana Women's Hospital	Hillsborough	353.3	3,095.7	55.7	15.0	1,114.0	No
	Griffin Industries	Hillsborough	364.1	3,096.4	47.2	2.0	944.0	No
	Speedling Inc.	Hillsborough	354.1	3,062.2	47.1	31.0	942.0	No
	Cast–Crete Corp of Florida	Hillsborough	371.9	3,099.2	43.4	15.0	868.0	No
	Westshore Glass Corp	Hillsborough	349.2	3,098.5	60.6	1.0	1,212.0	No
	R C Martin Concrete Products	Hillsborough	368.6	3,092.1	41.0	2.0	820.0	No
135	Hillsborough Co Rescource Recovery*	Hillsborough	368.2	3,092.7	41.7	702.0	834.0	No
	International Petroleum Corp	Hillsborough	389.0	3,098.0	33.2	41.0	664.0	No
	Unocal Chemical	Hillsborough	358.4	3,088.4	47.7	8.0	954.0	No
	Coastal Fuels Marketing	Manatee	346.5	3,057.8	55.3	51.0	1,106.0	No
111	Royster Phosphate (AMAX) Piney Point	Manatee	348.5	3,057.3	53.4	2,084.0	1,068.0	Yes
	Tropicana Products Inc.	Manatee	346.8	3,040.9	60.2	248.0	1,204.0	No
112	Florida Power & Light	Manatee	367.2	3,054.1	36.2	55,143.0	724.0	Yes
	Gator Asphalt	Manatee	347.7	3,030.4	64.7	6.0	1,294.0	No
	Utility Power Corporation	Manatee	347.8	3,044.6	57.7	7.0	1,154.0	No

Table 6–4. Summary of All SO2 Emitting Facilities Within 75 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	SO2 (tpy)	20 x D	Include in AAQS Modeling
	Manatee County Public Works Dept.	Manatee	357.1	3,038.8	52.2	1.0	1,044.0	No
	Ajax Paving Industries	Manatee	347.9	3,056.3	54.2	23.0	1,084.0	No
	American Clay Products	Manatee	348.1	3,057.6	53.7	4.0	1,074.0	No
113	Florida Power Intercession City*	Osceola	446.3	3,126.0	74.4	24,763.0	1,488.0	Yes
	Lykes Pasco Inc.	Pasco	383.5	3,139.2	74.3	11.0	1,486.0	No
136	Pasco Co Cogeneration Facility*	Pasco	385.6	3,139.0	73.6	175.0	1,472.0	No
114	Florida Power P L Bartow	Pinellas	342.4	3,082.6	60.6	61,853.0	1,212.0	Yes
115	Florida Power Higgins	Pinellas	336.5	3,098.4	71.7	12,071.0	1,434.0	Yes
116	Florida Power Bayboro	Pinellas	338.8	3,071.3	62.3	6,876.0	1,246.0	Yes
	Acre Iron & Metal	Pinellas	329.7	3,082.1	72.9	18.0	1,458.0	No
	Intercit	Pinellas	332.5	3,096.4	74.5	1.0	1,490.0	No
	All Children's Hospital	Pinellas	338.1	3,071.6	63.1	44.0	1,262.0	No
117	Pinellas Resource Recovery Facility*	Pinellas	335.2	3,084.1	68.0	3,418.0	1,360.0	Yes
	Alcoma Packing Co	Polk	451.6	3,085.5	53.9	956.0	1,078.0	No
	Citrus World	Polk	441.0	3,087.3	44.9	877.0	898.0	No
118	Lakeland City Power Larsen Power Station*	Polk	409.3	3,102.8	36.7	3,926.0	734	Yes
119	Lakeland City Power McIntosh Power Station*	Polk	409.2	3,106.1	40.0	30,176.0	800.0	Yes
	Owens–Brockway Glass Container	Polk	423.4	3,102.3	41.8	168.0	836.0	No
	Florida Mining & Minerals Alabama Lane	Polk	420.8	3,103.4	41.4	1.0	828.0	No
	C & M Products Co	Polk	405.5	3,079.1	12.9	4.0	258.0	No
	FMC Corp/Citrus Machinery Division	Polk	409.8	3,102.6	36.7	4.0	734.0	No
	Standard Sand	Polk	441.5	3,118.2	65.3	398.0	1,306.0	No
	Citrus Hill Mfg	Polk	447.9	3,068.3	46.9	841.0	938.0	No
	Coca Cola	Polk	421.6	3,103.7	42.1	35.0	842.0	No
	IMC Fertilizer Noralyn Mine	Polk	414.7	3,080.3	19.1	176.0	382.0	No
	Adams Packing Association	Polk	421.7	3,104.2	42.6	40.0	852.0	No
120	Gardinier	Polk	415.3	3,063.3	14.8	1,173.0	296.0	Yes

Table 6–4. Summary of All SO2 Emitting Facilities Within 75 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	SO2 (tpy)	20 x D	Include in AAQS Modeling
	Orange Co of Florida	Polk	418.7	3,083.6	24.3	26.0	486.0	No
121	Seminole Fertilizer (W R Grace)*	Polk	409.9	3086.7	21.6	9,129.0	432	Yes
122	Mobil Mining & Minerals SR 676*	Polk	398.5	3,085.1	18.3	832.0	366.0	Yes
123	Royster Company*	Polk	406.8	3,085.1	19.0	1,265.0	380.0	Yes
124	US Agri–Chemicals Hwy 60*	Polk	413.2	3,086.3	22.8	1,575.0	456.0	Yes
125	US Agri–Chemicals Hwy 630*	Polk	416.0	3,069.0	15.1	6,881.0	302.0	Yes
126	C F Industries Bonnie Mine Rd*	Polk	408.4	3,082.4	17.1	5,413.0	342.0	Yes
127	Farmland Industries Green Bay Plant*	Polk	409.5	3,080.1	15.6	4,213.0	312.0	Yes
128	Agrico Chemical Co Pierce*	Polk	403.7	3,079.0	12.3	417.0	246.0	Yes
129	Agrico Chemical Co South Pierce*	Polk	407.5	3,071.5	7.9	4,740.0	158.0	Yes
	IMC Fertilizer Prairie	Polk	402.9	3,087.0	20.1	137.0	402.0	No
130	Conserv Inc*	Polk	398.7	3,084.2	17.4	1,586.0	348.0	Yes
131	IMC Fertilizer New Wales*	Polk	396.7	3,079.4	13.1	6,296.0	262.0	Yes
132	Mobil–Electrophos Division*	Polk	405.6	3,079.4	13.2	1,440.0	264.0	Yes
	Holly Hill Fruit Products	Polk	441.0	3,115.4	62.8	217.0	1,256.0	No
	Kaplan Industries	Polk	418.3	3,079.3	21.2	398.0	424.0	No
	International Paper Company	Polk	421.7	3,104.3	42.7	1.0	854.0	No
133	Imperial Phosphates Ltd.*	Polk	404.8	3,069.5	4.5	275.0	90.0	Yes
	Macasphalt	Polk	423.1	3,101.5	41.0	12.0	820.0	No
	Bordo Citrus Product Inc.	Polk	427.8	3,097.5	40.6	30.0	812.0	No
	Westvaco Corporation	Polk	408.0	3,085.5	19.8	2.0	396.0	No
	Dundee Citrus	Polk	438.8	3,099.9	50.1	96.0	1,002.0	No
	John Carlos Florida	Polk	426.2	3,104.1	44.8	79.0	896.0	No
	Florida Privitization Inc.	Polk	418.3	3,048.0	25.7	5.0	514.0	No
	Pavex Corporation	Polk	413.0	3,086.2	22.6	233.0	452.0	No
	High Performance Finishes	Polk	428.0	3,096.0	39.6	1.0	792.0	No
	Laidlaw Environmental Services Inc.	Polk	424.7	3,091.9	34.4	240.0	688.0	No

Table 6–4. Summary of All SO2 Emitting Facilities Within 75 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	SO2 (tpy)	20 x D	Include in AAQS Modeling
	Metalcoat Inc of Florida	Polk	404.2	3,084.0	17.3	3.0	346.0	No
	Bio–Medical Service Corp of GA	Polk	413.9	3,081.3	19.3	16.0	386.0	No
134	Auburndale Cogeneration*	Polk	420.	3,103.3	41.3	882.0	826.0	Yes
	Demaco Corp	Sarasota	353.7	3,016.5	69.2	4.0	1,384.0	No
137	Ridge Cogeneration*	Polk	416.	3,100.4	36.9	479.0	738.0	No
138	Tampa City McKay Bay Refuse–to–Energy	Hillsborough	360.0	3,091.9	48.0	1,489.0	960.0	Yes
141	CLM CLI*	Hillsborough	361.8	3,088.3	45.7	731.0	914.0	No
146	Evans Packing *	Pasco	383.3	3,135.8	71.0	7.0	1,420.0	No

*Included in PSD emission inventory

Sources: FDER, 1991b, 1992b.
Koogler, 1992.
ECT, 1992.

Table 6–5. Summary of All NOx Emitting Facilities Within 50 km

Identi-fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	NOx (tpy)	20 x D	Include in AAQS Modeling
	Florida Fence Post	Hardee	409.2	3,039.9	28.3	38.0	566.0	No
	The Mancini Packing Co	Hardee	421.4	3,040.8	33.2	1.0	664.0	No
	Hardee Memorial Hospital	Hardee	419.2	3,046.7	27.3	1.0	546.0	No
	Wachula City Power	Hardee	418.4	3,047.0	26.5	71.0	530.0	No
100	Hardee Power Station Ft. Green Springs	Hardee	404.8	3,057.4	10.3	8,400.0	206.0	Yes
	Royster Co	Hillsborough	362.8	3,098.4	49.4	3.0	988.0	No
	Cargill Fertilizer Inc. (Gardinier)	Hillsborough	362.9	3,082.2	41.0	467.0	820.0	No
	H & S Properties	Hillsborough	360.3	3,093.2	48.4	9.0	968.0	No
	Florida Steel Corp	Hillsborough	364.6	3,092.8	44.6	32.0	892.0	No
	IMC Port Sutton Terminal	Hillsborough	360.1	3,087.5	45.7	180.0	914.0	No
	Nitram	Hillsborough	362.5	3,089.0	44.3	388.0	886.0	No
	Stilwell Foods of Florida	Hillsborough	389.8	3,098.9	33.8	9.0	676.0	No
103	TECO Hooker's Point	Hillsborough	358.0	3,091.0	49.2	1,256.0	984.0	Yes
105	TECO Big Bend	Hillsborough	361.9	3,075.0	39.9	50,132.0	798.0	Yes
106	TECO Gannon	Hillsborough	360.0	3,087.5	45.8	28,126.0	916.0	Yes
	Scrapall Inc.	Hillsborough	359.4	3,093.1	49.1	30.0	982.0	No
	GAF Building Materials Corp	Hillsborough	362.2	3,087.2	43.7	4.0	874.0	No
	Gulf Coast Lead Company	Hillsborough	364.0	3,093.5	45.5	32.0	910.0	No
	Eastern Electric Apparatus Repair Co	Hillsborough	366.6	3,092.0	42.5	1.0	850.0	No
	Weyerhaeuser Co	Hillsborough	362.8	3,098.3	49.4	5.0	988.0	No
	Consolidated Minerals Inc. Plant City	Hillsborough	393.8	3,096.3	30.2	583.0	604.0	No
	Delta Asphalt	Hillsborough	372.1	3,105.4	48.1	237.0	962.0	No
	W R Grace & Co	Hillsborough	360.2	3,093.0	48.4	3.0	968.0	No
	Sulfur Terminals Co	Hillsborough	358.0	3,090.0	48.8	31.0	976.0	No
	Amoco Oil	Hillsborough	357.8	3,092.0	49.9	29.0	998.0	No
109	IMC Ft. Lonesome	Hillsborough	389.6	3,067.9	11.4	611.0	228.0	Yes
110	Mobil Mining & Minerals Big Four Mine	Hillsborough	394.7	3,069.6	6.8	155.0	136.0	Yes

Table 6–5. Summary of All NOx Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	NOx (tpy)	20 x D	Include in AAQS Modeling
	Tarmac Florida Hialeah	Hillsborough	362.8	3,097.0	48.6	11.0	972.0	No
	Stauffer Chemical Company	Hillsborough	365.3	3,093.6	44.5	5.0	890.0	No
	Griffin Industries	Hillsborough	364.1	3,096.4	47.2	60.0	944.0	No
	Treasure Isle Inc.	Hillsborough	378.0	3,096.9	37.7	2.0	754.0	No
	Speedling, Inc.	Hillsborough	354.1	3,062.2	47.1	8.0	942.0	No
	Couch Construction Co.	Hillsborough	364.3	3,098.1	48.1	11.0	962.0	No
	Reed Minerals Division	Hillsborough	362.2	3,085.5	43.0	2.0	860.0	No
	Alumax Extrusions	Hillsborough	385.6	3,097.0	33.7	47.0	674.0	No
	R C Martin Concrete Products	Hillsborough	368.6	3,092.1	41.0	219.0	820.0	No
	Hillsborough Co Resource Recovery	Hillsborough	368.2	3,092.7	41.7	657.0	834.0	No
	City of Tampa Dept. of Sanitary Sewers	Hillsborough	364.0	3,089.5	43.3	4.0	866.0	No
112	Florida Power & Light	Manatee	367.2	3,054.1	36.2	17,349.0	724.0	Yes
118	Lakeland City Power Larsen Power Station*	Polk	409.3	3,102.8	36.7	48.0	734.0	No
119	Lakeland City Power McIntosh Power Station	Polk	409.2	3,106.1	40.0	5,237.0	800.0	Yes
	Owens–Brockway Glass Container	Polk	423.4	3,102.3	41.8	361.0	836.0	No
	Florida Mining & Minerals Alabama Lane	Polk	420.8	3,103.4	41.4	1.0	828.0	No
	Florida Tile	Polk	405.4	3,102.4	35.7	26.0	714.0	No
	Allsun Products	Polk	413.5	3,093.8	29.6	18.0	592.0	No
	Estech	Polk	411.5	3,074.2	12.7	11.0	254.0	No
	FMC Corp/Citrus Machinery Division	Polk	409.8	3,102.6	36.7	4.0	734.0	No
	Erly Juice Inc.	Polk	399.0	3,101.8	34.9	53.0	698.0	No
	Citrus Hill MFG	Polk	447.9	3,068.3	46.9	441.0	938.0	No
	Packaging Corp of America	Polk	423.4	3,102.8	42.2	6.0	844.0	No
	Coca Cola	Polk	421.6	3,103.7	42.1	483.0	842.0	No
	Hunt Brothers	Polk	445.3	3,083.0	47.1	1.0	942.0	No
	Adams Packing Association	Polk	421.7	3,104.2	42.6	13.0	852.0	No
	Gardinier	Polk	415.3	3,063.3	14.8	176.0	296.0	No

Table 6-5. Summary of All NOx Emitting Facilities Within 50 km

Identi-fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	NOx (tpy)	20 x D	Include in AAQS Modeling
	Orange Co of Florida	Polk	418.7	3,083.6	24.3	22.0	486.0	No
121	Seminole Fertilizer (W R Grace)*	Polk	409.5	3,085.1	21.6	539.0	432.0	Yes
	Mobil Mining & Minerals SR 676	Polk	398.2	3,085.0	18.2	191.0	366.0	No
	Royster Company	Polk	406.8	3,085.1	19.0	17.0	380.0	No
	US Agri-Chemicals Hwy 60	Polk	413.2	3,086.3	22.8	143.0	456.0	No
	US Agri-Chemicals Hwy 630	Polk	416.0	3,069.0	15.2	131.0	302.0	No
127	Farmland Industries Green Bay Plant*	Polk	409.5	3,080.1	15.6	410.0	312.0	Yes
	Agrico Chemical Co Pierce	Polk	403.7	3,079.0	12.3	118.0	246.0	No
	Agrico Chemical Co South Pierce	Polk	407.	3,071.5	7.9	59.0	158.0	No
	Conserv Inc.	Polk	398.7	3,084.2	17.4	11.0	348.0	No
131	IMC Fertilizer New Wales	Polk	396.7	3,079.4	13.1	494.0	262.0	Yes
	Mobil-Electrophos Division	Polk	405.6	3,079.4	13.2	24.0	264.0	No
	Kaplan Industries	Polk	418.3	3,079.3	21.2	98.0	424.0	No
	Winter Haven Hospital	Polk	428.7	3,100.4	43.4	2.0	868.0	No
	International Paper Company	Polk	421.7	3,104.3	42.7	6.0	854.0	No
	Quikrete of Florida	Polk	412.8	3,099.0	34.1	2.0	682.0	No
	Bordo Citrus Product Inc.	Polk	427.8	3,097.5	40.6	19.0	812.0	No
	Florida Distillers	Polk	428.0	3,108.1	49.2	18.0	984.0	No
	Florida Distillers Company	Polk	421.4	3,102.9	41.3	194.0	826.0	No
	Westvaco Corp	Polk	408.0	3,085.5	19.8	14.0	396.0	No
	Schering Berlin Polymers	Polk	410.7	3,098.9	33.3	617.0	666.0	No
	Sun Pac Foods	Polk	422.7	3,092.6	33.6	7.0	672.0	No
	National Linen Service	Polk	406.0	3,103.0	36.6	6.0	726.0	No
	Juice Bowl Products	Polk	409.4	3,099.9	34.0	109.0	680.0	No
	Union Camp Corp	Polk	402.0	3,102.0	35.0	2.0	700.0	No
	John Carlos Florida	Polk	426.2	3,104.1	44.8	28.0	896.0	No
	Florida Privitization Inc.	Polk	418.3	3,048.0	25.7	22.0	514.0	No

Table 6–5. Summary of All NOx Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM		Distance from Site (km)	NOx (tpy)	20 x D	Include in AAQS Modeling
			East	North				
	Central Florida Hot–Mix	Polk	412.5	3,097.7	32.8	3.0	656.0	No
	Purina Mills	Polk	402.0	3,087.0	20.0	6.0	400.0	No
	High Performance Finishers	Polk	428.0	3,096.0	39.6	1.0	792.0	No
	Metalcoat Inc. of Florida	Polk	404.2	3,084.0	17.3	2.0	346.0	No
	Ennis Drum Service Inc.	Polk	422.5	3,102.5	41.5	5.0	830.0	No
	UNC Reclamation	Polk	406.1	3,080.6	14.5	19.0	290.0	No
	Bio–Medical Service Corp of GA	Polk	413.9	3,081.3	19.3	19.0	386.0	No
	Citrus Hill Manufacturing Co	Polk	411.6	3,081.4	17.9	18.0	358.0	No
134	Auburndale Cogeneration*	Polk	420.	3,103.3	41.3	736.0	826.0	No
137	Ridge Cogeneration*	Polk	416.	3,100.4	36.9	55.0	738.0	No
138	Tampa City McKay Bay Refuse–to–Energy	Hillsborough	360.0	3,091.9	48.0	2,630.0	960.0	Yes
139	Citrus World	Polk	441.0	3,087.3	44.9	1,381.0	898.0	Yes

*Included in PSD emission inventory

Sources: FDER, 1991b, 1992b.
Koogler, 1992.
ECT, 1992.

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Amcon Products	Citrus	364.6	3,092.8	44.6	32.0	892.0	No
	Florida Fence Post	Hardee	409.2	3,039.9	28.3	6.0	566.0	No
	The Mancini Packing Company	Hardee	421.4	3,040.8	33.2	1.0	664.0	No
	Hardee Memorial Hospital	Hardee	419.2	3,046.7	27.3	1.0	546.0	No
	Wachula City Power	Hardee	418.4	3,047.0	26.5	21.0	530.0	No
	American Orange Corp	Hardee	429.8	3,047.3	34.9	181.0	698.0	No
100	Hardee Power Station Ft. Green Springs*	Hardee	404.8	3,057.4	10.3	1,251.0	206.0	Yes
	Cast Metals Corp	Hillsborough	368.8	3,094.6	42.4	8.0	848.0	No
	Royster Co	Hillsborough	362.8	3,098.4	49.4	18.0	988.0	No
104	Cargill Fertilizer Inc. (Gardinier)	Hillsborough	362.9	3,082.2	41.0	932.0	820.0	Yes
	Couch Construction Company	Hillsborough	362.1	3,096.7	48.9	26.0	978.0	No
	Eastern Association Terminal	Hillsborough	360.2	3,088.9	46.3	534.0	926.0	No
	H & S Properties	Hillsborough	360.3	3,093.2	48.4	9.0	968.0	No
	Florida Steel Corp	Hillsborough	364.6	3,092.8	44.6	144.0	892.0	No
	Marathon Petroleum Company	Hillsborough	362.2	3,087.2	43.7	13.0	874.0	No
	IMC Port Sutton Terminal	Hillsborough	360.1	3,087.5	45.7	442.0	914.0	No
	Nitram	Hillsborough	362.5	3,089.0	44.3	218.0	886.0	No
	Stilwell Foods of Florida	Hillsborough	389.8	3,098.9	33.8	2.0	676.0	No
	Holnam Inc.	Hillsborough	359.5	3,087.3	46.2	55.0	924.0	No
	Tampa Sand & Material	Hillsborough	360.1	3,092.2	48.0	17.0	960.0	No
	CSX Transportation Inc.	Hillsborough	361.0	3,089.0	45.7	404.0	914.0	No
	Cargill/Nutrena Feed Division	Hillsborough	360.8	3,095.8	49.5	21.0	990.0	No
103	TECO Hooker's Point	Hillsborough	358.0	3,091.0	49.2	1,231.0	984.0	Yes
105	TECO Big Bend*	Hillsborough	361.9	3,075.0	39.9	7,897.0	798.0	Yes
106	TECO Gannon	Hillsborough	360.0	3,087.5	45.8	5,857.0	916.0	Yes
	GNB Inc. (PAC CHL)	Hillsborough	361.8	3,088.3	44.6	25.0	892.0	No
	Central Phosphates Inc.	Hillsborough	359.1	3,089.8	47.7	26.0	954.0	No

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Florida Rock Industry	Hillsborough	362.3	3,097.5	49.3	20.0	986.0	No
	Scrapall Inc.	Hillsborough	359.4	3,093.1	49.1	31.0	982.0	No
	GAF Building Materials Corp	Hillsborough	362.2	3,087.2	43.7	57.0	874.0	No
	Gulf Coast Lead Company	Hillsborough	364.0	3,093.5	45.5	17.0	910.0	No
	Tampa Armature Works	Hillsborough	365.6	3,091.7	43.2	13.0	864.0	No
	Eastern Electric Apparatus Repair Co	Hillsborough	366.6	3,092.0	42.5	21.0	850.0	No
	Southeastern Galvanizing Division	Hillsborough	368.5	3,094.5	42.6	21.0	852.0	No
	Weyerhaeuser Co	Hillsborough	362.8	3,098.3	49.4	25.0	988.0	No
108	Consolidated Minerals Inc. Plant City	Hillsborough	393.8	3,096.3	30.2	756.0	604.0	Yes
	Delta Asphalt	Hillsborough	372.1	3,105.4	48.1	72.0	962.0	No
	W R Grace & Co	Hillsborough	360.2	3,093.0	48.4	11.0	968.0	No
	Tarmac Flordia	Hillsborough	362.8	3,098.4	49.4	23.0	988.0	No
	Union Oil Company of California	Hillsborough	358.0	3,089.1	48.3	14.0	966.0	No
	Sulfur Terminals Co	Hillsborough	358.0	3,090.0	48.8	9.0	976.0	No
	Amoco Oil	Hillsborough	357.8	3,092.0	49.9	9.0	998.0	No
	Florida M & M	Hillsborough	362.2	3,066.2	38.8	21.0	776.0	No
	Bay Concrete	Hillsborough	365.1	3,093.8	44.8	37.0	896.0	No
	Southern Prestressed	Hillsborough	363.2	3,098.4	49.1	2.0	982.0	No
	Southeastern Wire	Hillsborough	368.3	3,094.5	42.7	21.0	854.0	No
	Asgrow Florida Company	Hillsborough	388.6	3,104.6	39.6	5.0	792.0	No
	Paktank Florida	Hillsborough	360.8	3,087.3	45.0	178.0	900.0	No
	Amcon Concrete	Hillsborough	358.4	3,090.2	48.5	3.0	970.0	No
	Agrico Chemical Co	Hillsborough	362.1	3,076.1	40.0	195.0	800.0	No
	W R Bonasal Co	Hillsborough	363.6	3,098.1	48.6	19.0	972.0	No
109	IMC Ft. Lonesome*	Hillsborough	389.6	3,067.9	11.4	678.0	228.0	Yes
	Mobil Mining & Minerals Big Four Mine	Hillsborough	394.7	3,069.6	6.8	68.0	136.0	No
	Cargill	Hillsborough	358.1	3,091.7	49.5	22.0	990.0	No

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Tarmac Florida Hialeah	Hillsborough	362.8	3,097.0	48.6	36.0	972.0	No
	David J. Joseph Co.	Hillsborough	364.0	3,092.9	45.2	123.0	904.0	No
	North American Salt Co	Hillsborough	362.4	3,085.7	42.9	5.0	858.0	No
	Gulf Coast Metals	Hillsborough	364.7	3,093.6	45.0	13.0	900.0	No
	Amcon Concrete	Hillsborough	364.0	3,075.0	37.9	39.0	758.0	No
	LaFarge Corp.	Hillsborough	358.3	3,092.8	49.9	51.0	998.0	No
	Rinker Materials Corp.	Hillsborough	392.2	3,100.0	34.2	14.0	684.0	No
	Reynolds Aluminum Recycling	Hillsborough	362.7	3,097.5	49.0	14.0	980.0	No
	Tampa City McKay Bay Refuse–to–Energy	Hillsborough	360.0	3,091.9	48.0	344.0	960.0	No
	Southern Mill Creek Products Inc.	Hillsborough	362.8	3,097.7	49.0	6.0	980.0	No
	Stauffer Chemical Company	Hillsborough	365.3	3,093.6	44.5	9.0	890.0	No
	R V Shulnburg	Hillsborough	362.5	3,097.3	49.0	6.0	980.0	No
	Verlite Co	Hillsborough	363.0	3,098.1	49.1	64.0	982.0	No
	Hillsborough Co. Animal Control Center	Hillsborough	364.9	3,093.5	44.8	16.0	896.0	No
	MacDill AFB	Hillsborough	355.0	3,080.6	48.0	2.0	960.0	No
	S I Lime Co Division of Longview Lime	Hillsborough	362.9	3,084.7	42.0	48.0	840.0	No
	Tampa Bay Crematory	Hillsborough	372.9	3,090.7	36.8	10.0	736.0	No
	Humana Hospital	Hillsborough	373.3	3,093.4	38.3	4.0	766.0	No
	Griffin Industries	Hillsborough	364.1	3,096.4	47.2	4.0	944.0	No
	Treasure Isle Inc.	Hillsborough	378.0	3,096.9	37.7	11.0	754.0	No
	Speedling, Inc.	Hillsborough	354.1	3,062.2	47.1	19.0	942.0	No
	Cast–Crete Corp of Florida	Hillsborough	371.9	3,099.2	43.4	11.0	868.0	No
	Hydro Conduit Corp	Hillsborough	363.8	3,093.5	45.7	2.0	914.0	No
	Rinker Materials Corporation	Hillsborough	363.2	3,098.1	48.9	22.0	978.0	No
	Garrison Stevedoring	Hillsborough	357.8	3,091.7	49.8	182.0	996.0	No
	South Bay Hospital	Hillsborough	365.3	3,065.1	35.8	18.0	716.0	No
	Southern Culvert	Hillsborough	391.5	3,095.0	29.6	17.0	592.0	No

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi– fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Comco of America	Hillsborough	361.4	3,086.9	44.3	9.0	886.0	No
	Couch Construction Co	Hillsborough	364.3	3,098.1	48.1	45.0	962.0	No
	Reed Minerals Division	Hillsborough	362.2	3,085.5	43.0	70.0	860.0	No
	General Chemical Corp	Hillsborough	359.9	3,092.3	48.3	30.0	966.0	No
	Florida Brick & Clay Co	Hillsborough	384.9	3,097.1	34.1	26.0	682.0	No
	Consolidated Minerals Inc	Hillsborough	393.8	3,096.3	30.2	1.0	604.0	No
	Florida Precast Concrete	Hillsborough	360.4	3,094.2	48.9	132.0	978.0	No
	Glen–Mar Concrete Products	Hillsborough	363.2	3,093.3	46.0	22.0	920.0	No
	Ewell Industries	Hillsborough	367.0	3,092.8	42.7	13.0	854.0	No
	Rinker Materials Corp	Hillsborough	364.9	3,084.4	40.1	8.0	802.0	No
	Bay Concrete	Hillsborough	365.0	3,084.0	39.8	3.0	796.0	No
	Florida Rock Industries	Hillsborough	363.9	3,093.5	45.6	8.0	912.0	No
	Alumax Extrusions	Hillsborough	385.6	3,097.0	33.7	172.0	674.0	No
	Holman Inc.	Hillsborough	359.3	3,087.1	46.3	54.0	926.0	No
	Lehigh Portland Cement Comp Pt Sutton	Hillsborough	360.7	3,086.8	44.9	15.0	898.0	No
	R C Martin Concrete Products	Hillsborough	368.6	3,092.1	41.0	28.0	820.0	No
	Gaylord Container Corp	Hillsborough	366.3	3,092.3	42.9	108.0	858.0	No
	Hillsborough Co Resource Recovery	Hillsborough	368.2	3,092.7	41.7	172.0	834.0	No
	The Gibson–Homans	Hillsborough	365.5	3,094.8	45.1	21.0	902.0	No
	Lehigh Portland Cement Co Port Sutton	Hillsborough	360.7	3,086.8	44.9	18.0	898.0	No
	R & L Metals	Hillsborough	363.6	3,093.0	45.5	5.0	910.0	No
	Florida Rock Industry	Hillsborough	365.8	3,085.0	39.5	21.0	790.0	No
	Ewell Industries	Hillsborough	367.1	3,092.7	42.5	19.0	850.0	No
	Driggers Concrete	Hillsborough	360.0	3,065.9	41.0	21.0	820.0	No
	Florida Crushed Stone	Hillsborough	358.9	3,088.4	47.2	20.0	944.0	No
	Chevron Asphalt Inc.	Hillsborough	358.2	3,092.0	49.6	4.0	992.0	No
	Garder Asphalt Corp	Hillsborough	360.8	3,093.3	48.0	5.0	960.0	No

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Southport Stevedore	Hillsborough	358.5	3,091.8	49.2	30.0	984.0	No
	Crown Door Company	Hillsborough	362.1	3,092.5	46.5	13.0	930.0	No
	International Salt Company	Hillsborough	358.2	3,090.2	48.7	21.0	974.0	No
	Sani–Med Inc.	Hillsborough	359.6	3,079.9	43.4	16.0	868.0	No
	Lehigh Portland Cement Co	Hillsborough	361.3	3,086.9	44.4	7.0	888.0	No
	Leisey Shell Corp	Hillsborough	352.7	3,064.8	48.4	20.0	968.0	No
	Florida Petroleum	Hillsborough	360.9	3,094.0	48.3	16.0	966.0	No
	Haynes Funeral Home Plant City	Hillsborough	388.1	3,100.3	35.7	6.0	714.0	No
	Graves Enterprises Riverview	Hillsborough	363.1	3,085.3	42.1	350.0	842.0	No
	Metals & Materials Recycling	Hillsborough	386.5	3,097.4	33.7	1.0	674.0	No
	Westcon	Hillsborough	375.3	3,092.8	36.4	21.0	728.0	No
	Zipperer S. Agape Mortuary Services	Hillsborough	363.0	3,064.7	38.1	21.0	762.0	No
	Hillsborough Animal Control Center	Hillsborough	368.5	3,092.7	41.4	11.0	828.0	No
	Commercial Metals Inc	Hillsborough	358.5	3,088.3	47.5	108.0	950.0	No
	Chapman Contracting	Hillsborough	356.8	3,068.4	44.2	4.0	884.0	No
	Manna Pro Corporation	Hillsborough	364.7	3,092.6	44.4	16.0	888.0	No
	Palm Harbor Homes	Hillsborough	391.8	3,101.5	35.7	22.0	714.0	No
	Universal Waste & Transit	Hillsborough	364.9	3,093.7	44.9	7.0	898.0	No
	City Of Tampa Dept.	Hillsborough	364.0	3,089.5	43.3	48.0	866.0	No
	C–Cure of Florida	Hillsborough	386.0	3,098.7	35.1	21.0	702.0	No
	Tampa Bay Stevedores Inc	Hillsborough	358.3	3,088.6	47.9	24.0	958.0	No
	Kearney Development Company	Hillsborough	368.7	3,094.8	42.6	21.0	852.0	No
	Florida Mega–Mix	Hillsborough	364.5	3,093.4	45.0	22.0	900.0	No
	Unocal Chemical Division	Hillsborough	358.4	3,088.4	47.7	15.0	954.0	No
	Kimmins Recycling Corporation	Hillsborough	360.4	3,093.1	48.3	66.0	966.0	No
112	Florida Power & Light*	Manatee	367.2	3,054.1	36.2	40,179.0	724.0	Yes
	Manatee Scrap Processing	Manatee	366.9	3,053.8	36.6	108.0	732.0	No

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Humana Hospital	Pinellas	429.9	3,076.7	30.5	1.0	610.0	No
	Citrus World	Polk	441.0	3,087.3	44.9	601.0	898.0	No
118	Lakeland City Power Larsen Power Station*	Polk	409.3	3,102.8	36.7	107.0	734.0	No
119	Lakeland City Power McIntosh Power Station*	Polk	409.2	3,106.1	40.0	15,138.0	800.0	Yes
	Owens–Brockway Glass Container	Polk	423.4	3,102.3	41.8	189.0	836.0	No
	Florida Mining & Materials Alabama Lane	Polk	420.8	3,103.4	41.4	40.0	828.0	No
	Florida Tile	Polk	405.4	3,102.4	35.7	309.0	714.0	No
	C & M Products Co	Polk	405.5	3,079.1	12.9	162.0	258.0	No
	Allsun Products	Polk	413.5	3,093.8	29.6	318.0	592.0	No
	FMC Corp/Citrus Machinery Division	Polk	409.8	3,102.6	36.7	9.0	734.0	No
	Erly Juice Inc	Polk	399.0	3,101.8	34.9	117.0	698.0	No
	Vigoro Industries Inc.	Polk	427.9	3,097.4	40.6	136.0	812.0	No
	Citrus Hill Mfg	Polk	447.9	3,068.3	46.9	66.0	938.0	No
	Aristrech Chemical Corp	Polk	411.7	3,085.9	21.7	7.0	434.0	No
	Packaging Corp of America	Polk	423.4	3,102.8	42.2	38.0	844.0	No
	Coca Cola	Polk	421.6	3,103.7	42.1	387.0	842.0	No
	Adams Packing Association	Polk	421.7	3,104.2	42.6	144.0	852.0	No
	Gardinier	Polk	415.3	3,063.3	14.8	175.0	296.0	No
	Orange Co of Florida	Polk	418.7	3,083.6	24.3	119.0	486.0	No
121	Seminole Fertilizer (W R Grace)*	Polk	409.8	3,086.7	21.6	2,760.0	432.0	Yes
122	Mobil Mining & Minerals SR 676	Polk	398.5	3,085.1	18.3	990.0	366.0	Yes
123	Royster Company	Polk	406.8	3,085.1	19.0	1,393.0	380.0	Yes
124	US Agri–Chemicals Hwy 60	Polk	413.2	3,086.3	22.8	443.0	456.0	Yes
125	US Agri–Chemicals Hwy 630*	Polk	416.0	3,069.0	15.1	1,071.0	302.0	Yes
126	C F Industries Bonnie Mine Rd*	Polk	408.4	3,082.4	17.1	1,319.0	342.0	Yes
127	Farmland Industries Green Bay Plant*	Polk	409.5	3,080.1	15.6	1,486.0	312.0	Yes
128	Agrico Chemical Co Pierce*	Polk	403.7	3,079.0	12.3	840.0	246.0	Yes

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi–fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
129	Agrico Chemical Co South Pierce*	Polk	407.5	3,071.5	7.9	1,096.0	158.0	Yes
	IMC Fertilizer Prairie	Polk	402.9	3,087.0	20.1	288.0	402.0	No
130	Conserv Inc.*	Polk	398.7	3,084.2	17.4	1,598.0	348.0	Yes
131	IMC Fertilizer New Wales	Polk	396.7	3,079.4	13.1	1,430.0	262.0	Yes
132	Mobil–Electrophos Division*	Polk	405.6	3,079.4	13.2	544.0	264.0	Yes
	Florida Rock Industries	Polk	416.8	3,085.8	24.6	57.0	492.0	No
	Kaplan Industries	Polk	418.3	3,079.3	21.2	53.0	424.0	No
	Kaiser Aluminum	Polk	408.3	3,085.5	19.9	106.0	398.0	No
	Eger Concrete Lake Ida & 5th St	Polk	428.1	3,102.0	44.3	49.0	886.0	No
	Eger Concrete Eastside Dr N	Polk	410.5	3,102.5	36.7	11.0	734.0	No
	Pavers Incorporated	Polk	414.0	3,098.2	33.8	479.0	676.0	No
	Rinker Cencon Corp	Polk	412.4	3,099.0	34.0	159.0	680.0	No
	International Paper Company	Polk	421.7	3,104.3	42.7	8.0	854.0	No
133	Imperial Phosphate Ltd.	Polk	404.8	3,069.5	4.5	162.0	90.0	Yes
	Quikrete of Florida	Polk	412.8	3,099.0	34.1	253.0	682.0	No
	Macasphalt	Polk	423.1	3,101.5	41.0	70.0	820.0	No
	Bordo Citrus Product Inc	Polk	427.8	3,097.5	40.6	13.0	812.0	No
	Florida Rock Industries	Polk	428.0	3,105.2	46.8	55.0	936.0	No
	Florida Distillers Company	Polk	421.4	3,102.9	41.3	2.0	826.0	No
	Schering Berlin Polymers	Polk	410.7	3,098.9	33.3	30.0	666.0	No
	Sun Pac Foods	Polk	422.7	3,092.6	33.6	62.0	672.0	No
	Ewell Ind Bonnie Mine Rd	Polk	407.7	3,080.9	15.4	96.0	308.0	No
	Ewell Ind S Florida Ave	Polk	406.3	3,092.9	26.4	348.0	528.0	No
	IMC Fertilizer Rainbow Division	Polk	402.3	3,085.8	18.8	88.0	376.0	No
	Triangle Pacific Corp	Polk	413.3	3,098.8	34.1	6.0	682.0	No
	The Florida Brewery	Polk	422.8	3,104.7	43.5	121.0	870.0	No
	Ridge Pallets Inc.	Polk	418.6	3,084.1	24.5	165.0	490.0	No

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi– fication Number	Facility	County	UTM East	UTM North	Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
	Monier Roof Tile	Polk	414.0	3,102.5	37.8	44.0	756.0	No
	Union Camp Corp	Polk	402.0	3,102.0	35.0	47.0	700.0	No
	Lakeland City Electric & Utilities	Polk	404.0	3,105.3	38.4	8.0	768.0	No
	John Carlos Florida	Polk	426.2	3,104.1	44.8	29.0	896.0	No
	Florida Privitization Inc	Polk	418.3	3,048.0	25.7	281.0	514.0	No
	Pavex Corp	Polk	413.0	3,086.2	22.6	44.0	452.0	No
	Ott–Laughlin	Polk	427.8	3,099.7	42.3	1.0	846.0	No
	Central Florida Hot–Mix	Polk	412.5	3,097.7	32.8	19.0	656.0	No
	Lykes Pasco Packing	Polk	412.4	3,096.5	31.6	48.0	632.0	No
	Purina Mills	Polk	402.0	3,087.0	20.0	88.0	400.0	No
	High Performance Finishers	Polk	428.0	3,096.0	39.6	12.0	792.0	No
	Laidlaw Environmental Services Inc	Polk	424.7	3,091.9	34.4	9.0	688.0	No
	Ero Industries	Polk	427.5	3,095.6	39.0	33.0	780.0	No
	Ennis Drum Service Inc	Polk	422.5	3,102.5	41.5	4.0	830.0	No
	Florida Institute of Phosphate Research	Polk	415.0	3,085.8	23.5	4.0	468.0	No
	Resource Recovery of America Inc	Polk	401.8	3,085.8	18.8	10.0	376.0	No
	Bio–Medical Service Corp of GA	Polk	413.9	3,081.3	19.3	46.0	386.0	No
	Agrico Chemical	Polk	400.0	3,061.0	6.1	84.0	122.0	No
	Ridge Pallets Inc	Polk	419.1	3,078.1	21.2	96.0	424.0	No
	Pembroke Materials Inc	Polk	420.4	3,075.2	21.1	12.0	422.0	No
	Hull Materials, Inc.	Polk	399.4	3,070.6	3.9	13.0	78.0	No
134	Auburndale Cogeneration*	Polk	420.	3,103.3	41.3	161.0	826.0	Yes
137	Ridge Cogeneration*	Polk	416.	3,100.4	36.9	414.0	738.0	No
170	LaFarge Corp	Hillsborough	357.7	3,090.6	49.3	1,221.0	986.0	Yes
171	Estech–Duette Phosphate Mine	Manatee	388.9	3,047.2	23.2	750.0	464.0	Yes
164	Estech	Polk	411.5	3,074.2	12.7	311.0	254.0	Yes
173	IMC Noralyn Mine*	Polk	414.7	3,080.3	19.1	1,689.0	382.0	Yes

Table 6–6. Summary of All PM Emitting Facilities Within 50 km

Identi- fication Number	Facility	County	UTM		Distance from Site (km)	PM (tpy)	20 x D	Include in AAQS Modeling
			East	North				
174	IMC Kingsford	Polk	398.2	3,075.7	9.1	422.0	182.0	Yes
176	IMC/Uranium Recovery C F Industries*	Polk	408.4	3,082.8	17.4	1,071.0	348.0	Yes

*Included in PSD emission inventory

Sources: FDER, 1991b, 1992b.
Koogler, 1992.
ECT, 1992.

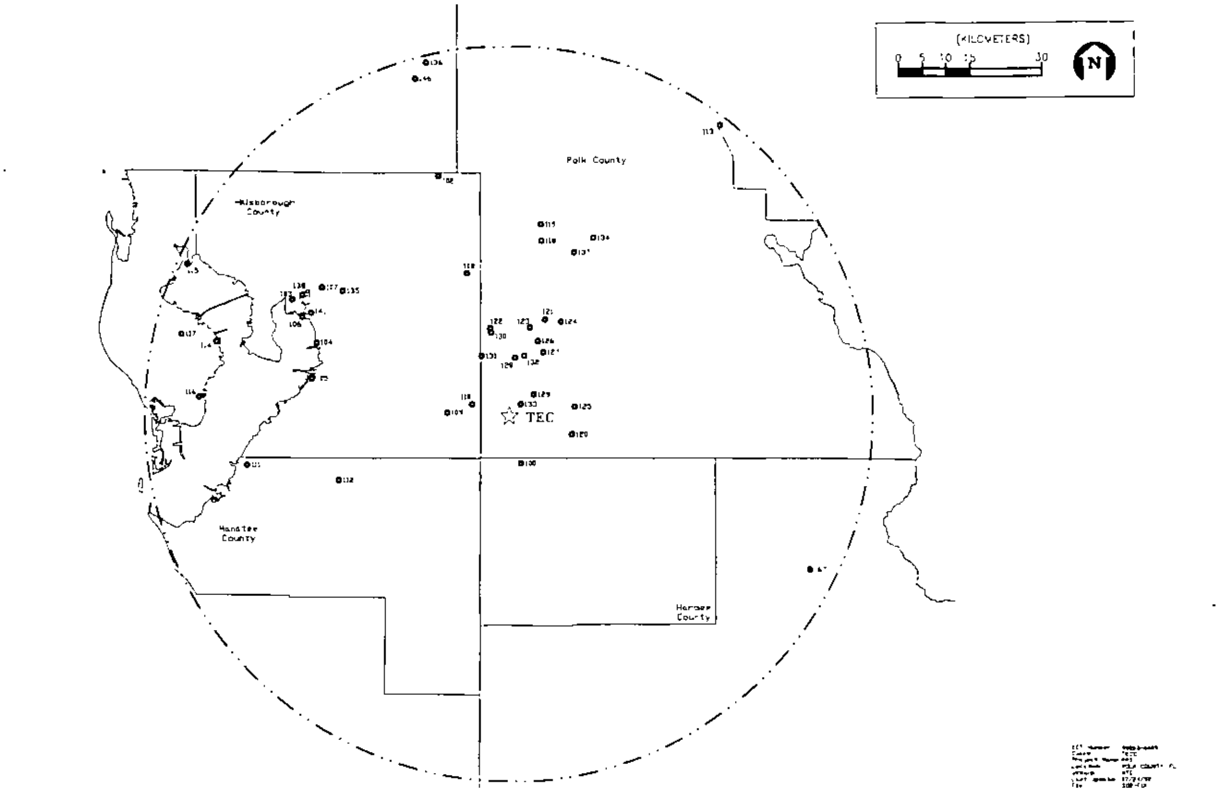


FIGURE 6-4.

LOCATIONS OF SO$_2$ SOURCES WITHIN 75 KM RADIUS

Source: ECT, 1992

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK
POWER
STATION

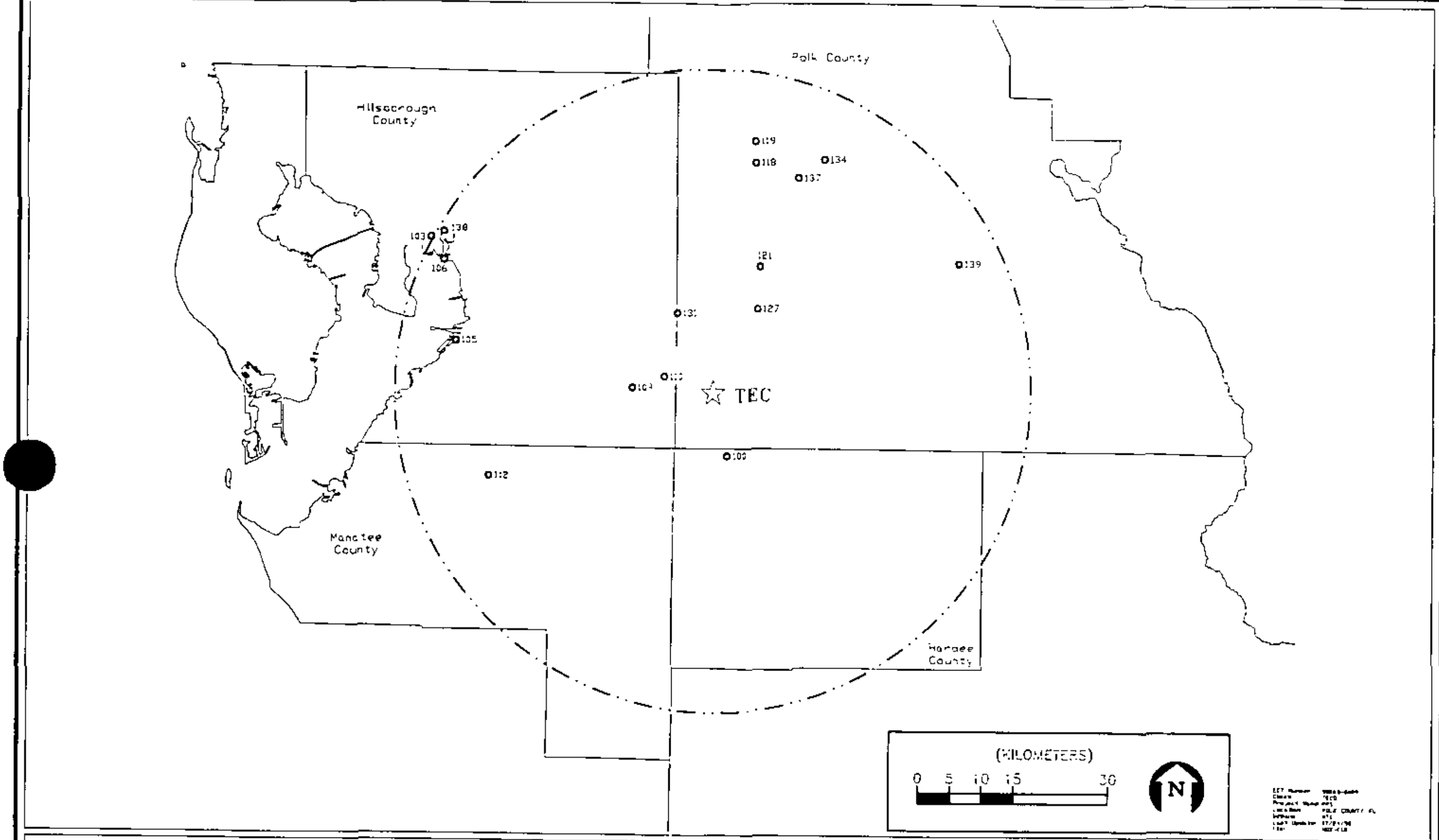


FIGURE 6-5.

LOCATIONS OF NOx SOURCES WITHIN 50 KM RADIUS

Source: ECT, 1992

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK
POWER
STATION

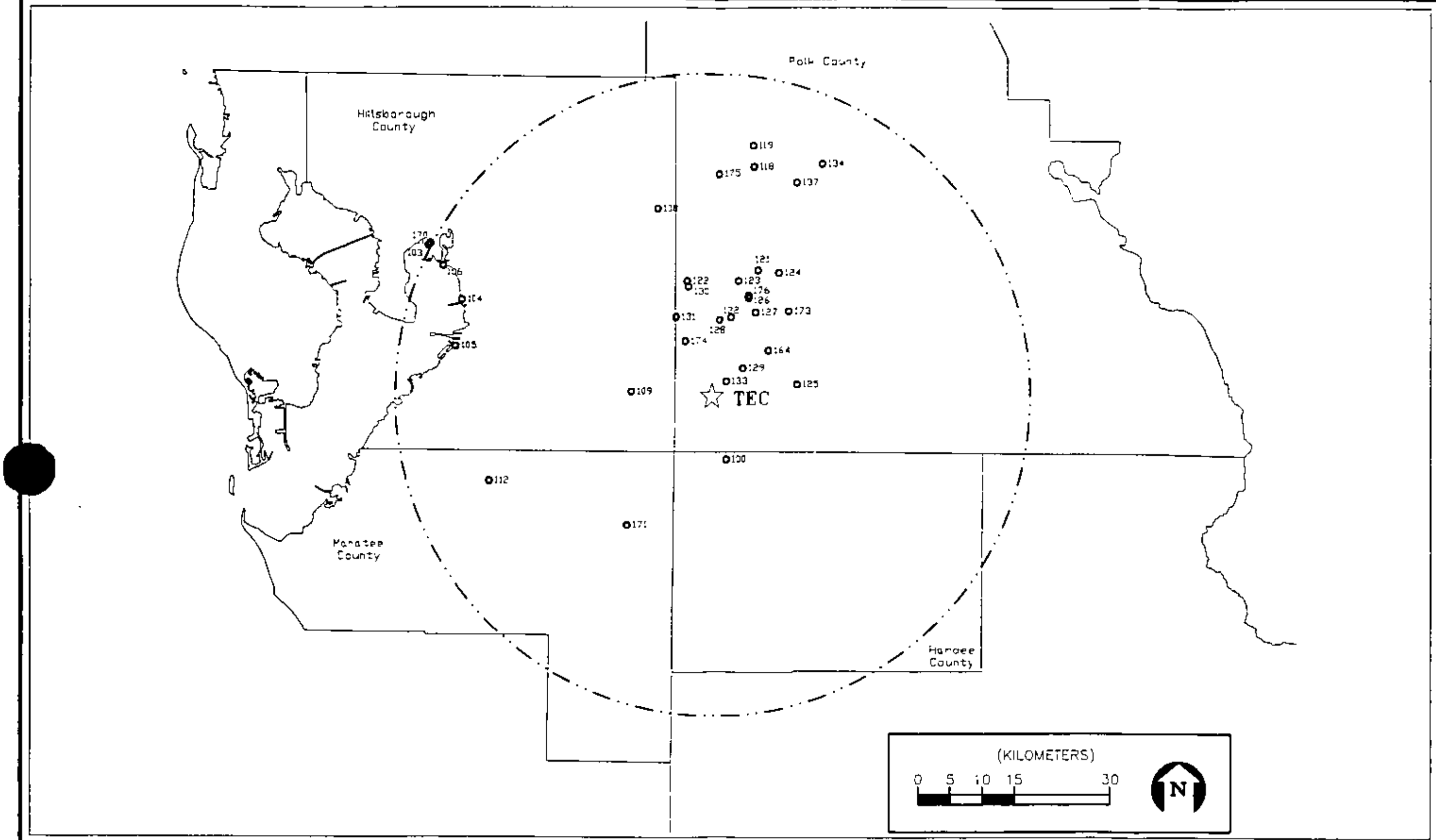


FIGURE 6-6.

LOCATIONS OF PM SOURCES WITHIN 50 KM RADIUS

Source: ECT, 1992

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK
POWER
STATION

The PSD Class I inventory for SO_2 was obtained from FDER staff. This inventory was updated by Koogler and Associates following a detailed inspection of the FDER inventory files in the FDER office in Tampa and the FDER pending permit files in Tallahassee. FDER staff indicated that the inventory updates were appropriate and acceptable. The complete Class I inventory for SO_2 is provided in Appendix B.2.

The PSD Class II inventory for SO_2 was developed as a subset of the PSD Class I inventory. The Class II inventory included all Class I sources within 75 km of the Polk Power Station. The complete Class II inventory for SO_2 is provided in Appendix B.3.

The inventory of NO_x emission sources for use in the AAQS analysis is provided in Appendix B.4. This inventory was derived from APIS information and was updated similar to the SO_2 AAQS inventory.

The PSD Class I inventory for NO_x was obtained from FDER staff. This inventory was updated and finalized based on telephone conversations with FDER staff. The complete Class I inventory for NO_x is provided in Appendix B.5.

The PSD Class II inventory for NO_x was derived as a subset of the PSD Class I inventory. The Class II inventory included all Class I sources within 50 km of the Polk Power Station. The complete Class II inventory for NO_x is provided in Appendix B.6.

The PM emissions inventory for the AAQS analysis is presented in Appendix B.7. As were the SO_2 and NO_x inventories, this inventory was updated from APIS information.

The PSD Class I inventory for PM was obtained from FDER staff and updated based on telephone conversations. The complete Class I inventory for PM is provided in Appendix B.8.

The PSD Class II inventory for PM was obtained from FDER staff and updated based on telephone conversations. The complete Class II inventory for PM is provided in Appendix B.9.

7.0 RESULTS OF SOURCE IMPACT ANALYSES AND AIR TOXICS ASSESSMENTS

7.1 SCREENING ANALYSES

The SCREEN model was used to determine the worst-case operating configurations to be carried forward to the refined modeling. The 7F CT was analyzed in the CC mode, consistent with the demonstration (i.e., IGCC only) and full buildout phases of project development. The 7F CT was screened over the range of representative load conditions (i.e., 100, 75, and 50 percent) and ambient temperatures (i.e., 20, 59, and 90°F). The fuels considered were oil, syngas with 100 percent CGCU, and syngas with 50 percent HGCU and 50 percent CGCU. For each SCREEN model run, a standard emission rate of 10 grams per second (g/sec) was used. The maximum 1-hour screening impact for each scenario was then derived by scaling to the appropriate emission rate. Screening analyses were conducted for SO_2, NO_x, PM, and CO.

The results of the screening analyses for the 7F CT are presented in Tables 7-1 through 7-4. For SO_2, Table 7-1 shows that the maximum SO_2 impact was found with the 7F CT firing syngas with 50/50 CGCU/HGCU, and 75 percent load, and with stack parameters consistent with the 90°F ambient temperature scenario. As shown in Tables 7-2 and 7-3, respectively, the same configuration produced the highest NO_x and PM impacts. For CO, the higher emissions firing oil at 50 percent load and 90°F ambient produced the highest 1-hour impact, as shown in Table 7-4.

Tables 7-5 through 7-8 summarize the screening results for the stand-alone CTs in CC and simple-cycle modes. Given the close similarity of stack parameters for natural gas and oil, and the greater emissions of all criteria pollutants firing oil, the oil-fired configurations would be expected to produce the highest impacts. Therefore, natural gas was not considered in the screening analysis.

Table 7-1. SCREEN Model Inputs and Results: 7F CT, SO2

							Sulfur Dioxide		
Mode	Fuel	Down-Wash	Load (%)	Ambient Temper-ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	18.48	11.60	1.16	21.44
CC	Oil	Yes	100	59	10	19.59	10.72	1.07	21.00
CC	Oil	Yes	100	90	10	21.56	9.84	0.98	21.22
CC	Oil	Yes	75	20	10	20.69	9.46	0.95	19.57
CC	Oil	Yes	75	59	10	24.56	8.83	0.88	21.69
CC	Oil	Yes	75	90	10	29.47	8.20	0.82	24.17
CC	Oil	Yes	50	20	10	20.89	7.06	0.71	14.75
CC	Oil	Yes	50	59	10	27.31	6.56	0.66	17.92
CC	Oil	Yes	50	90	10	34.23	6.18	0.62	21.15
CC	CG-CGCU	Yes	100	20	10	19.25	65.07	6.51	125.26
CC	CG-CGCU	Yes	100	59	10	21.24	65.32	6.53	138.74
CC	CG-CGCU	Yes	100	90	10	22.10	62.55	6.26	138.24
CC	CG-CGCU	Yes	75	20	10	21.55	51.07	5.11	110.06
CC	CG-CGCU	Yes	75	59	10	22.94	50.82	5.08	116.58
CC	CG-CGCU	Yes	75	90	10	28.43	49.68	4.97	141.24
CC	CG-CGCU	Yes	50	20	10	30.01	39.09	3.91	117.31
CC	CG-CGCU	Yes	50	59	10	32.60	38.46	3.85	125.38
CC	CG-CGCU	Yes	50	90	10	37.46	37.07	3.71	138.86
CC	CG-50/50	Yes	100	20	10	19.24	65.07	6.51	125.19
CC	CG-50/50	Yes	100	59	10	21.20	65.32	6.53	138.48
CC	CG-50/50	Yes	100	90	10	22.25	62.55	6.26	139.17
CC	CG-50/50	Yes	75	20	10	20.91	51.07	5.11	106.79
CC	CG-50/50	Yes	75	59	10	23.43	50.82	5.08	119.07
CC	CG-50/50	Yes	75	90	10	32.16	49.68	4.97	159.77
CC	CG-50/50	Yes	50	20	10	27.50	39.09	3.91	107.50
CC	CG-50/50	Yes	50	59	10	31.64	38.46	3.85	121.69
CC	CG-50/50	Yes	50	90	10	38.24	37.07	3.71	141.76

Source: ECT, 1992.

Table 7-2. SCREEN Model Inputs and Results: 7F CT, NOx

Mode	Fuel	Down-Wash	Load (%)	Ambient Temper-ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Nitrogen Oxides		
							Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	18.48	39.22	3.92	72.48
CC	Oil	Yes	100	59	10	19.59	36.32	3.63	71.15
CC	Oil	Yes	100	90	10	21.56	33.29	3.33	71.77
CC	Oil	Yes	75	20	10	20.69	32.03	3.20	66.27
CC	Oil	Yes	75	59	10	24.56	29.89	2.99	73.41
CC	Oil	Yes	75	90	10	29.47	27.87	2.79	82.13
CC	Oil	Yes	50	20	10	20.89	23.71	2.37	49.53
CC	Oil	Yes	50	59	10	27.31	22.32	2.23	60.96
CC	Oil	Yes	50	90	10	34.23	20.81	2.08	71.23
CC	CG-CGCU	Yes	100	20	10	19.25	26.10	2.61	50.24
CC	CG-CGCU	Yes	100	59	10	21.24	26.86	2.69	57.05
CC	CG-CGCU	Yes	100	90	10	22.10	28.12	2.81	62.15
CC	CG-CGCU	Yes	75	20	10	21.55	20.55	2.06	44.29
CC	CG-CGCU	Yes	75	59	10	22.94	21.18	2.12	48.59
CC	CG-CGCU	Yes	75	90	10	28.43	23.33	2.33	66.33
CC	CG-CGCU	Yes	50	20	10	30.01	15.76	1.58	47.30
CC	CG-CGCU	Yes	50	59	10	32.60	16.01	1.60	52.19
CC	CG-CGCU	Yes	50	90	10	37.46	16.65	1.66	62.37
CC	CG-50/50	Yes	100	20	10	19.24	83.73	8.37	161.10
CC	CG-50/50	Yes	100	59	10	21.20	83.23	8.32	176.45
CC	CG-50/50	Yes	100	90	10	22.25	79.82	7.98	177.60
CC	CG-50/50	Yes	75	20	10	20.91	65.95	6.60	137.90
CC	CG-50/50	Yes	75	59	10	23.43	65.45	6.55	153.35
CC	CG-50/50	Yes	75	90	10	32.16	62.80	6.28	201.96
CC	CG-50/50	Yes	50	20	10	27.50	50.57	5.06	139.07
CC	CG-50/50	Yes	50	59	10	31.64	49.68	4.97	157.19
CC	CG-50/50	Yes	50	90	10	38.24	47.16	4.72	180.34

Source: ECT, 1992.

Table 7-3. SCREEN Model Inputs and Results: 7F CT, PM

Mode	Fuel	Down-Wash	Load (%)	Ambient Temper-ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Particulate Matter Emission Rate (g/sec)	Particulate Matter Emission Rate Ratio	Particulate Matter Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	18.48	3.40	0.34	6.28
CC	Oil	Yes	100	59	10	19.59	3.28	0.33	6.43
CC	Oil	Yes	100	90	10	21.56	3.15	0.32	6.79
CC	Oil	Yes	75	20	10	20.69	3.15	0.32	6.52
CC	Oil	Yes	75	59	10	24.56	3.03	0.30	7.44
CC	Oil	Yes	75	90	10	29.47	3.03	0.30	8.93
CC	Oil	Yes	50	20	10	20.89	2.90	0.29	6.06
CC	Oil	Yes	50	59	10	27.31	2.90	0.29	7.92
CC	Oil	Yes	50	90	10	34.23	2.77	0.28	9.48
CC	CG-CGCU	Yes	100	20	10	19.25	9.08	0.91	17.48
CC	CG-CGCU	Yes	100	59	10	21.24	9.08	0.91	19.29
CC	CG-CGCU	Yes	100	90	10	22.10	8.83	0.88	19.51
CC	CG-CGCU	Yes	75	20	10	21.55	7.57	0.76	16.31
CC	CG-CGCU	Yes	75	59	10	22.94	7.57	0.76	17.37
CC	CG-CGCU	Yes	75	90	10	28.43	7.44	0.74	21.15
CC	CG-CGCU	Yes	50	20	10	30.01	6.31	0.63	18.94
CC	CG-CGCU	Yes	50	59	10	32.60	6.31	0.63	20.57
CC	CG-CGCU	Yes	50	90	10	37.46	6.05	0.61	22.66
CC	CG-50/50	Yes	100	20	10	19.24	9.08	0.91	17.47
CC	CG-50/50	Yes	100	59	10	21.20	9.08	0.91	19.25
CC	CG-50/50	Yes	100	90	10	22.25	8.83	0.88	19.65
CC	CG-50/50	Yes	75	20	10	20.91	7.57	0.76	15.83
CC	CG-50/50	Yes	75	59	10	23.43	7.57	0.76	17.74
CC	CG-50/50	Yes	75	90	10	32.16	7.44	0.74	23.93
CC	CG-50/50	Yes	50	20	10	27.50	6.31	0.63	17.35
CC	CG-50/50	Yes	50	59	10	31.64	6.31	0.63	19.96
CC	CG-50/50	Yes	50	90	10	38.24	6.05	0.61	23.14

Source: ECT, 1992.

Table 7-4. SCREEN Model Inputs and Results: 7F CT, CO

Mode	Fuel	Down-Wash	Load (%)	Ambient Temper-ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Carbon Monoxide Emission Rate (g/sec)	Carbon Monoxide Emission Rate Ratio	Carbon Monoxide Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	18.48	10.47	1.05	19.35
CC	Oil	Yes	100	59	10	19.59	9.71	0.97	19.02
CC	Oil	Yes	100	90	10	21.56	8.95	0.89	19.30
CC	Oil	Yes	75	20	10	20.69	7.69	0.77	15.91
CC	Oil	Yes	75	59	10	24.56	7.31	0.73	17.95
CC	Oil	Yes	75	90	10	29.47	7.06	0.71	20.81
CC	Oil	Yes	50	20	10	20.89	12.48	1.25	26.07
CC	Oil	Yes	50	59	10	27.31	11.73	1.17	32.03
CC	Oil	Yes	50	90	10	34.23	11.10	1.11	38.00
CC	CG-CGCU	Yes	100	20	10	19.25	12.36	1.24	23.79
CC	CG-CGCU	Yes	100	59	10	21.24	10.97	1.10	23.30
CC	CG-CGCU	Yes	100	90	10	22.10	10.34	1.03	22.85
CC	CG-CGCU	Yes	75	20	10	21.55	10.09	1.01	21.74
CC	CG-CGCU	Yes	75	59	10	22.94	9.46	0.95	21.70
CC	CG-CGCU	Yes	75	90	10	28.43	8.95	0.89	25.44
CC	CG-CGCU	Yes	50	20	10	30.01	8.83	0.88	26.50
CC	CG-CGCU	Yes	50	59	10	32.60	8.45	0.85	27.55
CC	CG-CGCU	Yes	50	90	10	37.46	8.20	0.82	30.72
CC	CG-50/50	Yes	100	20	10	19.24	12.48	1.25	24.01
CC	CG-50/50	Yes	100	59	10	21.20	10.97	1.10	23.26
CC	CG-50/50	Yes	100	90	10	22.25	10.34	1.03	23.01
CC	CG-50/50	Yes	75	20	10	20.91	10.21	1.02	21.35
CC	CG-50/50	Yes	75	59	10	23.43	9.46	0.95	22.16
CC	CG-50/50	Yes	75	90	10	32.16	8.70	0.87	27.98
CC	CG-50/50	Yes	50	20	10	27.50	8.95	0.89	24.61
CC	CG-50/50	Yes	50	59	10	31.64	8.57	0.86	27.12
CC	CG-50/50	Yes	50	90	10	38.24	8.07	0.81	30.86

Source: ECT, 1992.

Table 7-5. SCREEN Model Inputs and Results: Stand-Alone CT, SO2

Mode	Fuel	Down-Wash	Load (%)	Ambient Temperature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Sulfur Dioxide		
							Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	104.60	6.68	0.67	69.87
CC	Oil	Yes	100	59	10	116.90	6.05	0.61	70.72
CC	Oil	Yes	100	90	10	133.00	5.42	0.54	72.09
CC	Oil	Yes	75	20	10	138.60	5.30	0.53	73.46
CC	Oil	Yes	75	59	10	156.50	4.79	0.48	74.96
CC	Oil	Yes	75	90	10	174.90	4.41	0.44	77.13
CT	Oil	Yes	100	20	10	60.70	6.68	0.67	40.55
CT	Oil	Yes	100	59	10	68.21	6.05	0.61	41.27
CT	Oil	Yes	100	90	10	76.83	5.42	0.54	41.64
CT	Oil	Yes	75	20	10	52.32	5.30	0.53	27.73
CT	Oil	Yes	75	59	10	53.20	4.79	0.48	25.48
CT	Oil	Yes	75	90	10	59.93	4.41	0.44	26.43
CT	Oil	No	100	20	10	3.46	6.68	0.67	2.31
CT	Oil	No	100	59	10	3.79	6.05	0.61	2.29
CT	Oil	No	100	90	10	3.83	5.42	0.54	2.08
CT	Oil	No	75	20	10	3.84	5.30	0.53	2.04
CT	Oil	No	75	59	10	3.88	4.79	0.48	1.86
CT	Oil	No	75	90	10	3.92	4.41	0.44	1.73

Source: ECT, 1992.

Table 7–6. SCREEN Model Inputs and Results: Stand–Alone CT, NOx

							Nitrogen Oxides		
Mode	Fuel	Down–Wash	Load (%)	Ambient Temper–ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	104.60	22.82	2.28	238.70
CC	Oil	Yes	100	59	10	116.90	20.55	2.06	240.23
CC	Oil	Yes	100	90	10	133.00	18.66	1.87	248.18
CC	Oil	Yes	75	20	10	138.60	18.28	1.83	253.36
CC	Oil	Yes	75	59	10	156.50	16.52	1.65	258.54
CC	Oil	Yes	75	90	10	174.90	15.13	1.51	264.62
CT	Oil	Yes	100	20	10	60.70	22.82	2.28	138.52
CT	Oil	Yes	100	59	10	68.21	20.55	2.06	140.17
CT	Oil	Yes	100	90	10	76.83	18.66	1.87	143.36
CT	Oil	Yes	75	20	10	52.32	18.28	1.83	95.64
CT	Oil	Yes	75	59	10	53.20	16.52	1.65	87.89
CT	Oil	Yes	75	90	10	59.93	15.13	1.51	90.67
CT	Oil	No	100	20	10	3.46	22.82	2.28	7.90
CT	Oil	No	100	59	10	3.79	20.55	2.06	7.79
CT	Oil	No	100	90	10	3.83	18.66	1.87	7.15
CT	Oil	No	75	20	10	3.84	18.28	1.83	7.02
CT	Oil	No	75	59	10	3.88	16.52	1.65	6.41
CT	Oil	No	75	90	10	3.92	15.13	1.51	5.93

Source: ECT, 1992.

Table 7-7. SCREEN Model Inputs and Results: Stand-Alone CT, PM

Mode	Fuel	Down-Wash	Load (%)	Ambient Temper-ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Particulate Matter Emission Rate (g/sec)	Particulate Matter Emission Rate Ratio	Particulate Matter Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	104.60	2.65	0.27	27.72
CC	Oil	Yes	100	59	10	116.90	2.52	0.25	29.46
CC	Oil	Yes	100	90	10	133.00	2.52	0.25	33.52
CC	Oil	Yes	75	20	10	138.60	2.52	0.25	34.93
CC	Oil	Yes	75	59	10	156.50	2.40	0.24	37.56
CC	Oil	Yes	75	90	10	174.90	2.40	0.24	41.98
CT	Oil	Yes	100	20	10	60.70	2.65	0.27	16.09
CT	Oil	Yes	100	59	10	68.21	2.52	0.25	17.19
CT	Oil	Yes	100	90	10	76.83	2.52	0.25	19.36
CT	Oil	Yes	75	20	10	52.32	2.52	0.25	13.18
CT	Oil	Yes	75	59	10	53.20	2.40	0.24	12.77
CT	Oil	Yes	75	90	10	59.93	2.40	0.24	14.38
CT	Oil	No	100	20	10	3.46	2.65	0.27	0.92
CT	Oil	No	100	59	10	3.79	2.52	0.25	0.96
CT	Oil	No	100	90	10	3.83	2.52	0.25	0.97
CT	Oil	No	75	20	10	3.84	2.52	0.25	0.97
CT	Oil	No	75	59	10	3.88	2.40	0.24	0.93
CT	Oil	No	75	90	10	3.92	2.40	0.24	0.94

Source: ECT, 1992.

Table 7-8. SCREEN Model Inputs and Results: Stand-Alone CT, CO

							Carbon Monoxide		
Mode	Fuel	Down-Wash	Load (%)	Ambient Temper-ature (deg F)	Standard Emission Rate (g/sec)	Standard Maximum Impact (ug/m3)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact (ug/m3)
CC	Oil	Yes	100	20	10	104.60	8.95	0.89	93.62
CC	Oil	Yes	100	59	10	116.90	8.20	0.82	95.86
CC	Oil	Yes	100	90	10	133.00	7.44	0.74	98.95
CC	Oil	Yes	75	20	10	138.60	6.81	0.68	94.39
CC	Oil	Yes	75	59	10	156.50	6.31	0.63	98.75
CC	Oil	Yes	75	90	10	174.90	5.93	0.59	103.72
CT	Oil	Yes	100	20	10	60.70	8.95	0.89	54.33
CT	Oil	Yes	100	59	10	68.21	8.20	0.82	55.93
CT	Oil	Yes	100	90	10	76.83	7.44	0.74	57.16
CT	Oil	Yes	75	20	10	52.32	6.81	0.68	35.63
CT	Oil	Yes	75	59	10	53.20	6.31	0.63	33.57
CT	Oil	Yes	75	90	10	59.93	5.93	0.59	35.54
CT	Oil	No	100	20	10	3.46	8.95	0.89	3.10
CT	Oil	No	100	59	10	3.79	8.20	0.82	3.11
CT	Oil	No	100	90	10	3.83	7.44	0.74	2.85
CT	Oil	No	75	20	10	3.84	6.81	0.68	2.62
CT	Oil	No	75	59	10	3.88	6.31	0.63	2.45
CT	Oil	No	75	90	10	3.92	5.93	0.59	2.32

Source: ECT, 1992.

In the CC mode, downwash was considered exclusively, since all HRSG stacks would be influenced by one or more structures (see Section 6.6). However, for the stand-alone CTs, screening runs both with and without downwash were made, since the northern-most CT (EP 6) would be affected by the HRSG enclosure from the nearby CC unit; the other five CTs would not.

The 75-percent load, 90°F ambient temperature case produced the highest screening impact for all four pollutants for the CC configuration. For the CT with downwash, the 100-percent load, 90°F case resulted in the highest impacts for all pollutants. Without downwash, the 100-percent load, 20°F case produced the highest SO_2 and NO_x impacts, while the 100-percent load, 90°F case produced the highest PM impact, and the 100-percent load, 59°F case produced the highest CO impact.

7.2 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

For the configurations shown in the screening analyses to produce the highest impacts, 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 TGTU thermal oxidizer, and the H_2SO_4 plant thermal oxidizer; for CO, fugitive sources were also included. For PM, materials handling and process vent sources were added to this list.

Table 7-9 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 7-9 shows that SO_2, NO_x, and PM impacts were found to be significant for all averaging times. CO impacts were found to be 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. Details regarding maximum impacts are provided in Tables 7-10 through 7-16. As

Table 7-9. 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	2.18	1.0
	24-hour	19.0	5.0
	3-hour	68.6	25.0
NO_x	Annual	2.26	1.0
PM	Annual	1.83	1.0
	24-hour	27.9	5.0
CO	8-hour	67.1	500
	1-hour	169.2	2,000
Lead	Quarterly	0.0014	NA*

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

Source: ECT, 1992.

Table 7-10. Summary of SO_2 Impacts Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	2.18	--	--
Location					
Distance (meters)	--	--	1,310	--	--
Radial (°)	--	--	290	--	--
24-Hour average					
Highest ($\mu g/m^3$)	15.9	17.9	18.4	19.0	15.1
Location					
Distance (meters)	2,000	2,000	1,995	2,000	1,995
Radial (°)	120	120	130	120	130
Second highest ($\mu g/m^3$)	10.3	15.5	17.0	18.1	13.1
Location					
Distance (meters)	2,000	2,000	1,995	2,000	1,995
Radial (°)	110	120	130	120	130
3-Hour average					
Highest ($\mu g/m^3$)	48.4	53.3	67.3	56.0	68.6
Location					
Distance (meters)	1,675	2,000	1,995	2,000	1,660
Radial (°)	160	140	130	120	70
Second highest ($\mu g/m^3$)	34.7	41.4	44.3	51.5	51.7
Location					
Distance (meters)	2,000	1,660	1,995	2,000	2,000
Radial (°)	140	70	130	120	120

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-11. Summary of NO_x Impacts Due to Polk Power Station Sources (Demonstration Phase)*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.69	--	--
Location					
Distance (meters)	--	--	2,500	--	--
Radial (°)	--	--	110	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-12. Summary of NO_x Impacts Due to Polk Power Station Sources (Full Buildout)*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	2.26	--	--
Location					
Distance (meters)	--	--	1,310	--	--
Radial (°)	--	--	290	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-13. Summary of PM Impacts Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	1.83	--	--
Location					
Distance (meters)	--	--	1,415	--	--
Radial (°)	--	--	280	--	--
24-Hour average					
Highest ($\mu g/m^3$)	24.9	23.0	27.9	25.0	26.6
Location					
Distance (meters)	1,415	1,600	2,000	1,415	1,415
Radial (°)	280	270	250	280	280
Second highest ($\mu g/m^3$)	21.1	19.9	21.8	21.9	23.2
Location					
Distance (meters)	1,415	1,310	2,000	2,000	1,415
Radial (°)	280	290	250	250	280

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-14. Summary of CO Impacts Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
8-Hour average					
Highest ($\mu g/m^3$)	40.6	40.4	56.1	67.1	44.2
Location					
Distance (meters)	1,750	2,000	1,995	2,000	2,000
Radial (°)	300	120	130	120	140
Second highest ($\mu g/m^3$)	35.0	35.6	44.2	63.3	39.3
Location					
Distance (meters)	1,500	1,310	1,995	2,000	1,310
Radial (°)	300	290	130	120	290
1-Hour average					
Highest ($\mu g/m^3$)	167.0	149.7	168.8	169.2	162.5
Location					
Distance (meters)	2,000	1,675	2,000	2,000	2,000
Radial (°)	120	160	120	120	120
Second highest ($\mu g/m^3$)	148.0	140.2	165.6	168.1	147.8
Location					
Distance (meters)	1,310	2,000	2,000	2,000	1,310
Radial (°)	290	110	120	120	290

* Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-15. Summary of Lead Impacts Due to Polk Power Station Sources (Demonstration Phase)*

	Winter Quarter	Spring Quarter	Summer Quarter	Fall Quarter
Annual average				
Highest ($\mu g/m^3$)	0.000033	0.000046	0.000069	0.000059
Location				
Distance (meters)	2,000	1,980	1,980	2,000
Radial (°)	230	90	90	250

* Quarterly average impacts were based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-16. Summary of Lead Impacts Due to Polk Power Station Sources (Full Buildout)*

	Winter Quarter	Spring Quarter	Summer Quarter	Fall Quarter
Annual average				
Highest ($\mu g/m^3$)	0.0010	0.0014	0.0013	0.0011
Location				
Distance (meters)	2,000	2,000	1,415	1,600
Radial (°)	140	140	280	270

* Quarterly average impacts were based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

these tables show, the maximum Polk Power Station impacts were found consistently on or close to the property boundary. Also, Tables 7-11 and 7-12 show that the highest NO_x impacts were predicted for full buildout; the higher NO_x emissions from the 7F CT anticipated during the demonstration phase, without the stand-alone CCs and CTs, were shown to cause insignificant NO_x impacts. Tables 7-15 and 7-16 support the same conclusion with respect to lead impacts.

Illustrations of SIAs are provided in Figures 7-1 through 7-6. Figures 7-1, 7-2, and 7-3, 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 km. The 24-hour SIA extended out to approximately 25 km, while the 3-hour SIA had a maximum extent of approximately 20 km. [Note that the short-term SIAs (3- and 24-hour averages) represent a composite of the 5 years of model results. The extent of SIAs for individual years was sometimes considerably less than the maximum.]

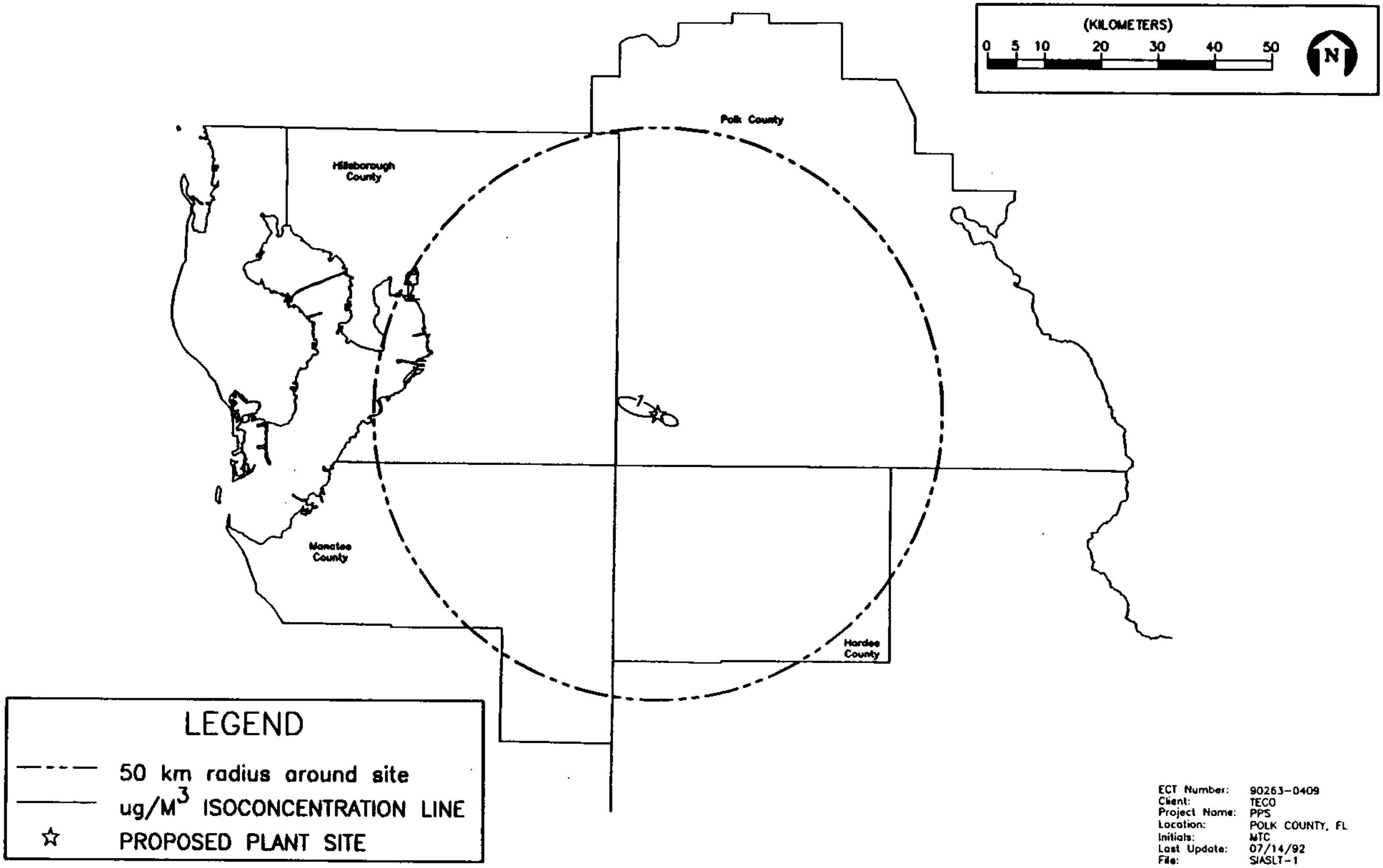
Figure 7-4 presents the annual NO_x SIA. Its maximum extent was found to be approximately 6 km from the grid origin.

Figures 7-5 and 7-6, 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.

7.3 AIR QUALITY IMPACT ANALYSES FOR AMBIENT AIR QUALITY STANDARDS

7.3.1 SULFUR DIOXIDE

Total potential SO_2 impacts within the Polk Power Station SIAs were determined for comparison with AAQS. This was accomplished by adding conservative estimates of



ECT Number: 90263-0409
Client: TECO
Project Name: PPS
Location: POLK COUNTY, FL
Initials: MTC
Last Update: 07/14/92
File: SIASLT-1

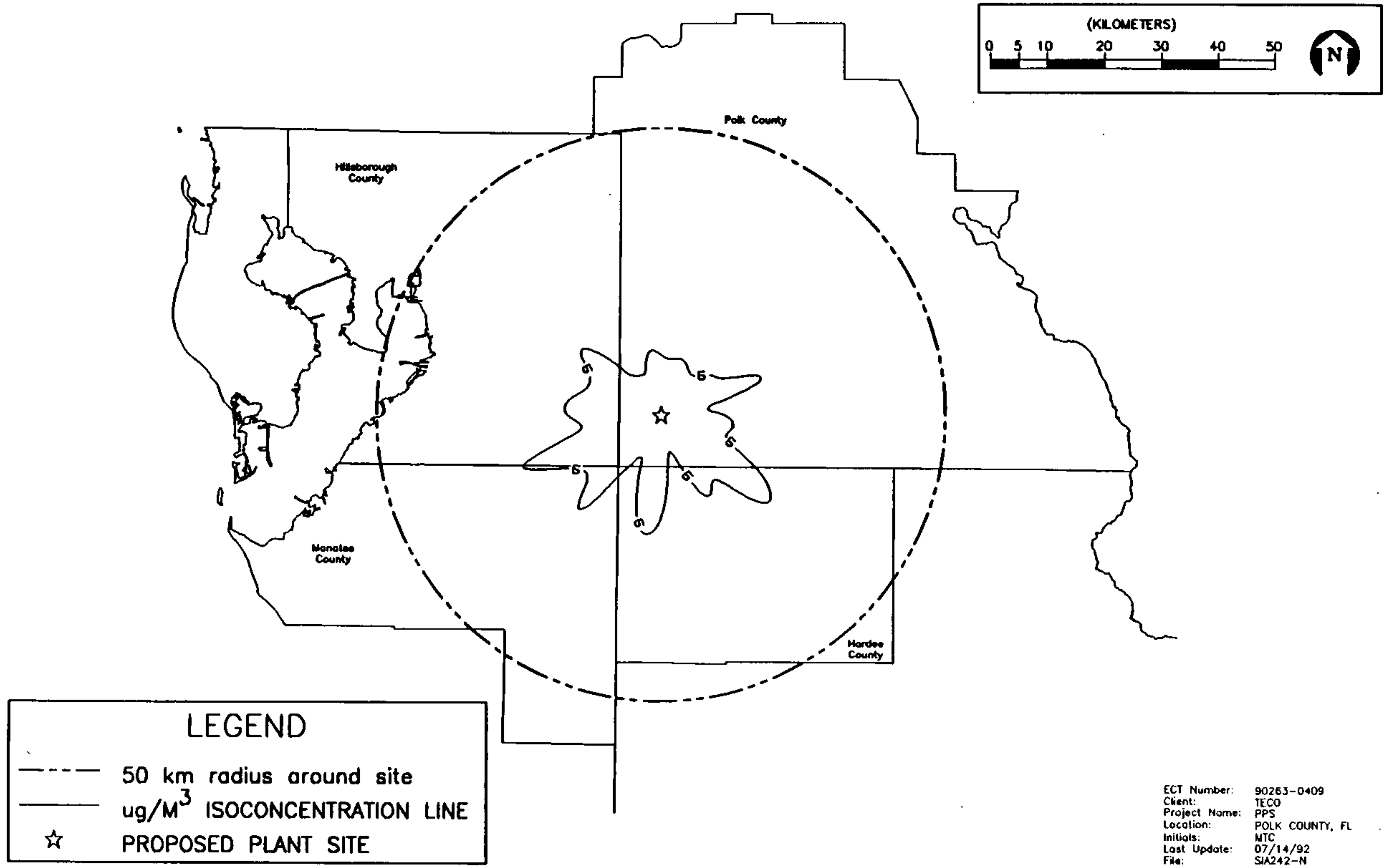
FIGURE 7-1.

ANNUAL SO_2 SIA

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION



ECT Number: 90263-0409
Client: TECO
Project Name: PPS
Location: POLK COUNTY, FL
Initials: MTC
Last Update: 07/14/92
File: SIA242-N

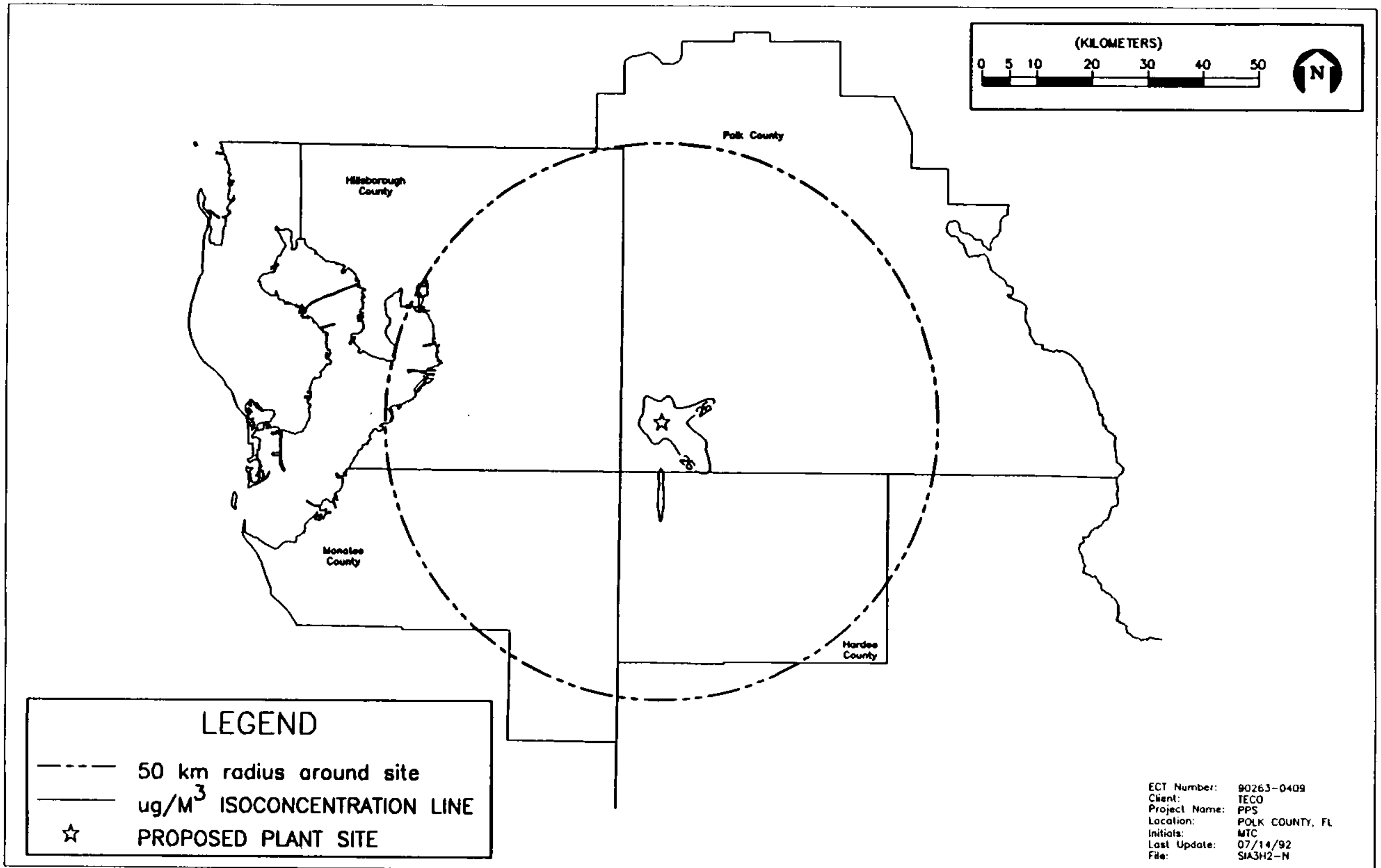
FIGURE 7-2.

24-HOUR SO_2 SIA

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION



ECT Number: 90263-0409
Client: TECO
Project Name: PPS
Location: POLK COUNTY, FL
Initials: MTC
Last Update: 07/14/92
File: SIA3H2-N

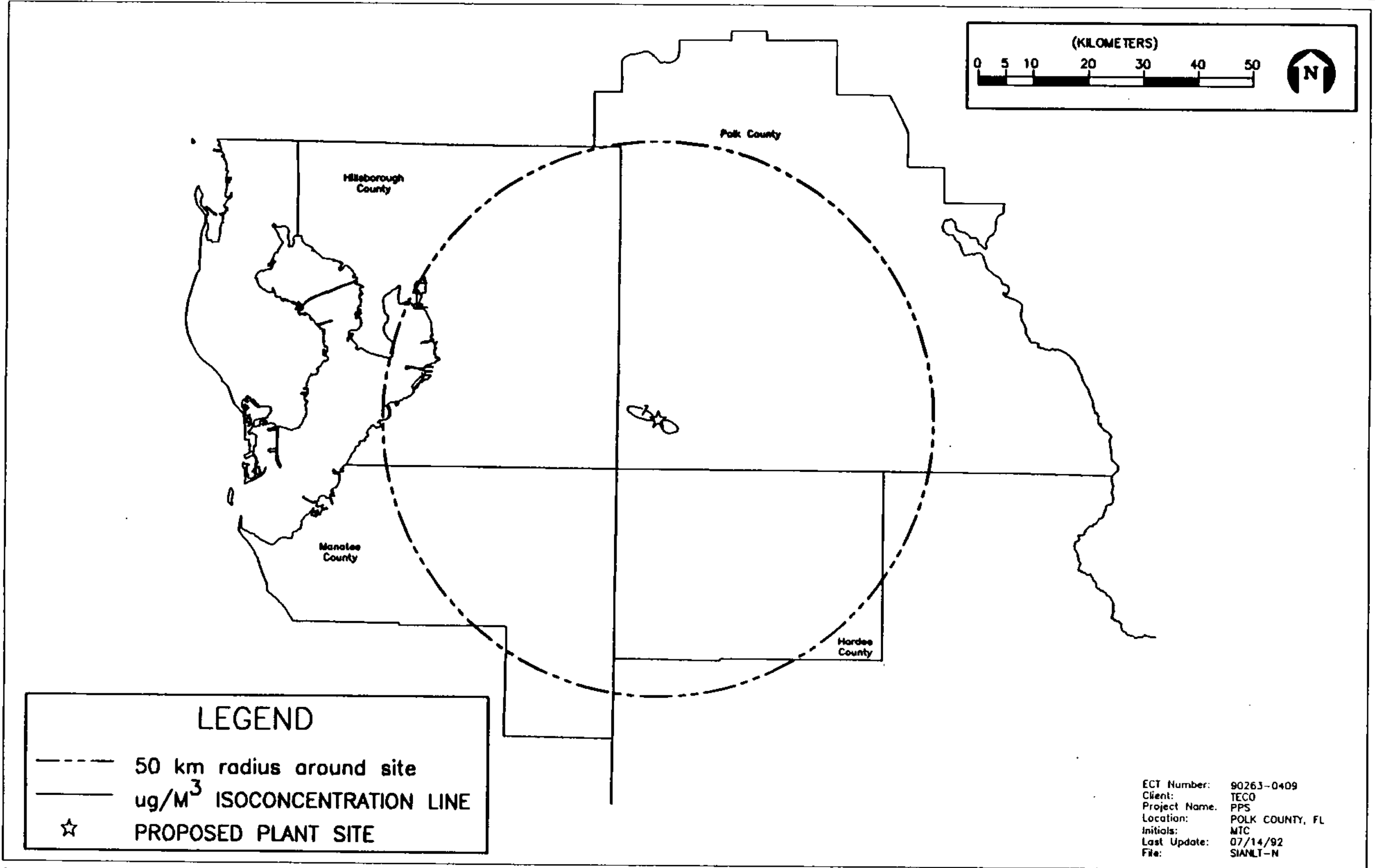
FIGURE 7-3.

3-HOUR SO_2 SIA

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION



ECT Number: 90263-0409
Client: TECO
Project Name. PPS
Location: POLK COUNTY, FL
Initials: MTC
Last Update: 07/14/92
File: SIANLT-N

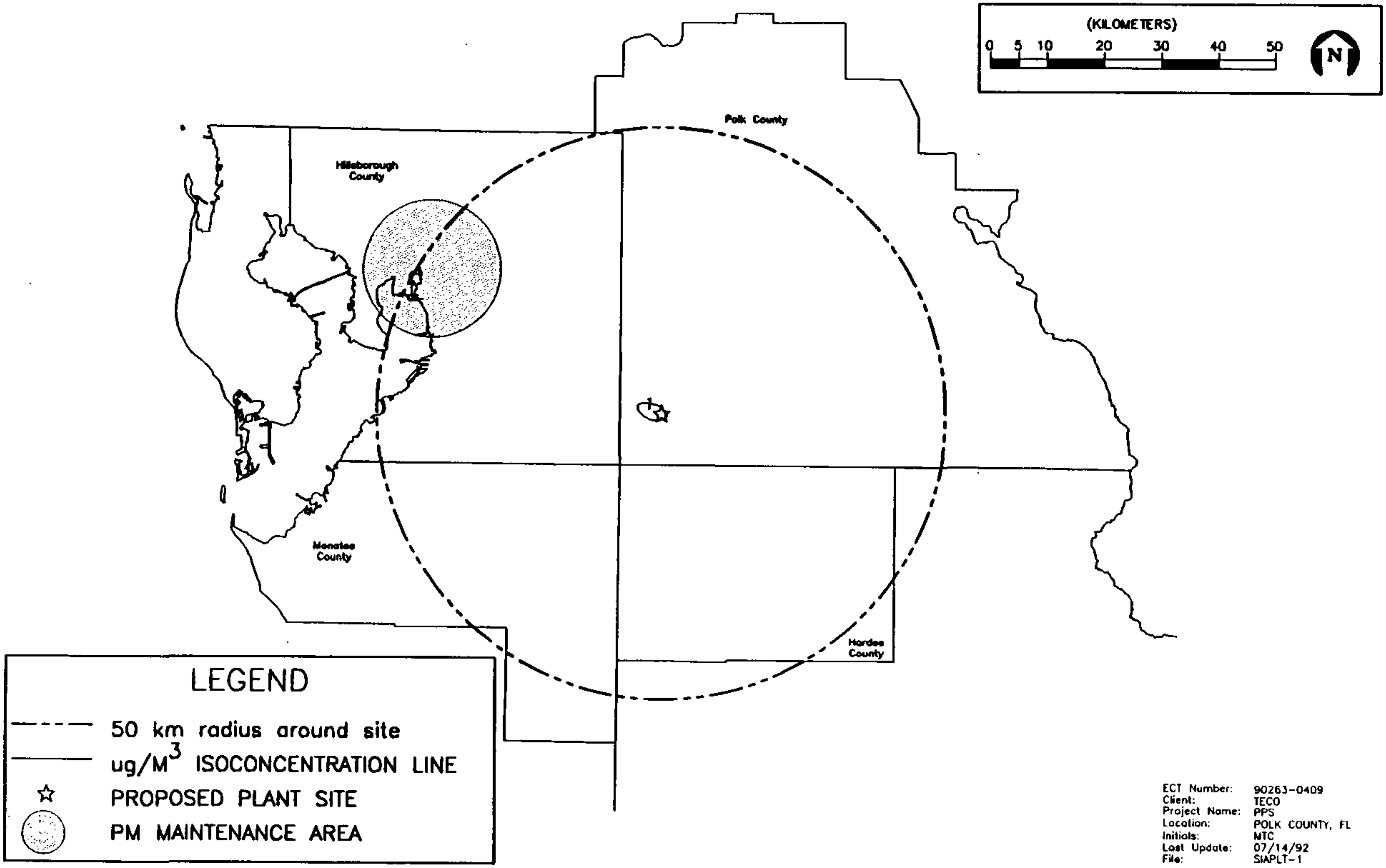
FIGURE 7-4.

ANNUAL NO_x SIA

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION



ECT Number: 90263-0409
Client: TECO
Project Name: PPS
Location: POLK COUNTY, FL
Initials: MTC
Last Update: 07/14/92
File: SIAPLT-1

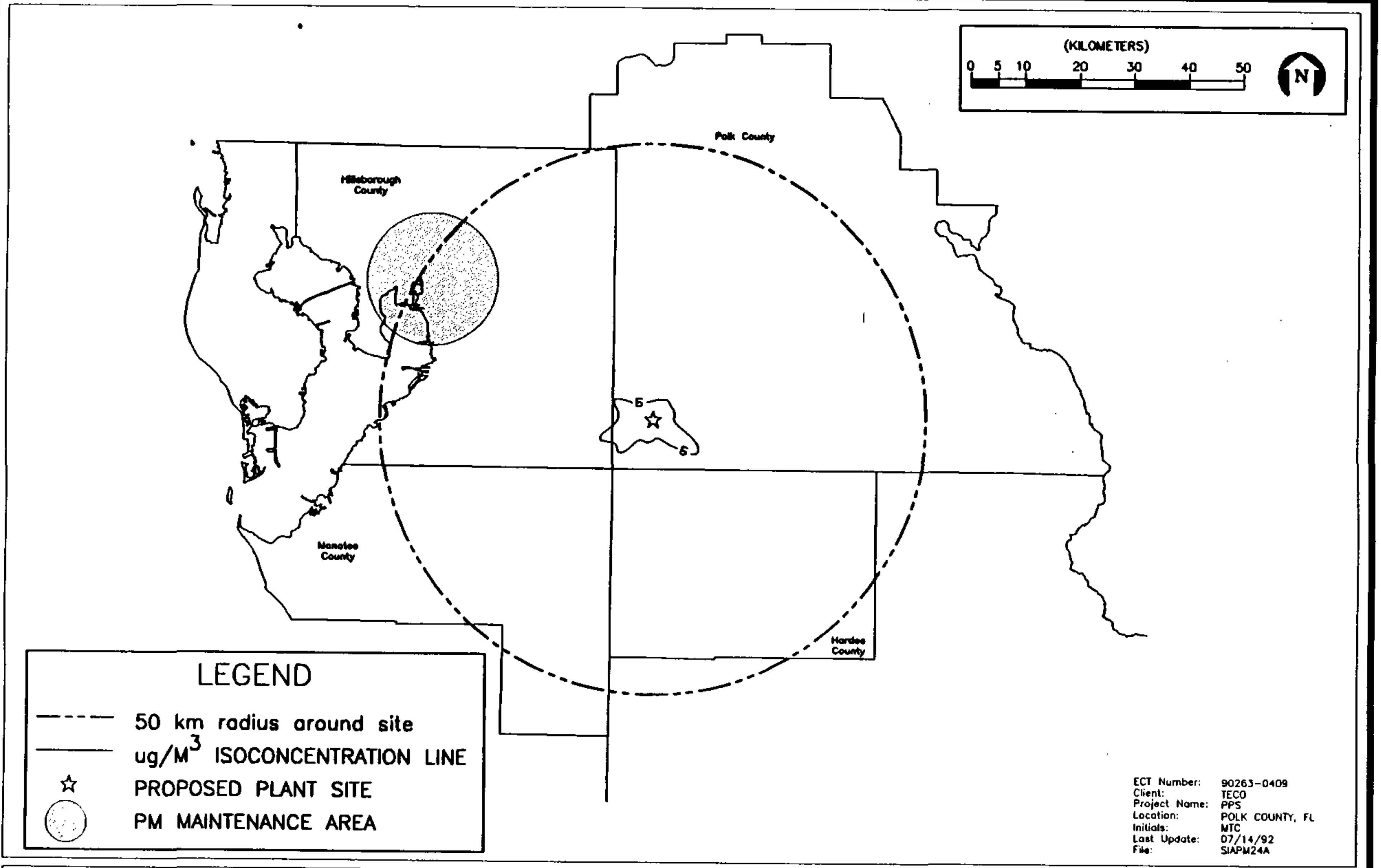
FIGURE 7-5.

ANNUAL PM SIA

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION



ECT Number: 90263-0409
Client: TECO
Project Name: PPS
Location: POLK COUNTY, FL
Initials: MTC
Last Update: 07/14/92
File: SIAPM24A

FIGURE 7-6.

24-HOUR PM SIA

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

background SO_2 concentrations (see Section 5.3.2) to modeled impacts due to Polk Power Station and other SO_2 sources in the area. Table 7-17 presents a summary of the modeling results. The maximum modeled annual impact was 41.4 $\mu g/m^3$, while the HSH 24- and 3-hour average impacts were 213.6 and 616.1 $\mu g/m^3$, respectively. Background SO_2 concentrations were estimated to be 5 $\mu g/m^3$ (annual), 13 $\mu g/m^3$ (24-hour), and 26 $\mu g/m^3$ (3-hour). When added to the modeled impacts, a total maximum potential annual SO_2 concentration of 46 $\mu g/m^3$ was predicted. This compares to the annual AAQS of 60 $\mu g/m^3$. Similarly, total maximum potential 24- and 3-hour concentrations of 227 and 642 $\mu g/m^3$, respectively, were predicted. These values compare to the respective AAQS of 260 and 1,300 $\mu g/m^3$.

Given the levels of the maximum potential SO_2 concentrations relative to the AAQS, further analysis was conducted. For the annual average, the modeling run for AAQS impacts was examined in detail with respect to the annual SIA model run for Polk Power Station. This examination revealed that the maximum modeled impact occurred at a receptor where the impact of Polk Power Station sources was only 0.35 $\mu g/m^3$ (i.e., less than significant). The maximum AAQS impact at a point of significant impact for Polk Power Station was 30.4 $\mu g/m^3$; Polk Power Station sources contributed 1.0 $\mu g/m^3$ to this total. With the background concentration added, the total maximum potential annual SO_2 concentration was determined to be 35 $\mu g/m^3$.

Additional modeling runs were made to further examine the short-term SO_2 impacts. As shown in Table 7-17, all of the modeled highest and second highest 24- and 3-hour impacts were observed at receptors centered on a location 8,000 m at 60 degrees (°) from Polk Power Station. At no other points within the modeled receptor grid were the impacts close in magnitude to these. Therefore, additional modeling runs were made with ISCST2 in this area. The initial runs were for Polk Power Station sources alone. The receptor grid extended from 6,000 to 9,000 m with 100-m ring spacing, and from 40° to 80° with 2° radial spacing. The results of these model runs were used to determine the days and periods on which Polk Power

Table 7-17. Summary of Initial Modeled SO_2 Impacts Due to All AAQS Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	41.5	--	--
Location					
Distance (meters)	--	--	6,000	--	--
Radial (°)	--	--	40	--	--
24-Hour average					
Highest ($\mu g/m^3$)	231.6	200.9	233.7	206.6	229.7
Location					
Distance (meters)	8,000	8,000	8,000	8,000	8,000
Radial (°)	60	60	60	70	60
Second highest ($\mu g/m^3$)	169.3	186.8	201.5	188.5	213.6
Location					
Distance (meters)	8,000	8,000	7,000	8,000	8,000
Radial (°)	60	60	60	60	60
3-Hour average					
Highest ($\mu g/m^3$)	575.7	684.6	765.0	683.2	727.5
Location					
Distance (meters)	8,000	5,000	8,000	7,000	7,000
Radial (°)	60	70	60	60	50
Second highest ($\mu g/m^3$)	563.1	550.3	600.4	592.3	616.1
Location					
Distance (meters)	8,000	7,000	8,000	8,000	8,000
Radial (°)	60	50	60	60	60

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Station SO_2 sources caused significant impacts. Table 7-18 identifies those days and periods.

The full set of AAQS sources was re-run with the refined grid on those days when Polk Power Station was shown to have significant 24- or 3-hour impacts. The results are summarized in Table 7-19. These results, especially the HSH impacts, were all significantly less than shown in Table 7-17. Even then, closer examination revealed that Polk Power Station sources were not contributing to the HSH values. For example, for both the HSH 24-hour impact of 162.7 $\mu g/m^3$ and the HSH 3-hour impact of 521.2 $\mu g/m^3$, Polk Power Station sources did not ever cause a significant impact at the receptors of HSH impacts. However, since the values generated by the refined analysis were less then previous and safely below the AAQS, no further analysis was conducted. Therefore, when added to background concentrations, the total maximum potential 24- and 3-hour SO_2 impacts were conservatively predicted to be 176 and 547 $\mu g/m^3$, respectively, compared to the standards of 260 and 1,300 $\mu g/m^3$.

7.3.2 NITROGEN OXIDES

An analysis similar to that for SO_2 was completed for NO_x. Table 7-20 presents the maximum modeled NO_x impact for the Polk Power Station SIA. A conservative background NO_2 concentration of 10 $\mu g/m^3$ was derived by doubling the annual average NO_2 concentration observed in 1988 at the rural Archbold research site in Highlands County (located approximately 75 km southeast of the Polk Power Station site) (Hunter/ESE, 1989). Thus, a total maximum potential NO_x impact of 16 $\mu g/m^3$ was predicted, as compared to the AAQS of 100 $\mu g/m^3$.

7.3.3 PARTICULATE MATTER (PM_{10})

Total PM_{10} impacts for comparison to the AAQS were derived in a manner similar to that used for SO_2 and NO_x. Table 7-21 presents the results of the modeling portion of the analysis. The maximum annual impact was predicted to be 11.3 $\mu g/m^3$, while the HSH 24-hour average impact was 101.6 $\mu g/m^3$. However,

Table 7-18. Days and Periods of Significant 24- and 3-Hour SO_2 Impacts, Refined Grid

Averaging Time	Year	Month	Day	Ending Hour
24-hour	1982	08	23	24
	1983	07	25	24
		08	09	24
	1984	05	04	24
		06	29	24
	1985	01	27	24
		04	15	24
		06	28	24
	1986	04	08	24
		06	30	24
		07	02	24
		07	03	24
		07	21	24
		07	30	24
3-hour	1982	06	06	21
	1983	04	23	24
		07	25	24
		07	26	03
	1984	None		
	1985	01	27	21
	1986	01	03	21
		04	08	24
		11	21	03

Source: ECT, 1992.

Table 7-19. Summary of Modeled Short-Term SO_2 Impacts Due to All AAQS Sources, Refined Grid, Selected Days and Periods*

	1982	1983	1984	1985	1986
24-Hour average					
Highest ($\mu g/m^3$)	195.6	196.0	123.8	182.2	177.7
Location					
Distance (meters)	7,000	7,300	7,600	7,600	7,100
Radial (°)	46	58	52	56	54
Second highest ($\mu g/m^3$)	63.9	162.7	95.2	118.1	154.8
Location					
Distance (meters)	7,000	7,500	7,600	7,700	7,200
Radial (°)	46	56	50	54	56
3-Hour average					
Highest ($\mu g/m^3$)	545.9	557.8	NA	551.1	595.4
Location					
Distance (meters)	7,000	7,700	--	7,600	7,500
Radial (°)	46	54	--	56	56
Second highest ($\mu g/m^3$)	388.3	440.7	NA	433.3	521.2
Location					
Distance (meters)	6,900	7,400	--	7,100	7,400
Radial (°)	46	56	--	54	56

*Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-20. Summary of Modeled NO_x Impacts Due to All AAQS Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	5.64	--	--
Location					
Distance (meters)	--	--	1,310	--	--
Radial (°)	--	--	290	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-21. Summary of Modeled PM (PM_{10}) Impacts Due to All AAQS Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest (μg/m^3)	--	--	11.3	--	--
Location					
Distance (meters)	--	--	2,000	--	--
Radial (°)	--	--	10	--	--
24-Hour average					
Highest (μg/m^3)	87.6	90.9	96.2	89.8	115.0
Location					
Distance (meters)	4,000	4,000	4,000	4,000	4,000
Radial (°)	40	70	40	40	60
Second highest (μg/m^3)	68.9	78.0	76.1	79.4	101.6
Location					
Distance (meters)	4,000	4,000	4,000	4,000	4,000
Radial (°)	40	50	40	50	60

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

closer review of the 24-hour impacts revealed that Polk Power Station did not have a significant impact at the highest and second highest concentrations for any of the 5 years. The second highest impact for 1985 (79.4 $\mu g/m^3$) was conservatively assumed to be the HSH. Background PM_{10} concentrations were estimated to be 18.4 $\mu g/m^3$ (annual) and 45.4 $\mu g/m^3$ (24-hour), as discussed in Section 5.3.3. Therefore, the total maximum potential annual PM_{10} concentration was predicted to be 30 $\mu g/m^3$, as compared to the AAQS of 50 $\mu g/m^3$. Similarly, the total maximum potential 24-hour PM_{10} impact was conservatively predicted to be 125 $\mu g/m^3$, compared to the AAQS of 150 $\mu g/m^3$.

7.3.4 SUMMARY

Table 7-22 summarizes the results of the impact analyses for AAQS. As shown, all estimates of predicted total impacts were found to be less than the AAQS. Therefore, it was concluded that development of the Polk Power Station project would not threaten compliance with any AAQS in the project vicinity.

7.4 AIR QUALITY IMPACT ANALYSES FOR PREVENTION OF SIGNIFICANT DETERIORATION CLASS II INCREMENTS

7.4.1 SULFUR DIOXIDE

A modeling analysis was carried out to determine maximum SO_2 Class II increment consumption within the Polk Power Station SIAs. The results are summarized in Table 7-23. For the annual averaging time, the predominance of increment expanding sources in the Polk Power Station vicinity resulted in negative increment consumption over the entire receptor grid. For the short-term averaging times, the highest and second highest concentrations were all much less than the allowable increments. For the 24-hour average, the HSH impact was 27.8 $\mu g/m^3$, relative to the allowable of 91 $\mu g/m^3$. For the 3-hour average, the HSH was 104.1 $\mu g/m^3$, versus the allowable of 512 $\mu g/m^3$. It was also noted that the highest short-term impacts all occurred at receptors where Polk Power Station sources were unlikely to have contributed significantly (i.e., above the modeling significance levels). However, since the reported values were well below the allowables, no further investigation was undertaken.

Table 7-22. 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	30.4	5	35	60
	24-hour	162.7*	13	176	260
	3-hour	521.2*	26	547	1,300
NO_x	Annual	5.64	10	16	100
PM (PM_{10})	Annual	11.3	18.4	30	50
	24-hour	79.4*	45.4	125	150

*HSH modeled impact.

Source: ECT, 1992.

Table 7-23. Summary of Modeled SO_2 Impacts Due to All PSD Class II Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.00†	--	--
Location					
Distance (meters)	--	--	--	--	--
Radial (°)	--	--	--	--	--
24-Hour average					
Highest ($\mu g/m^3$)	28.5	29.6	32.7	45.2	32.1
Location					
Distance (meters)	9,000	10,000	10,000	9,000	10,000
Radial (°)	230	180	200	350	190
Second highest ($\mu g/m^3$)	22.8	24.8	26.3	26.0	27.8
Location					
Distance (meters)	12,500	12,500	10,000	9,000	9,000
Radial (°)	190	190	190	350	190
3-Hour average					
Highest ($\mu g/m^3$)	145.9	113.7	128.8	120.6	119.7
Location					
Distance (meters)	10,000	6,000	10,000	9,000	10,000
Radial (°)	180	180	190	180	150
Second highest ($\mu g/m^3$)	92.0	96.0	98.7	104.1	93.7
Location					
Distance (meters)	10,000	8,000	10,000	10,000	10,000
Radial (°)	180	170	190	180	160

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

† Increment consumption was negative over the entire receptor grid.

Source: ECT, 1992.

7.4.2 NITROGEN OXIDES

The ISCLT2 model was used to calculate NO_x increment consumption in the vicinity of the Polk Power Station site. As shown in Table 7-24, the maximum concentration was 2.45 $\mu g/m^3$ at a receptor on the plant property line. This value is well below the allowable PSD Class II increment of 25 $\mu g/m^3$.

7.4.3 PARTICULATE MATTER (TOTAL SUSPENDED PARTICULATES)

Modeling of all PSD sources of PM emissions resulted in the predicted impacts summarized in Table 7-25. As shown, the maximum annual concentration was 4.78 $\mu g/m^3$, versus the allowable PSD Class II increment of 19 $\mu g/m^3$. For the 24-hour averaging time, the HSH impact was 32.3 $\mu g/m^3$, versus the allowable of 37 $\mu g/m^3$. For the annual averaging time, the maximum predicted value was well below the allowable, so no further analysis was done. Closer examination of some of the 24-hour impacts was warranted, however, given the values relative to the allowable. The highest impacts for 1983 (38.4 $\mu g/m^3$) and 1986 (39.7 $\mu g/m^3$) both occurred at receptors where the contributions of Polk Power Station sources were never significant. The HSH impact of 32.3 $\mu g/m^3$ occurred close to the facility property boundary. It was found to be contributed to significantly by Polk Power Station sources, but examination of the model output clearly showed decreasing impacts with distance from the property line. Therefore, no threat to the 24-hour increment was indicated.

7.4.4 SUMMARY

Table 7-26 presents a summary of the PSD Class II increment consumption analyses. As Table 7-26 shows, all estimates of predicted total impacts were less than the allowable Class II increments. Therefore, the development of the Polk Power Station project will not cause significant deterioration of air quality in the project vicinity.

Table 7-24. Summary of Modeled NO_x Impacts Due to All PSD Class II Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	2.45	--	--
Location					
Distance (meters)	--	--	1,310	--	--
Radial (°)	--	--	290	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-25. Summary of Model PM (TSP) Impacts Due to All PSD Class II Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	4.78	--	--
Location					
Distance (meters)	--	--	1,415	--	--
Radial (°)	--	--	280	--	--
24-Hour average					
Highest ($\mu g/m^3$)	34.3	38.4	33.6	30.5	39.7
Location					
Distance (meters)	4,000	4,000	4,000	8,000	4,000
Radial (°)	60	70	70	120	60
Second highest ($\mu g/m^3$)	26.9	27.7	28.3	26.5	32.3
Location					
Distance (meters)	2,300	4,000	2,300	4,000	2,500
Radial (°)	250	50	250	50	230

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-26. 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	27.8†	91
	3-hour	104.1†	512
NO_2	Annual	2.5	25
PM (TSP)	Annual	4.8	19
	24-hour	32.3†	37

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

Source: ECT, 1992.

7.5 AIR TOXICS ASSESSMENTS

7.5.1 NO-THREAT LEVEL ANALYSES

Maximum impacts due to Polk Power Station emission sources were determined for non-criteria pollutants using the ISC2 models. For the 7F and stand-alone CTs/CCs, source emission parameters consistent with the highest PM screening impacts were used for the analyses of non-criteria pollutant impacts. One exception was mercury, where the greater emission rate based on firing natural gas was substituted. Averaging times considered were consistent with the FDER no-threat levels.

Detailed modeling results for H_2SO_4, fluorides, mercury, beryllium, and arsenic are presented in Tables 7-27 through 7-33. For both mercury and arsenic, modeling was conducted for the demonstration phase as well as for full buildout since emissions during the demonstration phase from the 7F CT were projected to be higher. As shown, however, the impacts for the demonstration phase scenario were less than for full buildout. Table 7-34 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.

7.5.2 INHALATION CANCER RISK ASSESSMENT

Of the pollutants projected to be emitted from Polk Power Station combustion sources, 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. Risk assessment methodologies have been used by EPA to quantify air toxics impacts (Patrick, 1984; Haemisegger, 1985). The key terms in a risk assessment are:

- Unit Risk Factor (URF)--Estimated upper limit lifetime risk per unit of exposure; a URF is given in units of $(\mu g/m^3)^{-1}$.

Table 7-27. Summary of H_2SO_4 Impacts Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
24-Hour average					
Highest ($\mu g/m^3$)	1.33	1.41	1.64	1.62	1.14
Location					
Distance (meters)	2,000	2,135	1,995	2,000	1,995
Radial (°)	120	120	130	120	130
8-Hour average					
Highest ($\mu g/m^3$)	2.03	2.26	3.29	3.76	2.78
Location					
Distance (meters)	2,000	2,000	1,995	2,000	2,000
Radial (°)	140	140	130	120	140

* Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-28. Summary of Fluorides Impacts Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
1-Hour average					
Highest ($\mu g/m^3$)	0.057	0.057	0.058	0.060	0.058
Location					
Distance (meters)	1,675	1,675	2,000	2,000	2,000
Radial (°)	160	160	120	120	120

* Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-29. Summary of Mercury Impacts Due to Polk Power Station Sources (Demonstration Phase)*

	1982	1983	1984	1985	1986
24-Hour average					
Highest (μg/m^3)	0.00043	0.00043	0.00053	0.00044	0.00054
Location					
Distance (meters)	1,660	1,660	2,000	2,500	1,660
Radial (°)	70	70	130	240	70
8-Hour average					
Highest (μg/m^3)	0.00089	0.00116	0.00091	0.00090	0.00147
Location					
Distance (meters)	1,750	1,660	2,135	1,660	1,660
Radial (°)	360	70	120	70	70

* Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-30. Summary of Mercury Impacts Due to Polk Power Station Sources (Full Buildout)*

	1982	1983	1984	1985	1986
24-Hour average					
Highest ($\mu g/m^3$)	0.0034	0.0038	0.0048	0.0045	0.0035
Location					
Distance (meters)	2,000	2,000	1,995	2,000	1,995
Radial (°)	120	120	130	120	130
8-Hour average					
Highest ($\mu g/m^3$)	0.0060	0.0069	0.0099	0.0113	0.0084
Location					
Distance (meters)	2,000	2,000	1,995	2,000	2,000
Radial (°)	300	140	130	120	140

* Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 7-31. Summary of Beryllium Impacts Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.000061	--	--
Location					
Distance (meters)	--	--	1,310	--	--
Radial (°)	--	--	290	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-32. Summary of Arsenic Impacts Due to Polk Power Station Sources (Demonstration Phase)*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.000092	--	--
Location					
Distance (meters)	--	--	3,000	--	--
Radial (°)	--	--	290	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-33. Summary of Arsenic Impacts Due to Polk Power Station Sources (Full Buildout)*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.00019	--	--
Location					
Distance (meters)	--	--	1,310	--	--
Radial (°)	--	--	290	--	--

* Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 7-34. 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.

- Maximum Individual Risk (MIR)--Estimated increased lifetime risk for an individual exposed to the predicted highest annual average concentration of the pollutant; for example, an MIR of 3.0×10^{-4} implies that if 10,000 people breathe a given concentration for 70 years, then it is likely that no more than three of the 10,000 will develop cancer as a result of the exposure to that pollutant.
- Total Population Risk (TPR) (or Estimated Annual Incidence)--Estimated annual incidence of excess cancers for the entire affected population; a TPR of 0.05 per year for example, indicates that emissions of the pollutant will cause a plausible upper bound of one additional case of cancer every 20 years.

It should be emphasized that risk assessment methodologies involve a high degree of uncertainty. The primary sources of uncertainty are the various URFs (Kowalczyk, 1987; Gratt, 1989). In general, the URFs, reflecting EPA's desires, err on the side of caution; that is, they may tend to overestimate risk (Patrick, 1984; Haemisegger, 1985).

One assumption associated with the 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 large portion of their time.

Acknowledging the limits and conservative nature of risk assessment methodologies, a cancer risk assessment was conducted for the four metals [arsenic, beryllium, cadmium, and chromium (hexavalent)]. The approach involved the following steps:

1. Model the estimated metals emissions from the Polk Power Station combustion sources (full buildout scenario);
2. Determine the annual average concentrations within 10 km of the plant;

3. Estimate the theoretical maximum individual risk using the following equation:

$$MIR = \sum_{i} (C_i \times URF_i)$$

where: C_i = maximum annual average concentration for metal i (μg/m^3), and

URF_i = URF for metal i (μg/m^3)$^{-1}$; and

4. Estimate the theoretical TPR using the following equation:

$$TPR = \sum_{i,j} (C_{i,j} \times P_j \times URF_i) \div 70$$

where: $C_{i,j}$ = maximum annual average concentration of metal i in area j; and

P_j = number of persons living in area j.

Estimated metals emissions for the facility's combustion sources were taken from data presented in Section 2.2. Based on EPA (1989) data, 0.5 percent of total chromium emissions were presumed to be hexavalent (i.e., carcinogenic) when firing distillate fuel oil. Wetherold (1990) provided an estimate of 2-percent hexavalent chromium emissions for syngas combustion.

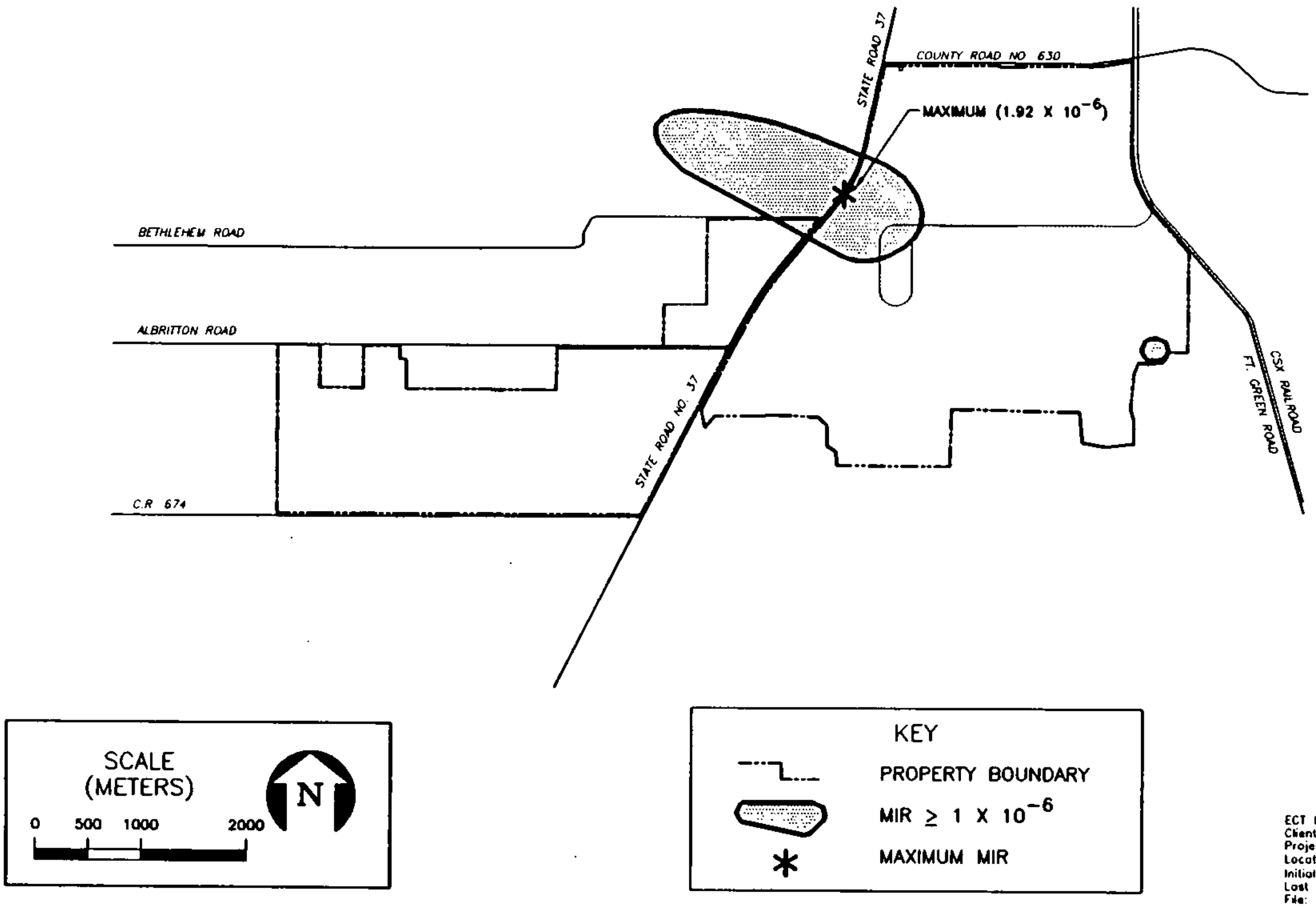
URFs were taken from Haemisegger (1985), Wolfinger (1989), Dydek (1989), and Dusetzina (1990), and are given as follows:

Pollutant	URF (μg/m^3)$^{-1}$
Arsenic	0.0043
Beryllium	0.0024
Cadmium	0.0017
Chromium (hexavalent)	0.012

Following the approach given previously, modeling of arsenic, beryllium, cadmium, and chromium (hexavalent) emissions from Polk Power Station was completed using ISCLT2. Applying the URFs, the MIR was calculated to be 1.92 x 10^{-6}. This value was predicted to occur at a point directly to the northwest of the plant site, as shown in Figure 7-7. Figure 7-7 also shows the areal distribution of MIR values at least 1.0 x 10^{-6}.

The break point between acceptable and unacceptable risk (MIR) is generally understood to fall between 10^{-4} and 10^{-6}. That is, an MIR greater than 10^{-4} is clearly unacceptable, while an MIR below 10^{-6} is clearly acceptable. The MIR found for the proposed Polk Power Station is considered acceptable, especially considering the conservative methodology employed.

To estimate TPR, it was assumed that the entire 1990 population residing in Ft. Meade, Mulberry, and Bowling Green, the nearest incorporated areas for which population data are available (a total of 9,800 persons), was exposed to the maximum impact. This approach was highly conservative since, as shown with Figure 7-7, the predicted extent of MIR values of at least 1.0 x 10^{-6} would impact few, if any, populated areas. With that highly conservative assumption, the TPR would still be only 0.00027, meaning that continuous operation of the plant would theoretically cause an additional case of cancer only every 3,700 years. In conclusion, the operation of Polk Power Station will not result in a significant increase in inhalation cancer risk.



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

FIGURE 7-7.

AREAL DISTRIBUTION OF PREDICTED MIR

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

8.0 ANALYSES OF ADDITIONAL IMPACTS IN THE PLANT VICINITY

8.1 GROWTH IMPACT ANALYSIS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and to assess air quality impacts that would result from that growth. As discussed previously, 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. Table 8-1 summarizes the projected phasing of construction personnel. 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 may possibly 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. The phasing of the operations workforce is presented in Table 8-2. Again, it is expected that most of these persons will be drawn from the immediate area. 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.

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

Table 8-1. Phasing of Polk Power Station Construction Personnel

Year	Total Nominal Station Capacity (MW)	Construction Personnel	
		Average	Peak
1994	0	400	400
1995	150	400	600
1996	260	400	400
1998	260	15	20
1999	335	15	20
2000	410	15	20
2001	480	40	60
2002	555	40	60
2003	775	40	40
2005	775	15	20
2006	850	15	20
2007	925	15	20
2008	1,000	15	20
2009	1,075	15	20
2010	1,150	15	20

Sources: UEC, 1992
ECT, 1992.

Table 8-2. Phasing of Polk Power Station Operational Workforce

Year	Total Nominal Station Capacity (MW)	Total Personnel	
		Operational	Maintenance
1995	150	50	0
1996	260	130	0
1997	260	130	6
1998	260	130	66
1999	335	140	0
2000	410	147	75
2001	480	162	5
2002	555	167	80
2003	775	182	21
2004	775	182	95
2005	775	182	17
2006	850	187	94
2007	925	192	26
2008	1,000	197	89
2009	1,075	202	39
2010	1,150	210	100

Sources: UEC, 1992.
ECT, 1992.

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 industrial development resulting from the establishment of Polk Power Station would be independently subject to PSD and other environmental review requirements.

8.2 IMPACTS ON SOILS AND VEGETATION

8.2.1 IMPACTS ON SOILS

Soil types have been mapped by the U.S. Department of Agriculture (USDA) in cooperation with the Polk County Soil Conservation Service (USDA, 1991). 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.

The Smyrna-Myakka soil complex consists primarily of fine sands which cover broad areas of flatwoods. These soils are somewhat poorly drained with slopes that are smooth to concave at 0 to 2 percent. The water table within these soils is typically 0 to 1 foot below land surface (ft bls) for 1 to 4 months in most years. The Smyrna soils have an organic matter content of 1 to 5 percent, and the Myakka soils have an organic matter content of 2 to 5 percent.

The Arents-Water complex is a soil type resulting from mining activities. The Arents consists of piles (various slopes) of soil material and overburden that originally overlaid the phosphate matrix. The water part of this classification forms after the ore has been mined.

The Ona fine sands are also found in broad areas of flatwoods. The Ona soils are somewhat poorly drained with shallow slopes of 0 to 2 percent. The water table within this soil unit is typically 0 to 1 ft bls for 1 to 4 months in most years.

Gaseous emission 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 alkaline organic soils 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 emission levels associated with plant operation, no impacts to soils are anticipated.

8.2.2 IMPACTS ON VEGETATION

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. Table 8-3 provides the acreages and percentages for the various land use and cover types.

It is difficult to project site-specific ecological impacts due to air emissions based upon data and conclusions in the available literature because of significant variations in experimental designs relating dose, duration, and vegetation species. Minor variations in experimental design and the conditions under which the various vegetation species have been fumigated can result in large differences in the tolerance limits of tested species.

Table 8-4 presents generalized injury threshold concentrations and characteristic injury symptoms for important air pollution constituents. In an attempt to minimize interpretive error while still providing some basis for comparison, another table is provided which lists Florida native and cultivated plant species and categorizes those species according to literature-reported responses to exposure from pertinent combustion emissions (Table 8-5). In each case, the vegetation is categorized using the lowest threshold for injury (regardless of experimental method) reported in the literature.

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. The following discussion summarizes descriptions from the literature of the effects upon vegetation associated with the relevant pollutants.

Table 8-3. Current Acreages and Percentages of Land Use/Cover on the Tampa Electric Company Polk Power Station Site*

Land Use/Cover Type	Acres	Percentage
Light industrial	3	0.1
Gas transmission pipeline	13	0.3
Electrical transmission line	27	0.6
Improved pasture	453	10.4
Orange grove	17	0.4
Palmetto rangeland	5	0.1
Shrub and brushland	18	0.4
Pine flatwoods	118	2.7
Oak hammock	78	1.8
Mixed oak/pine woods	530	12.2
Canals and ditches	1	0.1
Ponds and lakes	200	4.6
Freshwater swamp	66	1.5
Freshwater marsh	101	2.3
Scraped over areas	472	10.9
Spoil banks	60	1.4
Phosphate mined land	2,186	50.2
Total	**4,348**	**100**

*Current acreages as of December 19, 1991. It should also be noted that 94.6 percent of the entire site has been previously or will be mined or disturbed through mining operations. Current acreages reflect unmined areas and mined areas that are still disturbed and unreclaimed, but have revegetated since mining. Therefore, for this table, Category 751 includes only those areas currently disturbed and not revegetated.

Source: ECT, 1992.

Table 8-4. General Plant Injury Symptoms and Threshold Concentrations for Important Air Pollutants*

Pollutant	Symptoms	Part of Leaf Affected	Injury Treshold $\mu g/m^3$	Sustained Exposure
Sulfur dioxide	Bleached spots, intercostal chlorosis	Mesophyll cells	785	8 hours
Ozone	Flecking, stippling, bleached spotting, pigmentation; conifer needle tips become brown and necrotic	Palisade or spongy parenchyma in leaves with no palisade	59	4 hours
Nitrogen dioxide	Irregular, white or brown collapsed lesions on intercostal tissue and near leaf margin	Mesophyll cells	4,700	4 hours
Hydrogen fluoride	Tip and margin burns, dwarfing, leaf abscission; narrow brown-red band separates necrotic from green tissue; fungal disease, cold and high temperatures, drought, and wind may produce similar markings; suture red spot on peach fruit	Epidermis and mesophyll cells	0.08	5 weeks
Mercury	Chlorosis and abscission; brown spotting; yellowing of veins	Epidermis and meophyll cells	<8,200	1 to 2 days
Sulfuric acid	Necrotic spots on upper surface similar to those caused by caustic or acidic compounds; high humidity needed	All		

*From: Hindawi; I.J. (1970).

Table 8-5. Air Pollutant Injury Threshold Concentrations for Plants Cultivated in or Native to Central Florida*

Common Name	Scientific Name	SO_2	O_3	NO_x	HF	SO_2/O_3 Synergism	SO_2NO_x Synergism	Mercury Vapor
Red Maple	Acer rubrum		>196^{d} (chronic)					>50^{g} (7 days)
Box elder	Acer negundo				4-7^{c} (9 days)			
Maple	Acer sp.	≥5,240^{e} (8 hours)	196^{d} (chronic)					>50^{g} (7 days)
Lambs-quarters	Chenopodium album			1.88×10^{6b} (2 hours)				
Orange	Citrus sinensis	>5,240^{e} (8 hours)		>7,380^{b} (2 hours)				
Strawberry	Fragaria sp.							>50^{g} (7 days)
Sunflower	Helianthus annuus			>7,380^{b} (2 hours)				≥50^{g} (7 days)
Morning glory	Ipomoea purpurea	131-1,310^{e} (8 hours)						>50^{g} (7 days)
Privet	Ligustrum sp.		196^{d} (chronic)					≥50^{g} (7 days)
Tomato	Lycopersicon esculentum			7,380^{b} (2 hours)		262/195^{f} (4 hours)	131/62^{f} (4 hours)	>50^{g} (7 days)
Boston fern	Nephrolepis exaltata							50^{g} (7 days)
Black gum	Nyssa sylvatica var. bilflora		>196^{d} (chronic)					
Oxalis	Oxalis sp.							50^{g} (7 days)
Virginia creeper	Parthenocissus quinquefolia		196^{d} (chronic)					
Bean	Phaseolus vulgaris			7,380^{b} (2 hours)				

Table 8-5. Air Pollutant Injury Threshold Concentrations for Plants Cultivated in or Native to Central Florida*

Common Name	Scientific Name	SO_2	O_3	NO_x	HF	SO_2/O_3 Synergism	SO_2NO_x Synergism	Mercury Vapor
Caribbean pine	Pinus caribaea	131-1,310[e] (8 hours)						
Slash pine	Pinus elliottii	650[a] (2 hours)						
Peach	Prunus persica				4-7[c] (9 days)			
Black cherry	Prunus serotina		196[a] (4 hours) 373[a] (2 hours)					
Bracken fern	Pteridium aquilinium	131-1,310[e] (8 hours)						
Blackberry	Rubus sp.	131-1,310[e] (8 hours)						
Willow	Salix sp.		196[d] (chronic)					50[g] (7 days)
American elm	Ulmus americana	131-1,310[e] (8 hours)						

*Concentrations in μg/m^3 (averaging times shown in parentheses).

Sources: [a] Linzon, 1986.
[b] Taylor and MacLean, 1970.
[c] Treshow and Pack, 1970.
[d] Heath, 1975.
[e] Jones *et al.*, 1974.
[f] Reinert, *et al.*, 1975.
[g] Siegel, *et al.*, 1984.

8.2.2.1 Sulfur Dioxide

Natural (ambient) background concentrations of SO_2 range between 0.28 and 2.8 $\mu g/m^3$ on a mean annual basis (Prinz and Brandt, 1985). The most common source of atmospheric SO_2 is the combustion of fossil fuels (Mudd and Kozlowski, 1975). Gaseous SO_2 primarily affects vegetation by diffusion through the stomata (Varshney and Garg, 1979). Small amounts of SO_2 may also be absorbed through the protective cuticle. Adverse effects on plants from SO_2 are primarily due to impacts on photosynthetic processes. SO_2 can react with chlorophyll by bleaching or phaeophytinization. This latter process constitutes a photosynthetic deactivation of the chlorophyll molecule. Acute damage due to SO_2 appears as marginal or intercostal areas of dead tissue which at first cause leaves to appear water-soaked (Barrett and Benedict, 1970). Chronic injuries are less apparent; the leaves remain turgid and continue to function at a reduced level. In more severe cases of chronic SO_2 exposure, there is some bleaching of the chlorophyll which appears as a mild chlorosis or yellowing of the leaf and/or a silvering or bronzing of the undersurface. Species which are categorized as sensitive to SO_2 emissions are those which show damage to at least 5 percent of the leaf area upon being exposed to 131 to 1,310 $\mu g/m^3$ SO_2 for a period of 8 hours (Jones *et al.*, 1974).

Researchers have conducted numerous studies to determine the effects of SO_2 exposure to a wide variety of selected plant species. A review of the literature demonstrates that the most sensitive vascular plants (e.g., white ash, sumacs, yellow poplar, goldenrods, legumes, blackberry, southern pine, red oak, black oak, ragweeds) exhibit visible injury to short-term (3 hours) exposure to SO_2 concentrations ranging from 790 to 1,570 $\mu g/m^3$. Caribbean pine (Pinus caribaea) seedlings, similar in ecology and appearance to South Florida slash pine (Pinus elliotti var. densa) exhibited up to 5-percent needle necrosis when exposed to 1,310 $\mu g/m^3$ SO_2 for 4 hours (Umbach and Davis, 1988). Citrus is reported as being more tolerant to SO_2 exposures, with visible injury appearing when SO_2 concentrations exceed 1,572 to 2,096 $\mu g/m^3$ for a 3-hour period (EPA, 1976). Native plant species common to the region are either tolerant (red maple, live oak, cypress, slash pine) or sensitive (bracken fern) to SO_2 exposures (Woltz and Howe, 1981; USDA, 1972; EPA, 1976; Loomis and Padgett, 1973). Complicating generalizations regarding SO_2 injury is the observation that the genetic variability of native annual plants can result in the selection of SO_2 resistant strains in as little as 25 years (Westman *et al.*, 1985).

The maximum 3- and 24-hour SO_2 impacts projected for Polk Power Station sources alone are 69 and 19 $\mu g/m^3$, respectively. When added to the impacts of other facilities and to an estimate of background SO_2, maximum 3- and 24-hour SO_2 impacts of 547 and 176 $\mu g/m^3$ were projected. All of these impact levels are lower than doses known to cause vegetative injury.

8.2.2.2 Nitrogen Oxides

During combustion, atmospheric nitrogen is oxidized to nitrogen oxide (NO) and small amounts of nitrogen dioxide (NO_2) (Taylor *et al.*, 1975). The NO is photochemically oxidized to NO_2, which in turn is subsequently consumed in the production of ozone. Impacts to vegetation from NO_2 result from high concentrations occurring during short time periods (Taylor and MacLean, 1970). Acute exposures of this sort will cause necrotic lesions in leaf tissue and excessive defoliation (MacLean *et al.*, 1968). Short-term (acute) exposures of NO_2 of less than 1,880 $\mu g/m^3$ for 1 hour have caused no adverse effects (Taylor *et al.*, 1975). Maximum short-term NO_2 concentrations caused by emissions from Polk Power Station would be less than this level.

8.2.2.3 Ozone

Under unpolluted, ambient conditions the atmospheric concentration of ozone is normally in the range of 20 to 39 $\mu g/m^3$ (Heath, 1975). Reversible reactions between molecular oxygen, ozone, NO_x, and reactions with hydrocarbons as well as metals yield increases in the atmospheric ozone concentration. Ozone is not directly emitted from fossil fuel combustion, but is formed down-wind in a photochemical reaction. Vegetation is categorized as sensitive if injury results from a chronic exposure to ozone at a concentration of 196 $\mu g/m_3$ (Heath, 1975). According to

Reich (1987), agricultural crops are the most sensitive to ozone, with hardwoods intermediate and conifers least sensitive.

Leaf damage is manifested as regions of necrosis and chlorosis; at the level of observation by the un-aided eye, the damage appears to be similar to the effects from SO_2. At the microscopic level, substantial damage to the palisade cells in the mesophyll layer in the leaf blade is evident, especially adjacent to stomata.

In conifers, high ozone levels result in enhanced premature needle senescence (Wright *et al.*, 1991). Jordan *et al.*, (1991) correlated high concentrations of ozone with increased foliar tannins in loblolly pine. Pye (1988) reported that ozone can reduce growth and photosynthesis at concentrations common in many areas of the United States.

The state-of-the-art is such that it is difficult to predict what effect the proposed plant emissions will have on ambient ozone concentrations from either a local or regional scale. However, the maximum 1-hour ambient ozone concentration of 99 $\mu g/m^3$ reported in the plant area is below the minimum chronic threshold concentration reported to be injurious to vegetation.

8.2.2.4 Particulate Matter

In addition to gaseous emissions, small amounts of PM will be emitted. Typically, the density of particulate limits impacts such that only vegetation in proximity to the source may be affected.

Included among the PM will be low concentrations of mercury, beryllium, arsenic, and lead. The mercury may occur as both mercury vapors and particulates. The mechanism of mercury phytotoxicity is currently under investigation. Past investigations indicate that mercury vapors will cause chlorosis, abscission of older leaves, growth reduction, and poor development. Most investigations have been restricted to greenhouse crops where air quality monitoring was not conducted. One investigation indicates that vegetation exposed to 50 $\mu g/m^3$ mercury for 7 days experienced leaf abscission (Siegel *et al.*, 1984).

The literature regarding effects on vegetation from beryllium, arsenic, and lead is scarce. One investigation indicates that vegetation growth was reduced by beryllium concentrations in excess of 735 $\mu g/m^3$ (Gough *et al.*, 1979). Arsenic uptake by vegetation to a concentration of 5 micrograms per gram ($\mu g/g$) is considered harmful. Lead retards plant growth above a concentration of 30 $\mu g/g$ in the soil.

The predicted maximum concentrations of mercury, beryllium, arsenic, and lead fall well below those levels reported as damage-causing to vegetation.

8.2.2.5 Carbon Monoxide

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). Microorganisms within the soil appear to be a major sink for CO. No impacts to vegetation from CO are expected.

8.2.2.6 Sulfuric Acid Mist

Acidic precipitation or acid rain is coupled to the emissions of the pollutant SO_2 mainly formed during the burning of high-sulfur fossil fuels. This compound is oxidized in the atmosphere and dissolves in rain forming H_2SO_4 which falls as acidic precipitation (Ravera, 1989). A small amount of fuel-bound sulfur may also be emitted directly as H_2SO_4. Concentration data are not available, but H_2SO_4 mist has yielded necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

Emissions of SO_2 and H_2SO_4 from Polk Power Station will be limited by the use of low-sulfur fuels. Therefore, no impacts from H_2SO_4 mist are expected. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentration of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well publicized (decline of conifer forests in the Appalachians), documented detrimental effects of acid rain on Florida vegetation are lacking (Gholz, 1985; Charles, 1991).

8.2.2.7 Fluorides

Fluoride is widespread in the earth's crust as a natural component of soil, rocks, and minerals (MacIntire, 1945). The effects of fluoride emissions upon vegetation can be stimulation of growth at low concentrations (Treshow and Harner, 1968) or necrosis at leaf tips (Treshow and Pack, 1970). Fluoride toxicity is dependent upon the rate of conversion to hydrogen fluoride or silicon tetrafluoride. Fluoride can have the effect of reducing growth and vigor in vegetation at levels well below those concentrations which result in visible injury. Especially sensitive vegetation will be affected by chronic concentrations of hydrogen fluoride in excess of 4 to 7 $\mu g/m^3$ for a 9-day exposure period (Treshow and Pack, 1970). These concentrations would require that fluoride evolve to the highly toxic hydrogen fluoride form and that the vegetation be chronically exposed to this gaseous product.

8.2.2.8 Synergistic Effects

Combinations of air pollutants, where individual components are present in concentrations below their respective thresholds for vegetation injury, may still affect vegetation. If the effects appear to be directly proportional to the sum of the component's concentrations, the effect is termed additive. If effects are in excess of those expected from the summation of the component's concentrations, the effects are termed synergistic.

The most commonly investigated combination of pollutants is that of SO_2 and ozone. The mechanism for this synergistic effect is believed to involve the influence of SO_2 on stomatal opening (Unsworth *et al.*, 1972). Under controlled humidity and ambient CO_2 concentrations, an increase in SO_2 will have the effect of enhancing stomatal opening, even at night. It is believed that the synergistic response is a result of an increase in susceptibility to vegetation injury, since in the presence of open stomata pollutant gases enter the leaf tissue more easily. Concentrations of ozone at or below the typical injury threshold will result in injury to less than 5 percent of the leaf area. The same holds true for vegetation when exposed to concentrations of SO_2 at or below the injury threshold. However, vegetation exposed to combinations of the two gasses at concentrations of 262 $\mu g/m^3$ SO_2 and 195 $\mu g/m^3$ ozone can result in damage to much more than 5 percent of the leaf area (Reinert *et al.*, 1975). Furthermore, the symptoms are those of injury from ozone. Such levels predicted for this project are below those thresholds.

Synergism effects associated with SO_2 and other emissions products appear to operate under a similar mechanism. Recalling that NO_2 emissions are implicated in vegetation impacts based upon conversion to phytotoxic ozone, the appropriate synergistic reactions involve SO_2-ozone and SO_2-NO_2. Typically injury thresholds for susceptible plants approximate the injury thresholds as reported for SO_2 previously (Reinert *et al.*, 1975).

8.3 VISIBILITY IMPAIRMENT POTENTIAL

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 syngas, natural gas, and low-sulfur 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, there are virtually no areas of aesthetic or visual importance and significance.

9.0 ANALYSES OF POTENTIAL IMPACTS ON THE CHASSAHOWITZKA NATIONAL WILDERNESS AREA PREVENTION OF SIGNIFICANT DETERIORATION CLASS I AREA

9.1 OVERVIEW AND APPROACH

The Chassahowitzka National Wilderness Area (NWA) is located in northwestern Hernando and southwestern Citrus Counties, as shown in Figure 9-1. This area is classified as a PSD Class I area. Chassahowitzka's southern boundary is approximately 120 km to the northwest of the Polk Power Station site. In the past, proposed facilities under review with respect to the PSD regulations were not required to examine impacts at Class I areas located more than 100 km away; it was assumed that the air quality impacts of a proposed facility that distance away would be minimal.

More recently, however, proposed facilities located beyond 100 km from a Class I area have been required to satisfy Class I area review criteria. The two principal criteria are: (1) the PSD Class I increments, which have been established for TSP, SO_2, and NO_2; and (2) other air quality related values (AQRVs). AQRVs include visibility, soils, vegetation, and wildlife resources.

PSD Class I increments were presented in Section 3.2 (see Table 3-5). These increments represent low levels of air pollutant concentrations that can be added at a Class I area. The concept of *significance* has recently been applied to the analysis of Class I impacts. The National Park Service (NPS) has developed significance levels for Class I impacts, as has the Virginia Department of Air Pollution Control (VDAPC). Table 9-1 summarizes these criteria. Like the significant impact levels for AAQS and PSD Class II increment analyses (see Table 3-4 in Section 3.2), the Class I significance levels are intended to minimize the extent of analysis for sources with little potential to impact a Class I area.

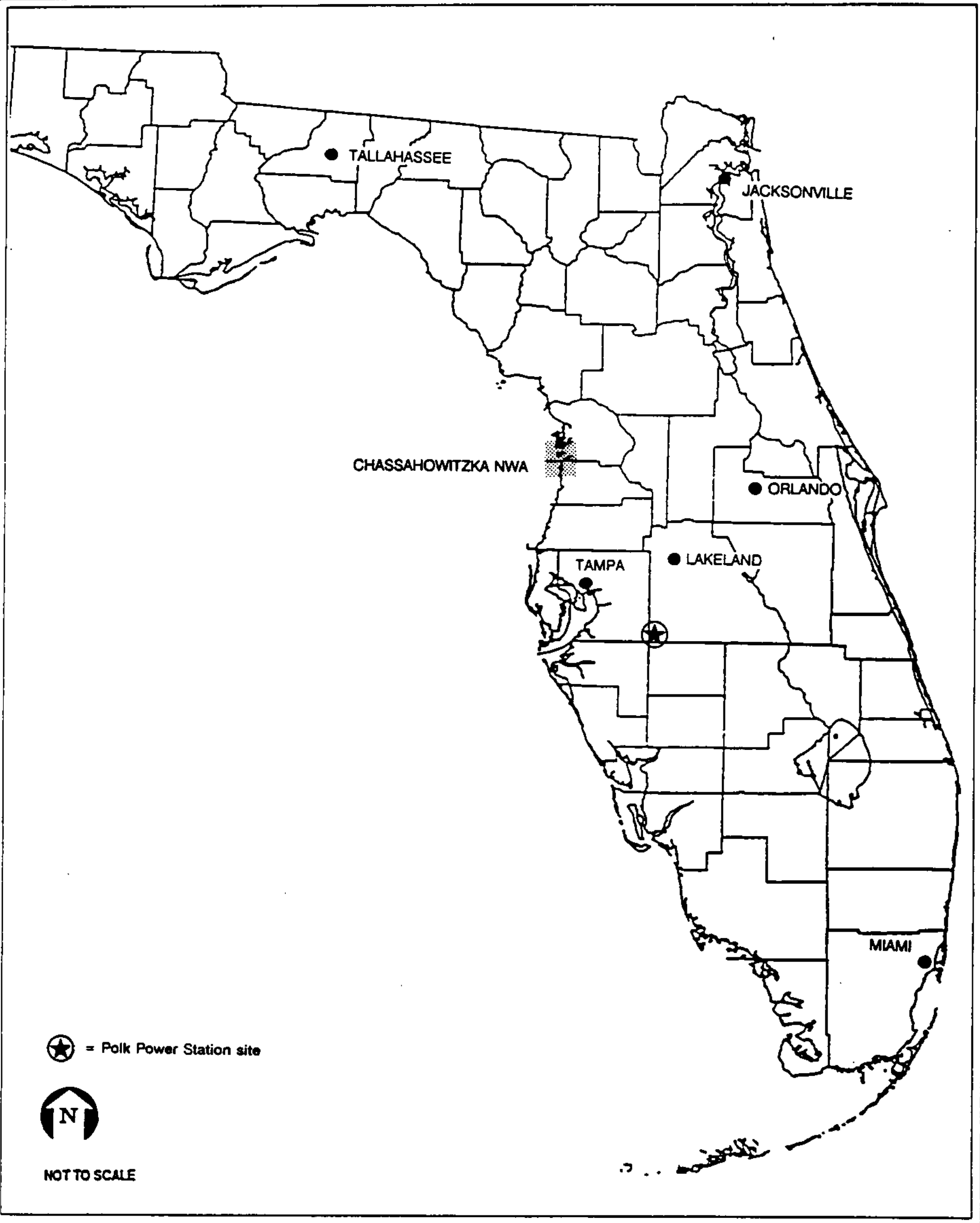


FIGURE 9-1.

RELATIVE LOCATIONS OF POLK POWER STATION AND CHASSAHOWITZKA NWA

Source: ECT, 1992.

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Table 9-1. Significant Impact Levels for Class I Analyses

Pollutant	Averaging Period	Concentration ($\mu g/m^3$) NPS	 VDAPC
SO_2	Annual	0.025	0.1
	24-hour	0.07	0.275
	3-hour	0.48	1.23
PM (TSP)	Annual	0.025	0.27
	24-hour	0.07	1.35
NO_2	Annual	0.025	0.1

Sources: NPS, 1992.
EPA, 1991a.

Irrespective of a proposed facility's ability to comply with the PSD Class I increments (or to show insignificant impacts), potential effects on AQRVs are to be analyzed. Especially unique, sensitive resources at a Class I area should receive primary attention.

For this project, all of the analyses described in the preceding paragraphs were carried out. Section 9.2 describes the modeling runs used to address compliance with the PSD Class I increments. Section 9.3 presents the analysis of potential visibility impacts, and Section 9.4 describes potential impacts on soils, vegetation, and wildlife. Section 9.5 presents conclusions regarding the potential for emissions from Polk Power Station to affect the resources of the Chassahowitzka NWA.

9.2 AIR QUALITY ANALYSES FOR PREVENTION OF SIGNIFICANT DETERIORATION CLASS I INCREMENTS

9.2.1 MODELS AND MODEL INPUTS

9.2.1.1 Industrial Source Complex 2 Models

As a first step in the Class I increment analyses, emissions from Polk Power Station sources were modeled with the ISC2 models. The ISC2 models would be expected to produce highly conservative estimates of Class I increment consumption for Polk Power Station due to the assumptions inherent to the models. These assumptions include: (1) constant, uniform wind for each hour (i.e., steady-state Gaussian plume dispersion); and (2) straight-line plume transport to all downwind distances. Because of these assumptions, the ISC2 models are recommended for transport distances of less than 50 km (EPA, 1986). The Polk Power Station site is approximately 120 km away from the Chassahowitzka NWA.

Emission rates and stack parameters used with the ISC2 models were the same as used in the SIA model runs described in Section 7.2. Thirteen receptors were placed at the boundary of the Chassahowitzka Class I area, consistent with guidance received from FDER. All other inputs and procedures associated with the use of the ISC2 models that were presented in Section 6.0 were used for this analysis.

9.2.1.2 MESOPUFF-II Model

Introduction

Conventional air quality models such as the ISC2 are not truly appropriate for assessing source impacts beyond approximately 50 km because the models do not account for temporal or spacial variations in plume transport direction nor do they limit the downwind transport of a pollutant as a function of windspeed and travel time. To overcome these deficiencies in conventional air quality models, long-range transport models such as MESOPUFF-II (EPA, 1984) have been developed.

The MESOPUFF-II model is described in Appendix B of the EPA Guideline on Air Quality Models (Revised) (EPA, 1986). The Appendix B models can be used on a case-by-case basis only if they perform functions not available in "Appendix A" models. As previously discussed, MESOPUFF-II is capable of accounting for several long-range transport and dispersion phenomena that are not addressed in conventional air quality models. The model is currently recommended by EPA and NPS for estimating pollutant impacts at receptors 50 to 100 km or more from a source.

MESOPUFF-II is a short-term plume transport model that mathematically simulates the transport and dispersion of pollutants from individual sources. A continuous plume from each single source is modeled as a series of discrete puffs that are transported and dispersed independently until they leave the user-defined modeling grid. Pollutant concentrations are calculated at discrete receptors according to the proximity of a puff to a receptor and the concentration of a pollutant within a puff. The transport distance and direction are determined from hourly, gridded wind fields derived from one or more sets of meteorological data. Hourly pollutant concentrations are calculated at each receptor representing the cumulative impact of all sources input to the model. Longer term averages (3-hour, 24-hour and/or annual) are determined by block averaging hourly concentrations. The version of MESOPUFF-II used for this study was obtained by Koogler & Associates from NPS in early 1992.

The MESOPUFF-II modeling package consists of four individual programs: the READ62 and MESOPAC-II programs that pre-process meteorological data, the MESOPUFF-II dispersion model, and the MESOFILE-II post-processing program. The READ62 program (an update of READ56) reads and processes the twice-daily upper wind and temperature sounding data. If data are missing, READ62 notes the incomplete sounding and the user must complete the data set. The MESOPAC-II program is the meteorological pre-processor program that computes the time and space interpolated fields of meteorological variables. The MESOPAC-II reads the upper air data files created by READ62 and hourly surface meteorological data and precipitation data. These data are read for all meteorological stations in the MESOPUFF-II grid and a single output file, containing the derived meteorological fields, is produced as an input file to MESOPUFF-II.

Both MESOPAC-II and MESOPUFF-II employ a Cartesian coordinate reference grid consisting of three nested grids: a meteorological grid, a computational, grid and a sampling grid. The meteorological grid defines the meteorological stations and the meteorological field which controls the transport and dispersion of pollutants. The computational grid defines that portion of the meteorological grid in which puffs are tracked, and the sampling grid defines the receptor points at which pollutant concentrations are calculated.

MESOPUFF-II utilizes the meteorological data file created by MESOPAC-II and source information to calculate hourly pollutant concentrations. In addition to accounting for plume meander, the model can also account for dry deposition, chemical transformation, and wet removal of a pollutant.

The data generated by MESOPUFF-II are post-processed with MESOFILE-II. The format of this program was modified by Koogler & Associates to produce concentration values for each receptor for each Julian day of meteorological data utilized. Koogler & Associates also developed the program HIGH50 to produce tables of the highest and second-highest concentrations for each receptor and to produce maximum-50 or maximum-100 concentration tables for each model run.

The input to the MESOPUFF-II program included the data file generated by MESOPAC-II and an inventory of PSD increment consuming and expanding SO_2 sources in west-central Florida. The final inventory included 136 sources obtained from FDER permit files and from emission inventories in PSD permit applications on file with FDER (see Appendix B.2).

As published, MESOPUFF-II limits the number of puffs in the computational grid to 500. Because a full year of meteorological data were utilized for each model run and because of the large number of sources (136), the model was expanded by Koogler & Associates to allow 2,000 puffs to be active at any one time. Even with this expansion of the model, only 20 sources could be run at a time.

Spatial Scale

The meteorological grid used with MESOPUFF-II consisted of a 15 by 15 point grid with 20 km spacing between grid points. This resulted in a grid that was 280 km in both the east-west and a north-south dimensions. The southwest corner of the grid was located at latitude 26°33'27"N and longitude 83°17'48"W, or approximately 175 km southwest of Tampa as shown in Figure 9-2.

The computational grid was 10 grid points in the east-west dimension by 12 grid points in the north-south dimension. The southwest corner of the computational grid was located at point (3, 4) of the meteorological grid.

The sampling grid was defined by 13 discrete receptors defining the boundary of the Chassahowitzka NWA. These receptors were selected to be consistent with guidance received from FDER.

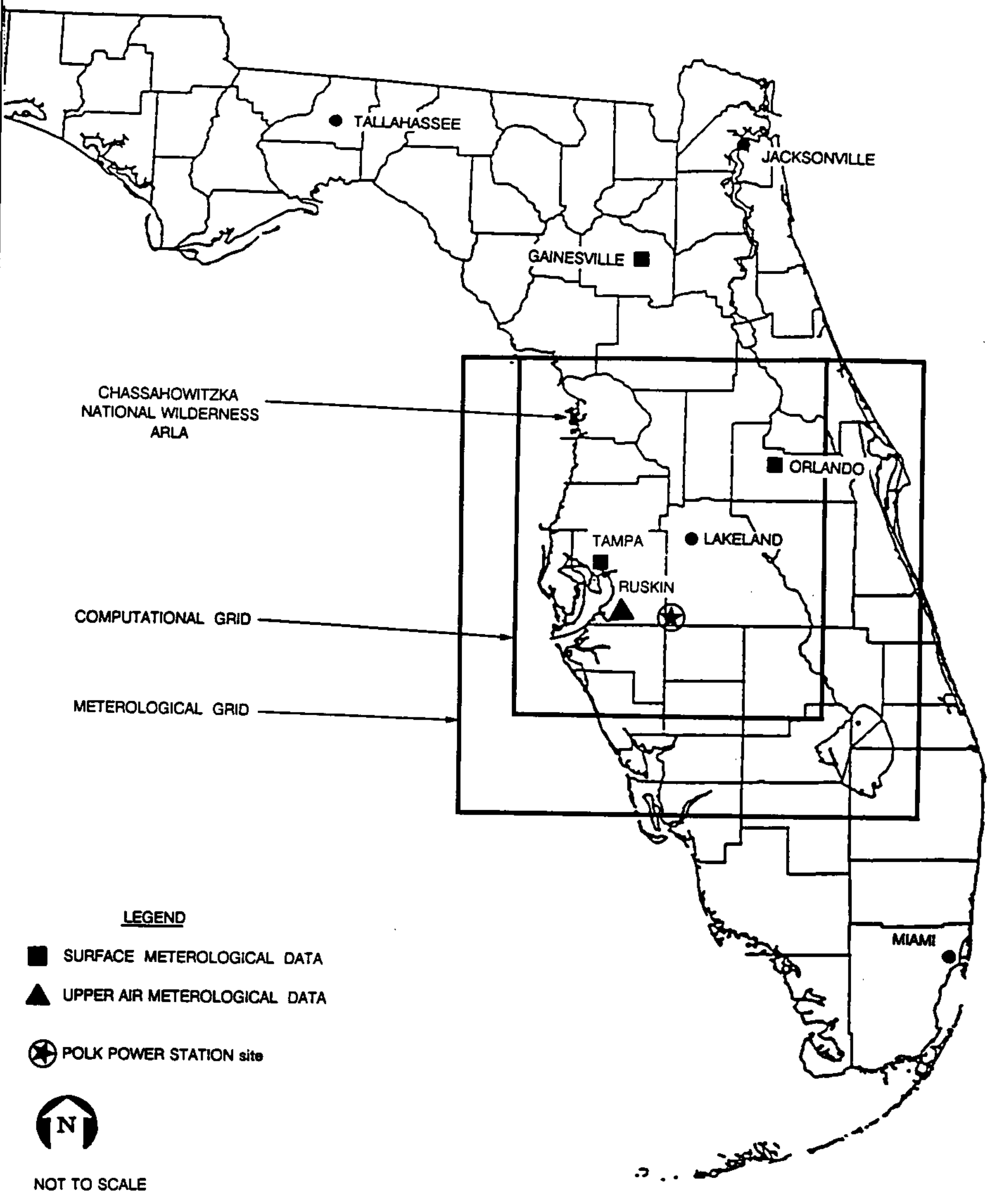

FIGURE 9-2.

MESOPUFF-II METEOROLOGICAL AND COMPUTATIONAL GRIDS
Source: Koogler, 1992.

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The computational grid was situated to create at least a two grid point buffer between sources and receptors and the boundary of the grid.

Meteorological Database

The meteorological data for the full 1986 calendar year were selected for modeling. The use of these data was based on ISC2 model runs which indicated that these data would likely result in impacts that were more critical than impacts generated with any other meteorological data in the 1982 to 1986 data set.

Upper air rawinsonde data for Ruskin, Florida, West Palm Beach, Florida, and Waycross, Georgia, for calendar year 1986, were processed with the READ62 program. In the initial processing, it was observed that data from Waycross would require extensive data editing to account for missing data. Also, initial modeling demonstrated that the upper air data from Waycross had no affect on the model because of the distance of the station from the edge of the meteorological grid and the closer proximity of other upper air stations. As a result, only upper air data from Ruskin and West Palm Beach, Florida, were processed through READ62 and incorporated into the input to MESOPAC-II.

Upper air measurements were processed by the program READ62. The top pressure level (model variable PSTOP) was set at 500 millibars. If READ62 indicated a reading for this pressure level or another required reading was missing, the value was estimated by interpolating between measurements from adjacent levels or by persisting the previous valid reading. Program options for READ62 are summarized in Table 9-2.

Surface observations for calendar year 1986 were obtained from the EPA SCRAM Bulletin Board for the three surface stations: Tampa, Orlando, and Gainesville. These data were supplemented with data from the National Climatic Center to provide station pressure, relative humidity, a weather code designating precipitation type, and precipitation data. The precipitation data are no longer available in the

Table 9-2. Options Selected for READ62

Variable	Description	Selected Value
1. Card 1 - Starting and Ending Hours, Upper Pressure Level		
IBYR, IBDAY, IBHR, IEYR, IEDAY, IEHR	Starting and ending year, day, hour	As needed
PSTOP	Top pressure level for which data are extracted	500 mb
2. Card 2 - Missing Data Control Variables		
LHT	Height field control variable	True
LTEMP	Height field control variable	True
LWD	Wind direction field control variable	True
LWS	Windspeed field control variable	True

Source: Koogler, 1992.

required TD9657 format; thus, data were obtained in the TD3280 format and converted to TD9657 format for use in MESOPAC-II. Missing surface data were estimated by assuming data persistence from the previous valid observation.

Land use information, required by MESOPAC-II to calculate surface roughness lengths, was obtained from the *Water Resource Atlas of Florida* (FSU, 1984). The land use specified for each 20 by 20 km cell of the meteorological grid was based on the land use category representing the greatest fraction of the total area within each grid.

The program options selected for MESOPAC-II are summarized in Table 9-3.

Application of MESOPUFF-II

MESOPUFF-II was utilized to calculate 3-hour and 24-hour SO_2 concentrations at the 13 receptors used to define the Chassahowitzka NWA. The SO_2 sources input to the MESOPUFF-II model were all significant PSD increment consuming and expanding sources beyond 50 km of Chassahowitzka. Sources within 50 km were modeled with the ISCST2. The same 13 receptors used with MESOPUFF-II were used with ISCST2. The 3- and 24-hour average SO_2 concentrations produced by ISCST2 were added directly to the corresponding concentrations produced by MESOPUFF-II to obtain resulting total impacts for each of the 13 receptors.

MESOPUFF-II is designed to simulate the meandering transport, dispersion, transformation, and removal of pollutants. The transformation and removal mechanisms include dry deposition, chemical transformation, and wet removal. The use of these options, if exercised, is discussed in the presentation of model results.

MESOPUFF-II simulates a continuously released pollutant plume with a series of discrete puffs. The greater the puff release rate, the more nearly the model simulates the continuous release of the pollutant. The disadvantage of increasing the puff release rate is the computational burden. Another factor influencing the

Table 9-3. Options Selected for MESOPAC-II

Variable	Description	Selected Value
1. Card Group 1 - Title		
TITLE	Title of run	As needed
2. Card Group 2 - General Run Information		
NYR, IDYSTR, IHRMAX	Year, start, day and number	As needed
NSSTA, NUSTA	Number of surface and rawinsonde stations	As needed
3. Card Group 3 - Grid Data		
IMAX, JMAX	Number of grid points in the X and Y direction	15, 15
DGRID	Grid spacing	20 km
4. Card Group 4 - Output Options		
VARIOUS	Disk and printer control variables for writing data to disk	As needed
5. Card Group 5 - Land Use Categories at Each Grid Point		
ILANDU	Land use categories at each grid point	15 by 15 array

Table 9-3. Options Selected for MESOPAC-II (Continued, Page 2 of 3)

Variable	Description	Selected Value
6. Card Group 6 - Default Override Options		
IOPTS(1)	Surface windspeed measurement heights control variable	0 (Default-10 m)
IOPTS(2)	von Karman constant control variable	0 (Default)
IOPTS(3)	Friction velocity constants control variable	0 (Default)
IOPTS(4)	Mixing height constants control variable	0 (Default)
IOPTS(5)	Windspeed control variable	0 (Default - RADIUS = 99 km, ILWF = 2, IUWF = 4)
IOPTS(6)	Surface roughness lengths control variable	0 (Default)
IOPTS(7)	Option to adjust heat flux estimate	0 (Default)
IOPTS(8)	Radiation reduction factors control variable	0 (Default)
IOPTS(9)	Heat flux constant control variable	0 (Default)
IOPTS(10)	Option to begin run at date other than at start of meteorological data files	0 or 1, as needed

Table 9-3. Options Selected for MESOPAC-II (Continued, Page 3 of 3)

Variable	Description	Selected Value
7 - 14. Card Groups 7 to 14		
VARIOUS	Options input to override default values	Not used
15. Card Group 15 - Surface Station Data		
VARIOUS	Surface meteorological station information	As needed
16. Card Group 16 - Rawinsonde Station Data		
VARIOUS	Rawinsonde meteorological station information	As needed

Source: Koogler, 1992.

selection of puff release rate is the source-receptor distance. The smaller this distance, the greater the puff release rate must be for the model to reasonably simulate plume behavior. Because all of the sources included in the emission inventory were at distances of 50 km or greater from the Chassahowitzka NWA, and because of the large number of sources within the inventory, a puff release rate of one per hour (NPUF = 1) was selected. The puff sampling rate utilized by the model was a minimum of two per hour (NSAMAD = 2) and the reference windspeed used with the variable puff sampling option was two meters per second (WSAMP = 2).

To eliminate erratic results from sources close to the receptors, the minimum puff sampling age (AGEMIN) was set to 900 seconds. As only sources beyond 50 km were modeled with MESOPUFF-II, a windspeed in excess of 55 m/sec (124 mph) would be required for AGEMIN to have an affect on the model.

The model option utilizing a vertical Gaussian plume distribution in the mixed layer was utilized. The alternative would have been to assume an instantly dispersed plume throughout the mixed layer. The utilization of the Gaussian distribution more reasonably represents plume behavior for sources near the receptors but will not be of any great significance once plume travel time exceeds a few hours.

Another model variable (TMDEP) was used to define the basis for establishing dispersion parameters. This variable was selected so that, for distances up to 50 km, the dispersion parameters would be distance dependent, and for longer traveler distances, the parameters would be time dependent. All program options used with MESOPUFF-II are summarized in Table 9-4.

Table 9-4. Options Selected for MESOPUFF-II

Variable	Description	Selected Value
1. Card Group 1 - Title		
TITLE	Title of run	As needed
2. Card Group 2 - General Run Information		
NSYR, NSDAY, NSHR	Year, start day and hour	As needed
NADVIS	Number of hours in run	As needed
NPTS	Number of point sources	As needed
NAREAS	Number of area sources	Not used
NREC	Number of non-gridded receptors	13 (Class I Area)
NSPEC	Number of chemical species to model	1 (SO2)
3. Card Group 3 - Computational Variables		
IAVG	Concentration averaging time	24 hours
NPUF	Puff release rate for each source	1 puff/hr
NSAMAD	Minimum sampling rate	2 samples/hr
LVSAMP	Variable sampling rate option	True (increase rate with higher windspeeds)
WSAMP	Reference windspeed height (used if LVSAMP is true)	10 m

Table 9-4. Options Selected for MESOPUFF-II (Continued, Page 2 of 4)

Variable	Description	Selected Value
LSGRID	Control variable for concentration computations at sampling grid points	False (sampling at non-gridded points only)
AGEMIN	Minimum age of puffs to be sampled	900 seconds
4. Card Group 4 - Grid Information		
VARIOUS	Numbers that define the beginning and end of the meteorological and computational grids	1, 15
MESHDN	Sampling grid spacing factor	1
5. Card Group 5 - Technical Options		
LGAUSS	Vertical concentration distribution option	True
LCHEM	Chemical transformation option	True/False*
LDRY	Dry deposition option	True/False*
LWET	Wet deposition option	True/False*
L3VL	Three vertical layer option	False*
6. Card Group 6 - Default Override Options		
VARIOUS	Disk and printer option to write data to disk	As needed
LPRINT	Printer output option (Print every IPRINT hours)	True

Table 9-4. Options Selected for MESOPUFF-II (Continued, Page 3 of 4)

Variable	Description	Selected Value
IPRINT	Printing interval	24 hours
7. Card Group 7 - Default Override Options		
IOPTS(1)	Control variable for input of dispersion parameters	1 (see Card Group 8)
IOPTS(2)	Control variable for input of diffusivity constants	0 (Default)
IOPTS(3)	Control variable for input of SO2 canopy resistance	0 (Default)
IOPTS(4)	Control variable for input of dry deposition parameters	0 (Default)
IOPTS(5)	Control variable for input of wet removal parameters	0 (Default)
IOPTS(6)	Control variable for input of chemical transformation method	0 (Default)
8. Card Group 8 - Dispersion Parameters		
AY, BY, ZY BZ, AZT	Arrays of dispersion coefficients	Default
TMDEP	Distance beyond which the time-dependent equations are used for Sigma Y and Z	50,000 m

Table 9-4. Options Selected for MESOPUFF-II (Continued, Page 4 of 4)

Variable	Description	Selected Value
JSUP	Stability class used to determine growth rates for puffs above boundary layer	5 (Default)
9-13. Card Groups 9 to 13		
VARIOUS	Options input to override default values	Not used
14. Card Group 14 - Point Source Data		
VARIOUS	Point source information-location, stack and emission data	As needed
15. Card Group 15 - Area Source Data		
VARIOUS	Area source information-location, initial dispersion and emission data	Not used
16. Card Group 16 - Non-Gridded Receptor Coordinates		
XREC, YREC	X and Y coordinates of non-gridded receptors	Used

*Model runs used various combinations of these transformation and removal options.

Source: Koogler, 1992.

9.2.2 MODELING RESULTS

9.2.2.1 Sulfur Dioxide

ISC2 Results

As the first step in the analysis of PSD Class I increment consumption for SO_2, SO_2 emissions from Polk Power Station sources were run using the ISC2 models. These results are summarized in Table 9-5. As shown, the highest SO_2 impacts were all above the stringent NPS significance levels, and all but the annual average impact were above the VDAPC significance levels.

Since Polk Power Station was shown to have significant SO_2 impacts, the next step was to model all PSD sources using the ISC2 models to obtain a conservative prediction of total Class I increment consumption. The results of these model runs are summarized in Table 9-6. Annual increment consumption over the entire receptor grid was negative. However, for the short-term averaging times, the HSH impacts exceeded the Class I allowables. For the 24-hour average, the HSH impact was 8 $\mu g/m^3$, versus the allowable of 5 $\mu g/m^3$. For the 3-hour average, the HSH impact was 29.7 $\mu g/m^3$, versus the allowable of 25 $\mu g/m^3$.

MESOPUFF-II Results

Given the conservative nature of the ISC2 models for this type of analysis, the next step was to employ the MESOPUFF-II model. As described previously, the model has several options to account for pollutant deposition and transformation. For the PSD Class I increment analysis reported herein, the MESOPUFF-II model was run exercising none of the deposition or transformation options. The only model option exercised was the assumption of the Gaussian pollutant distribution in the vertical dimension.

MESOPUFF-II/ISCST2 modeling results for 24-hour average SO_2 impacts at the Chassahowitzka NWA are summarized in Table 9-7. The modeling analysis indicated a number of 24-hour periods where the Class I increment could be exceeded. During none of these days, however, did the proposed Polk Power Station have a significant

Table 9-5. Summary of SO_2 Impacts at Chassahowitzka NWA Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest (μg/m^3)	--	--	0.061	--	--
Location					
UTMX (km)	--	--	340.3	--	--
UTMY (km)	--	--	3,165.7	--	--
24-Hour average					
Highest (μg/m^3)	0.78	1.01	0.49	1.08	1.16
Location					
UTMX (km)	342.0	343.0	343.7	343.0	340.3
UTMY (km)	3,174.0	3,176.2	3,178.3	3,176.2	3,169.8
Second highest (μg/m^3)	0.65	0.78	0.41	0.78	0.91
Location					
UTMX (km)	342.0	343.0	342.0	340.7	340.3
UTMY (km)	3,174.0	3,176.2	3,174.0	3,171.9	3,169.8
3-Hour average					
Highest (μg/m^3)	6.01	4.41	3.87	5.73	7.13
Location					
UTMX (km)	342.0	343.0	342.0	343.7	340.3
UTMY (km)	3,174.0	3,176.2	3,174.0	3,178.3	3,169.8
Second highest (μg/m^3)	3.50	3.60	3.25	4.34	4.97
Location					
UTMX (km)	340.3	340.3	342.0	340.3	340.3
UTMY (km)	3,169.8	3,165.7	3,174.0	3,165.7	3,165.7

*Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 9-6. Summary of SO_2 Impacts at Chassahowitzka NWA Due to All PSD Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.00†	--	--
Location					
UTMX (km)	--	--	--	--	--
UTMY (km)	--	--	--	--	--
24-Hour average					
Highest ($\mu g/m^3$)	7.9	7.8	8.5	7.9	8.3
Location					
UTMX (km)	340.7	343.0	342.4	340.3	343.0
UTMY (km)	3,171.9	3,176.2	3,180.6	3,169.8	3,176.2
Second highest ($\mu g/m^3$)	7.0	5.8	7.0	6.4	8.0
Location					
UTMX (km)	342.0	340.3	340.7	340.3	343.0
UTMY (km)	3,174.0	3,165.7	3,171.9	3,167.7	3,176.2
3-Hour average					
Highest ($\mu g/m^3$)	27.7	28.8	47.9	38.3	33.8
Location					
UTMX (km)	340.3	343.0	341.1	336.5	331.5
UTMY (km)	3,169.8	3,176.2	3,183.4	3,183.4	3,183.4
Second highest ($\mu g/m^3$)	27.1	24.5	28.0	27.7	29.7
Location					
UTMX (km)	340.3	343.0	343.7	336.5	341.1
UTMY (km)	3,169.8	3,176.2	3,178.3	3,183.4	3,183.4

*Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

†Increment consumption was negative over the entire receptor grid.

Source: ECT, 1992.

Table 9-7. Summary of MESOPUFF-II/ISCST2 PSD Class I Area SO_2 Increment Analysis: 24-Hour Average

1986

Julian Day	Receptor	24-Hour Impact of All PSD Sources ($\mu g/m^3$)	24-Hour Impact of Emissions From Polk Power Station ($\mu g/m^3$)
135	2	7.1*	<0.01
333	7	5.0†	0.39
333	8	4.7**	0.39
195	1	<0.0***	1.00††

*Maximum 24-hour impact of all PSD sources.

†Maximum 24-hour impact of all PSD sources with a significant impact from Polk Power Station.

**Second-high 24-hour impact of all PSD sources with a significant impact from Polk Power Station.

††Maximum 24-hour impact due to Polk Power Station alone.

***Negative impact resulting from increment expanding sources.

Source: Koogler, 1992.

impact, as most stringently defined by NPS. The maximum predicted 24-hour impact was 7.1 $\mu g/m^3$ at Receptor No. 2 on Julian Day 137. During this time period, emissions from Polk Power Station had an impact of only 0.005 $\mu g/m^3$ (i.e., less than significant). For Julian Day 333, at Receptor No. 7, the maximum expected impact of all PSD sources was 5.0 $\mu g/m^3$ (equal to but not exceeding the Class I 24-hour increment); the impact of emissions from Polk Power Station was 0.395 $\mu g/m^3$. Overall, the maximum expected impact at Chassahowitzka due to Polk Power Station was 1.0 $\mu g/m^3$ on Julian Day 195 at Receptor No. 1. Under these conditions, however, the maximum expected impact of all PSD sources was less than 0.0 $\mu g/m^3$ (a negative impact) due to the predominance of increment expanding sources.

Similarly, modeling results for 3-hour average SO_2 impacts at Chassahowitzka are summarized in Table 9-8. The maximum predicted impact of all PSD sources was 47.0 $\mu g/m^3$. This occurred at Receptor No. 11 on Julian Day 119(09) and resulted entirely from the impact of sources within 50 km of the area. During this 3-hour period, the SO_2 emissions from Polk Power Station had no impact. The two highest 3-hour impacts of all PSD sources that occurred when emissions from the proposed project had positive impacts were on Julian Days 274(12) and 43(15). On Julian Day 274(12), the maximum 3-hour SO_2 of all PSD sources was 11.5 $\mu g/m^3$; the impact due to the proposed project was only 0.0015 $\mu g/m^3$. On Julian Day 43(15), the maximum 3-hour impact of all PSD sources was 7.4 $\mu g/m^3$, and the impact due to the proposed project was 0.37 $\mu g/m^3$. The maximum 3-hour SO_2 impact of the proposed Polk Power Station in the Chassahowitzka NWA was 3.12 $\mu g/m^3$, occurring on Julian Day 309(09) at Receptor No. 1. During this time period, the 3-hour impact of all PSD sources was less than zero.

It should be noted that, for this analysis, the permit allowable SO_2 emission rates were used for most sources; data were not readily available to accurately estimate actual emissions from all sources included in the analysis. However, EPA allows the use of actual emissions for PSD increment analyses. As actual emissions are generally less than permitted emissions, this analysis and the results described

Table 9-8. Summary of MESOPUFF-II/ISCST2 PSD Class I Area SO_2 Increment Analysis: 3-Hour Average

Julian Day	3-Hour Period Ending with Hour Shown	Receptor	24-Hour Impact of All PSD Sources (μg/m³)	24-Hour Impact of Emissions From Polk Power Station (μg/m³)
119	09	11	47.0*	0.00
274	12	5	11.5†	<0.01
43	15	2	7.4**	0.37
309	09	1	<0.0***	3.12††

*Maximum 3-hour impact of all PSD sources.
†Maximum 3-hour impact of all PSD sources with an impact from Polk Power Station.
**Second-high 3-hour impact of all PSD sources with an impact from Polk Power Station.
††Maximum 3-hour impact due to Polk Power Station alone.
***Negative impact resulting from increment expanding sources.

Source: Koogler, 1992.

previously could be considered conservative. Even with the use of conservative impacts and assumptions, no exceedances of the Class I increments with a significant contribution from Polk Power Station were shown. Therefore, the analysis demonstrated that Polk Power Station will not cause or contribute to an exceedance of SO_2 increments at the Chassahowitzka NWA.

9.2.2.2 Nitrogen Oxides

Similar to the analysis for SO_2, the first step for NO_x was to model the impacts of Polk Power Station sources using ISCLT2. The results are summarized in Table 9-9, which shows that the maximum annual impact was 0.050 $\mu g/m^3$. This impact is below the VDAPC significance level, but above the NPS significance level. Therefore, additional analysis with all NO_x PSD sources was completed. The result, presented in Table 9-10, showed that total increment consumption was 0.23 $\mu g/m^3$, which is much less than the Class I allowable of 2.5 $\mu g/m^3$.

9.2.2.3 Particulate Matter (Total Suspended Particulate)

For PM (TSP), the impacts of Polk Power Station sources were modeled with the ISC2 models. The results are summarized in Table 9-11. As shown, the maximum annual impact was predicted to be 0.015 $\mu g/m^3$, which is less than both the NPS and VDAPC significance levels. The highest 24-hour average impacts were predicted to be well below the VDAPC significance level but somewhat above the NPS significance level. Therefore, additional analysis with all PM PSD sources was conducted. The results are summarized in Table 9-12. A maximum annual average impact of 1.25 $\mu g/m^3$ was predicted, relative to the allowable increment of 5 $\mu g/m^3$. The HSH 24-hour impact was 5.9 $\mu g/m^3$, relative to the allowable increment of 10 $\mu g/m^3$.

It is noted that the inventory of PM sources used for the analysis of Class I impacts included no increment expanding sources. Refinements and updates to this inventory would certainly incorporate such sources, and the inclusion of these sources would reduce total maximum increment consumption for both annual and 24-hour averaging

Table 9-9. Summary of NO_x Impacts at Chassahowitzka NWA Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.050	--	--
Location					
UTMX (km)	--	--	340.3	--	--
UTMY (km)	--	--	3,165.7	--	--

*Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 9-10. Summary of NO_x Impacts at Chassahowitzka NWA Due to All PSD Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.23	--	--
Location					
UTMX (km)	--	--	340.3	--	--
UTMY (km)	--	--	3,165.7	--	--

*Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986).

Source: ECT, 1992.

Table 9-11. Summary of PM (TSP) Impacts at Chassahowitzka NWA Due to Polk Power Station Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	0.015	--	--
Location					
UTMX (km)	--	--	340.3	--	--
UTMY (km)	--	--	3,165.7	--	--
24-Hour average					
Highest ($\mu g/m^3$)	0.32	0.38	0.18	0.40	0.47
Location					
UTMX (km)	340.7	342.0	342.0	343.0	340.3
UTMY (km)	3,171.9	3,174.0	3,174.0	3,176.2	3,169.8
Second highest ($\mu g/m^3$)	0.22	0.27	0.16	0.30	0.36
Location					
UTMX (km)	343.7	342.0	342.0	340.3	340.3
UTMY (km)	3,178.3	3,174.0	3,174.0	3,165.7	3,169.8

*Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

Table 9-12. Summary of PM (TSP) Impacts at Chassahowitzka NWA Due to All PSD Sources*

	1982	1983	1984	1985	1986
Annual average					
Highest ($\mu g/m^3$)	--	--	1.25	--	--
Location					
UTMX (km)	--	--	340.3	--	--
UTMY (km)	--	--	3,165.7	--	--
24-Hour average					
Highest ($\mu g/m^3$)	7.6	6.8	5.9	5.9	7.2
Location					
UTMX (km)	340.7	340.3	340.3	342.4	342.0
UTMY (km)	3,171.9	3,165.7	3,169.8	3,180.6	3,174.0
Second highest ($\mu g/m^3$)	4.9	5.6	4.5	5.8	5.9
Location					
UTMX (km)	340.3	340.3	340.3	343.7	343.7
UTMY (km)	3,165.7	3,165.7	3,165.7	3,178.3	3,178.3

*Annual average impact was based on ISCLT2 results using STAR data (1982 through 1986). Short-term average impacts were based on ISCST2 results for the individual years indicated.

Source: ECT, 1992.

times. However, since even the use of a conservative source inventory resulted in no exceedances of an allowable increment, no further analysis was deemed necessary.

9.2.2.4 Summary

Table 9-13 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.

9.3 IMPACTS ON VISIBILITY

A Level 1 visibility screening analysis was conducted using the VISCREEN program, consistent with EPA (1988b) guidance. Emissions input to the VISCREEN program were the maximum short-term (lb/hr) emission rates for primary PM, NO_x, and H_2SO_4 from Polk Power Station stack sources. These rates were 205 lb/hr of PM, 2,133 lb/hr of NO_x, and 115 lb/hr of H_2SO_4. Table 9-14 summarizes the results of the Level 1 analysis, which, even with the conservative assumptions inherent to such an analysis, resulted in impact values well below the screening thresholds. Therefore, it could be concluded that Polk Power Station emissions will not cause impairment of visibility in the Chassahowitzka Class I area.

9.4 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

9.4.1 IMPACTS ON SOILS

The USDA (1991a and 1991b) lists the primary soil type in Chassahowitzka as Weekiwachee-Durbin muck. This soil type is characterized by high levels of sulfur and organic content. Sulfur levels may approach 4 percent in the upper soil layer. Daily flooding by high tides cause the pH to vary between 6.1 and 7.8.

Typically, SO_2 represents the greatest threat to soil since this pollutant causes increased sulfur content and decreased pH. However, for this project, given the extremely low levels of SO_2 emitted, the distance from the source, the naturally high

Table 9-13. 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	0.0*	2
	24-hour	5.0	5
	3-hour	11.5†	25
NO_2	Annual	0.2	2.5
PM (TSP)	Annual	1.3	5
	24-hour	5.9**	10

* Increment consumption was negative over the entire receptor grid.
† Impact due to Polk Power Station was not actually significant.
**HSH modeled impact.

Source: ECT, 1992.

Table 9-14. Level 1 Visibility Screening Results for the Chassahowitzka NWA

Background	Theta*	Delta E† Threshold	Delta E† Plume	Contrast** Threshold	Contrast** Plume
Sky	10	2.00	0.115	0.05	-0.000
Sky	140	2.00	0.045	0.05	-0.002
Terrain	10	2.00	0.017	0.05	0.000
Terrain	140	2.00	0.005	0.05	0.000

*Theta is the scattering angle between direct solar radiation and the line of sight. Theta equal to 10 degrees (°) is the worst-case sun angle for forward scattering, and theta equal to 140° is the worst-case for backward scattering.

†Delta E, the color difference parameter, indicates the perceived magnitude of color and brightness changes; it is the basis for determining plume perceptibility. The threshold value of 2.00 is used to determine if there is the potential for visibility impairment from the plume. If the absolute value of the plume contrast is greater than the threshold value, the potential is present for visibility impairment.

**Contrast is a measure of the difference in light intensity between the plume and the background. The threshold value of 0.05 is used to determine if there is the potential for visibility impairment from the plume. If the absolute value of the plume contrast is greater than the threshold value, the potential is present for visibility impairment.

Source: ECT, 1992.

sulfur content of the Class I area soils, and the pH variability caused by tidal influences, no impacts to soils are expected.

9.4.2 IMPACTS ON VEGETATION

The Chassahowitzka NWA is a complex ecosystem of vegetation assemblages that depend on the subtle interplay of slight changes in elevation, salinity, hydroperiod, and edaphic factors for distribution, extent, and species composition. The mosaic of plant communities at the Chassahowitzka NWA is represented by pine woods and hammock forests within areas of higher ground, various freshwater forested and nonforested wetlands situated within lowland depressions that are inundated/saturated with fresh water for at least part of the year (mixed swamp, marsh, etc.) and brackish to saltwater wetlands such as salt marsh and mangrove swamp distributed at lower elevations on land that is normally inundated by tidal action and freshwater pulses from upland surface water runoff. The predominant flora associated with these associations is typically common to the Central Florida region and characterized by a high diversity of terrestrial, wetland, and aquatic species. Common vascular taxa within the Chassahowitzka NWA would include slash pine, laurel oak, live oak, cabbage palm, sweet gum, red maple, saw palmetto, and gallberry in the inland areas and needlerush, red mangrove, cordgrass, and saltgrass in the brackish to marine reaches.

As presented in Section 8.2.2, the literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of Polk Power Station would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka due to emissions from Polk Power Station will be far less, as presented previously. The potential for damage at the Chassahowitzka NWA could, therefore, be considered negligible given: (1) the much lower air pollution impacts predicted at Chassahowitzka relative to the immediate Polk Power Station plant vicinity, and (2) the absence of any plant species at Chassahowitzka that would be especially sensitive to the very low predicted pollutant concentrations.

9.4.3 IMPACTS ON WILDLIFE

Wildlife resources in the 30,500-acre Chassahowitzka NWA are fairly typical of central Florida's Gulf Coast. The eastern portions of the site are fringed by hardwood swamp habitats, but the primary habitats are the estuarine and brackish marshes along with the saltwater bays containing many mangrove-covered islands. These habitats support large numbers of resident and migratory waterfowl, water birds, and shorebirds. Wading birds are also quite common. Deer, raccoons, black bears, otters, and bobcats are the notable mammals. Alligators are numerous. Bald eagles and the West Indian manatee are the primary endangered/threatened species utilizing the area.

Air pollution impacts to wildlife have been reported in the literature although many of the incidents involved acute exposures to pollutants usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the levels of pollutants produced by this project will cause injury or death to wildlife. Concentrations of pollutants will be low, emissions will be dispersed over a large area, and mobility of wildlife will minimize their exposure to any unusual concentrations caused by equipment malfunction or unique weather patterns.

Bioaccumulation, particularly of mercury, has been a concern in Florida. There is increasing evidence that mercury may be naturally evolved in Florida and that, combined with manmade sources, is becoming bioaccumulated in certain fish and wildlife. It is unknown what naturally occurring levels may be present in onsite fish and wildlife. However, the likelihood that the small amount attributable to this project would all be methylated, end up in the food chain, and then consumed by predators is considered negligible.

The acid rain effects on wildlife in Florida are primarily those related to aquatic animals. Acidified water may prevent fish egg hatching, damage larvae, and lower immunity factors in adult fish (Barker, 1983). Acid rain can also result in release of metals (especially aluminum) from lake sediments; this can cause a biochemical deterioration of fish gills leading to death by suffocation. However, the sensitivity of Florida lakes to acid rain is in question. Florida lakes have a wide natural range of pH (from 4 pH units to 8.8 pH units). Most well-buffered lakes are in central and south Florida, and rainfall is in the pH range of 4.8 to 5.1. According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degration of aquatic systems have occurred as a direct result of acid precipitation in Florida. The air emissions from Polk Power Station that could contribute to the formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife at Chassahowitzka.

In conclusion, it is unlikely that the projected air emission levels from the Polk Power Station will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka NWA.

9.5 CONCLUSIONS

As described in the previous sections, analyses were undertaken to evaluate the potential for emissions from Polk Power Station to affect the resources of the Chassahowitzka NWA. Air quality impacts with respect to PSD Class I increments were projected using the ISC2 and MESOPUFF-II models. The modeling inputs and assumptions were conservative (i.e., predicted impacts would be higher than actually expected or observed). However, even with this conservatism no increment exceedances were predicted.

Similarly, a very conservative Level 1 assessment of potential visibility impacts showed that emissions from Polk Power Station will not impair visibility resources at Chassahowitzka.

Finally, the literature was reviewed to establish pollutant levels that would have the potential to impact soils, vegetation, and wildlife. Air quality impacts at Chassahowitzka due to emissions from Polk Power Station are predicted to be very low relative to the thresholds documented in the literature. This would be expected given the use of clean fuels at, and low emissions from, Polk Power Station.

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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:

$$A_s = 30{,}000\ scfm \times 0.02\ gr/scf \times (1\ lb/7{,}000\ gr) \times (60\ min/hr);$$
$$A_s = 5.14\ lb/hr;\ and$$
$$A_s = 0.65\ g/\text{sec}.$$

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 [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:

$$A_L = 12{,}500\ scfm \times 0.02\ gr/scf \times 10\ hr/delivery \times 200\ delivery/yr \times (1\ lb/7{,}000\ gr) \times (1\ t/2{,}000\ lb) \times (60\ \text{min}/hr);$$

$$A_L = 2.14\ tpy;\ and$$

$$A_L = 0.27\ g/\text{sec}.$$

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 (%) = 15%.

Substituting, the emission factor is:

$$E = [0.0032 \times 0.74 \times (8.6/5)^{1.3}] \ / \ (15/2)^{1.4};$$

$$E = 0.000285\ lb/t.$$

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 = 0.000285 lb/t; and
H = hourly coal transfer = 3,000 t/hr.

Substituting, the short-term emissions are

$$A_s = 0.000285\ lb/t \times 3{,}000\ t/hr;$$

$$A_s = 0.86\ lb/hr;\ and$$

$$A_s = 0.11\ g/\text{sec}.$$

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 = 0.000285 lb/t;
T = annual coal usage = 952,020 tpy; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are

$$A_L = 0.000285\ lb/t \times 952{,}020\ tpy \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.14\ tpy;\ and$$
$$A_L = 0.004\ g/\text{sec}.$$

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 (%) = 15%.

Substituting, the emission factor is:

$$E = [0.0032 \times 0.74 \times (8.6/5)^{1.3}]\ /\ (15/2)^{1.4};$$
$$E = 0.000285\ lb/t.$$

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 = 0.000285 lb/t; and
H = hourly coal transfer = 775 t/hr.

Substituting, the short-term emissions are

$$A_s = 0.000285\ lb/t \times 775\ t/hr;$$
$$A_s = 0.22\ lb/hr;\ and$$
$$A_s = 0.03\ g/\text{sec.}$$

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 = 0.000285 lb/t;
T = annual coal usage = 952,020 tpy; and
c_2 = conversion constant = 1 t/2,000 lb.

Substituting, the annual emissions are

$$A_L = 0.000285\ lb/t \times 952{,}020\ tpy \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.14\ tpy;\ and$$
$$A_L = 0.004\ g/\text{sec.}$$

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:

$$u^{*} = 0.1 \times u_{10}^{+} \times (u_s/u_r)$$

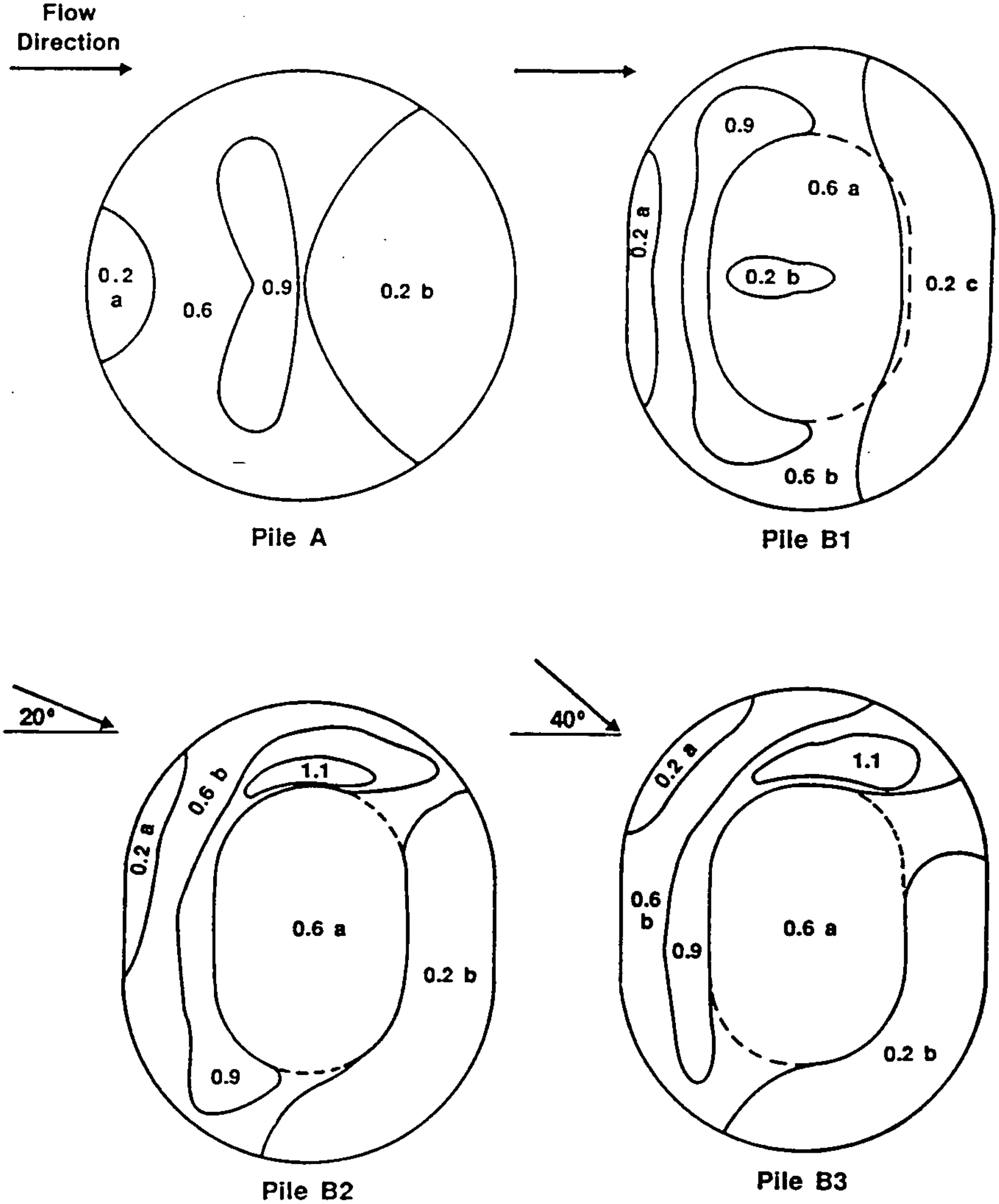
where: u^{*} = friction velocity (m/sec);
u_{10}^{+} = windspeed (m/sec) at 10 m; and
u_s/u_r = friction velocity coefficient (dimensionless), derived from Pile B3 (Figure A.2-1).

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.



Pile A

Pile B1

Pile B2

Pile B3

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

			Friction Velocity (m/sec)			
Period	Windspeed at 7 m (m/sec)	Windspeed at 10 m (m/sec)	u_*/u_r 0.2	u_*/u_r 0.6	u_*/u_r 0.9	u_*/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 of the pile (m) = 100.6 m;
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:

$$R_{S1} = 0.14 \times 100.6\ m \times 34.5\ m;$$
$$R_{S1} = 485.9\ m^2;$$
$$R_{S2} = 0.04 \times 100.6\ m \times 34.5\ m;\ and$$
$$R_{S2} = 138.8\ m^2.$$

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/m^2)	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:

$$\begin{aligned} A_s &= 0.5 \times [(485.9\ m^2 \times 16.52\ g/m^2) + (138.8\ m^2 \times 43.82\ g/m^2)]; \\ A_s &= 3.89\ lb/hr;\ and \\ A_s &= 0.49\ g/\text{sec}. \end{aligned}$$

The short-term emission rate from the long-term pile is:

$$\begin{aligned} A_S &= 0.1\ [(1{,}898.5\ m^3 \times 16.52\ g/m^3) + (542.4\ m^2 \times 43.82\ g/m^2)]; \\ A_S &= 3.04\ lb/hr; \\ A_S &= 0.38\ g/\text{sec}. \end{aligned}$$

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:

$$\begin{aligned} A_L = {} & 0.5\ [138.8\ m^2 \times 6.38\ g/m^2) + (138.8\ m^2 \times 0.24) + (138.8\ m^2 \times 7.81\ g/m^2); \\ & + (138.8\ m^2 \times 43.82\ g/m^2) + (485.9\ m^2 \times 16.52\ g/m^2) + (138.8\ m^2 \times 6.38\ g/m^2); \\ & + (138.8\ m \times 7.81\ g/m^2)] \times (1\ lb/453.6\ g) \times (1\ t/2{,}000\ lb); \\ A_L = {} & 0.01\ tpy;\ and \\ = {} & 0.0003\ g/sec. \end{aligned}$$

For the long-term stockpile, this calculation is:

$$\begin{aligned} A_L = {} & 0.1\ [(542.4\ m^2 \times 6.38\ g/m^2) + (542.4\ m^2 \times 0.26\ g/m^2) \\ & + (542.4\ m^2 \times 7.81\ g/m^2) + (542.4\ m^2 \times 43.82\ g/m^2) \\ & + (1{,}898.5\ m^2 \times 16.52\ g/m^2) + (542.4\ m^2 \times 6.38\ g/m^2) + (542.4\ m^2 \times 7.81\ g/m^2)] \\ & \times (1\ lb/453.6\ g) \times 1\ t/2{,}000\ lb; \\ A_L = {} & 0.09\ tpy;\ and \\ = {} & 0.0025\ g/sec. \end{aligned}$$

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:

$$A_L = 100\ lb/hr \times 0.5\ hr/day \times 13\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.33\ tpy;\ and$$
$$A_L = 0.009\ g/sec.$$

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:

$$A_L = 0.5\ lb/hr \times 24\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 2.19\ tpy;\ and$$
$$A_L = 0.06\ g/\mathrm{sec}.$$

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:

$$A_L = 0.21\ lb/hr\ 1\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.038\ tpy;\ and$$
$$A_L = 0.001\ g/\text{sec}.$$

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):

$$A_s = 0.5\ lb/hr;\ and$$
$$A_s = 0.06\ g/\text{sec}.$$

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) = 0.5 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:

$$A_L = 0.5\ lb/hr \times 1\ hr/day \times 365\ day/yr \times 1\ t/2{,}000\ lb;$$
$$A_L = 0.09\ tpy;\ and$$
$$A_L = 0.003\ g/\text{sec}.$$

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:

$$\begin{aligned} A_s = {} & \{0.70\ [(40 \times 0.00083) + (2 \times 0.228) + (12 \times 0.0017) + (16 \times 0.0494) + \\ & (2 \times 0.104) + (261 \times 0.0056)] \times 0.1202 \times 0.50 \times 2.2\} + \\ & \{0.10\ [(1{,}750 \times 0.00083) + (2 \times 0.228) + (8 \times 0.0017) + (10 \times 0.0494) + \\ & (4 \times 0.104) + (460 \times 0.0056)] \times 0.015 \times 0.50 \times 2.2\} \\ = {} & 0.284\ lb/hr \\ = {} & 0.036\ g/sec \end{aligned}$$

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	20
	NH_3	0.00	20 percent in sulfur recover unit	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	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).

APPENDIX B

EMISSIONS INVENTORIES

APPENDIX B.1

SO_2 EMISSIONS INVENTORY FOR AAQS ANALYSIS

Emission Inventory for NAAQS Analysis for SO2

Identi-fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
100a	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.4	92.53	22.90	389.0	23.90	4.88
100b	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.3	92.53	22.90	389.0	23.90	4.88
100c	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.5	92.53	22.90	389.0	23.90	4.88
102a	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	19.98	7.62	560.8	17.74	1.07
102b	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	44.14	33.53	316.3	19.69	1.52
102c	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	44.14	33.53	316.3	19.69	1.52
102d	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	54.60	60.35	353.0	16.40	2.44
102e	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	54.60	60.35	353.0	17.77	2.44
102f	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	2.97	28.65	326.3	7.93	3.05
102g	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	13.19	54.86	331.3	13.32	2.80
102h	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	13.19	54.86	313.6	8.18	2.80
102i	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	13.19	54.86	324.7	9.78	2.80
102j	Hillsborough	CF Industries (Central Phosphate)	388.0	3,116.0	0.12	2.44	373.0	0.33	0.61
103a	Hillsborough	TECO Hooker's Point	358.0	3,091.0	41.37	85.35	419.1	6.19	3.44
103b	Hillsborough	TECO Hooker's Point	358.0	3,091.0	41.37	85.35	438.0	5.57	3.44
103c	Hillsborough	TECO Hooker's Point	358.0	3,091.0	57.00	85.35	434.1	8.17	3.66
103d	Hillsborough	TECO Hooker's Point	358.0	3,091.0	57.00	85.35	421.9	7.34	3.66
103e	Hillsborough	TECO Hooker's Point	358.0	3,091.0	84.61	85.35	448.0	11.09	3.44
103f	Hillsborough	TECO Hooker's Point	358.0	3,091.0	107.93	85.35	434.1	22.37	2.87
104a	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	36.75	45.70	355.0	9.20	2.29
104b	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	52.54	45.72	339.7	10.61	2.44
104c	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	54.61	21.34	344.1	11.43	2.74
104d	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.12	12.19	321.9	9.94	0.52
104e	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.06	6.10	488.6	15.89	1.22
104f	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	4.00	40.54	315.2	15.38	2.13
105a	Hillsborough	TECO Big Bend	361.9	3,075.0	3,309.00	149.35	404.7	13.74	7.32
105b	Hillsborough	TECO Big Bend	361.9	3,075.0	3,275.32	149.35	404.7	13.02	7.32

Emission Inventory for NAAQS Analysis for SO2

Identi-fication Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
105c	Hillsborough	TECO Big Bend	362.0	3,075.0	3,372.92	149.35	410.2	14.47	7.32
105e	Hillsborough	TECO Big Bend	361.7	3,075.5	39.59	22.86	770.8	18.74	4.27
105f	Hillsborough	TECO Big Bend	361.7	3,075.2	39.59	22.86	770.8	18.74	4.27
105g	Hillsborough	TECO Big Bend	361.9	3,075.0	11.34	10.67	816.3	15.17	4.57
105h	Hillsborough	TECO Big Bend	362.0	3,075.0	654.70	149.40	342.2	19.81	7.32
106a	Hillsborough	TECO Gannon	360.0	3,087.5	380.43	93.27	415.8	28.90	3.05
106b	Hillsborough	TECO Gannon	360.0	3,087.5	380.43	93.27	420.8	30.85	3.05
106c	Hillsborough	TECO Gannon	360.0	3,087.5	483.96	93.27	419.7	38.64	3.23
106d	Hillsborough	TECO Gannon	360.0	3,087.5	567.71	93.27	426.9	22.97	3.05
106e	Hillsborough	TECO Gannon	360.0	3,087.5	691.28	93.27	423.6	23.18	4.45
106f	Hillsborough	TECO Gannon	360.0	3,087.5	1,149.41	93.27	433.0	24.74	5.36
106g	Hillsborough	TECO Gannon	360.0	3,087.5	1.38	10.67	816.3	136.61	1.52
107a	Hillsborough	Gulf Coast Lead Company	364.0	3,093.5	48.45	29.57	344.1	37.59	0.61
107b	Hillsborough	Gulf Coast Lead Company	364.0	3,093.5	0.75	8.84	309.1	20.85	0.34
108c	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.12	6.10	605.2	20.21	0.37
108d	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	11.57	46.33	299.7	12.14	1.77
108e	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	15.43	46.33	298.0	13.17	1.77
109a	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	24.59	38.10	339.0	10.13	2.90
109b	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	24.59	38.10	346.0	18.40	2.44
109c	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	0.26	6.10	616.3	8.31	0.30
110a	Hillsborough	Mobil Mining & Minerals Big Four Mine	394.7	3,069.6	16.38	30.48	333.0	12.58	1.83
110b	Hillsborough	Mobil Mining & Minerals Big Four Mine	394.7	3,069.6	0.60	8.20	505.0	7.57	0.41
110c	Hillsborough	Mobil Mining & Minerals Big Four Mine	394.7	3,069.6	1.90	30.50	334.0	7.26	1.82
111a	Manatee	Royster Phosphates (AMAX) Piney Point	348.6	3,057.3	56.75	60.96	336.9	9.50	2.83
111b	Manatee	Royster Phosphates (AMAX) Piney Point	348.5	3,057.3	0.89	60.96	309.1	23.94	2.13
111c	Manatee	Royster Phosphates (AMAX) Piney Point	348.5	3,057.3	2.36	9.14	558.0	7.71	1.22
112a	Manatee	Florida Power & Light	367.2	3,054.1	1,047.90	152.10	425.8	23.61	7.99

Emission Inventory for NAAQS Analysis for SO2

Identi–fication Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
112b	Manatee	Florida Power & Light	367.2	3,054.1	539.67	152.10	425.8	23.98	7.92
113a	Osceola	Florida Power Intercession City	446.3	3,126.0	20.99	7.92	703.6	18.06	4.24
113b	Osceola	Florida Power Intercession City	446.3	3,126.0	20.99	7.92	703.6	18.06	4.24
113c	Osceola	Florida Power Intercession City	446.3	3,126.0	20.99	4.57	505.2	18.06	4.24
113d	Osceola	Florida Power Intercession City	446.3	3,126.0	20.99	7.92	703.6	18.06	4.24
113e	Osceola	Florida Power Intercession City	446.3	3,126.0	20.99	7.92	703.6	18.06	4.24
113f	Osceola	Florida Power Intercession City	446.3	3,126.0	20.99	7.92	703.6	18.06	4.24
113i	Osceola	Florida Power Intercession City	446.3	3,126.0	310.90	15.24	819.8	56.21	4.21
113j	Osceola	Florida Power Intercession City	446.3	3,126.0	276.10	15.24	880.8	32.07	7.04
114a	Pinellas	Florida Power P L Bartow	342.4	3,082.6	423.07	91.44	428.6	36.32	2.74
114b	Pinellas	Florida Power P L Bartow	342.4	3,082.6	448.72	91.44	424.7	31.34	2.74
114c	Pinellas	Florida Power P L Bartow	342.4	3,082.6	710.54	91.44	408.0	34.57	3.35
114d	Pinellas	Florida Power P L Bartow	342.4	3,082.6	1.81	9.14	541.3	5.19	0.91
114e	Pinellas	Florida Power P L Bartow	342.4	3,082.6	71.77	13.72	771.9	22.55	5.27
114f	Pinellas	Florida Power P L Bartow	342.4	3,082.6	71.77	13.72	771.9	22.55	5.27
114g	Pinellas	Florida Power P L Bartow	342.4	3,082.6	3.57	13.72	771.9	22.55	5.27
114h	Pinellas	Florida Power P L Bartow	342.4	3,082.6	49.49	13.72	771.9	22.55	5.27
115a	Pinellas	Florida Power Higgins	336.5	3,098.4	97.34	53.04	428.6	8.44	3.81
115b	Pinellas	Florida Power Higgins	336.5	3,098.4	94.95	53.04	427.4	8.53	3.81
115c	Pinellas	Florida Power Higgins	336.5	3,098.4	130.02	53.04	422.4	7.47	3.81
115d	Pinellas	Florida Power Higgins	336.5	3,098.4	4.20	16.76	727.4	113.47	4.60
115e	Pinellas	Florida Power Higgins	336.5	3,098.4	5.61	16.76	727.4	113.47	4.60
115f	Pinellas	Florida Power Higgins	336.5	3,098.4	0.95	16.76	727.4	113.47	4.60
115g	Pinellas	Florida Power Higgins	336.5	3,098.4	14.45	16.15	727.4	113.47	4.60
116a	Pinellas	Florida Power Bayboro	338.8	3,071.3	49.49	12.19	755.2	6.54	6.98
116b	Pinellas	Florida Power Bayboro	338.8	3,071.3	49.49	12.19	755.2	6.54	6.98
116c	Pinellas	Florida Power Bayboro	338.8	3,071.3	49.49	12.19	755.2	6.54	6.98

Emission Inventory for NAAQS Analysis for SO2

Identi–fication Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
116d	Pinellas	Florida Power Bayboro	338.8	3,071.3	49.49	12.19	755.2	6.54	6.98
117a	Pinellas	Pinellas Co. Resource Recovery Facility	335.2	3,084.1	25.05	49.07	504.7	26.82	2.38
117b	Pinellas	Pinellas Co. Resource Recovery Facility	335.2	3,084.1	7.14	49.07	504.7	26.82	2.38
117d	Pinellas	Pinellas Co. Resource Recovery Facility	335.2	3,084.1	62.24	49.10	522.0	27.70	2.74
118a	Polk	Lakeland City Power Larsen Power Station	409.3	3,102.8	93.37	50.29	433.0	5.64	3.05
118b	Polk	Lakeland City Power Larsen Power Station	409.3	3,102.8	0.40	50.29	444.1	6.47	3.05
118c	Polk	Lakeland City Power Larsen Power Station	409.3	3,102.8	0.35	50.29	444.1	6.47	3.05
118d	Polk	Lakeland City Power Larsen Power Station	409.3	3,102.8	18.71	50.29	444.1	6.86	3.05
118e	Polk	Lakeland City Power Larsen Power Station	409.3	3,102.8	0.20	9.75	699.7	171.38	1.52
118g	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	341.56	45.72	419.1	23.96	2.74
119a	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	1.47	6.10	652.4	23.54	0.79
119b	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	1.47	6.10	652.4	23.54	0.79
119c	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	8.32	10.97	791.3	0.39	2.80
119d	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	25.68	47.55	402.4	21.29	3.17
119e	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	500.10	76.20	350.0	19.70	4.88
119g	Polk	Lakeland City Power McIntosh Power Station	409.3	3,102.8	29.11	30.48	783.2	28.22	5.79
120a	Polk	Gardinier	415.3	3,063.3	33.77	19.20	290.2	7.09	2.90
121b	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	40.36	60.96	341.3	24.58	1.52
121c	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	4.40	40.23	316.3	26.40	2.13
121d	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	0.03	24.38	313.6	16.63	2.01
121e	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	40.97	15.24	333.0	17.29	2.04
121h	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	40.97	15.24	333.0	17.29	2.04
121i	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	0.06	6.10	366.3	17.46	0.30
121j	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	0.06	10.36	366.3	0.12	0.30
121k	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	0.06	9.45	366.3	0.03	0.61
121l	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	0.06	7.92	366.3	0.12	0.30
121m	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	0.06	7.92	366.3	0.12	0.30

Emission Inventory for NAAQS Analysis for SO2

Identi– fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper– ature (K)	Velocity (m/s)	Diameter (m)
121n	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	87.00	45.72	311.0	16.70	1.52
121o	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	40.32	60.96	347.0	25.10	1.52
121p	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	40.32	60.96	347.0	25.10	1.52
121q	Polk	Seminole Fertilizer (W R Grace)	409.8	3,087.0	40.20	60.96	347.0	25.10	1.52
122a	Polk	Mobil Mining & Minerals SR 676	398.5	3,085.1	19.75	24.38	344.1	12.65	2.29
122c	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.3	1.76	3.96	521.9	2.12	0.76
122d	Polk	Mobil Mining & Minerals SR 676	398.2	3,085.0	2.44	25.90	339.0	15.20	2.29
123b	Polk	Royster Company	406.8	3,085.1	1.12	31.09	316.3	8.16	2.68
123c	Polk	Royster Company	406.8	3,085.1	1.04	13.72	299.7	2.55	1.13
123e	Polk	Royster Company	406.8	3,085.1	35.70	61.00	360.0	12.20	2.13
124a	Polk	US Agri–Chemicals Hwy 60	413.2	3,086.3	45.34	28.96	305.2	8.42	2.10
125a	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	6.42	21.34	477.4	14.98	1.13
125d	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.06	1.83	405.2	104.86	0.09
125e	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	63.00	53.40	355.0	15.91	2.59
125f	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	63.00	53.40	355.0	15.91	2.59
126d	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	0.52	10.97	588.6	13.45	0.76
126f	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	50.40	63.41	361.0	10.88	2.13
126g	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.3	50.40	63.41	370.0	7.88	2.13
126h	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.3	42.00	63.10	351.0	9.87	2.59
127a	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	33.58	30.48	355.0	9.27	2.29
127b	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	33.58	30.48	355.0	9.27	2.29
127d	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	2.33	28.96	605.2	3.58	1.68
127e	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.09	12.19	366.3	0.03	0.61
127f	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.09	12.19	366.3	0.03	0.61
127g	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.12	12.19	366.3	0.03	0.61
127h	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.09	12.19	366.3	2.67	0.61
127j	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	45.72	45.72	355.0	9.65	2.44

Emission Inventory for NAAQS Analysis for SO2

Identi– fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper– ature (K)	Velocity (m/s)	Diameter (m)
128a	Polk	Agrico Chemical Company Pierce	403.7	3,079.0	3.80	24.38	316.3	5.76	3.05
128b	Polk	Agrico Chemical Company Pierce	403.7	3,079.0	8.21	24.38	320.8	21.25	2.44
129a	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	0.03	10.67	494.1	15.77	1.46
129b	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	37.83	45.72	349.7	28.30	1.55
129c	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	37.83	45.72	344.1	26.06	1.55
129d	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	37.83	45.72	349.7	9.53	2.90
129f	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	6.10	42.67	304.7	10.66	2.74
129g	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	113.50	45.73	350.0	39.06	1.60
129j	Polk	Agrico Chemical Company South Pierce	407.5	3,071.5	4.41	38.10	327.4	14.55	3.05
130b	Polk	Conserve Inc.	398.7	3,084.2	3.34	24.69	327.4	3.77	2.29
130c	Polk	Conserve Inc.	398.7	3,084.2	0.12	8.23	533.0	13.74	0.61
130d	Polk	Conserve Inc.	398.7	3,084.2	0.17	11.89	533.0	8.91	0.98
130f	Polk	Conserve Inc.	398.7	3,084.2	42.00	45.70	352.0	10.30	2.30
131a	Polk	IMC Fertilizer New Wales	396.5	3,079.0	0.43	40.54	313.6	15.18	2.13
131b	Polk	IMC Fertilizer New Wales	396.6	3,078.8	71.74	28.96	564.1	17.10	1.71
131e	Polk	IMC Fertilizer New Wales	396.7	3,079.4	2.76	52.12	316.3	17.97	1.83
131h	Polk	IMC Fertilizer New Wales	396.7	3,079.4	5.54	36.60	319.1	20.15	1.83
131i	Polk	IMC Fertilizer New Wales	396.7	3,079.4	4.80	52.40	319.0	15.80	1.40
131j	Polk	IMC Fertilizer New Wales	396.7	3,079.4	189.00	61.00	350.0	15.31	2.60
131k	Polk	IMC Fertilizer New Wales	396.7	3,079.4	126.00	60.70	350.0	15.31	2.60
132a	Polk	Mobil–Electrophos Division	405.6	3,079.4	7.11	29.26	306.9	7.7	2.13
132b	Polk	Mobil–Electrophos Division	405.6	3,079.4	28.76	30.48	319.1	12.34	1.31
132c	Polk	Mobil–Electrophos Division	405.6	3,079.4	2.22	7.32	421.9	12.83	0.46
132d	Polk	Mobil–Electrophos Division	405.6	3,079.4	1.09	7.32	463.6	3.23	0.91
132e	Polk	Mobil–Electrophos Division	405.6	3,079.4	2.27	18.29	321.9	14.34	0.76
133a	Polk	Imperial Phosphates Ltd.	404.8	3,069.5	6.91	27.43	333.0	20.65	1.52
133b	Polk	Imperial Phosphates Ltd.	404.8	3,069.5	1.01	27.43	494.1	7.28	0.61

Emission Inventory for NAAQS Analysis for SO2

Identification Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
			East	North					
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	25.40	48.80	411.0	14.30	5.49
138a	Hillsborough	Tampa City McKay Bay Refuse-to-Energy	360.0	3,091.9	21.42	45.70	449.7	21.30	1.34
167a	Highlands	TECO Sebring Sebring Airport	464.3	3,035.4	55.62	45.72	441.3	24.17	1.83
167b	Highlands	TECO Sebring Sebring Airport	464.3	3,035.4	55.62	45.72	449.7	24.35	1.83

Sources: FDER, 1991, 1992.
ECT, 1992.

APPENDIX B.2

SO_2 EMISSIONS INVENTORY FOR PSD CLASS I ANALYSIS

Emission Inventory for PSD Class 1 Analysis for SO2

Identi–fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
100d	Hardee	Hardee Power Station	404.8	3,057.4	277.60	22.90	389.0	23.90	4.88
102k	Hillsborough	CF Industries	388.0	3,116.0	88.20	33.50	316.0	19.50	1.50
102l	Hillsborough	CF Industries proposed D	388.0	3,116.0	54.60	60.35	353.0	17.77	2.44
102m	Hillsborough	CF Industries proposed C	388.0	3,116.0	54.60	60.35	353.0	17.77	2.44
102n	Hillsborough	CF Industries baseline C	388.0	3,116.0	–50.40	60.35	353.0	16.40	2.44
102o	Hillsborough	CF Industries baseline D	388.0	3,116.0	–50.40	60.35	353.0	16.40	2.44
102p	Hillsborough	CF Industries	388.0	3,116.0	–105.00	18.80	316.0	18.80	1.52
104g	Hillsborough	Cargill Fertilizer (Gardinier) SAP #7	363.4	3,082.4	46.20	45.72	355.0	9.20	2.29
104h	Hillsborough	Cargill Fertilizer (Gardinier) SAP #8	363.4	3,082.4	52.50	45.72	355.0	8.63	2.44
104i	Hillsborough	Cargill Fertilizer (Gardinier) SAP #9	363.4	3,082.4	54.60	45.72	344.0	12.50	2.74
104j	Hillsborough	Cargill Fertilizer (Gardinier) dryer	363.4	3,082.4	–28.89	20.73	310.0	13.12	1.07
104k	Hillsborough	Cargill Fertilizer (Gardinier) SAP #4, 5, 6	363.4	3,082.4	–196.30	22.60	322.0	19.51	1.52
104l	Hillsborough	Cargill Fertilizer (Gardinier) SAP #7	363.4	3,082.4	–50.71	45.72	355.0	9.20	2.29
105h	Hillsborough	TECO Big Bend – Unit 4	361.9	3,075.0	654.70	149.40	342.2	19.81	7.32
105i	Hillsborough	TECO Big Bend – Units 1 & 2	361.9	3,075.0	–2,436.00	149.40	422.0	28.65	7.32
105j	Hillsborough	TECO Big Bend – Unit 3	361.9	3,075.0	–1,218.00	149.40	418.0	14.33	7.32
110b	Hillsborough	Mobil Big–4 boiler (AMAX)	394.8	3,067.7	0.60	8.20	505.0	7.57	0.41
110c	Hillsborough	Mobil Big–4 dryer (AMAX)	394.9	3,069.8	1.90	30.50	334.0	7.26	1.82
113i	Osceola	FPC/Intercession City prop turbines/7 EA	446.3	3,126.0	310.90	15.24	819.8	56.21	4.21
113j	Osceola	FPC/Intercession City prop turbines/7 FA	446.3	3,126.0	276.10	15.24	880.8	32.07	7.04
117d	Pinellas	Pinellas Co Resource Recovery Facility	335.3	3,084.4	62.24	49.10	522.0	27.72	2.74
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,102.8	29.11	30.48	783.2	28.22	5.79
119g	Polk	Lakeland McIntosh 3	409.5	3,105.8	500.10	76.20	350.0	19.70	4.88
121n	Polk	WR Grace/Seminole SAP #3	409.8	3,087.0	42.87	45.72	311.0	16.70	1.52
121o	Polk	WR Grace/Seminole SAP #4	409.8	3,087.0	40.32	60.96	347.0	25.10	1.52
121p	Polk	WR Grace/Seminole SAP #5	409.8	3,087.0	40.32	60.96	347.0	25.10	1.52
121q	Polk	WR Grace/Seminole SAP #6	409.8	3,087.0	40.32	60.96	347.0	25.10	1.52
121r	Polk	WR Grace/Seminole dryer	409.8	3,087.0	–39.41	15.24	327.0	17.32	2.04
121s	Polk	WR Grace/Seminole SAP #1	409.8	3,087.0	–108.00	45.72	352.0	16.50	1.37
121t	Polk	WR Grace/Seminole SAP #2	409.8	3,087.0	–108.00	45.72	352.0	16.50	1.37
121u	Polk	WR Grace/Seminole SAP #3	409.8	3,087.0	–52.50	45.72	311.0	16.70	1.52
122d	Polk	Mobil Mining & Minerals SR 676 #4 dryer	398.3	3,084.3	2.44	25.90	339.0	15.20	2.29

Emission Inventory for PSD Class 1 Analysis for SO2

Identi–fication Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
122e	Hillsborough	Mobil Mining & Minerals SR 676 calciner	398.3	3,084.3	–13.89	28.40	340.0	19.24	1.09
123d	Polk	Royster #1	406.7	3,085.2	–152.70	51.00	356.0	9.90	2.13
123e	Polk	Royster #2	406.7	3,085.2	35.70	61.00	360.0	12.20	2.13
124b	Polk	US Agri–Chem Hwy 60 dryer	413.2	3,086.3	–4.99	15.80	332.0	10.01	1.83
124c	Polk	US Agri–Chem Hwy 60 SAP	413.2	3,086.3	–41.90	28.96	305.0	7.50	2.12
125e	Polk	US Agri–Chem Hwy 630 H2SO4 1	416.1	3,068.6	63.00	53.40	355.0	15.91	2.59
125f	Polk	US Agri–Chem Hwy 630 H2SO4 2	416.1	3,068.6	63.00	53.40	355.0	15.91	2.59
125g	Polk	US Agri–Chem Hwy 630 H2SO4 X	416.2	3,068.7	–78.80	29.00	314.0	6.77	3.02
125h	Polk	US Agri–Chem Hwy 630 GTSP	416.0	3,069.0	–18.27	38.35	330.0	17.60	1.52
125i	Polk	US Agri–Chem Hwy 630 rock dryer	416.0	3,069.0	–15.79	25.60	332.0	16.26	1.52
126e	Polk	CF Industries DAP 1–3	408.5	3,082.5	3.97	36.40	339.0	16.11	2.13
126f	Hillsborough	CF Industries H2SO4 5	408.5	3,082.5	50.40	63.41	361.0	10.88	2.13
126g	Hillsborough	CF Industries H2SO4 6	408.5	3,082.5	50.40	63.41	370.0	7.28	2.13
126h	Hillsborough	CF Industries H2SO4 7	408.5	3,082.5	42.00	67.10	351.0	9.80	2.40
126i	Hillsborough	CF Industries H2SO4 1	408.5	3,082.5	–60.90	30.49	350.0	12.20	1.37
126j	Hillsborough	CF Industries H2SO4 2	408.5	3,082.5	–110.25	30.49	350.0	10.37	1.68
126k	Hillsborough	CF Industries H2SO4 3	408.5	3,082.5	–107.10	30.49	364.0	4.27	2.74
126l	Hillsborough	CF Industries H2SO4 4	408.5	3,082.5	–174.83	30.49	358.0	7.93	2.13
126m	Hillsborough	CF Industries H2SO4 5	408.5	3,082.5	–226.80	63.41	358.0	10.67	2.13
126n	Hillsborough	CF Industries H2SO4 6	408.5	3,082.5	–170.10	63.41	359.0	10.37	2.13
127i	Polk	Farmland Industries 3, 4 H2SO4	409.5	3,079.5	67.16	30.48	355.0	9.27	2.29
127j	Polk	Farmland Industries 5 H2SO4	409.5	3,079.5	41.96	45.72	355.0	9.65	2.44
127k	Polk	Farmland Industries 1, 2 H2SO4	409.5	3,079.5	–83.98	30.48	311.0	20.18	1.37
128c	Polk	Agrico Pierce dryers 1, 2	404.1	3,079.0	–24.32	24.38	339.0	12.94	1.52
128d	Polk	Agrico Pierce dryers 3, 4	404.1	3,079.0	–23.00	24.38	339.0	18.82	2.43
129h	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	–75.60	45.73	350.0	26.40	1.60
129i	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	113.50	45.73	350.0	39.06	1.60
129j	Polk	Agrico South Pierce DAP plant	407.5	3,071.3	4.41	38.10	328.0	14.60	3.10
130e	Polk	Conserve Inc. rock dryer	398.4	3,084.2	–3.88	24.40	339.0	12.90	1.52
130f	Polk	Conserve Inc.	398.4	3,084.2	42.00	45.70	352.0	10.30	2.30
130g	Polk	Conserve Inc.	398.4	3,084.2	–54.60	30.50	308.0	18.90	1.80
131h	Polk	IMC New Wales DAP	396.6	3,078.9	5.54	36.60	319.1	20.15	1.83

Emission Inventory for PSD Class 1 Analysis for SO2

Identi- fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper- ature (K)	Velocity (m/s)	Diameter (m)
131i	Polk	IMC New Wales multiphos	396.6	3,078.9	4.80	52.40	314.0	15.80	1.40
131j	Polk	IMC New Wales SAP #1, 2, 3 projected	396.6	3,078.9	189.00	61.00	350.0	15.31	2.60
131k	Polk	IMC New Wales SAP #4, 5 projected	396.6	3,078.9	126.00	60.70	350.0	15.31	2.60
131l	Polk	IMC New Wales rock dryer	396.6	3,078.9	−34.27	21.00	347.0	18.60	2.13
131m	Polk	IMC New Wales SAP #1, 2, 3 baseline	396.6	3,078.9	−146.00	61.00	350.0	14.28	2.60
132f	Polk	Mobil−Electrophos boiler	405.6	3,079.4	−6.53	7.32	464.0	3.23	0.91
132g	Polk	Mobil−Electrophos boiler	405.6	3,079.4	−10.00	6.10	464.0	7.71	0.91
132h	Polk	Mobil−Electrophos rock dryer	405.6	3,079.4	−20.90	18.29	350.0	6.79	1.83
132i	Polk	Mobil−Electrophos calciner	405.6	3,079.4	−7.11	25.61	306.0	6.97	2.13
132j	Polk	Mobil−Electrophos coke dryer	405.6	3,079.4	−2.97	18.29	322.0	22.87	0.70
132k	Polk	Mobil−Electrophos furnace	405.6	3,079.4	−47.25	29.27	314.0	8.52	2.13
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	6.35	48.80	411.0	14.30	5.49
135a	Hillsborough	Hillsborough Co Resource Recovery Facility	368.2	3,092.7	21.40	50.00	491.0	18.30	1.80
136a	Pasco	Proposed Pasco Co Cogeneration Facility	385.6	3,139.0	5.04	30.48	384.3	17.13	3.35
137a	Polk	Ridge Cogeneration	416.7	3,100.4	13.80	99.10	350.0	14.54	3.05
140a	Hernando	Asphalt Pavers No. 3	359.9	3,162.4	2.25	12.20	377.0	10.58	1.37
140b	Hernando	Asphalt Pavers No. 4	361.4	3,168.4	2.25	8.50	357.4	10.95	1.08
141a	Hillsborough	CLM Chl	361.8	3,088.3	21.02	30.00	375.0	20.00	0.61
142a	Pasco	Couch Construction − Odessa (asphalt)	340.7	3,119.5	7.25	9.14	436.0	22.30	1.40
143a	Pasco	Couch Construction − Zephyrhills (asphalt)	390.3	3,129.4	3.54	6.10	422.0	21.00	1.38
144a	Pasco	Dris Paving (Asphalt)	340.6	3,119.2	0.23	12.20	339.0	6.47	3.05
145a	Hernando	ER Jahna (lime dryer)	386.7	3,155.8	0.82	10.67	327.0	8.99	1.83
146a	Pasco	Evans Packing	383.3	3,135.8	0.20	12.30	466.2	9.20	0.40
147a	Hernando	FDOC boiler #3	382.2	3,166.1	2.99	9.14	478.0	4.57	0.61
148a	Hernando	Florida Mining & Materials kiln 2	356.2	3,169.9	1.45	32.01	394.2	9.90	4.88
149a	Hernando	Florida Crushed Stone kiln 1	360.0	3,162.4	98.40	97.60	442.0	23.23	4.88
150a	Citrus	Crystal River 4	334.2	3,204.5	1,008.80	182.90	398.0	21.00	6.90
150b	Citrus	Crystal River 5	334.2	3,204.5	1,008.80	182.90	398.0	21.00	6.90
150c	Citrus	Crystal River 1	334.2	3,204.5	−314.00	152.00	422.0	42.10	4.57
150d	Citrus	Crystal River 2	334.2	3,204.5	−1,859.00	153.00	422.0	42.10	4.88
151a	Volusia	FPC/DeBary prop turbines	465.7	3,197.2	466.40	15.24	819.8	56.21	4.21
152a	Pinellas	Hospital Corp of AM boiler #1	333.4	3,141.0	0.08	10.98	533.0	4.00	0.31

Emission Inventory for PSD Class 1 Analysis for SO2

Identi-fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
152b	Pinellas	Hospital Corp of AM boiler #2	333.4	3,141.0	0.08	10.98	533.0	4.00	0.31
153a	Osceola	Kissimmee Util Exist	460.1	3,129.3	32.10	18.30	422.0	38.00	3.66
154a	Lake	Proposed Lake Co Cogeneration Facility	434.0	3,198.8	5.04	30.48	384.3	17.13	3.35
155a	Pasco	New Port Richey Hospital boiler #1	331.2	3,124.5	0.06	10.98	544.0	3.88	0.31
155b	Pasco	New Port Richey Hospital boiler #2	331.2	3,124.5	0.03	10.98	544.0	3.88	0.31
156a	Hernando	Oman Construction (Asphalt)	359.8	3,164.9	2.09	7.62	347.0	6.29	1.83
157a	Orange	Orlando Util Stanton 1	483.5	3,150.6	105.40	167.60	325.7	21.60	5.80
157b	Orange	Orlando Util Stanton 2	483.5	3,150.6	242.40	167.60	324.2	23.50	5.80
158a	Pasco	Overstreet Paving (Asphalt)	355.9	3,143.7	3.67	9.14	408.0	16.00	1.30
159a	Pasco	Pasco County Resource Recovery Facility	347.1	3,139.2	14.10	83.82	394.3	15.70	3.05
161a	Hillsborough	Borden dryer	394.6	3,069.6	−6.48	30.48	344.0	14.79	1.82
161b	Polk	Borden dryer	414.5	3,109.0	−5.29	17.07	333.0	8.26	2.34
162a	Polk	Brewster Imperial dryer	404.8	3,069.5	−19.60	27.44	339.0	15.25	2.29
163a	Polk	Dolime dryer	404.8	3,069.5	−5.68	27.43	333.0	20.67	1.52
163b	Polk	Dolime boiler	404.8	3,069.5	−4.52	27.43	494.1	7.25	0.61
164a	Polk	Estech/Swift dryer	411.5	3,074.2	−23.94	18.29	339.0	8.47	2.95
164b	Polk	Estech/Swift dryer	411.5	3,074.2	−22.80	18.75	340.0	5.06	2.95
164c	Polk	Estech/Swift SAP	411.5	3,074.2	−92.87	30.79	358.0	3.90	2.13
165a	Hillsborough	Gen. Port Cement kiln 4	358.0	3,090.6	−62.99	35.97	505.2	17.61	2.74
165b	Hillsborough	Gen. Port. Cement kiln 5	358.0	3,090.6	−69.30	45.42	494.1	5.80	3.81
166a	Hillsborough	Stauffer boiler	325.6	3,116.7	−4.86	7.32	464.0	3.23	0.91
166b	Hillsborough	Stauffer dryer	325.6	3,116.7	1.50	18.29	322.0	22.87	0.70
166c	Hillsborough	Stauffer furnace	325.6	3,116.7	−50.93	49.00	335.0	3.60	1.20
166d	Hillsborough	Stauffer kiln	325.6	3,116.7	−7.36	25.61	306.0	6.97	2.13
166e	Hillsborough	Stauffer roaster	325.6	3,116.7	−0.45	25.61	322.0	6.97	0.91
167a	Highlands	TECO Sebring Airport	464.3	3,035.4	111.20	45.70	446.0	24.10	1.80

Sources: FDER, 1991, 1992.
Koogler, 1992.
ECT, 1992.

APPENDIX B.3

SO_2 EMISSIONS INVENTORY FOR PSD CLASS II ANALYSIS

Emission Inventory for PSD Class 2 Analysis for SO2

Identi–fication Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
100d	Hardee	Hardee Power Station	404.8	3,057.4	277.60	22.90	389.0	23.90	4.88
102k	Hillsborough	CF Industries	388.0	3,116.0	88.20	33.50	316.0	19.50	1.50
102l	Hillsborough	CF Industries proposed D	388.0	3,116.0	54.60	60.35	353.0	17.77	2.44
102m	Hillsborough	CF Industries proposed C	388.0	3,116.0	54.60	60.35	353.0	17.77	2.44
102n	Hillsborough	CF Industries baseline C	388.0	3,116.0	−50.40	60.35	353.0	16.40	2.44
102o	Hillsborough	CF Industries baseline D	388.0	3,116.0	−50.40	60.35	353.0	16.40	2.44
102p	Hillsborough	CF Industries	388.0	3,116.0	−105.00	18.80	316.0	18.80	1.52
104g	Hillsborough	Cargill Fertilizer (Gardinier) SAP #7	363.4	3,082.4	46.20	45.72	355.0	9.20	2.29
104h	Hillsborough	Cargill Fertilizer (Gardinier) SAP #8	363.4	3,082.4	52.50	45.72	355.0	8.63	2.44
104i	Hillsborough	Cargill Fertilizer (Gardinier) SAP #9	363.4	3,082.4	54.60	45.72	344.0	12.50	2.74
104j	Hillsborough	Cargill Fertilizer (Gardinier) dryer	363.4	3,082.4	−28.89	20.73	310.0	13.12	1.07
104k	Hillsborough	Cargill Fertilizer (Gardinier) SAP #4, 5, 6	363.4	3,082.4	−196.30	22.60	322.0	19.51	1.52
104l	Hillsborough	Cargill Fertilizer (Gardinier) SAP #7	363.4	3,082.4	−50.71	45.72	355.0	9.20	2.29
105h	Hillsborough	TECO Big Bend – Unit 4	361.9	3,075.0	654.70	149.40	342.2	19.81	7.32
105i	Hillsborough	TECO Big Bend – Units 1 & 2	361.9	3,075.0	−2,436.00	149.40	422.0	28.65	7.32
105j	Hillsborough	TECO Big Bend – Unit 3	361.9	3,075.0	−1,218.00	149.40	418.0	14.33	7.32
110b	Hillsborough	Mobil Big–4 boiler (AMAX)	394.8	3,067.7	0.60	8.20	505.0	7.57	0.41
110c	Hillsborough	Mobil Big–4 dryer (AMAX)	394.9	3,069.8	1.90	30.50	334.0	7.26	1.82
113i	Osceola	FPC/Intercession City prop turbines/7 EA	446.3	3,126.0	310.90	15.24	819.8	56.21	4.21
113j	Osceola	FPC/Intercession City prop turbines/7 FA	446.3	3,126.0	276.10	15.24	880.8	32.07	7.04
117d	Pinellas	Pinellas Co Resource Recovery Facility	335.3	3,084.4	62.24	49.10	522.0	27.72	2.74
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,102.8	29.11	30.48	783.2	28.22	5.79
119g	Polk	Lakeland McIntosh 3	409.5	3,105.8	500.10	76.20	350.0	19.70	4.88
121n	Polk	WR Grace/Seminole SAP #3	409.8	3,087.0	42.87	45.72	311.0	16.70	1.52
121o	Polk	WR Grace/Seminole SAP #4	409.8	3,087.0	40.32	60.96	347.0	25.10	1.52
121p	Polk	WR Grace/Seminole SAP #5	409.8	3,087.0	40.32	60.96	347.0	25.10	1.52
121q	Polk	WR Grace/Seminole SAP #6	409.8	3,087.0	40.32	60.96	347.0	25.10	1.52
121r	Polk	WR Grace/Seminole dryer	409.8	3,087.0	−39.41	15.24	327.0	17.32	2.04
121s	Polk	WR Grace/Seminole SAP #1	409.8	3,087.0	−108.00	45.72	352.0	16.50	1.37
121t	Polk	WR Grace/Seminole SAP #2	409.8	3,087.0	−108.00	45.72	352.0	16.50	1.37
121u	Polk	WR Grace/Seminole SAP #3	409.8	3,087.0	−52.50	45.72	311.0	16.70	1.52
122d	Polk	Mobil Mining & Minerals SR 676 #4 dryer	398.3	3,084.3	2.44	25.90	339.0	15.20	2.29

Emission Inventory for PSD Class 2 Analysis for SO2

Identi–fication Number	County	Facility	UTM		SO2 (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
122e	Hillsborough	Mobil Mining & Minerals SR 676 calciner	398.3	3,084.3	–13.89	28.40	340.0	19.24	1.09
123d	Polk	Royster #1	406.7	3,085.2	–152.70	51.00	356.0	9.90	2.13
123e	Polk	Royster #2	406.7	3,085.2	35.70	61.00	360.0	12.20	2.13
124b	Polk	US Agri–Chem Hwy 60 dryer	413.2	3,086.3	–4.99	15.80	332.0	10.01	1.83
124c	Polk	US Agri–Chem Hwy 60 SAP	413.2	3,086.3	–41.90	28.96	305.0	7.50	2.12
125e	Polk	US Agri–Chem Hwy 630 H2SO4 1	416.1	3,068.6	63.00	53.40	355.0	15.91	2.59
125f	Polk	US Agri–Chem Hwy 630 H2SO4 2	416.1	3,068.6	63.00	53.40	355.0	15.91	2.59
125g	Polk	US Agri–Chem Hwy 630 H2SO4 X	416.2	3,068.7	–78.80	29.00	314.0	6.77	3.02
125h	Polk	US Agri–Chem Hwy 630 GTSP	416.0	3,069.0	–18.27	38.35	330.0	17.60	1.52
125i	Polk	US Agri–Chem Hwy 630 rock dryer	416.0	3,069.0	–15.79	25.60	332.0	16.26	1.52
126e	Polk	CF Industries DAP 1–3	408.5	3,082.5	3.97	36.40	339.0	16.11	2.13
126f	Hillsborough	CF Industries H2SO4 5	408.5	3,082.5	50.40	63.41	361.0	10.88	2.13
126g	Hillsborough	CF Industries H2SO4 6	408.5	3,082.5	50.40	63.41	370.0	7.28	2.13
126h	Hillsborough	CF Industries H2SO4 7	408.5	3,082.5	42.00	67.10	351.0	9.80	2.40
126i	Hillsborough	CF Industries H2SO4 1	408.5	3,082.5	–60.90	30.49	350.0	12.20	1.37
126j	Hillsborough	CF Industries H2SO4 2	408.5	3,082.5	–110.25	30.49	350.0	10.37	1.68
126k	Hillsborough	CF Industries H2SO4 3	408.5	3,082.5	–107.10	30.49	364.0	4.27	2.74
126l	Hillsborough	CF Industries H2SO4 4	408.5	3,082.5	–174.83	30.49	358.0	7.93	2.13
126m	Hillsborough	CF Industries H2SO4 5	408.5	3,082.5	–226.80	63.41	358.0	10.67	2.13
126n	Hillsborough	CF Industries H2SO4 6	408.5	3,082.5	–170.10	63.41	359.0	10.37	2.13
127i	Polk	Farmland Industries 3, 4 H2SO4	409.5	3,079.5	67.16	30.48	355.0	9.27	2.29
127j	Polk	Farmland Industries 5 H2SO4	409.5	3,079.5	41.96	45.72	355.0	9.65	2.44
127k	Polk	Farmland Industries 1, 2 H2SO4	409.5	3,079.5	–83.98	30.48	311.0	20.18	1.37
128c	Polk	Agrico Pierce dryers 1, 2	404.1	3,079.0	–24.32	24.38	339.0	12.94	1.52
128d	Polk	Agrico Pierce dryers 3, 4	404.1	3,079.0	–23.00	24.38	339.0	18.82	2.43
129h	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	–75.60	45.73	350.0	26.40	1.60
129i	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	113.50	45.73	350.0	39.06	1.60
129j	Polk	Agrico South Pierce DAP plant	407.5	3,071.3	4.41	38.10	328.0	14.60	3.10
130e	Polk	Conserve Inc. rock dryer	398.4	3,084.2	–3.88	24.40	339.0	12.90	1.52
130f	Polk	Conserve Inc.	398.4	3,084.2	42.00	45.70	352.0	10.30	2.30
130g	Polk	Conserve Inc.	398.4	3,084.2	–54.60	30.50	308.0	18.90	1.80
131h	Polk	IMC New Wales DAP	396.6	3,078.9	5.54	36.60	319.1	20.15	1.83

Emission Inventory for PSD Class 2 Analysis for SO2

Identi-fication Number	County	Facility	UTM East	UTM North	SO2 (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
131i	Polk	IMC New Wales multiphos	396.6	3,078.9	4.80	52.40	314.0	15.80	1.40
131j	Polk	IMC New Wales SAP #1, 2, 3 projected	396.6	3,078.9	189.00	61.00	350.0	15.31	2.60
131k	Polk	IMC New Wales SAP #4, 5 projected	396.6	3,078.9	126.00	60.70	350.0	15.31	2.60
131l	Polk	IMC New Wales rock dryer	396.6	3,078.9	−34.27	21.00	347.0	18.60	2.13
131m	Polk	IMC New Wales SAP #1, 2, 3 baseline	396.6	3,078.9	−146.00	61.00	350.0	14.28	2.60
132f	Polk	Mobil−Electrophos boiler	405.6	3,079.4	−6.53	7.32	464.0	3.23	0.91
132g	Polk	Mobil−Electrophos boiler	405.6	3,079.4	−10.00	6.10	464.0	7.71	0.91
132h	Polk	Mobil−Electrophos rock dryer	405.6	3,079.4	−20.90	18.29	350.0	6.79	1.83
132i	Polk	Mobil−Electrophos calciner	405.6	3,079.4	−7.11	25.61	306.0	6.97	2.13
132j	Polk	Mobil−Electrophos coke dryer	405.6	3,079.4	−2.97	18.29	322.0	22.87	0.70
132k	Polk	Mobil−Electrophos furnace	405.6	3,079.4	−47.25	29.27	314.0	8.52	2.13
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	6.35	48.80	411.0	14.30	5.49
135a	Hillsborough	Hillsborough Co Resource Recovery Facility	368.2	3,092.7	21.40	50.00	491.0	18.30	1.80
136a	Pasco	Proposed Pasco Co Cogeneration Facility	385.6	3,139.0	5.04	30.48	384.3	17.13	3.35
137a	Polk	Ridge Cogeneration	416.7	3,100.4	13.80	99.10	350.0	14.54	3.05
141a	Hillsborough	CLM Chl	361.8	3,088.3	21.02	30.00	375.0	20.00	0.61
146a	Pasco	Evans Packing	383.3	3,135.8	0.20	12.30	466.2	9.20	0.40
161a	Hillsborough	Borden dryer	394.6	3,069.6	−6.48	30.48	344.0	14.79	1.82
161b	Polk	Borden dryer	414.5	3,109.0	−5.29	17.07	333.0	8.26	2.34
163a	Polk	Dolime dryer	404.8	3,069.5	−5.68	27.43	333.0	20.67	1.52
163b	Polk	Dolime boiler	404.8	3,069.5	−4.52	27.43	494.1	7.25	0.61
164a	Polk	Estech/Swift dryer	411.5	3,074.2	−23.94	18.29	339.0	8.47	2.95
164b	Polk	Estech/Swift dryer	411.5	3,074.2	−22.80	18.75	340.0	5.06	2.95
164c	Polk	Estech/Swift SAP	411.5	3,074.2	−92.87	30.79	358.0	3.90	2.13
165a	Hillsborough	Gen. Port Cement kiln 4	358.0	3,090.6	−62.99	35.97	505.2	17.61	2.74
165b	Hillsborough	Gen. Port. Cement kiln 5	358.0	3,090.6	−69.30	45.42	494.1	5.80	3.81
167a	Highlands	TECO Sebring Airport	464.3	3,035.4	111.20	45.70	446.0	24.10	1.80

Sources: FDER, 1991, 1992.
Koogler, 1992.
ECT, 1992.

APPENDIX B.4

NO_x EMISSIONS INVENTORY FOR AAQS ANALYSIS

APPENDIX B.5

NO$_x$ EMISSIONS INVENTORY FOR PSD CLASS I ANALYSIS

APPENDIX B.6

NO_x EMISSIONS INVENTORY FOR PSD CLASS II ANALYSIS

Emission Inventory for NAAQS Analysis for NOx

Identification Number	County	Facility	UTM East	UTM North	NOx (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
100a	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.4	80.61	22.86	388.56	23.90	4.88
100b	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.3	80.61	22.86	388.56	23.90	4.88
100c	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.5	80.61	22.86	388.56	23.90	4.88
No 100d	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.4	35.99	22.90	389.00	23.90	4.88
103b	Hillsborough	TECO Hooker's Point	358.0	3,091.0	1.53	85.35	438.00	5.57	3.44
103c	Hillsborough	TECO Hooker's Point	358.0	3,091.0	12.93	85.35	434.11	8.17	3.66
103d	Hillsborough	TECO Hooker's Point	358.0	3,091.0	18.97	85.35	421.89	7.34	3.66
103e	Hillsborough	TECO Hooker's Point	358.0	3,091.0	1.73	85.35	448.00	11.09	3.44
103f	Hillsborough	TECO Hooker's Point	358.0	3,091.0	1.01	85.35	434.11	22.37	2.87
105a	Hillsborough	TECO Big Bend	361.9	3,075.0	329.70	149.35	404.67	13.74	7.32
105b	Hillsborough	TECO Big Bend	361.9	3,075.0	474.43	149.35	404.67	13.02	7.32
105c	Hillsborough	TECO Big Bend	362.0	3,075.0	251.11	149.35	410.22	14.47	7.32
105d	Hillsborough	TECO Big Bend	362.0	3,075.0	327.60	149.40	342.20	19.81	7.32
105e	Hillsborough	TECO Big Bend	361.7	3,075.5	3.71	22.86	770.78	18.74	4.27
105f	Hillsborough	TECO Big Bend	361.7	3,075.2	56.43	22.86	770.78	18.74	4.27
105g	Hillsborough	TECO Big Bend	361.9	3,075.0	0.32	10.67	816.33	15.17	4.57
106a	Hillsborough	TECO Gannon	360.0	3,087.5	15.89	93.27	415.78	28.90	3.05
106b	Hillsborough	TECO Gannon	360.0	3,087.5	134.22	93.27	420.78	30.85	3.05
106c	Hillsborough	TECO Gannon	360.0	3,087.5	168.54	93.27	419.67	38.64	3.23
106d	Hillsborough	TECO Gannon	360.0	3,087.5	23.69	93.27	426.89	22.97	3.05
106e	Hillsborough	TECO Gannon	360.0	3,087.5	289.74	93.27	423.56	23.18	4.45
106f	Hillsborough	TECO Gannon	360.0	3,087.5	177.32	93.27	433.00	24.74	5.36
106g	Hillsborough	TECO Gannon	360.0	3,087.5	0.35	10.67	816.33	136.61	1.52
109a	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	10.36	38.10	339.00	10.13	2.90
109b	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	7.14	38.10	346.00	18.40	2.44
109c	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	0.09	6.10	616.33	8.31	0.30
110a	Hillsborough	Mobil Mining & Minerals Big Four Mine	394.7	3,069.6	4.46	30.48	333.00	12.58	1.83
112a	Manatee	Florida Power & Light	367.2	3,054.1	297.08	152.10	425.78	23.61	7.99
112b	Manatee	Florida Power & Light	367.2	3,054.1	202.39	152.10	425.78	23.98	7.92

Emission Inventory for NAAQS Analysis for NOx

Identi- fication Number	County	Facility	UTM East	UTM North	NOx (g/s)	Height (m)	Temper- ature (K)	Velocity (m/s)	Diameter (m)
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,108.8	21.04	30.48	783.00	28.22	5.79
119a	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	0.03	6.10	652.44	23.54	0.79
119b	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	0.03	6.10	652.44	23.54	0.79
119c	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	0.23	10.97	791.33	0.39	2.80
119d	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	44.80	47.55	402.44	21.29	3.17
119e	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	100.65	76.20	350.00	19.70	4.88
119f	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	5.04	45.72	419.11	23.96	2.74
121d	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.32	24.38	313.56	16.63	2.01
121e	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.0	7.60	15.24	333.00	17.29	2.04
121u	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.0	7.60	15.24	333.00	17.29	2.04
121v	Polk	Seminole Fertilizer (W R Grace)	409.9	3,086.8	1.00	19.80	383.00	28.20	1.83
127a	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	1.44	30.48	355.00	9.27	2.29
127b	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	1.44	30.48	355.00	9.27	2.29
127c	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	1.50	45.72	355.00	9.65	2.44
127j	Polk	Farmland 5 H2SO4	409.5	3,079.5	1.25	45.72	355.00	9.65	2.44
127l	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	2.76	39.32	326.89	12.41	2.29
127m	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.66	19.81	321.89	4.48	0.30
127n	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.12	14.02	443.56	12.66	1.22
127o	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.46	28.96	605.22	3.58	1.68
127p	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.43	39.32	327.44	6.84	2.29
129i	Polk	Agrico South Pierce	407.5	3,071.3	3.98	45.73	350.00	39.06	1.60
131a	Polk	IMC Fertilizer New Wales	396.5	3,079.0	0.06	40.54	313.56	15.18	2.13
131c	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.84	61.00	350.00	15.31	2.60
131e	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.58	52.12	316.33	17.97	1.83
131f	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.58	36.60	319.10	20.15	1.83
131g	Polk	IMC Fertilizer New Wales	396.5	3,079.1	0.09	40.54	316.33	20.66	1.83
131h	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.70	52.43	313.56	15.97	1.37
131j	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.84	61.00	350.00	15.31	2.60
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	21.17	48.80	411.00	14.30	5.49

Emission Inventory for NAAQS Analysis for NOx

Identi-fication Number	County	Facility	UTM East	UTM North	NOx (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
136a	Pasco	Pasco County Cogeneration	385.6	3,139.0	11.64	30.48	384.30	17.13	3.35
137a	Polk	Ridge Cogeneration	416.7	3,100.4	8.93	99.10	350.00	14.54	3.05
138a	Hillsborough	Tampa City McKay Bay Refuse-to-Energy	360.0	3,091.9	9.47	45.72	499.67	21.34	1.34
138b	Hillsborough	Tampa City McKay Bay Refuse-to-Energy	360.0	3,091.9	9.47	45.72	499.67	21.34	1.34
138c	Hillsborough	Tampa City McKay Bay Refuse-to-Energy	360.0	3,091.9	9.47	45.72	499.67	21.34	1.34
138d	Hillsborough	Tampa City McKay Bay Refuse-to-Energy	360.0	3,091.9	9.47	45.72	499.67	21.34	1.34
138e	Hillsborough	Tampa City McKay Bay Refuse-to-Energy	360.0	3,091.9	37.83	45.72	505.22	12.50	1.77
139a	Polk	Citrus World	441.0	3,087.3	7.08	22.86	322.44	10.88	0.98
139b	Polk	Citrus World	441.0	3,087.3	2.27	12.19	355.22	8.28	1.71
139c	Polk	Citrus World	441.0	3,087.3	2.04	12.19	505.22	1.50	1.10
139d	Polk	Citrus World	441.0	3,087.3	3.80	12.19	505.22	1.50	1.10
139e	Polk	Citrus World	441.0	3,087.3	3.80	12.19	505.22	2.48	0.85
139f	Polk	Citrus World	441.0	3,087.3	3.63	22.86	325.22	12.30	0.76
139g	Polk	Citrus World	441.0	3,087.3	1.61	12.19	436.33	17.40	1.19
139h	Polk	Citrus World	441.0	3,087.3	4.03	12.19	436.33	17.40	1.19
139i	Polk	Citrus World	441.0	3,087.3	7.31	24.38	313.00	22.15	0.76
139j	Polk	Citrus World	441.0	3,087.3	1.90	12.19	505.22	1.50	1.10
139k	Polk	Citrus World	441.0	3,087.3	2.27	9.14	558.00	32.95	0.91

Sources: FDER, 1991, 1992.
ECT, 1992.

Emission Inventory for PSD Class 1 Analysis for NOx

Identi-fication Number	County	Facility	UTM East	UTM North	NOx (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
100d	Hardee	Hardee Power Station	404.8	3,057.4	35.99	22.90	389.0	23.90	4.88
113i	Osceola	FPC Intercession City prop turbines/7EA	446.3	3,126.0	91.80	15.24	819.8	56.21	4.21
113j	Osceola	FPC Intercession City prop turbines/7EA	446.3	3,126.0	84.20	15.24	880.8	32.07	7.04
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,102.8	21.04	30.48	783.2	28.22	5.79
121v	Polk	WR Grace/Seminole	409.9	3,086.8	1.00	19.80	383.0	28.20	1.83
127j	Polk	Farmland 5 H2SO4	409.5	3,079.5	1.25	45.72	355.0	9.65	2.44
129h	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	−2.93	45.73	350.0	26.40	1.60
129i	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	3.98	45.73	350.0	39.06	1.60
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	21.17	48.80	411.0	14.30	5.49
136a	Pasco	Proposed Pasco Co Cogeneration Facility	385.6	3,139.0	11.64	30.48	384.3	17.13	3.35
137a	Polk	Ridge Cogeneration	416.7	3,100.4	8.93	99.10	350.0	14.54	3.05
148a	Hernando	Florida Mining & Materials kiln 2	356.2	3,169.9	11.56	32.01	394.2	9.90	4.88
151a	Volusia	FPC DeBary prop turbines	465.7	3,197.2	137.60	15.24	819.8	56.21	4.21
154a	Lake	Lake County Cogeneration	434.0	3,198.8	11.64	30.48	348.3	17.13	3.35
157b	Orange	Orlando Util Stanton 2	483.5	3,150.6	91.80	167.60	324.2	23.50	5.80
159a	Pasco	Pasco County Resource Recovery	347.1	3,139.2	40.57	83.82	394.3	15.70	3.05
169a	Marion	Enron − Silver Springs	418.8	3,240.9	1.33	13.72	641.0	36.51	0.49

Sources: FDER, 1991, 1992.
ECT, 1992.

Emission Inventory for PSD Class 2 Analysis for NOx

Identi- fication Number	County	Facility	UTM East	UTM North	NOx (g/s)	Height (m)	Temper- ature (K)	Velocity (m/s)	Diameter (m)
100d	Hardee	Hardee Power Station	404.8	3,057.4	35.99	22.90	389.0	23.90	4.88
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,102.8	21.04	30.48	783.2	28.22	5.79
121v	Polk	WR Grace/Seminole	409.9	3,086.8	1.00	19.80	383.0	28.20	1.83
127j	Polk	Farmland 5 H2SO4	409.5	3,079.5	1.25	45.72	355.0	9.65	2.44
129h	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	−2.93	45.73	350.0	26.40	1.60
129i	Polk	Agrico South Pierce H2SO4	407.5	3,071.3	3.98	45.73	350.0	39.06	1.60
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	21.17	48.80	411.0	14.30	5.49

Sources: FDER, 1991, 1992.
ECT, 1992.

APPENDIX B.7

PM EMISSIONS INVENTORY FOR AAQS ANALYSIS

Emission Inventory for NAAQS Analysis for PM

Identification Number	County	Facility	UTM		PM (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
			East	North					
100a	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.4	14.38	22.86	389.0	23.90	4.88
100b	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.3	14.38	22.86	389.0	23.90	4.88
100c	Hardee	Hardee Power Station Ft. Green Springs	404.8	3,057.5	14.38	22.86	389.0	23.90	4.88
103a	Hillsborough	TECO Hooker's Point	358.0	3,091.0	3.77	85.35	419.1	6.19	3.44
103b	Hillsborough	TECO Hooker's Point	358.0	3,091.0	3.77	85.35	438.0	5.57	3.44
103c	Hillsborough	TECO Hooker's Point	358.0	3,091.0	5.18	85.35	434.1	8.17	3.66
103d	Hillsborough	TECO Hooker's Point	358.0	3,091.0	5.18	85.35	421.9	7.34	3.66
103e	Hillsborough	TECO Hooker's Point	358.0	3,091.0	7.69	85.35	448.0	11.09	3.44
103f	Hillsborough	TECO Hooker's Point	358.0	3,091.0	9.85	85.35	434.1	22.37	2.87
104aa	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.17	18.29	588.6	6.94	2.53
104bb	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.55	9.14	298.6	13.20	1.07
104cc	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.60	12.19	298.0	11.21	0.46
104d	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.03	12.19	321.9	9.94	0.52
104dd	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.40	15.24	303.6	12.42	0.76
104e	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	1.21	6.10	488.6	15.89	1.22
104ee	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.98	9.75	308.6	8.04	0.40
104f	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	2.53	40.54	315.2	15.38	2.13
104ff	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.09	6.10	298.6	16.31	0.37
104gg	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.09	6.10	298.6	10.44	0.46
104hh	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.09	9.14	298.6	16.31	0.37
104ii	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.09	13.72	298.6	16.31	0.37
104jj	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.14	22.86	298.6	12.42	0.58
104kk	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.03	11.58	255.2	17.75	0.82
104m	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	2.45	38.41	328.6	11.32	2.44
104n	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.14	26.52	331.9	8.18	0.37
104p	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.63	27.43	333.6	17.32	1.07

Emission Inventory for NAAQS Analysis for PM

Identi– fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper– ature (K)	Velocity (m/s)	Diameter (m)
104q	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	2.88	16.46	320.2	19.69	1.31
104r	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.72	27.43	334.1	19.58	1.01
104s	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.72	27.43	334.1	21.96	1.01
104t	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	3.86	16.76	323.6	19.93	1.31
104u	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	1.27	20.12	333.0	16.17	0.61
104v	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.66	19.81	303.0	11.74	1.22
104w	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	1.04	20.73	314.7	11.09	1.07
104x	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	0.66	19.81	301.9	14.43	1.22
104y	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	1.04	20.73	319.1	1.16	1.07
104z	Hillsborough	Cargill Fertilizer (Gardinier)	362.9	3,082.2	2.25	22.56	305.2	7.84	1.22
105a	Hillsborough	TECO Big Bend	361.9	3,075.0	50.96	149.35	404.7	13.74	7.32
105b	Hillsborough	TECO Big Bend	361.9	3,075.0	50.44	149.35	404.7	13.02	7.32
105c	Hillsborough	TECO Big Bend	362.0	3,075.0	51.97	149.35	410.2	14.47	7.32
105e	Hillsborough	TECO Big Bend	361.7	3,075.5	4.17	22.86	770.8	18.74	4.27
105f	Hillsborough	TECO Big Bend	361.7	3,075.2	4.17	22.86	770.8	18.74	4.27
105g	Hillsborough	TECO Big Bend	361.9	3,075.0	4.17	10.67	816.3	15.17	4.57
105h	Hillsborough	TECO Big Bend	361.9	3,075.0	54.61	149.35	341.9	18.21	7.32
105i	Hillsborough	TECO Big Bend	361.9	3,075.0	0.66	31.09	394.1	16.04	0.76
105j	Hillsborough	TECO Big Bend	361.9	3,075.0	2.10	34.44	394.1	123.77	0.27
105k	Hillsborough	TECO Big Bend	361.9	3,075.0	0.03	42.37	333.0	18.19	0.49
105l	Hillsborough	TECO Big Bend	361.9	3,075.0	0.06	54.56	298.6	21.04	0.52
105m	Hillsborough	TECO Big Bend	361.9	3,075.0	0.06	54.56	298.6	21.04	0.52
105n	Hillsborough	TECO Big Bend	361.9	3,075.0	0.06	54.56	298.6	21.04	0.52
106a	Hillsborough	TECO Gannon	360.0	3,087.5	15.89	93.27	415.8	28.90	3.05
106b	Hillsborough	TECO Gannon	360.0	3,087.5	15.89	93.27	420.8	30.85	3.05
106c	Hillsborough	TECO Gannon	360.0	3,087.5	20.18	93.27	419.7	38.64	3.23

Emission Inventory for NAAQS Analysis for PM

Identi- fication Number	County	Facility	UTM		PM (g/s)	Height (m)	Temper- ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
106d	Hillsborough	TECO Gannon	360.0	3,087.5	23.69	93.27	426.9	22.97	3.05
106e	Hillsborough	TECO Gannon	360.0	3,087.5	28.76	93.27	423.6	23.18	4.45
106f	Hillsborough	TECO Gannon	360.0	3,087.5	47.91	93.27	433.0	24.74	5.36
106g	Hillsborough	TECO Gannon	360.0	3,087.5	15.40	10.67	816.3	136.61	1.52
106h	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	21.95	449.7	10.96	0.21
106i	Hillsborough	TECO Gannon	360.0	3,087.5	0.14	32.61	449.7	30.37	0.30
106j	Hillsborough	TECO Gannon	360.0	3,087.5	0.37	31.70	449.7	18.27	0.61
106k	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	53.34	298.6	21.49	0.52
106l	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	53.34	298.6	21.49	0.52
106m	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	53.95	298.6	15.52	0.61
106n	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	53.34	298.6	21.49	0.52
106o	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	53.04	298.6	24.26	0.37
106p	Hillsborough	TECO Gannon	360.0	3,087.5	0.03	53.34	298.6	21.49	0.52
108aa	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.12	16.46	298.0	19.14	0.43
108bb	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.06	3.05	338.6	18.19	0.24
108cc	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.03	15.24	294.1	20.70	0.15
108d	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	1.76	46.33	299.7	12.14	1.77
108dd	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.03	21.34	298.0	12.58	0.18
108e	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	2.10	46.33	298.0	13.17	1.77
108f	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	1.67	30.48	338.0	11.98	1.37
108g	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	1.76	24.38	319.1	6.20	1.68
108h	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	1.64	46.33	300.2	9.61	1.77
108i	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	1.90	45.72	313.0	18.34	1.77
108j	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.26	24.69	315.2	9.05	0.82
108k	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.17	32.61	298.0	33.69	0.37
108l	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.86	30.48	319.1	0.01	0.91

Emission Inventory for NAAQS Analysis for PM

Identi- fication Number	County	Facility	UTM		PM (g/s)	Height (m)	Temper- ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
108m	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.06	29.57	298.0	13.58	0.30
108n	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.12	15.85	298.0	19.14	0.43
108o	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.09	14.02	298.0	17.97	0.18
108p	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.26	18.90	298.0	24.95	0.55
108q	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.14	20.42	298.0	11.50	0.46
108r	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.09	21.34	298.0	31.89	0.37
108s	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.89	10.36	327.4	19.16	0.82
108t	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.20	17.37	298.0	28.75	0.46
108u	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.20	16.46	298.0	19.96	0.55
108v	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.20	13.72	349.7	14.17	0.55
108w	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.12	6.10	605.2	20.21	0.37
108x	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	4.40	24.38	308.0	79.21	1.37
108y	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	0.66	9.75	295.8	10.76	0.46
108z	Hillsborough	Consolidated Minerals Plant City	393.8	3,096.3	1.76	46.33	295.2	11.16	1.77
109a	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	3.17	38.10	339.1	15.16	2.44
109b	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	3.14	38.10	339.1	16.80	2.44
109d	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	13.26	45.72	316.3	8.43	0.82
109e	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	6.77	22.86	314.7	17.33	0.85
112a	Manatee	Florida Power & Light	367.2	3,054.1	1,089.30	152.10	425.8	23.61	7.99
112b	Manatee	Florida Power & Light	367.2	3,054.1	67.45	152.10	425.8	23.98	7.92
112c	Manatee	Florida Power & Light	367.2	3,054.1	15.95	30.50	319.0	12.20	1.30
119a	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	12.41	45.72	419.1	23.96	2.74
119b	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	0.12	6.10	652.4	23.54	0.79
119c	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	0.12	6.10	652.4	23.54	0.79
119d	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	0.58	10.97	791.3	0.39	2.80
119e	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	14.05	47.55	402.4	21.29	3.17

Emission Inventory for NAAQS Analysis for PM

Identification Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
119f	Polk	Lakeland City Power McIntosh Power Station	409.2	3,106.1	408.56	76.20	349.7	32.85	4.88
121aa	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	1.38	24.38	299.7	17.90	0.52
121aaa	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.12	10.67	305.2	9.98	0.55
121bb	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	1.27	15.24	294.1	8.02	0.34
121bbb	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.0	3.77	15.24	333.0	17.29	2.04
121cc	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.58	20.73	294.1	2.46	0.52
121ccc	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.43	30.48	300.2	9.70	0.61
121dd	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	1.73	45.72	304.1	9.32	2.04
121ddd	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.46	30.48	324.7	9.70	0.61
121ee	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	1.93	16.76	294.1	17.42	1.07
121eee	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.03	24.38	327.4	0.00	3.51
121ff	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	1.35	60.96	341.3	24.58	1.52
121fff	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.06	6.10	366.3	17.46	0.30
121gg	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	33.60	30.48	324.7	13.40	2.04
121ggg	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.06	10.36	366.3	0.12	0.30
121hh	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.43	16.15	301.9	4.19	0.67
121hhh	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.06	9.45	366.3	0.03	0.61
121ii	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.26	12.80	307.4	9.41	1.16
121iii	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.06	7.92	366.3	0.12	0.30
121jj	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.63	30.48	294.1	13.20	2.13
121jjj	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.06	7.92	366.3	0.12	0.30
121kk	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.63	27.43	296.9	11.37	0.98
121ll	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.52	14.02	296.9	8.09	0.61
121mm	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	2.82	40.23	316.3	26.40	2.13
121nn	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.75	21.34	299.7	21.27	1.28
121oo	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	1.38	22.56	305.2	9.98	0.55

Emission Inventory for NAAQS Analysis for PM

Identification Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
121pp	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	1.93	16.76	298.0	17.42	1.07
121qq	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	1.93	16.76	294.1	17.42	1.07
121rr	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.58	14.02	298.0	15.16	0.24
121ss	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.58	16.15	294.1	20.21	0.12
121tt	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.81	16.15	299.7	7.68	0.67
121uu	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	3.17	24.38	313.6	16.63	2.01
121vv	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.0	3.77	15.24	333.0	17.29	2.04
121w	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	3.77	30.18	330.2	16.21	2.29
121ww	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	1.30	60.96	346.9	28.46	1.52
121x	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.09	30.48	260.8	15.52	1.52
121xx	Polk	Seminole Fertilizer (W R Grace)	409.9	3,087.0	3.34	60.96	346.9	28.46	1.52
121y	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.09	17.98	317.4	9.70	0.61
121yy	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.12	10.67	305.2	9.98	0.55
121z	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	3.22	24.38	294.1	8.38	0.76
121zz	Polk	Seminole Fertilizer (W R Grace)	409.8	3,086.7	0.12	10.67	305.2	9.98	0.55
122a	Polk	Mobil Mining & Minerals SR 676	398.5	3,085.1	4.55	24.38	344.1	12.65	2.29
122b	Polk	Mobil Mining & Minerals SR 676	398.5	3,085.1	5.50	24.38	344.1	12.65	2.29
122f	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.2	1.12	30.48	338.6	19.02	1.10
122g	Polk	Mobil Mining & Minerals SR 676	398.2	3,085.0	3.11	25.91	338.6	16.10	2.29
122h	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.2	1.41	24.38	326.9	11.68	0.49
122i	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.2	1.55	24.38	326.9	11.68	0.49
122j	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.1	0.14	4.57	312.4	16.50	0.43
122k	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.3	0.72	3.96	521.9	2.12	0.76
122l	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.3	1.96	25.91	299.7	14.54	1.68
122m	Polk	Mobil Mining & Minerals SR 676	398.3	3,085.1	7.00	25.91	296.9	19.40	1.52
122n	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.3	1.38	12.19	344.1	11.83	1.07

Emission Inventory for NAAQS Analysis for PM

Identi–fication Number	County	Facility	UTM		PM (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
			East	North					
122o	Polk	Mobil Mining & Minerals SR 676	398.4	3,085.3	0.06	24.08	349.7	14.64	0.24
123b	Polk	Royster Company	406.8	3,085.1	29.48	31.09	316.3	8.16	2.68
123e	Polk	Royster Company	406.8	3,085.1	3.83	60.96	366.3	9.90	2.13
123f	Polk	Royster Company	406.8	3,085.1	4.87	24.38	305.8	10.85	0.91
123g	Polk	Royster Company	406.8	3,085.1	1.93	22.56	308.0	3.80	1.07
124d	Polk	US Agri–Chemicals Hwy 60	413.2	3,086.3	5.04	19.20	308.6	9.31	1.52
124e	Polk	US Agri–Chemicals Hwy 60	413.2	3,086.3	4.87	39.93	327.4	11.09	2.13
124f	Polk	US Agri–Chemicals Hwy 60	413.2	3,086.3	2.85	22.56	299.7	48.51	0.61
125aa	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.23	1.83	399.7	0.00	0.09
125k	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	2.45	15.85	336.3	11.10	1.83
125l	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	5.07	15.85	334.7	10.96	1.83
125m	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	25.07	21.34	477.4	14.98	1.13
125n	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.20	28.35	326.9	10.66	1.52
125o	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.23	28.35	326.9	10.66	1.52
125p	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.40	27.13	300.2	2.44	4.57
125q	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	2.50	19.51	308.0	24.91	0.43
125r	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	3.08	24.38	315.2	3.83	0.76
125s	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.46	37.19	304.1	15.43	0.85
125t	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.12	16.15	355.2	8.62	0.46
125u	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	2.48	21.03	315.2	22.16	0.52
125v	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.12	16.15	355.2	8.62	0.46
125w	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.12	16.15	310.8	8.62	0.46
125x	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.12	17.68	310.8	8.62	0.46
125y	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.12	18.29	333.0	22.64	0.30
125z	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	0.49	1.83	405.2	104.86	0.09
126aa	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	15.27	42.70	298.0	21.60	0.80

Emission Inventory for NAAQS Analysis for PM

Identi- fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper- ature (K)	Velocity (m/s)	Diameter (m)
126o	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	5.10	42.67	298.0	21.73	0.76
126p	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	0.83	62.79	338.6	6.51	2.13
126q	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.3	1.50	62.79	333.0	6.69	2.13
126r	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	5.10	36.88	338.6	18.76	1.83
126s	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	5.44	35.66	338.6	11.31	2.44
126t	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	2.45	36.58	333.0	17.17	2.29
126u	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	1.27	16.76	298.0	9.01	1.37
126v	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	4.95	41.45	333.0	18.05	2.83
126w	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	1.38	10.97	588.6	13.45	0.76
126x	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	5.12	41.15	298.0	7.92	1.52
126y	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	1.76	19.81	298.0	15.36	1.22
126z	Polk	C F Industries Bonnie Mine Rd	408.4	3,082.4	0.12	30.48	299.7	5.95	0.76
127aa	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.09	12.19	366.3	0.03	0.61
127bb	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.09	12.19	366.3	2.67	0.61
127l	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.66	30.48	349.7	8.70	2.29
127m	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.66	30.48	351.9	9.74	2.29
127n	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	2.94	39.32	326.9	12.41	2.29
127o	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	4.46	27.43	305.2	5.48	0.91
127p	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.31	50.29	298.0	8.86	0.70
127q	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.43	26.82	349.7	19.09	0.73
127r	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.22	39.62	311.9	5.66	1.22
127s	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.80	39.32	319.1	10.66	2.13
127t	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.80	39.93	298.0	9.92	2.44
127u	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.22	39.32	327.4	7.47	2.29
127v	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	2.94	56.39	338.0	5.17	1.52
127w	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	6.62	35.05	349.7	22.72	0.67

Emission Inventory for NAAQS Analysis for PM

Identification Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
127x	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	3.40	39.32	327.4	6.84	2.29
127y	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.06	12.19	366.3	0.03	0.61
127z	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	0.09	12.19	366.3	0.03	0.61
128e	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	4.46	24.38	316.3	5.76	3.05
128f	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	4.22	24.38	320.8	21.25	2.44
128g	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	13.94	28.96	683.0	14.75	1.77
128h	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	1.90	10.36	298.0	5.92	0.70
128i	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	1.90	27.43	298.0	3.60	0.98
128j	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	1.90	27.43	298.0	4.79	0.70
128k	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	1.90	24.69	298.0	4.15	2.13
128l	Polk	Agrico Chemical Co Pierce	403.7	3,079.0	3.17	24.69	298.0	3.69	2.13
129j	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	3.02	38.10	327.4	14.55	3.05
129k	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	4.12	30.48	306.3	6.87	1.22
129l	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.55	26.82	307.4	9.24	0.91
129m	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.43	38.10	319.1	15.84	1.07
129n	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.03	29.26	298.0	1.15	0.40
129o	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.03	20.73	298.0	2.87	0.46
129p	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.03	16.15	298.0	1.72	0.46
129q	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.26	19.81	310.2	5.48	0.49
129r	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	0.23	19.81	300.2	88.45	0.49
129s	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	4.00	3.05	344.1	20.69	0.55
129t	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	4.40	42.67	304.7	10.66	2.74
129u	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	5.07	24.38	296.9	7.80	3.35
129v	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	5.07	24.38	295.2	7.23	3.35
129w	Polk	Agrico Chemical Co South Pierce	407.5	3,071.5	4.32	18.29	323.0	9.70	0.30
130b	Polk	Conserv Inc.	398.7	3,084.2	4.43	24.69	327.4	3.77	2.29

Emission Inventory for NAAQS Analysis for PM

Identi-fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
130c	Polk	Conserv Inc.	398.7	3,084.2	0.29	8.23	533.0	13.74	0.61
130d	Polk	Conserv Inc.	398.7	3,084.2	0.43	11.89	533.0	8.91	0.98
130f	Polk	Conserv Inc.	398.7	3,084.2	28.91	45.72	349.7	10.31	2.29
130h	Polk	Conserv Inc.	398.7	3,084.2	17.73	12.80	310.8	10.60	1.22
130i	Polk	Conserv Inc.	398.7	3,084.2	1.18	15.85	321.9	20.18	0.76
130j	Polk	Conserv Inc.	398.7	3,084.2	1.18	24.38	327.4	23.81	1.07
130k	Polk	Conserv Inc.	398.7	3,084.2	1.18	21.95	360.8	31.08	0.98
130l	Polk	Conserv Inc.	398.7	3,084.2	0.63	63.09	330.2	21.12	0.43
130m	Polk	Conserv Inc.	398.7	3,084.2	0.63	63.09	330.2	21.12	0.43
130n	Polk	Conserv Inc.	398.7	3,084.2	0.63	54.56	338.6	14.37	0.18
130o	Polk	Conserv Inc.	398.7	3,084.2	0.20	55.47	310.8	2.97	0.43
130p	Polk	Conserv Inc.	398.7	3,084.2	1.38	63.09	333.0	51.22	0.27
131a	Polk	IMC Fertilizer New Wales	396.5	3,079.0	3.60	40.54	313.6	15.18	2.13
131aa	Polk	IMC Fertilizer New Wales	396.5	3,079.3	2.53	40.54	313.6	1.01	0.91
131bb	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	18.29	313.6	9.70	0.30
131cc	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	13.72	313.6	9.70	0.30
131dd	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	26.52	438.6	86.24	0.46
131e	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.78	52.12	316.3	17.97	1.83
131ee	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	26.52	438.6	86.24	0.46
131ff	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	5.18	380.2	38.27	0.40
131gg	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	17.37	352.4	22.96	0.40
131hh	Polk	IMC Fertilizer New Wales	396.7	3,079.4	3.34	52.43	313.6	15.97	1.37
131ii	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	32.61	313.6	20.96	0.55
131jj	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	19.81	352.4	14.37	0.46
131kk	Polk	IMC Fertilizer New Wales	396.7	3,079.4	2.13	21.64	299.7	10.35	0.30
131ll	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.12	30.48	299.7	54.62	0.46

Emission Inventory for NAAQS Analysis for PM

Identi-fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
131mm	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	31.70	313.6	21.48	0.49
131n	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.60	12.19	315.2	20.12	0.91
131nn	Polk	IMC Fertilizer New Wales	396.7	3,079.4	1.78	52.12	316.3	17.97	1.83
131o	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.17	33.53	316.3	13.86	0.43
131oo	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.58	28.65	352.4	10.78	1.83
131p	Polk	IMC Fertilizer New Wales	396.5	3,079.1	4.26	40.54	316.3	20.66	1.83
131pp	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.06	30.48	311.9	12.58	0.55
131q	Polk	IMC Fertilizer New Wales	396.5	3,079.0	1.93	40.54	333.0	21.43	1.22
131qq	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.20	26.21	299.7	16.50	0.21
131r	Polk	IMC Fertilizer New Wales	396.5	3,079.2	3.63	40.54	315.2	18.87	1.83
131rr	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	35.97	313.6	10.35	0.30
131s	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.46	19.81	313.6	51.75	0.30
131ss	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.35	32.61	338.6	15.84	1.07
131t	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	18.29	313.6	16.17	0.30
131tt	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.66	7.62	333.0	10.49	1.31
131u	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	34.14	313.6	10.35	0.30
131uu	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.78	51.82	316.3	1.97	1.52
131v	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	32.00	313.6	42.69	0.30
131vv	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.81	12.19	299.7	9.39	0.27
131w	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	35.66	313.6	38.81	0.30
131x	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.20	5.49	313.6	9.70	0.30
131y	Polk	IMC Fertilizer New Wales	396.8	3,079.4	4.64	52.43	321.9	13.14	2.44
131z	Polk	IMC Fertilizer New Wales	396.7	3,079.4	0.43	34.14	313.6	10.35	0.30
132b	Polk	Mobil–Electrophos Division	405.6	3,079.4	15.95	30.48	319.1	12.34	1.31
132l	Polk	Mobil–Electrophos Division	405.6	3,079.4	3.71	15.24	308.0	18.73	0.91
132m	Polk	Mobil–Electrophos Division	405.6	3,079.4	3.63	29.26	306.9	7.70	2.13

Emission Inventory for NAAQS Analysis for PM

Identi-fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
132n	Polk	Mobil-Electrophos Division	405.6	3,079.4	2.42	25.60	321.9	25.77	1.07
132o	Polk	Mobil-Electrophos Division	405.6	3,079.4	1.93	18.29	321.9	14.34	0.76
133a	Polk	Imperial Phosphates Ltd.	404.8	3,069.5	2.27	27.43	333.0	20.65	1.52
133b	Polk	Imperial Phosphates Ltd.	404.8	3,069.5	0.12	27.43	494.1	7.28	0.61
133c	Polk	Imperial Phosphates Ltd.	404.8	3,069.5	2.27	27.43	333.0	19.78	1.40
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	36.80	48.80	411.0	14.30	5.49
137a	Polk	Ridge Cogeneration	416.7	3,100.4	11.91	99.10	350.0	14.54	3.05
164d	Polk	Estech	411.5	3,074.2	1.58	18.90	338.6	11.58	2.04
164e	Polk	Estech	411.5	3,074.2	3.89	18.29	334.1	6.24	3.05
164f	Polk	Estech	411.5	3,074.2	1.27	14.63	311.9	11.43	0.34
164g	Polk	Estech	411.5	3,074.2	1.27	10.97	311.9	7.83	0.34
164h	Polk	Estech	411.5	3,074.2	0.95	10.97	315.8	11.11	0.34
170a	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.14	29.87	298.0	12.13	0.49
170aa	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.58	6.10	310.8	24.06	0.67
170b	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.14	29.87	298.0	12.13	0.49
170bb	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.37	35.05	310.8	21.50	0.58
170c	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.35	31.09	298.0	19.71	0.58
170cc	Hillsborough	LaFarge Corp.	357.7	3,090.6	11.98	44.50	494.7	40.43	2.44
170d	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.14	28.96	298.0	11.50	0.46
170dd	Hillsborough	LaFarge Corp.	357.7	3,090.6	5.67	30.79	401.9	6.09	3.81
170e	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.40	30.48	298.0	12.42	0.76
170ee	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.37	14.94	298.0	19.40	0.61
170f	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	44.81	298.0	13.43	0.52
170ff	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.37	22.25	298.0	23.29	0.58
170g	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	44.81	298.0	13.43	0.52
170gg	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.17	27.43	298.0	32.34	0.30

Emission Inventory for NAAQS Analysis for PM

Identi-fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper-ature (K)	Velocity (m/s)	Diameter (m)
170h	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	44.81	298.0	13.43	0.52
170hh	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.37	10.06	364.1	16.84	0.73
170i	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.14	52.12	298.0	25.66	0.34
170ii	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	25.30	355.2	19.02	1.04
170j	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	25.30	298.0	24.49	0.40
170jj	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	17.37	342.4	17.37	0.67
170k	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.17	14.33	298.0	19.14	0.40
170kk	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	10.06	364.1	16.84	0.73
170l	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.63	25.30	298.0	24.45	0.70
170ll	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.26	25.30	355.2	19.02	1.04
170m	Hillsborough	LaFarge Corp.	357.7	3,090.6	1.09	25.30	298.0	19.02	1.04
170mm	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.26	17.37	342.4	17.37	0.67
170n	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.40	17.37	298.0	17.37	0.67
170nn	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.26	10.06	364.1	16.84	0.73
170o	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.49	9.14	298.0	16.84	0.73
170oo	Hillsborough	LaFarge Corp.	357.7	3,090.6	2.53	53.04	298.0	23.00	0.46
170p	Hillsborough	LaFarge Corp.	357.7	3,090.6	1.09	25.30	298.0	19.02	1.04
170pp	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.29	53.04	298.0	28.75	0.46
170q	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.40	27.43	298.0	26.73	0.34
170qq	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.17	18.29	298.0	34.15	0.30
170r	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.49	4.88	298.0	16.84	0.73
170rr	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.17	18.29	298.0	34.15	0.30
170s	Hillsborough	LaFarge Corp.	357.7	3,090.6	1.09	25.30	298.0	19.02	1.04
170ss	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.14	37.49	298.0	25.87	0.30
170t	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.40	17.37	298.0	17.37	0.67
170u	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.49	9.14	298.0	16.84	0.73

Emission Inventory for NAAQS Analysis for PM

Identi–fication Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temper–ature (K)	Velocity (m/s)	Diameter (m)
170v	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.20	10.36	298.0	32.61	0.34
170w	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.26	14.94	298.0	10.69	0.67
170x	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.26	14.94	298.0	10.69	0.67
170y	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.26	21.95	298.0	80.85	0.24
170z	Hillsborough	LaFarge Corp.	357.7	3,090.6	0.32	1.52	310.8	17.92	0.58
171a	Manatee	Estech–Duette Phosphate Mine	388.9	3,047.2	7.20	18.29	342.4	14.86	2.87
171b	Manatee	Estech–Duette Phosphate Mine	388.9	3,047.2	7.20	38.10	321.3	30.24	1.07
171c	Manatee	Estech–Duette Phosphate Mine	388.9	3,047.2	7.20	18.29	318.0	30.31	0.85
173a	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	4.38	23.17	394.1	17.30	1.98
173b	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	4.72	16.76	341.3	8.82	2.83
173c	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	1.27	16.46	319.1	19.40	0.30
173d	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	1.90	8.23	302.4	16.17	0.61
173e	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	3.83	11.58	333.0	7.17	0.58
173f	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	3.83	11.58	333.0	7.17	0.58
173g	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	5.21	11.58	333.0	7.17	0.58
173h	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	3.22	7.62	296.9	11.50	0.46
173i	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	0.35	8.23	296.9	4.85	0.61
173j	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	1.90	8.23	302.4	16.17	0.61
173k	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	4.35	41.15	288.6	16.75	0.85
173l	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	1.90	13.11	303.0	18.11	0.61
173m	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	4.98	7.32	316.3	8.09	0.61
173n	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	2.39	7.32	316.3	8.09	0.61
173o	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	4.40	45.72	310.8	15.84	1.07
174a	Polk	IMC Fertilizer Kingsford	398.2	3,075.7	3.51	18.29	316.3	19.66	0.76
174b	Polk	IMC Fertilizer Kingsford	398.2	3,075.7	0.14	17.68	310.8	15.23	0.58
174c	Polk	IMC Fertilizer Kingsford	398.2	3,075.7	3.25	21.34	346.9	14.52	2.13

Emission Inventory for NAAQS Analysis for PM

Identification Number	County	Facility	UTM East	UTM North	PM (g/s)	Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
174d	Polk	IMC Fertilizer Kingsford	398.2	3,075.7	4.46	32.31	308.0	20.70	0.76
174e	Polk	IMC Fertilizer Kingsford	398.2	3,075.7	0.78	10.67	296.9	10.35	0.76
176a	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	2.42	27.43	299.7	16.50	0.21
176b	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	5.82	18.29	302.4	9.50	1.07
176c	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	1.47	30.48	321.9	12.98	0.55
176d	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	0.12	30.48	299.7	5.95	0.76
176e	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	23.90	25.91	296.9	11.64	0.15
176f	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	0.63	25.91	296.9	11.64	0.15
176g	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	0.40	27.43	299.7	16.50	0.21
176i	Polk	IMC/Uranium Recovery C F Industries	408.4	3,082.8	0.12	15.24	313.6	8.09	0.61

Sources: FDER, 1991, 1992.
ECT, 1992.

APPENDIX B.8

PM EMISSIONS INVENTORY FOR PSD CLASS I ANALYSIS

Emission Inventory for Class 1 PSD Analysis for PM

Identi– fication Number	County	Facility	UTM		PM* (g/s)	Height+ (m)	Temper– ature (K)	Velocity** (m/s)	Diameter (m)
			East	North					
100d	Hardee	Hardee Power Station	404.8	3,057.4	43.14	22.90	389.0	23.90	4.88
105h	Hillsborough	TECO Big Bend	361.9	3,057.0	54.61	149.35	341.9	18.21	7.32
105l	Hillsborough	TECO Big Bend	361.9	3,075.0	167.30	149.40	342.0	20.00	7.32
109a	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	3.17	38.10	339.1	15.16	2.44
109b	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	3.14	38.10	339.1	16.80	2.44
109d	Hillsborough	IMC Ft. Lonesome	359.6	3,067.9	13.26	45.72	316.3	8.43	0.82
112a	Manatee	Florida Power & Light	367.2	3,054.1	218.00	152.10	425.8	23.61	7.99
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,102.8	1.89	30.48	783.0	28.22	5.79
119g	Polk	Lakeland McIntosh	409.5	3,105.8	408.20	76.20	350.0	32.60	4.90
119h	Polk	Lakeland McIntosh	409.5	3,105.8	14.00	45.70	419.0	23.77	2.74
121kkk	Polk	WR Grace/Seminole	409.8	3,087.0	13.61	15.24	333.0	17.10	2.00
121q	Polk	WR Grace/Seminole	409.8	3,087.0	4.68	60.96	347.0	25.10	1.52
125m	Polk	US Agri–Chemicals Hwy 630	416.0	3,069.0	25.07	21.34	477.4	14.98	1.13
126aa	Polk	CF Industries Bonnie Mine Road	408.4	3,082.4	15.27	42.70	298.0	21.60	0.80
126t	Polk	CF Industries Bonnie Mine Road	408.4	3,082.4	2.45	36.58	333.0	17.17	2.29
126v	Polk	CF Industries Bonnie Mine Road	408.4	3,082.4	4.95	41.45	333.0	18.05	2.83
127aa	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	28.09	30.50	308.0	18.30	1.40
128f	Polk	Agrico Chemical Pierce	403.7	3,079.0	4.22	24.38	320.8	21.25	2.44
128g	Polk	Agrico Chemical Pierce	403.7	3,079.0	13.94	28.96	683.0	14.75	1.77
129i	Polk	Agrico South Pierce	407.5	3,071.3	49.10	45.70	350.0	39.06	1.60
130f	Polk	Conserv Inc.	398.7	3,084.2	28.91	45.72	349.7	10.31	2.29
130h	Polk	Conserv Inc.	398.7	3,084.2	17.73	12.80	310.8	10.60	1.22
132b	Polk	Mobil–Electrophos Division	405.6	3,079.4	15.95	30.48	319.1	12.34	1.31
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	36.80	48.80	411.0	14.30	5.49
136a	Pasco	Pasco Co Cogeneration Facility	385.6	3,139.0	2.52	30.48	384.3	17.13	3.35
137a	Polk	Ridge Cogeneration	416.7	3,100.4	11.91	99.10	350.0	14.54	3.05
140a	Hernando	Asphalt Pavers No. 3	361.4	3,168.4	1.20	8.50	366.0	17.00	1.20

Emission Inventory for Class 1 PSD Analysis for PM

Identi-fication Number	County	Facility	UTM East	UTM North	PM* (g/s)	Height+ (m)	Temper-ature (K)	Velocity** (m/s)	Diameter (m)
146a	Pasco	Evans Packing	383.3	3,135.8	12.10	25.90	346.0	17.30	1.00
148a	Hernando	Florida Mining & Materials rotary kiln 2	356.2	3,169.9	1.70	27.40	470.0	7.60	4.90
148b	Hernando	Florida Mining & Materals cement & blending silo	356.2	3,169.9	0.60	64.40	351.0	17.00	0.70
148c	Hernando	Florida Mining & Materials clinker cooler 2	356.2	3,169.9	0.90	15.20	477.0	21.90	2.30
148d	Hernando	Florida Mining & Materials clinker silo (3)	356.2	3,169.9	0.22	45.70	358.0	16.20	0.90
148e	Hernando	Florida Mining & Materials finish mill & kiln feed	356.2	3,169.9	0.70	22.80	347.0	15.20	1.40
148f	Hernando	Florida Mining & Materials clay crusher	356.2	3,169.9	1.00	6.10	405.0	15.20	1.50
148g	Hernando	Florida Mining & Materials raw materials handling	356.2	3,169.9	1.20	24.50	314.0	10.90	0.91
149a	Hernando	Florida Crushed Stone cement kiln	360.0	3,162.4	10.90	97.60	381.0	13.71	4.88
149b	Hernando	Florida Crushed Stone raw meal transfer	360.0	3,162.5	0.04	21.30	355.2	12.90	0.30
149c	Hernando	Florida Crushed Stone premix bins	360.0	3,162.3	0.08	38.10	314.0	9.70	0.61
149d	Hernando	Florida Crushed Stone fly ash bin	360.0	3,162.3	0.08	38.10	314.0	9.70	0.61
149e	Hernando	Florida Crushed Stone raw materials bin	360.0	3,162.3	0.10	30.50	314.0	12.90	0.61
149f	Hernando	Florida Crushed Stone blending silo	360.0	3,162.3	0.42	73.20	355.0	13.72	1.10
149g	Hernando	Florida Crushed Stone kiln feed	360.0	3,162.3	0.10	15.20	366.0	9.70	0.61
149h	Hernando	Florida Crushed Stone cooler discharge	360.1	3,162.2	0.10	8.80	366.0	9.70	0.61
149i	Hernando	Florida Crushed Stone clinker silo	360.1	3,162.1	0.08	61.00	366.0	14.39	0.46
149j	Hernando	Florida Crushed Stone clinker silo	360.1	3,162.1	0.08	41.20	366.0	14.39	0.46
149k	Hernando	Florida Crushed Stone cement silo discharge	360.1	3,162.1	0.08	15.20	344.0	14.39	0.46
149l	Hernando	Florida Crushed Stone finish mill	360.1	3,162.2	0.81	21.30	372.2	12.93	1.50
149m	Hernando	Florida Crushed Stone silo discharge	360.1	3,162.1	0.23	15.20	314.0	14.48	0.76
149n	Hernando	Florida Crushed Stone cement silos	360.1	3,162.1	0.30	61.00	355.2	14.39	0.46
149o	Hernando	Florida Crushed Stone deep bukt cnvyr (area)	360.1	3,162.1	0.00021	15.00		45.00	
149p	Hernando	Florida Crushed Stone iron ore storage (area)	360.1	3,162.1	0.000029	15.00		90.00	
149q	Hernando	Florida Crushed Stone cement dist. sys. (area)	360.1	3,162.1	0.00013	10.00		20.00	
149r	Hernando	Florida Crushed Stone coal ldng/pshng (area)	360.1	3,162.1	0.00008	10.00		80.00	
149s	Hernando	Florida Crushed Stone veh. traffic (area)	360.1	3,162.1	0.000028	10.00		80.00	

Emission Inventory for Class 1 PSD Analysis for PM

Identi–fication Number	County	Facility	UTM		PM* (g/s)	Height+ (m)	Temper–ature (K)	Velocity** (m/s)	Diameter (m)
			East	North					
149t	Hernando	Florida Crushed Stone wind erosion (area)	360.1	3,162.1	0.0000002	10.00		80.00	
150aa	Citrus	FPC Unit 5 cooling tower	334.3	3,205.3	22.10	135.00	311.0	3.32	65.20
150bb	Citrus	FPC Units 4 & 5 power generation	334.7	3,205.3	157.60	178.20	396.0	21.03	7.77
150cc	Citrus	FPC Units 4 & 5 coal baghouses	334.5	3,205.3	0.88	42.70	310.0	21.20	0.84
150dd	Citrus	FPC progress material baghouses	334.1	3,204.6	0.21	18.30	325.0	11.40	0.61
150e	Citrus	FPC Unit 4/5 active ash pile (wind erosion) (area)	335.5	3,205.1	0.00003	12.00		100.00	
150f	Citrus	FPC haul road to Unit 4/5 active ash Pile (area)	335.5	3,205.1	0.00003	12.00		100.00	
150g	Citrus	FPC Unit 4/5 coal transfer (area)	334.1	3,203.8	0.0000004	3.00		380.00	
150h	Citrus	FPC Unit 4/5 inactive ash pile (wind erosion) (area)	335.5	3,205.0	0.000013	24.40		125.00	
150i	Citrus	FPC Unit 4/5 inactive ash pile (wind erosion) (area)	335.6	3,205.0	0.000013	24.40		125.00	
150j	Citrus	FPC Unit 4/5 inactive ash pile (wind erosion) (area)	335.0	3,205.2	0.0000058	3.00		150.00	
150k	Citrus	FPC Unit 4/5 inactive ash pile (wind erosion) (area)	335.0	3,205.0	0.0000058	3.00		150.00	
150l	Citrus	FPC Unit 4/5 inactive ash pile (wind erosion) (area)	335.2	3,205.2	0.0000058	3.00		150.00	
150m	Citrus	FPC Unit 4/5 inactive ash pile (wind erosion) (area)	335.2	3,205.0	0.0000058	3.00		150.00	
150n	Citrus	FPC Unit 4/5 active coal pile (maintenance) (area)	335.0	3,205.2	0.0000089	3.00		150.00	
150p	Citrus	FPC Unit 4/5 active coal pile (maintenance) (area)	335.0	3,205.0	0.0000089	3.00		150.00	
150q	Citrus	FPC progress material (fugitive emissions) (area)	334.1	3,204.5	0.0001280	5.00		80.00	
150r	Citrus	FPC ideal basic (wind erosion) (area)	333.5	3,204.2	0.0000024	5.00		300.00	
150s	Citrus	FPC ideal basic (general operations) (area)	333.5	3,204.2	0.0000008	5.00		300.00	
150t	Citrus	FPC ideal basic quarry (wind erosion) (area)	334.2	3,207.6	0.0000459	3.80		56.10	
150u	Citrus	FPC ideal basic quarry (general operations) (area)	334.2	3,207.6	0.00039	3.80		56.10	
150v	Citrus	FPC helper cooling tower #1	333.8	3,204.6	12.60	16.10	312.0	6.19	31.60
150w	Citrus	FPC helper cooling tower #2	333.7	3,204.6	12.60	16.10	312.0	6.19	31.60
150x	Citrus	FPC helper cooling tower #3	333.4	3,204.6	12.60	16.10	312.0	6.19	31.60
150y	Citrus	FPC helper cooling tower #4	333.2	3,204.6	12.60	16.10	312.0	6.19	31.60
150z	Citrus	FPC Unit 4 cooling tower	334.3	3,205.5	22.10	135.00	311.0	3.32	65.20
154a	Lake	Lake Co Cogeneration Facility	434.0	3,198.8	2.52	30.48	384.3	17.13	3.35

Emission Inventory for Class 1 PSD Analysis for PM

Identi– fication Number	County	Facility	UTM East	UTM North	PM* (g/s)	Height+ (m)	Temper– ature (K)	Velocity** (m/s)	Diameter (m)
159a	Pasco	Pasco Co Resource Recovery Facility	347.1	3,139.2	2.03	83.82	394.3	15.70	3.05
173g	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	28.00	11.58	333.0	7.17	0.58
176e	Polk	IMC/Uranium Recovery CF Industries	408.4	3,082.8	23.90	25.90	297.0	11.60	0.20
177a	Hernando	DLS coal handling	397.2	3,182.6	0.08	7.00	314.0	7.50	0.30
177b	Hernando	DLS kiln 1	397.2	3,182.6	0.71	21.00	391.0	13.60	1.20
178a	Manatee	Biochemical Energy	418.3	3,048.0	8.90	11.00	450.0	20.10	0.90

*For area sources, this parameter becomes the emission rate in g/s/m^2.

+For area sources, this parameter becomes the effective emission height in m.

**For area sources, this parameter becomes the width of the square area source in m.

Sources: FDER, 1991, 1992.
ECT, 1992.

APPENDIX B.9

PM EMISSIONS INVENTORY FOR PSD CLASS II ANALYSIS

Emission Inventory for Class 2 PSD Analysis for PM

Identi-fication Number	County	Facility	UTM East	UTM North	PM* (g/s)	Height+ (m)	Temper-ature (K)	Velocity** (m/s)	Diameter (m)
100d	Hardee	Hardee Power Station	404.8	3,057.4	43.14	22.90	389.0	23.90	4.88
105h	Hillsborough	TECO Big Bend	361.9	3,057.0	54.61	149.35	341.9	18.21	7.32
1051	Hillsborough	TECO Big Bend	361.9	3,075.0	167.30	149.40	342.0	20.00	7.32
109a	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	3.17	38.10	339.1	15.16	2.44
109b	Hillsborough	IMC Ft. Lonesome	389.6	3,067.9	3.14	38.10	339.1	16.80	2.44
109d	Hillsborough	IMC Ft. Lonesome	359.6	3,067.9	13.26	45.72	316.3	8.43	0.82
118g	Polk	Lakeland City Power CT (Larsen)	409.2	3,102.8	1.89	30.48	783.0	28.22	5.79
119g	Polk	Lakeland McIntosh	409.5	3,105.8	408.20	76.20	350.0	32.60	4.90
119h	Polk	Lakeland McIntosh	409.5	3,105.8	14.00	45.70	419.0	23.77	2.74
121kkk	Polk	WR Grace/Seminole	409.8	3,087.0	13.61	15.24	333.0	17.10	2.00
121q	Polk	WR Grace/Seminole	409.8	3,087.0	4.68	60.96	347.0	25.10	1.52
125m	Polk	US Agri-Chemicals Hwy 630	416.0	3,069.0	25.07	21.34	477.4	14.98	1.13
126aa	Polk	CF Industries Bonnie Mine Road	408.4	3,082.4	15.27	42.70	298.0	21.60	0.80
126t	Polk	CF Industries Bonnie Mine Road	408.4	3,082.4	2.45	36.58	333.0	17.17	2.29
126v	Polk	CF Industries Bonnie Mine Road	408.4	3,082.4	4.95	41.45	333.0	18.05	2.83
127aa	Polk	Farmland Industries Green Bay Plant	409.5	3,080.1	28.09	30.50	308.0	18.30	1.40
128f	Polk	Agrico Chemical Pierce	403.7	3,079.0	4.22	24.38	320.8	21.25	2.44
128g	Polk	Agrico Chemical Pierce	403.7	3,079.0	13.94	28.96	683.0	14.75	1.77
129i	Polk	Agrico South Pierce	407.5	3,071.3	49.10	45.70	350.0	39.06	1.60
130f	Polk	Conserv Inc.	398.7	3,084.2	28.91	45.72	349.7	10.31	2.29
130h	Polk	Conserv Inc.	398.7	3,084.2	17.73	12.80	310.8	10.60	1.22
132b	Polk	Mobil-Electrophos Division	405.6	3,079.4	15.95	30.48	319.1	12.34	1.31
134a	Polk	Auburndale Cogeneration	420.8	3,103.3	36.80	48.80	411.0	14.30	5.49
137a	Polk	Ridge Cogeneration	416.7	3,100.4	11.91	99.10	350.0	14.54	3.05
173g	Polk	IMC Fertilizer Noralyn Mine	414.7	3,080.3	28.00	11.58	333.0	7.17	0.58
176e	Polk	IMC/Uranium Recovery CF Industries	408.4	3,082.8	23.90	25.90	297.0	11.60	0.20

*For area sources, this parameter becomes the emission rate in g/s/m^2.
+For area sources, this parameter becomes the effective emission height in m.
**For area sources, this parameter becomes the width of the square area source in m.

Sources: FDER, 1991, 1992.
ECT, 1992.