INTEROFFICE MEMORANDUM

Date: 11-Jun-1999 01:44pm
From: Waters, Glenn D.
GDWATERS@southernco.com
Dept:
Tel No:

To: Scott M. Sheplak (E-mail) (sheplak_s@dep.state.fl.us)
CC: Angela Morrison (E-mail) (morrisona@hgss.com)
CC: Vick, James O. (JOVICK@southernco.com)
CC: Doug Roberts (E-mail) (robertsd@hgss.com)

Subject: Smith 3 Construction Application

Pursuant to your call yesterday, I've been able to re-check our Smith 3 application and it only indicates that the application is for construction. No checks were made in the section regarding Title V in the application on page 2. As indicated yesterday, Gulf Power does not request that the Smith Unit 3 Title V application be processed in concert with the PSD evaluation under the Power Plant Siting Act. It is our intent to re-open the Smith Title V permit at the necessary time to add the new unit after the PSD is completed.

Please let me know that you received this email. Also, please let me know if you need further documentation regarding this matter. My email address is gdwaters@southernco.com Thanks.

BEST AVAILABLE COPY

Gulf Power Smith Unit #3

6/7/99
PA99-40

TO

DATE 06/10/99 TIME ~10:30 a.m.

WHILE YOU WERE OUT

M Owain Waters

of Gulf Power

PHONE 850/444-6527

AREA CODE NUMBER EXTENSION

TELEPHONED		PLEASE CALL		WILL CALL AGAIN	
RETURNED YOUR CALL		CALL IMMEDIATELY			
CAME TO SEE YOU		WANTS TO SEE YOU			

MESSAGE Owain intended to reopen the FINAL permit to add the new unit. He doesn't want to hold up the T&V permit. The contractor for the PSD/PA went ahead & prepared the T&V.

By

6/10/99
Scott Goodland to [illegible]
to remove from [illegible],
processing.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 11-Jun-1999 01:55pm
From: Scott Sheplak TAL
SHEPLAK_S
Dept: Air Resources Management
Tel No: 850/488-1344

To:	Scott Goorland TAL	(GOORLAND_S)
To:	Hamilton Oven TAL	(OVEN_H)
To:	Alvaro Linero TAL	(LINERO_A)
To:	Jonathan Holtom TAL	(HOLTOM_J)
To:	Patricia Comer TAL	(COMER_P)

Subject: FWD: Smith 3 Construction Application

See attached message from Dwain Waters with Gulf Power.

INTEROFFICE MEMORANDUM

Date: 11-Jun-1999 01:44pm
From: Waters, Glenn D.
GDWATERS@southernco.com
Dept:
Tel No:

Subject: Smith 3 Construction Application

Pursuant to your call yesterday, I've been able to re-check our Smith 3 application and it only indicates that the application is for construction. No checks were made in the section regarding Title V in the application on page 2. As indicated yesterday, Gulf Power does not request that the Smith Unit 3 Title V application be processed in concert with the PSD evaluation under the Power Plant Siting Act. It is our intent to re-open the Smith Title V permit at the necessary time to add the new unit after the PSD is completed.

Please let me know that you received this email. Also, please let me know if you need further documentation regarding this matter. My email address is gdwaters@southernco.com Thanks.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 10-Jun-1999 03:32pm
From: Scott Goorland TAL
GOORLAND_S
Dept: Office General Counsel
Tel No: 850/921-9687

To: Patricia Comer TAL (COMER_P)
CC: Scott Sheplak TAL (SHEPLAK_S)

Subject: Title V permit application withdrawal

Pat,

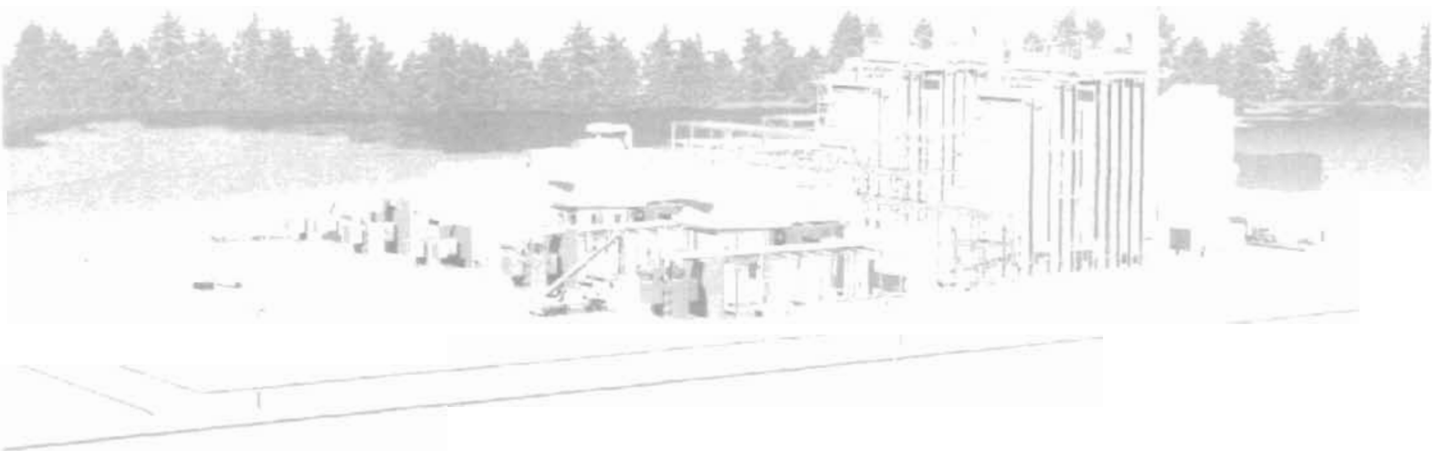
I got a call this morning from Scott Sheplak concerning Title V. There is an applicant who is coming through Siting for a permit, but who has also filed the Title V application simultaneously. The applicant has decided to hold off on requesting the Title V until after the Siting permit issues, and would like to know of there are any special requirements such as a Notice of Withdrawal, or other procedures necessary to withdraw the Title V application. Scott please correct this if any of the information here is incorrect. If you could email Scott regarding this issue it would be much appreciated, as I will be on annual leave tomorrow.

thanks,
Scott

GULF POWER

SMITH UNIT 3

Site Certification Application



Volume 4 **June 1999**

GULF POWER
A SOUTHERN COMPANY

ECT
Environmental Consulting & Technology, Inc.

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS

PA-99-40

PSD-FI-269

RECEIVED
JUN 07 1999
BUREAU OF
AIR REGULATION

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PREVENTION OF SIGNIFICANT DETERIORATION APPLICATION

PREVENTION OF SIGNIFICANT DETERIORATION APPLICATION

SMITH UNIT 3

Prepared for:

GULF POWER COMPANY
Pensacola, Florida

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 990151-0300

June 1999

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Gulf Power Company (Gulf) is planning to construct and operate a natural gas-fired combustion turbine generator (CTG)-based combined cycle (CC) unit at its existing Lansing Smith Electric Generating Plant. This new unit, designated Smith Unit 3, will have a nominal generating capacity of 540 megawatts (MW). At average annual site conditions with duct burner (DB) firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. The existing Lansing Smith Electric Generating Plant is located in Bay County northwest of Panama City. The existing Lansing Smith facility includes: (a) two coal-fired electric generating units having nominal generating capacities of 175 MW (Unit 1) and 205 MW (Unit 2); (b) one No. 2 fuel oil-fired combustion turbine having a nominal generating capacity of 40 MW; and (c) ancillary supporting equipment and processes including coal handling and storage. The proposed Smith Unit 3 is being licensed under the Florida Electrical Power Plant Siting Act.

Operation of the proposed project will result in the emission of air contaminants. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the appendices, constitutes Gulf's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, F.A.C.

Smith Unit 3 will be located in an attainment area and will have potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). Consequently, Smith Unit 3 qualifies as a new major facility and is subject to the prevention of significant deterioration (PSD) new source review (NSR) requirements of Rule 62-212.400, F.A.C. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and a summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (dispersion modeling methodology) and 7.0 (dispersion modeling results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of Smith Unit 3 and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.

Attachments A through D provide the FDEP Application for Air Permit—Title V Source, CTG vendor information, emission rate calculations, and NO_x netting analysis, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in diskette format in Attachment E.

1.2 SUMMARY

Smith Unit 3 will consist of two nominal 170-MW General Electric (GE) PG7241 (FA) CTGs, two heat recovery steam generators (HRSGs) equipped with supplemental DBs, and one nominal 200-MW steam turbine generator (STG); i.e., a 2-on-1 configuration. At average annual site conditions with DB firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. Ancillary equipment includes a mechanical draft cooling tower and water treatment and storage facilities. The CTGs will be fired exclusively with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf).

The planned construction start date for Smith Unit 3 is November 1, 2000. Smith Unit 3 projected date for the facility to begin commercial operation is May 31, 2002, following initial equipment startup and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, Smith Unit 3 will have the potential to emit 757 tpy of nitrogen oxides (NO_x), 701 tpy of carbon monoxide (CO), 253 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM/PM_{10}), 105 tpy of sulfur dioxide (SO_2), and 93 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, Smith Unit 3 will potentially emit 12 tpy of sulfuric acid (H_2SO_4) mist. Due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit No. 1, a federally enforceable NO_x emissions cap of 3,587 tpy, using continuous emissions monitoring systems (CEMS) to demonstrate compliance, for Smith Units 1 and 3 is requested to achieve a net reduction of 9 tpy in NO_x emissions from the Lansing Smith Plant following construction of Smith Unit 3. No increases in emissions of CO, VOC, or PM/PM_{10} are expected due to the installation of low-NO_x burners for Unit 1. A detailed NO_x netting analysis and a discussion of CO, VOC, and PM/PM_{10} emissions associated with Unit 1 low-NO_x burner installation are provided in Attachment D. Based on these annual emission rate potentials, CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist emissions are subject to PSD review.

As presented in this report, the analyses required for this permit application resulted in the following conclusions:

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM_{10}. The CTGs and DBs will utilize the latest burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emission rates, and will be fired exclusively with pipeline-quality natural gas.

- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOC for the CTGs and DBs. At base load operation without DB firing, the CTG/HRSG CO exhaust concentration is projected to be 13 parts per million by dry volume (ppmvd) at 15 percent oxygen. At base load operation with DB firing and without steam power augmentation, the CTG/HRSG CO exhaust concentration is projected to be 16 ppmvd at 15 percent oxygen. At base load operation with DB firing and with steam power augmentation, the CTG/HRSG CO exhaust concentration is projected to be 23 ppmvd at 15 percent oxygen for 1,000 hours per year (hr/yr). At base load operation without DB firing, the CTG/HRSG VOC exhaust concentration is projected to be 3 ppmvd at 15 percent oxygen. At base load operation with DB firing and without steam power augmentation, the CTG/HRSG VOC exhaust concentration is projected to be 4 ppmvd at 15 percent oxygen. At base load operation with DB firing and with steam power augmentation, the CTG/HRSG VOC exhaust concentration is projected to be 6 ppmvd at 15 percent oxygen for 1,000 hr/yr. These concentrations are consistent with prior FDEP BACT determinations for CTG/HRSG units; e.g., City of Tallahassee Purdom Unit 8, Lakeland Utilities McIntosh Unit 5, and Santa Rose Energy. Cost effectiveness of a CO oxidation catalyst control system was determined to be $1,567 per ton of CO. Installation of a CO oxidation catalyst control system is considered to be economically unreasonable.
- BACT for SO_2 and H_2SO_4 mist will be achieved through the exclusive use of low-sulfur, pipeline-quality natural gas.
- Smith Unit 3 is projected to emit CO, PM/PM_{10}, SO_2, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants, with the exception of PM_{10}. Accordingly, Smith Unit 3 qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants except PM_{10}. Representative, current quality-

assured ambient PM_{10} data collected by FDEP at a monitoring site located in Panama City, Bay County, was used to satisfy the PSD preconstruction ambient air monitoring requirements for PM_{10}.

- With the exception of PM_{10}, the ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.259(259), F.A.C. Accordingly, a multi-source interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was required for PM_{10} only.
- Based on refined dispersion modeling, Smith Unit 3 will not cause nor contribute to a violation of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.
- Modeling of H_2SO_4 mist emissions shows that maximum project impacts will be well below FDEP's draft ambient reference concentrations.
- The ambient impact analysis also demonstrates that project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Bradwell Bay Wilderness Area) is located approximately 125 kilometers (km) southeast of the Smith Unit 3 site. Air quality and visibility impacts on this Class I area will be negligible.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed Smith Unit 3 will be located in Bay County approximately 13 km (8 miles) northwest of Panama City. The approximately 50-acre plant site is bordered on the south by the existing Lansing Smith Generating Plant property, on the west by a Gulf electric transmission line corridor, and on the north and east by undeveloped property owned by Gulf. Figure 2-1 shows the location of Smith Unit 3 within the state of Florida. The project site location and surroundings are provided in Figure 2-2. Figure 2-3 provides portions of a U.S. Geological Survey (USGS) topographical map showing the project site location relative to local landmarks.

Major components of Smith Unit 3 include:

1. The base CC generating plant, consisting of two F-class CTG/HRSG units and one STG; i.e., a 2-on-1 configuration.
2. Mechanical draft cooling tower.
3. Ancillary equipment, including raw and demineralized water storage tanks.

The CTGs will be GE PG7241 (FA) units. The two CTGs will have provisions for steam power augmentation and will each be capable of producing a nominal 170 MW of electricity. The two HRSG units, which will be equipped with supplemental DBs, will furnish steam to the STG for the additional generation of electricity. The STG will be capable of generating an additional nominal 200 MW of power for an overall nominal generation capacity of 540 MW. At average annual site conditions with DB firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. The CTGs and DBs will be fired exclusively with pipeline quality natural gas.

Smith Unit 3 will be capable of continuous operation at base load for up to 8,760 hr/yr. The CTGs will normally operate between 50- and 100-percent load, with commensurate STG

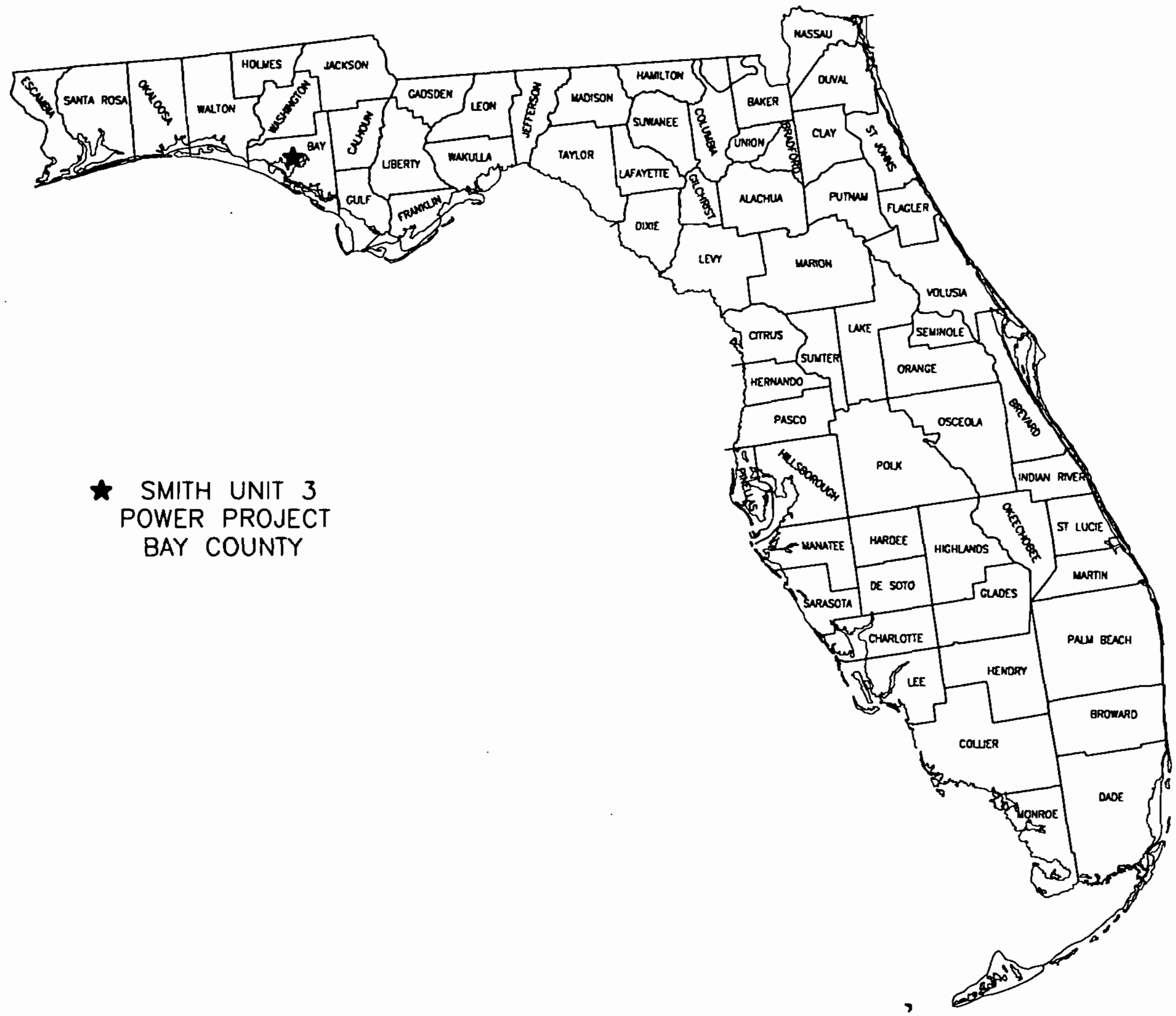

FIGURE 2-1.

SITE LOCATION WITHIN THE STATE OF FLORIDA

Source: ECT, 1999.

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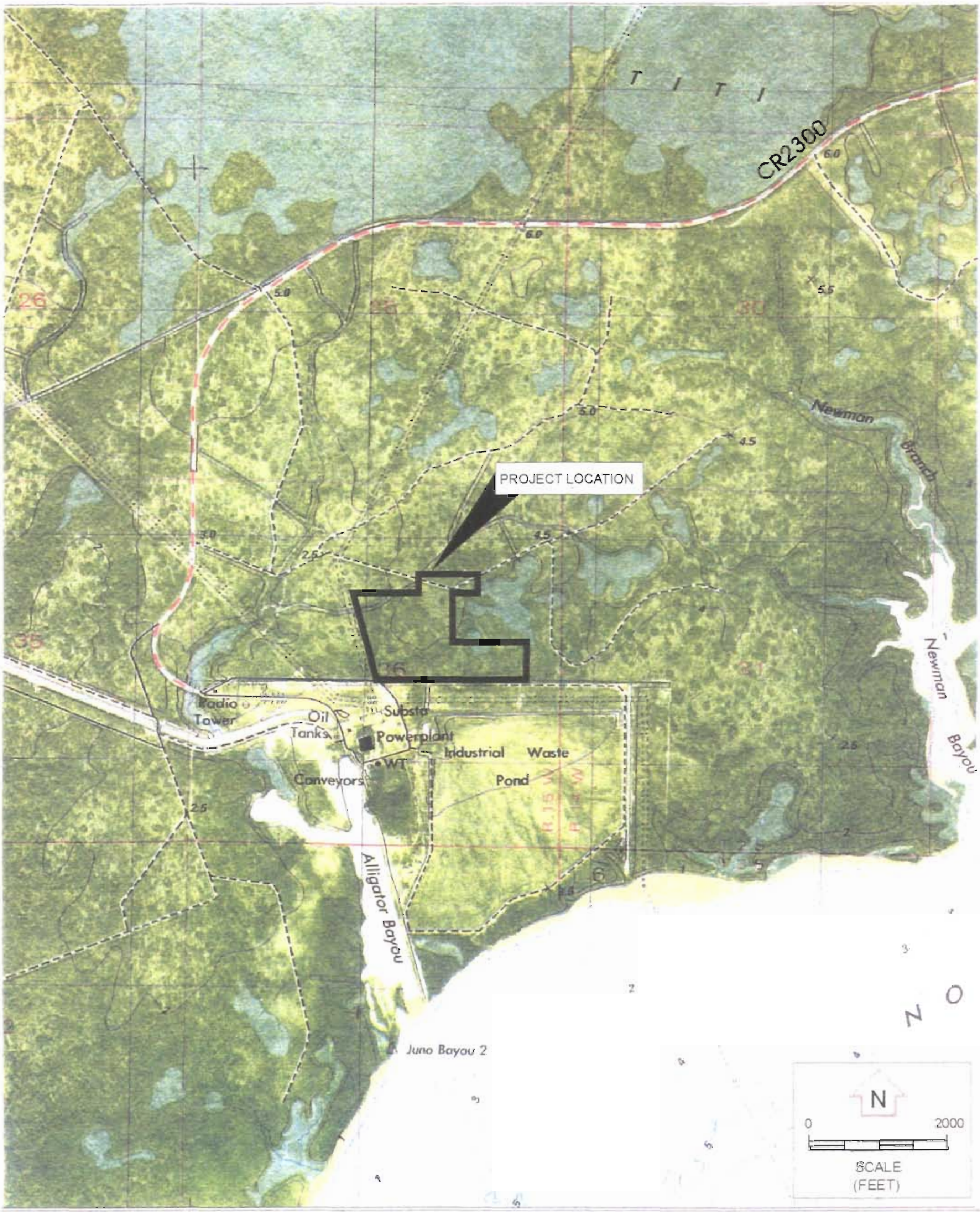

FIGURE 2-2.

PROJECT SITE LOCATION AND SURROUNDINGS

Sources: USGS topo map of Southport, Fl., 1992; ECT, 1999.

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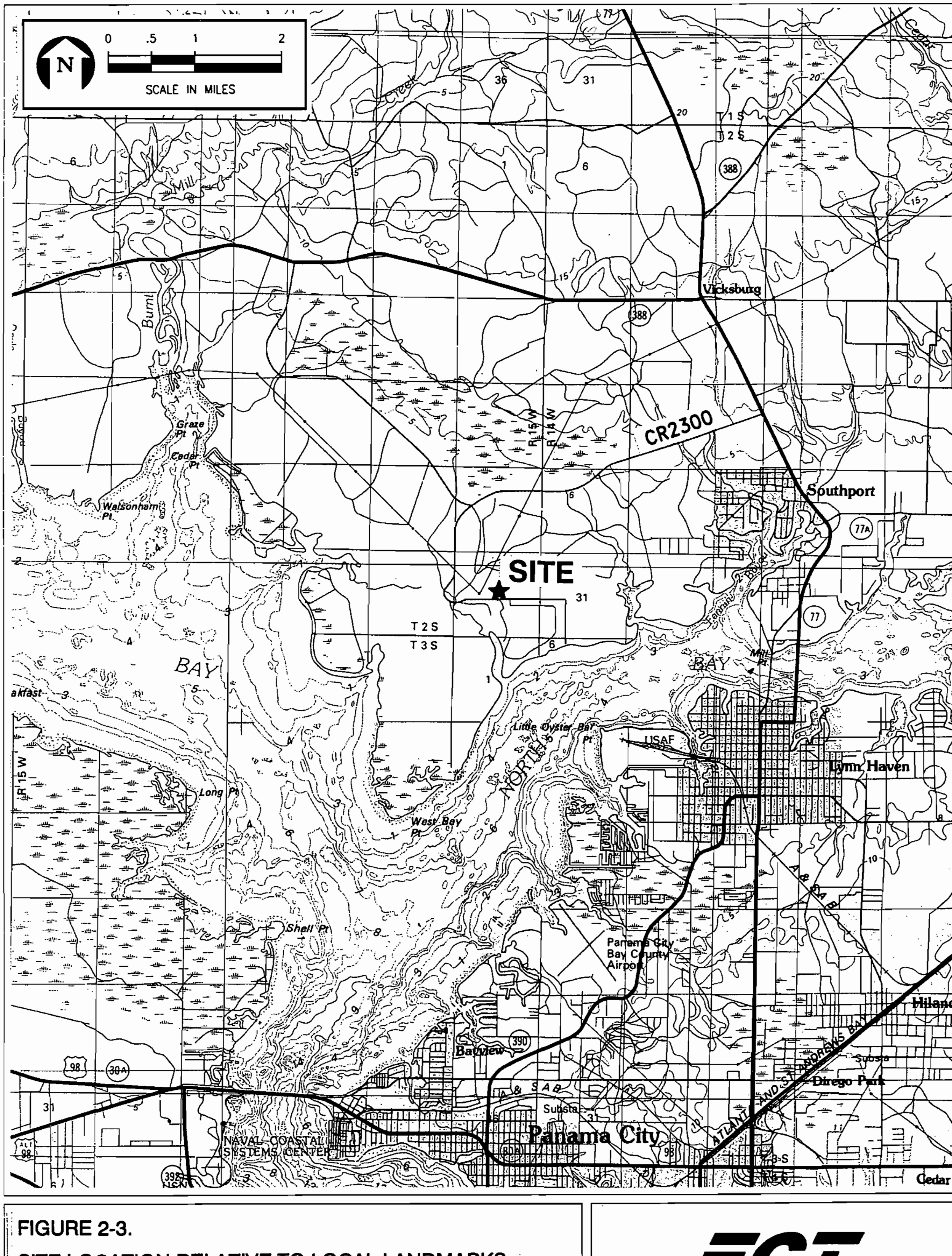

FIGURE 2-3.
SITE LOCATION RELATIVE TO LOCAL LANDMARKS

Sources: USGS 30x60–minute topo map: Panama City, FL, 1981.

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load. Neither CTG will be designed to operate in simple cycle mode (i.e., bypassing the HRSG).

Combustion of natural gas in the CTGs and DBs will result in emissions of particulate matter (PM/PM_{10}), SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Cooling tower operation will result in PM/PM_{10} emissions due to drift losses.

Emission control systems proposed for the CTG/HRSG units include the use of dry low-NO_x combustors for control of NO_x; good combustion practices for abatement of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions. Drift eliminators will be utilized to control PM/PM_{10} emissions from the mechanical draft cooling tower.

A plot plan showing facility property lines, major process equipment and structures, and all emission points is presented in Figure 2-4. Primary access to the plant will be provided by County Road (CR) 2300 which terminates at the existing power plant entrance. CR 2300 connects to State Road (SR) 77 to the north. The entrance will have security gates to control site access. The entire site perimeter will be fenced or include natural barriers at the property boundary.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed Smith Unit 3 natural gas-fired CC facility will include two nominal 170-MW CTGs, two HRSGs with supplemental DBs, and one nominal 200-MW STG. At average annual site conditions with DB firing, Unit 3 will generate 566 MW. At summer peaking site conditions with DB firing and steam power augmentation, Unit 3 will generate 574 MW. A process flow diagram of Smith Unit 3 is presented in Figure 2-5.

CTGs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft which is used to drive an electrical generator, thereby converting a portion of the engine's

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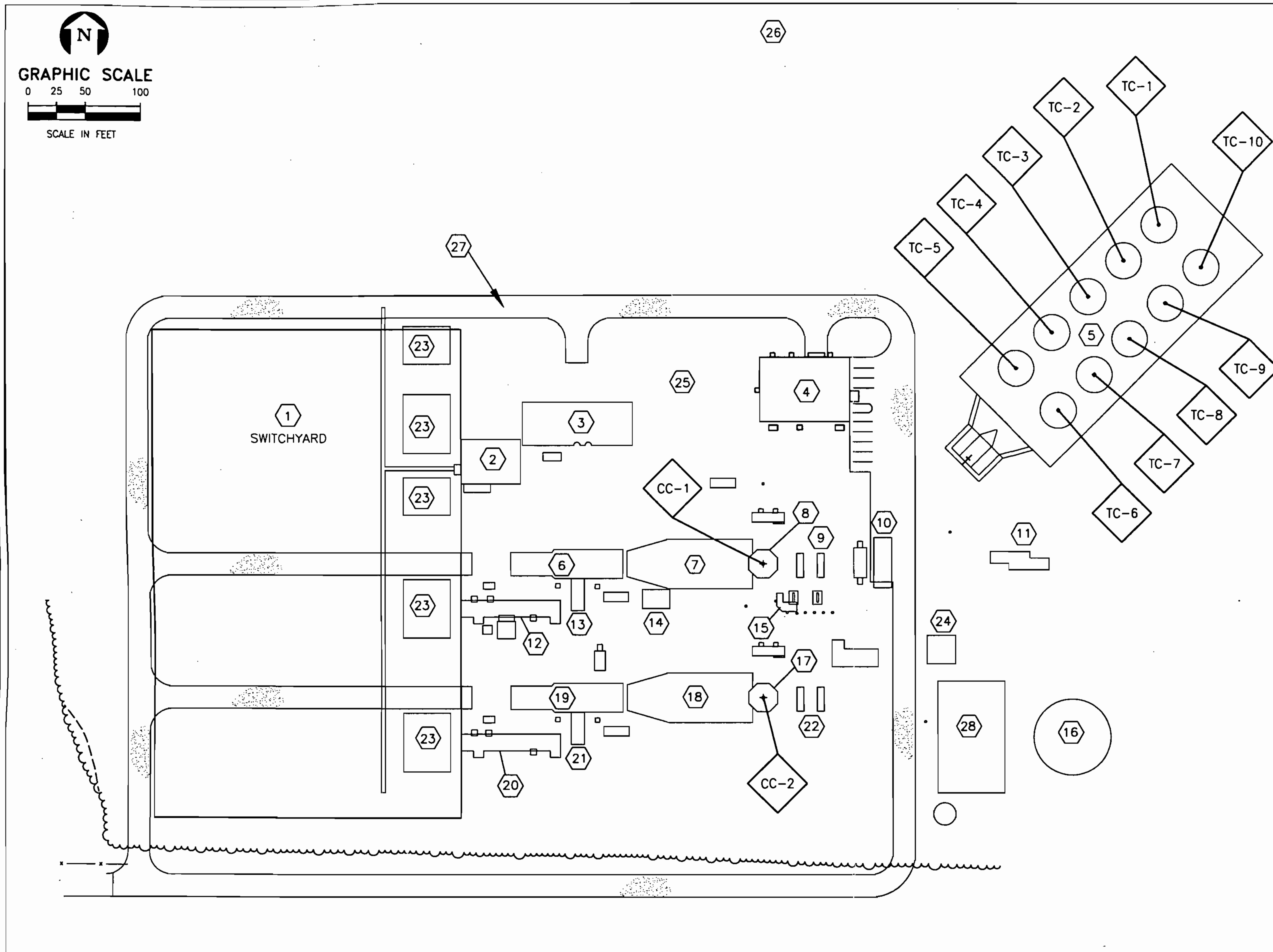

AREA /STRUCTURE LEGEND

NAME	SIZE (SQ. FEET)
CC-1 EMISSION POINT	
1 SWITCHYARD	120,346.68
2 ELECTRICAL BUILDING	2,351.44
3 STEAM TURBINE	3,768.28
4 ADMINISTRATION BUILDING	4,586.67
5 COOLING TOWER	33,178.27
6 NORTH GAS TURBINE	2,412.20
7 NORTH HEAT RECOVERY STEAM GENERATOR (HRSG)	4,617.73
8 NORTH STACK	534.43
9 NORTH BOILER FEED PUMP	258.02
10 FEEDWATER TRANSFORMER	720.00
11 480 VOLT MCC AND TRANSFORMER	664.06
12 BAC/PEECC	1,427.18
13 ACCESSORY MODULE	335.50
14 PHOSPHATE FEED SKID	425.00
15 AMMONIA SUPPLY SYSTEM	181.91
16 CONDENSATE STORAGE TANK	3,631.68
17 SOUTH STACK	534.43
18 SOUTH HEAT RECOVERY STEAM GENERATOR (HRSG)	4,617.73
19 SOUTH GAS TURBINE	2,412.20
20 GEC/PEECC	1,427.18
21 ACCESSORY MODULE	335.50
22 SOUTH BOILER FEED PUMP	258.02
23 TRANSFORMERS	9,541.24
24 WASTE WATER SUMP	325.13
25 INTERIOR PLANT YARD (GRAVEL)	76,418.62
26 BALANCE OF SITE (GRAVEL)	814,224.3
27 ROADWAY (CONCRETE)	87,682.38
28 WATER TREATMENT BUILDING	6,000.00
29 GRASSED SLOPES	50,000.00
30 MISC. CONC. PADS (INTERIOR YARD)	2,000.00

FIGURE 2-4.

SMITH UNIT 3 PLOT PLAN

Source: ECT, 1999.

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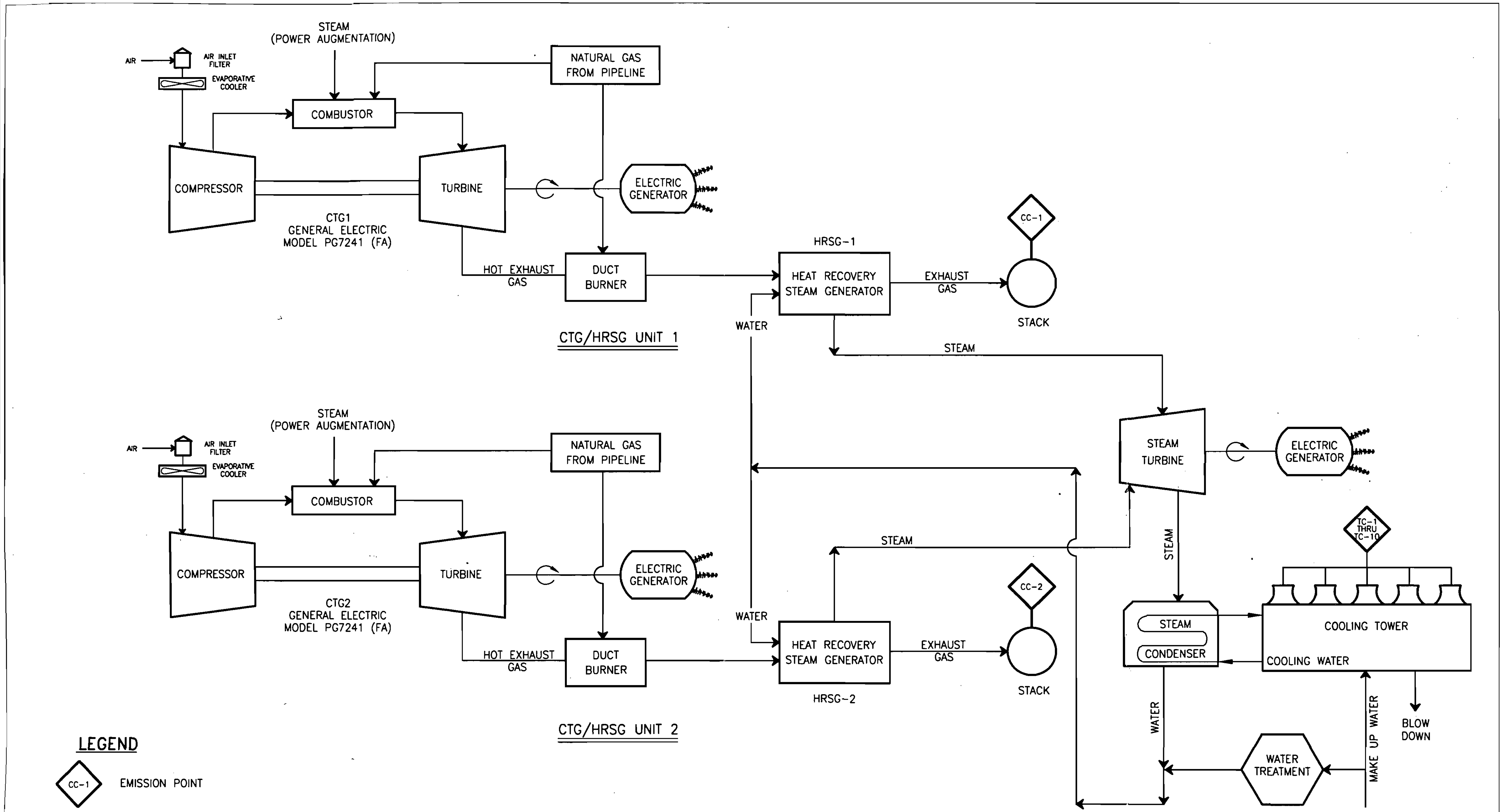

FIGURE 2-5.

PROCESS FLOW DIAGRAM

Source: ECT, 1999.

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mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. During warm days when the ambient air temperature exceeds 65 degrees Fahrenheit (°F), the turbine inlet ambient air is cooled by an evaporative cooler, thus providing denser air for combustion and improving the power output. The compressed combustion air is then combined with natural gas fuel and burned in the CTG's high-pressure combustor to produce hot exhaust gases. These high pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power which is used to drive an electric generator as well as the CTG combustion air compressor. The CTGs will also utilize steam power augmentation to increase power production during periods of peak demand.

The hot exhaust gases from the CTGs next flow to the HRSGs for the production of steam. Each CTG will use an HRSG to recover exhaust heat from the CTG and produce steam to power the STG. The STG, in turn, will drive an electric generator having a nominal generation capacity of 170 MW. The two HRSGs include supplemental DB firing for the production of additional steam during peak demand periods. The DBs, which will be fired exclusively with natural gas, each have a nominal heat input rating of 275 million British thermal units per hour (MMBtu/hr), lower heating value (LHV). Following reuse of the CTG exhaust waste heat by the HRSGs, the exhaust gases are discharged to the atmosphere.

Normal operation is expected to consist of both CTG/HRSG units operating at base load. Alternate operating modes include reduced load (i.e., between 50 and 100 percent of base load) operation for one or both of the CTG/HRSG units depending on power demands, use of inlet air evaporative cooling under high ambient temperature conditions, and supplemental HRSG DB firing and steam power augmentation during peak demand periods. The CTGs will not be designed with bypass stacks and will operate only in the CC mode. The CTG/HRSG units are designed for continuous operation (i.e., 8,760 hr/yr) and may operate at up to a 100 percent annual capacity factor.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to startup, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG hot, warm, and cold start-up and shutdown periods may last for more than 2 hours in a 24-hour period, the following periods of excess emissions above the 2-hour per 24-hour limit are requested for the Smith Unit 3 CTGs: (a) up to 1 hour per start-up during hot start-up to CC operation, (b) up to 2 hours per start-up during warm start-up to CC operation, (c) up to 4 hours per start-up during cold start-up to CC operation, and (d) up to 4 hours per shutdown during shutdowns from CC operation. Hot start-up is defined as a startup to CC operation following a complete shutdown lasting less than or equal to 8 hours. Warm start-up is defined as a startup to CC operation following a complete shutdown lasting between 8 and 48 hours. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. CTG start-up is defined as that period of time from initiation of CTG firing unit until the unit reaches steady-state load operation. Steady-state operation is reached when the CTG reaches minimum load (i.e., 50 percent load) and the steam turbine is declared available for load changes.

The CTGs and DBs will utilize dry low-NO_x combustion technology to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTGs and DBs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions. The mechanical draft cooling tower will be equipped with drift eliminators achieving a drift loss rate of no more than 0.001 percent.

2.3 EMISSION AND STACK PARAMETERS

Table 2-1 provides maximum hourly criteria pollutant CTG/HRSG emission rates. Maximum hourly noncriteria pollutant (i.e., H_2SO_4 mist) emission rates are summarized in Table 2-2. The highest hourly emission rates for each pollutant are prescribed, taking

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Pb	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	0†	20.8	2.62	12.7	1.60	78.7	9.91	78.7	9.91	10.2	1.29	Neg.	Neg.
	65‡	20.9	2.63	11.9	1.50	82.9	10.45	75.4	9.49	9.8	1.23	Neg.	Neg.
	95**	21.5	2.65	12.4	1.57	113.3	14.28	116.6	14.69	16.8	2.12	Neg.	Neg.
75	0	19.8	2.50	9.3	1.18	56.1	7.07	46.2	5.82	5.2	0.66	Neg.	Neg.
	65	19.8	2.50	8.6	1.09	51.7	6.51	42.9	5.41	5.2	0.65	Neg.	Neg.
	95	19.8	2.50	8.2	1.04	49.5	6.24	40.7	5.13	4.2	0.53	Neg.	Neg.
50	0	19.8	2.50	7.4	0.94	44.0	5.54	37.4	4.71	4.4	0.55	Neg.	Neg.
	65	19.8	2.50	6.9	0.87	41.8	5.27	35.2	4.44	4.4	0.55	Neg.	Neg.
	95	19.8	2.50	6.6	0.83	39.6	4.99	34.1	4.30	5.0	0.63	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible.

* Excludes H_2SO_4 mist.
† Emission rates include supplemental duct burner firing.
‡ Emission rates include use of evaporative cooler and supplemental duct burner firing.
** Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table 2-2. Maximum Noncriteria Pollutant Emission Rates for Three Loads and Four Ambient Temperatures (Per CTG/HRSG Unit)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4 mist lb/hr	H_2SO_4 mist g/s
100	0*	1.46	0.184
	65†	1.36	0.172
	95*‡	1.43	0.180
75	0	1.07	0.135
	65	0.99	0.125
	95*	0.94	0.119
50	0	0.85	0.108
	65	0.80	0.100
	95*	0.76	0.095

* Emission rates include supplemental duct burner firing.
† Emission rates include use of evaporative cooler and supplemental duct burner firing.
‡ Emission rates include use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.

into account load and ambient temperature to develop maximum hourly emission estimates for each CTG/HRSG unit.

Maximum hourly emission rates for SO_2 and H_2SO_4 mist, in units of pounds per hour (lb/hr), are projected to occur for operations at low ambient temperature (i.e., 0°F), CTG baseload, and DB firing. For PM/PM_{10}, NO_x, CO, and VOCs, maximum hourly mass emission rates are projected to occur at 95°F, CTG baseload with steam power augmentation, and DB firing. The bases for these emission rates are provided in Attachment C.

Table 2-3 presents projected maximum annualized criteria and noncriteria emissions for Smith Unit 3. The maximum annualized rates were conservatively estimated for each CTG/HRSG unit assuming 7,760 hr/yr at 65°F, CTG baseload with DB firing and 1,000 hr/yr at 95°F, CTG baseload with steam power augmentation and DB firing.

Annual emission rate estimates for the mechanical draft cooling tower and total Smith Unit 3 annual emissions are shown in Table 2-3. Details of the annualized emission calculations are also included in Attachment C. Stack parameters for the natural gas-fired CTG/HRSG units are provided in Table 2-4.

Table 2-3. Maximum Annualized Emission Rates in tpy for Smith Unit 3

Pollutant	CTG/HRSG Units	Cooling Tower	Unit 3 Totals
NO_x	757	N/A	757
CO	701	N/A	701
PM/PM_{10}*	184	80	264
SO_2	105	N/A	105
VOC	93	N/A	93
H_2SO_4 mist	12	N/A	12

Note: N/A = not applicable.

*Excludes H_2SO_4 mist.

Sources: ECT, 1999.
GE, 1999
Gulf Power, 1999.

Table 2-4. Stack Parameters for Three Unit Loads and Three Ambient Temperatures (Per CTG/HRSG)

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	0*	121	36.7	190	361	81.5	24.8	16.8	5.11
	65†	121	36.7	186	359	74.2	22.6	16.8	5.11
	95‡	121	36.7	170	350	73.3	22.3	16.8	5.11
75	0	121	36.7	170	350	62.6	19.1	16.8	5.11
	65	121	36.7	166	348	58.7	17.9	16.8	5.11
	95	121	36.7	180	355	58.1	17.7	16.8	5.11
50	0	121	36.7	159	344	50.2	15.3	16.8	5.11
	65	121	36.7	155	341	47.6	14.5	16.8	5.11
	95	121	36.7	173	351	47.9	14.6	16.8	5.11

Note: m = meter.
K = Kelvin.
m/sec = meter per second.

*Stack parameters reflect supplemental duct burner firing.
†Stack parameters reflect use of evaporative cooler and supplemental duct burner firing.
‡Stack parameters reflect use of evaporative cooler, supplemental duct burner firing, and steam power augmentation.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

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3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS; reference Section 62-204.240, F.A.C. Table 3-1 presents the current national and Florida AAQS.

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. The proposed Smith Unit 3 is located in Bay County approximately 13 km northwest of Panama City. Bay County is presently designated in 40 CFR §81.310 as better than national standards (for total suspended particulates [TSPs] and SO_2), unclassifiable/attainment (for CO), unclassifiable or better than national standards (for nitrogen dioxide [NO_2]), and not designated (for lead). 40 CFR §81.310 also indicates that the 1-hour ozone standard is not applicable. Bay County is designated attainment (for ozone, SO_2, CO, and NO_2) and unclassifiable (for PM_{10} and lead) by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

Smith Unit 3 will be located in Bay County. As noted above, Bay County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, Smith Unit 3 is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [μg/m3] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2 (ppmv)	3-hour[1]		0.5	0.5
	24-hour[1]	0.14		0.1
	Annual[2]	0.030		0.02
SO_2	3-hour[1]			1,300
	24-hour[1]			260
	Annual[2]			60
PM_{10}[13]	24-hour[3]	150	150	
	Annual[4]	50	50	
PM_{10}	24-hour[5]			150
	Annual[6]			50
$PM_{2.5}$[11,12]	24-hour[7]	65	65	
	Annual[8]	15	15	
CO (ppmv)	1-hour[1]	35		35
	8-hour[1]	9		9
CO	1-hour[1]			40,000
	8-hour[1]			10,000
Ozone (ppmv)	1-hour[9]			0.12
	8-hour[10,11]	0.08	0.08	
NO_2 (ppmv)	Annual[2]	0.053	0.053	0.05
NO_2	Annual[2]			100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

1 Not to be exceeded more than once per calendar year.
2 Arithmetic mean.
3 Standard attained when the 99th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
4 Arithmetic mean, as determined by 40 CFR 50, Appendix N.
5 Not to be exceeded more than once per year, as determined by 40 CFR 50, Appendix K.
6 Standard attained when the expected annual arithmetic mean is less than or equal to the standard, as determined by 40 CFR 50, Appendix K.
7 Standard attained when the 98th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
8 Arithmetic mean, as determined by 40 CFR 50, Appendix N.
9 Standard attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.
10 Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.
11 The U.S. Court of Appeals for the District of Columbia Circuit (Circuit Court) held that these standards are not enforceable. American Trucking Association v. U.S.E.P.A., 1999 WL300618 (Circuit Court).
12 The Circuit Court may vacate standards following briefing. Id.
13 The Circuit Court held PM_{10} standards vacated upon promulgation of effective $PM_{2.5}$ standards.

Sources: 40 CFR 50.
Section 62-204.240, F.A.C.

3.3 PSD NSR APPLICABILITY

CTG-CC, such as the proposed Smith Unit 3, are considered by FDEP to fall within the Section 62-212.400, Table 212.400-1, F.A.C., Major Facility Category of "fossil-fuel-fired steam electric plants." Accordingly, new CTG-CC plants of more than 250 MMBtu/hr heat input, with potential emissions of 100 tpy or more of any regulated pollutant, and located in an attainment area are classified as *new major facilities* subject to PSD NSR.

The proposed Smith Unit 3 will have a heat input greater than 250 MMBtu/hr, will be located in an attainment area, and will have potential emissions of a regulated pollutant in excess of 100 tpy. Therefore, Smith Unit 3 qualifies as a new major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants which are emitted at or above the specified PSD significant emission rate levels. Due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit No. 1, a federally enforceable NO_x emissions cap of 3,587 tpy, using CEMS to demonstrate compliance, for Smith Units 1 and 3 is requested to achieve a net reduction of 9 tpy in NO_x emissions from the Lansing Smith Plant following construction of Smith Unit 3. No increases in emissions of CO, VOC, or PM/PM_{10} are expected due to the installation of low-NO_x burners for Unit 1. There are no other creditable contemporaneous emission rate increases or decreases that have occurred at the Lansing Smith Plant within the last 5 years. Comparisons of estimated potential annual emission rates for Smith Unit 3 and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of PM, PM_{10}, SO_2, CO, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Detailed emission rate estimates for Smith Unit 3 are provided in Attachment C.

Table 3-2. Projected Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	-9	40	No
CO	701	100	Yes
PM	264	25	Yes
PM_{10}	264	15	Yes
SO_2	105	40	Yes
Ozone/VOC	93	40	Yes
Lead	Negligible	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Not Present	3	No
H_2SO_4 mist	12	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not Present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not Present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not Present	40	No
Municipal waste combustor metals (measured as PM)	Not Present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not Present	3.5×10^{-6}	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 1999.

4.0 PSD NSR REQUIREMENTS

4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(5)(c), F.A.C., an analysis of BACT is required for each pollutant which is emitted by the proposed Smith Unit 3 in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(42), F.A.C., BACT is "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation. Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant which exceeds the PSD significant emission rate thresholds shown 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. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit unless determined to be infeasible. 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 limitations may not exceed any applicable federal new source performance standard (NSPS) or national emission standard for hazardous air pollutants (NESHAPs), or any other emission limitation established by state regulations.

BACT analyses are 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." Using 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 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.

4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of 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; i.e., those that exceed the PSD significant emission rate thresholds shown in Table 3-2.

Preconstruction 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 used if the data meet certain quality assurance (QA) 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).

Rule 62-212.400(2)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility shall be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., 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 PSD *de minimis* ambient impact levels presented in Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 4-1). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the proposed Smith Unit 3 is discussed in Section 8.0.

4.3 AMBIENT IMPACT ANALYSIS

An air quality or 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 FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220(4), F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* as published

Table 4-1. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	Significance Level ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	PM_{10}	10
	SO_2	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Hydrogen sulfide	0.2
NA	Ozone	100 tpy of VOC emissions

Source: Section 62-212.400, Table 212.400-3, F.A.C.

in Appendix W to 40 CFR Part 51. 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 Rule 62-210.200(259), F.A.C., significant impact level, as presented in Table 4-2.

Ozone is one pollutant for which a source impact analysis 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.

Various lengths of record for meteorological data can be used 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 PSD increments specify that the standard should not be exceeded at any location more than once per 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 for SO_2 and TSP 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 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

Table 4-2. Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	1
	24-Hour	5
	3-Hour	25
PM_{10}	Annual	1
	24-Hour	5
NO_2	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(260), F.A.C.

then promulgated, as regulations, the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated PSD increments for 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 March 28, 1988, for Florida; new major sources or modifications constructed after this date will consume NO_2 increment.

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments which were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which includes a revised NAAQS for PM_{10} and a new NAAQS for particulate matter less than or equal to 2.5 micrometers ($PM_{2.5}$), became effective on September 16, 1997. The new NAAQS for $PM_{2.5}$ has been recently remanded to EPA and is not currently effective. In addition, due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for State permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 4-3.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a 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

Table 4-3. PSD Allowable Increments ($\mu g/m^3$)

Pollutant	Averaging Time	Class I	Class II	Class III
PM_{10}	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
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 at any one location.

Source: Section 62-204.260, F.A.C.

time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

1. The actual emissions representative of sources in existence on the applicable minor source baseline date.
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.

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

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

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment. *Major source baseline date* means January 6, 1975, for PM (TSP/PM_{10}) 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 (in Florida, December 27, 1977, for PM/PM_{10} and SO_2; and March 28, 1988 for NO_x) was submitted by a major stationary source or major modification subject to the requirements of 40 CFR §52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2.

The ambient impact analysis for Smith Unit 3 is provided in Sections 6.0 (methodology) and 7.0 (results).

4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(5)(e), F.A.C., requires 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 Smith Unit 3. 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.
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 NAAQS 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 Smith Unit 3.

The additional impact analyses for the Smith Unit 3 is provided in Section 9.0.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method as previously described in Section 4.1. 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 reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- 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 draft *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.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA, 1996). Specific factors used in estimating capital and annual operating costs are summarized in Table 5-1.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 x purchased equipment cost
Freight	0.05 x purchased equipment cost
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
Indirect Capital Costs	
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	0.03 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

Source: EPA, 1996.

The fifth and final step is the selection of a BACT emission limitation or a design, equipment, work practice, operational standard, or combination thereof, corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As indicated in Section 3.3, Table 3-2, projected annual emission rates of CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist for Smith Unit 3 exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 5.3, 5.4, and 5.5 for combustion products (PM/PM_{10}), products of incomplete combustion (CO and VOC), and acid gases (SO_2, and H_2SO_4 mist), respectively.

5.2 <u>FEDERAL AND FLORIDA EMISSION STANDARDS</u>

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR Part 60), NESHAP (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by 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 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.
- Stationary gas turbines with a manufacturer's rated base load 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 Smith Unit 3 CTGs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, § 60.332(a)(1) and § 60.333, respectively.

The Smith Unit 3 DBs each have a rated heat input greater than 250 MMBtu/hr and, therefore, are subject to the requirements of NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*. Specifically, emissions from the DBs are limited to no more than 0.03 lb PM /MMBtu per §60.42a(a)(1); 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity per §60.42a(b); 0.20 lb SO_2/MMBtu (30-day rolling average) per §60.43a(b)(2); and 1.6 lb NO_x/MW-hr (30-day rolling average) per §60.43a(d)(1). The proposed Smith Unit 3 has no applicable NESHAP requirements.

FDEP emission standards for stationary sources are contained in Chapters 62-296, F.A.C., *Stationary Sources—Emission Standards*. Chapter 62-296, F.A.C., contains general emission standards for sources emitting PM (Section 62-296.320, F.A.C.) which are not applicable to Smith Unit 3 but are applicable to the Lansing Smith facility. Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTGs. Rule 62-296.405(2) contains visible emissions, PM, SO_2, and NO_x limitations for new fossil fuel steam generators with more than 250 MMBtu/hr heat input which are applicable to the Smith Unit 3 DBs. For each air contaminant, Rule 62-296.405(2) references Rule 62-204.800(7) and 40 CFR Subpart Da. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart Da.

Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment and maintenance areas) and 62-296.700, F.A.C. (for PM nonattainment and maintenance areas). Because Smith Unit 3 will be located in Bay County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines*, and Subpart Da, *Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*, are applicable to the Smith Unit 3 CTGs and DBs, respectively. There are no applicable NESHAP requirements.

Applicable federal and state emission standards are summarized in Tables 5-2 and 5-3, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Attachment C. BACT emission limitations proposed for Smith Unit 3 are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM_{10}

PM/PM_{10} emissions resulting from the combustion of natural gas are due to oxidation of ash and sulfur contained in the fuel. Due to its low ash and sulfur content, natural gas combustion generates inherently low PM/PM_{10} emissions.

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies used for controlling PM/PM_{10} include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- 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 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

Table 5-2. Federal Emission Limitations

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:

FBN = fuel bound nitrogen.

FBN (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.

NSPS Subpart Da, Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

Pollutant	Emission Limitation
NO_X	1.6 lb/MW-hr (gross output)
SO_2	0.20 lb/MMBtu
PM	0.03 lb/MMBtu
Opacity	20 percent

Sources: 40 CFR 60, Subparts Da and GG.

Table 5-3. Florida Emission Limitations

Pollutant	Emission Limitation
General Visible Emissions Standard Rule 62-296.320(4)(b)1., F.A.C.	
• Visible emissions	< 20 percent opacity (averaged over a 6-minute period)

Source: Chapter 62-296, F.A.C.

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 (cfm-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/PM_{10} emissions from CTGs and DBs, none of the above described control equipment have been applied to natural gas-fired CTGs and DBs because exhaust gas PM concentrations are inherently low. CTGs operate with a significant amount of excess air which generates large exhaust gas flow rates. The Smith Unit 3 CTGs and DBs will be fired exclusively with natural gas. Combustion of natural gas will generate low PM emissions in comparison to other fuels due to the low ash and sulfur content of natural gas. The minor PM emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM concentrations. The estimated maximum PM/PM_{10} exhaust concentration from each CTG/DB unit is approximately 0.004 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

PM emissions will also occur due to cooling tower operation. Smith Unit 3 will include a 10-cell, induced draft counterflow cooling tower. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large size water droplets (e.g., greater than 200 microns) constitute the majority of the drift released. These large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM emissions because of the fine PM formed by crystallization of the dissolved solids contained in the droplet.

The only feasible technology for controlling PM from cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. Drift eliminator configurations include herringbone (blade-type), wave form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics, fiber reinforced cement, metal, plastic, and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

Factors affecting cooling tower PM emission rates include drift droplet loss rate (expressed as a percent of recirculating cooling water flow rate), concentration of dissolved solids in the recirculating cooling water, and the recirculating cooling water flow rate (i.e., size of the tower).

PM emissions from the Smith Unit 3 cooling tower will be controlled using high efficiency drift eliminators achieving a drift loss rate of no more than 0.001 percent of the cooling tower recirculating water flow.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

BACT PM/PM_{10} limits obtained from the RBLC database for natural gas-fired CTGs are provided in Table 5-4. Recent Florida BACT determinations for natural gas-fired CTGs are shown in Table 5-5. All determinations are based on the use of clean fuels and good combustion practice. Table 5-6 provides RBLC database PM BACT determinations for cooling towers. A recent Florida BACT determination for cooling towers is the determination of 0.002 percent drift loss rate made for the City of Tallahassee Purdom Unit 8.

Because post-process stack controls for PM/PM_{10} are not appropriate for natural gas-fired CTGs and DBs, the use of good combustion practices and clean fuels is considered to be BACT. The Smith Unit 3 CTGs and DBs will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel that is completely oxidized in the combustion

Table 5-4. RBLC PM Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
			Issuance	Update					
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	2.5 LBS/HR (GAS)	EFFICIENT OPERATION OF THE COMBUSTION TURBINE	BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
AL-0110	SOUTHERN NATURAL GAS	WARD	3/4/98	4/24/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	4.3 LB/DAY	NATURAL GAS, AIR INTAKE COOLER, VENTING THE LUBE OIL VENT INTO THE EXHAUST STREAM OF THE TURBINE FOR OXIDATION	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.012 LB/MMBTU	LUBE OIL VENT COALESCER. OPACITY LIMIT APPLIES TO LUBE OIL VENTS.	LAER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25.8 LB/H	FUEL SPEC: NATURAL GAS FIRED	OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAN	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	18 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	19 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOW	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	0.0065 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0066	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	5 LB/H	GOOD COMBUSTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	7 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	0.0136 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	7 LB/HR AT 20 F	FUEL SPEC: LOW SULFUR FUELS	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	0.006 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	0.0064 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	18 LB/HR	CLEAN FUEL	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	5 LBS/HR		BACT-PSD
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	92 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	18.3 LB/HR	NO CONTROL CLEAN FUEL	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	5 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSH	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0023 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	0.006 LB/MMBTU	TURBINE DESIGN	BACT-PSD
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	0.006 LB/MMBTU	TURBINE DESIGN	OTHER
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	SEE P2 DESC.	COMBUSTION AIR FILTERS, GOOD COMBUSTION PRAC. AND MAINT.	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW			BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	5.3 LBS/HR	HIGH COMBUSTION EFFICIENCY	BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	30.6 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE COMBUSTOR	BACT-PSD
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	0.004 LB/MMBTU GAS (BASE)	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL	BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	0.004 LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	33816	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	0.0062 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	11/5/92	9/13/94	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COUR	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.035 LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	8 LB/HR		BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	0.0015 % OF FLOW	TWO STAGE MIST ELIMINATOR TO RESTRICT DRIFT.	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	12 LB/HR	GOOD COMBUSTION PRACTICES. FUEL SPEC: USE OF NG/LPG.	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	35339	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	59 LB/HR	GOOD COMBUSTION PRACTICES. FUEL SPEC: USE OF NG/LPG.	BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	0.005 LB/MMBTU, GAS		BACT-PSD
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	45 LBS/HR	FUEL SPEC: LOW ASH CONTENT FUELS	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	3.79 TPY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	34456	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	52 TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96.3 TPY	USE OF CLEAN LOW ASH FUEL	BACT/NSPS
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96.3 TPY	USE OF CLEAN LOW ASH FUEL	BACT/NSPS

Source: RBLC 1999.

Table 5-5. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size MW	Turbine Size MMBtu/hr	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	857	9.0	0.01	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,214	10.5	0.0134	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	367	(9.0)	0.0245	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	869	(8.7)	0.0100	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,615	9.0	(0.0056)	Combustion design and clean fuels
09/28/93	Florida Gas Transmission	N/A	32	0.64	N/A	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,755	17.0	0.013	Combustion design and clean fuels
02/25/94	Florida Power Corp. Polk County Site	235	1,510	9.0	0.006	Combustion design and clean fuels
03/07/95	Orange Cogeneration, L.P.	39	388	5.0	(0.013)	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	403	5.0	0.0065	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	971	7.0	(0.0072)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		7.0		Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,468	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,174	—	—	Combustion design and clean fuels
09/29/98	Florida Power Corporation Hines Energy Center	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
11/25/98	Florida Power & Light Fort Myers Repowering	170	1,760	—	—	Combustion design and clean fuels
12/04/98	Santa Rosa Energy LLC	167	1,780	—	—	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1999.

Table 5-6. RBLC PM Summary - Cooling Towers

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Last Update	Process Description	Thruput Rate	Emission Lmits	Control System Description	Basis
CA-0713	TEXACO REFINING AND MARKETING, INC.	BAKERSFIELD	1/19/96	11/23/96	COOLING TOWER	18,000 GAL PER MIN	30.2 LB/DAY	CELLULAR TYPE DRIFT ELIMINATOR	BACT-OTHER
FL-0050	FLORIDA POWER CORPORATION	CRYSTAL RIVER	8/30/90	5/14/93	COOLING TOWER, 4 EACH	735,000 G/M SALT WATER	0.004 % OF CIRCULATION WATER	DRIFT ELIMINATOR	BACT-PSD
NJ-0016	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	9/4/92	8/8/94	COOLING TOWER, MECHANICAL DRAFT	27,000,000 LB/H H2O RECIRC.	0.909 LB/HR	DRIFT ELIMINATOR	BACT-PSD
NJ-0019	CROWN/VISTA ENERGY PROJECT (CVEP)	WEST DEPTFORD	10/1/93	8/31/94	COOLING TOWER (2)		5.9 LB/HR	DRIFT ELIMINATOR	BACT-PSD

Source: RBLC, 1999.

process, is projected to be greater than 99 percent. The CTGs and DBs will be fired exclusively with natural gas. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTGs, a visible emissions limit of 10 percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}.

5.4 BACT ANALYSIS FOR CO AND VOC

CO and VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO and VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam 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. Emissions of NO_x and CO/VOC are inversely related; i.e., decreasing NO_x emissions will result in an increase in CO and VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and CO/VOC formation in order to develop units which achieve acceptable emission levels for all three pollutants.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOCs from gas turbines and duct burners: (1) combustion process design and (2) oxidation catalysts.

Combustion Process Design

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 CTGs, approximately 99 percent, CO and VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOCs to carbon dioxide (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 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. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 percent for CO. 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 an oxidation catalyst control system 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.

Technical Feasibility

Both CTG combustor design and oxidation catalyst control systems are considered to be technically feasible for the Smith Unit 3 CTGs and DBs. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO and VOC are provided in the following sections.

5.4.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse 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. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs and DBs fired with natural gas.

Because CO and VOC emission rates from CTGs and DBs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., below the defined PSD significant impact levels for CO and negligible reductions in ambient VOC levels. The location of Smith Unit 3 (Bay County, Florida) is classified attainment for all criteria pollutants. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. 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 Smith Unit 3 indicate that maximum CO impacts, without oxidation catalyst, will be insignificant.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CTG due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for the Smith Unit 3 CTGs is projected to have a pressure drop across the catalyst bed of approximately 1.0 inch of water (H_2O). This pressure drop will result in a 0.2 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 2,978,400 kilowatt-hours (kwh) (10,163 MMBtu) per year at base load (170-MW) operation and 100 percent capacity factor per CTG. This energy penalty is equivalent to the use of 19.4 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3) for both CTGs. The lost power generation energy penalty, based on a power cost of $0.0186/kwh, is $110,975 per year for both CTGs.

5.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-7. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 5-8 and 5-9.

The base case Smith Unit 3 (i.e., for both CTG/HRSG units) annual CO emission rate is 701.3 tpy. The controlled annual CO emission rate, based on an 80 percent control efficiency, is 140.3 tpy. Base case and controlled CO emission rates are summarized in Table 5-10.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $1,567 per ton of CO removed. Based on the high control costs, use of oxidation catalyst

Table 5-7. Economic Cost Factors

Factor	Units	Value
Interest rate	%	8.51
Control system life	Years	15
Oxidation catalyst life	Years	3
Electricity cost	$/kwh	0.01863
Labor costs (base rates)	$/hour	
Operator		24.50
Maintenance		24.50

Sources: ECT, 1999.
Gulf, 1999.

Table 5-8. Capital Costs for Oxidation Catalyst System, Two CTGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	1,457,778	A
Sales tax	87,467	0.06 x A
Freight	72,889	0.05 x A
Installation		
Foundations and supports	129,451	0.08 x A
Handling and erection	226,539	0.14 x A
Electrical	64,725	0.04 x A
Piping	32,363	0.02 x A
Insulation for ductwork	16,181	0.01 x A
Painting	16,181	0.01 x A
Subtotal Installation Cost	**485,440**	
Subtotal Direct Costs	**2,103,573**	
Indirect Costs		
Engineering	161,813	0.10 x A
Construction and field expenses	80,907	0.05 x A
Contractor fees	161,813	0.10 x A
Startup	32,363	0.02 x A
Performance test	16,181	0.01 x A
Contingency	48,544	0.03 x A
Subtotal Indirect Costs	**501,621**	
TOTAL CAPITAL INVESTMENT	**2,605,195** (TCI)	

Source: ECT, 1999.

Table 5-9. Annual Operating Costs for Oxidation Catalyst System, Two CTGs

Item	Dollars		OAQPS Factor
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	1,568,000		
Credit for used catalyst	(192,000)		
Subtotal Catalyst Costs	1,376,000		
Annualized Catalyst Costs	**538,855**		
Energy Penalties			
Turbine backpressure	110,975		
Subtotal Direct Costs	**649,830**	(TDC)	
Indirect Costs			
Administrative charges	52,104		0.02 x TCI
Property taxes	26,052		0.01 x TCI
Insurance	26,052		0.01 x TCI
Capital recovery	124,974		
Subtotal Indirect Costs	**229,182**		
TOTAL ANNUAL COST	**879,012**		

Sources: ECT, 1999.
Gulf, 1999.

Table 5-10. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
Control Option	Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	32.0	140.3	561.1		879,012	1,567	20,326	Y	Y
Baseline	160.1	701.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) CTGs, 100-percent load for 7,760 hr/yr with duct burner firing at 59°F ambient temperature and 1,000 hr/yr with duct burner firing and steam power augmentation at 95°F ambient temperature.

Sources: GE, 1999.
ECT, 1999.

technology to control CO emissions is not considered to be economically feasible. Results of the oxidation catalyst economic analysis are summarized in Table 5-10.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO and VOCs from CTGs and DBs is typically required only for facilities located in CO and/or ozone nonattainment areas. BACT CO and VOC limits obtained from the RBLC database for natural gas-fired CTGs are provided in Tables 5-11 and 5-12, respectively. FDEP gas turbine CO BACT determinations for the past 5 years range from 9 to 30 ppmvd with an average CO limit of 26 ppmvd. Of the 15 recent FDEP CO BACT determinations for CTGs, 13 determinations established a limit of 20 ppmvd or higher. A summary of FDEP CO and VOC BACT determinations for natural gas-fired combustion turbines for the previous 5 years is provided in Table 5-13 and 5-14.

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 appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs and DBs fired with natural gas. Because CO emission rates from CTGs and DBs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality, i.e., well below the defined PSD significant impact levels for CO.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs. These control techniques have been considered by FDEP to represent BACT for CO and VOCs for all CTG projects permitted within the past 5 years. CO and VOC emissions from the CTG/HRSG units at base load with or without steam power augmentation, and without duct burner firing, will be less than or equal to 13 and 3 ppmvd at 15 percent oxygen, respectively. With duct burner firing and no steam power augmentation, CO and VOC emissions from the CTG/HRSG units at base load will be less than or equal to 16 and 4 ppmvd at 15 percent

Table 5-11. RBLC CO Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Control Efficiency	Basis
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12600 BHP	0.42 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CONTROLS		BACT-PSD
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	28 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES		BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	60 PPM @ 16% O2	LEAN BURN		BACT-PSD
CA-0418	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	8/4/93	TURBINE, GAS-FIRED	47.64 MMBTU/H	7.74 PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	80	BACT-PSD
CA-0463	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	5/31/92	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	7.74 PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	80	BACT-PSD
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		10 PPM @ 15% O2	OXIDATION CATALYST	75	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT. BURNERS	385 MMBTU/H EACH TURBINE	22.4 PPM @ 15% O2			BACT-PSD
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #2, GE FRAME 6	33 MW	250 T/YR, LESS THAN	CO CATALYST		OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAN	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	30 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWE	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	30 PPMVD	GOOD COMBUSTION		BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	25 PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES TO GE CT		BACT-PSD
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	9/28/95	5/31/98	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION		BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION		BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	12 LBS/HR	GOOD COMBUSTION;10 PPMVD AT 15% OXYGEN.		BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	40 LBS/HR	GOOD COMBUSTION; 40 PPMVD AT 15% OXYGEN.		BACT-PSD
LA-0079	ENRON LOUISIANA ENERGY COMPANY	EUNICE	8/5/91	10/30/91	TURBINE, GAS, 2	39.1 MMBTU/H	60 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS		BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	165.9 LB/HR	COMBUSTION CONTROL		BACT
LA-0089	FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	3/2/95	4/17/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	25.8 LB/HR	PROPER OPERATION		BACT-PSD
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	972.4 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	70 LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.		BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	198.6 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE		BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-OTHER
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
MI-0206	KALAMAZOO POWER LIMITED	COMSTOCK	12/3/91	3/23/94	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805.9 MMBTU/H	20 PPMV	DRY LOW NOX TURBINES		BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	59 LB/HR	COMBUSTION CONTROL		BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.0055 LB/MMBTU	CATALYTIC OXIDATION	80	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHI	33329	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN		BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	1.8 PPMDV	OXIDATION CATALYST		OTHER
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11257 HP	50 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	ENGINE, GAS-FIRED, RECIPROCATING	1000 HP	2.6 G/B-HP-H	CLEAN/LEAN BURN TECHNOLOGY		BACT-PSD
NM-0022	MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	CARLSBAD	1/11/95	4/26/95	TURBINES, NATURAL GAS (2)	5500 HP	13.2 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.	66	BACT-PSD
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	27.6 PPM @ 15% O2			BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES		BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	27 LBS/HR	DRY LOW-NOX TECHNOLOGY, PROPER AIR-FUEL RATIO.		BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	152.5 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR		BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240 MW	4 PPM @ 15% O2			LAER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	10 PPM	COMBUSTION CONTROLS		BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/82	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	25 PPM	COMBUSTION CONTROL		BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	3 PPM	OXIDATION CATALYST		BACT-OTHER
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	11/24/92	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	13 PPM	COMBUSTION CONTROLS		BACT-OTHER
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS		BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	34485	8/6/97	TURBINES, NATURAL GAS (2)	1720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	4/1/94	5/1/95	TURBINES, NATURAL GAS (2)	1696 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	110 T/YR	OXIDATION CATALYST	90	OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	9/23/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	3.1 PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 FOR NO. 2 OIL.	80	OTHER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	50 PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	33 PPMDV	COMBUSTION CONTROLS.		BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	100 PPMDV AT MIN. LOAD	COMBUSTION CONTROLS.		BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	11 PPM @ 15% O2, GAS			BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	33450	5/31/92	TURBINE, GAS, 2	49 MMBTU/H	0.114 LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	23 LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	300 TPY	INTERNAL COMBUSTION CONTROLS		BACT
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96 TPY	GOOD COMBUSTION OPERATING PRACTICES		BACT/NSPS
WA-0027	SUMAS ENERGY INC.	SUMAS	6/25/91	8/1/91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	CO CATALYST	80	BACT-PSD
						Minimum	1.8 PPM			
						Maximum	60.0 PPM			
						Average	21.9 PPM			

Source: RBLC 1999.

Table 5-12. RBLC VOC Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Control Efficiency	Basis
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	8 LB/HR	NATURAL GAS AS PRIMARY FUEL		LAER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	16.7 LB/H			OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	26.7 T/YR			OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	35.2 T/YR			OTHER
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	1.6 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWE	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	1 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	7 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	10 PPMVD	GOOD COMBUSTION		BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	6 LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	7 PPMVW	GOOD COMBUSTION PRACTICES		BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	0.003 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	6 PPMVD	COMPLETE COMBUSTION		BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	3.6 LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION		BACT
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	2 LB/HR	COMBUSTION CONTROL		BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHI	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0046 LB/MMBTU	TURBINE DESIGN		OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	4 PPMDV	TURBINE DESIGN		BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11257 HP	25 PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE P2	GOOD COMBUSTION PRACTICES		BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW				BACT-PSD
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	33816	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	0.0045 LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.1 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	105 PPM @ 15% O2	OXIDATION CATALYST	50	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	4.4 LB/HR	GOOD COMBUSTION PRACTICES		BACT-OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	9/23/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	4 PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL EMISSION LI	12	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	25 PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	5 PPM @ 15% O2			BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	7/31/91	5/31/92	TURBINE, GAS, 2	49 MMBTU/H	0.016 LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	10 LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	77.86 LBS/DAY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK		LAER
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	38 TPY	INTERNAL COMBUSTION CONTROLS		BACT
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	5 PPMDV	COMBUSTION CONTROLS.		BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	6 PPMDV	COMBUSTION CONTROL.		BACT-PSD

Source: RBLC 1999.

Table 5-13. Florida BACT CO Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	30	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
02/21/94	Polk Power Partners	84	25	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	30	Good combustion
06/01/95	Panda-Kathleen	75	25	Good combustion
09/28/95	City of Key West	23	20	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
09/29/98	Florida Power Corporation Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/04/98	Santa Rosa Energy, LLC	167	9	Good combustion
			24 (with duct burner)	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1999.

Table 5-14. Florida BACT VOC Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40		Good combustion
04/09/93	Kissimmee Utility Authority	80		Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184		Good combustion
02/25/94	Florida Power Corp. Polk County Site	235		Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	10	Good combustion
06/01/95	Panda-Kathleen	75		Good combustion
09/28/95	City of Key West	23		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		Good combustion
05/98	City of Tallahassee Purdom Unit 8	160		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4	Good combustion
09/29/98	Florida Power Corporation Hines Energy Complex	165	7	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	1.4	Good combustion
12/04/98	Santa Rosa Energy, LLC	167	1.4	Good combustion
			84 (with duct burner)	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1999.

oxygen, respectively. With duct burner firing and steam power augmentation, CO and VOC emissions from the CTG/HRSG units at base load will be less than or equal to 23 and 6 ppmvd as 15 percent oxygen, respectively. This latter operating condition, however, will occur for no more than 1,000 hr/yr. These CO and VOC emissions are consistent with recent FDEP BACT determinations for CTG/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5. CO and VOC BACT emission limits proposed for Smith Unit 3 are summarized in Table 5-15.

5.5 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and post-combustion add-on controls; i.e., flue gas desulfurization (FGD) systems.

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas containing sulfur compounds (e.g., hydrogen sulfide), a variety of technologies are available to remove these sulfur compounds to acceptable levels. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline.

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be 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 will 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

Table 5-15. Proposed CO and VOC BACT Emission Limits

Emission Source	Proposed CO and VOC BACT Emission Limits* ppmvd at 15 percent oxygen	lb/hr
GE PG7241 (FA) CTGs and DBs (Per CTG/HRSG Unit)		
A. With or Without Steam Power Augmentation, Without Duct Burner Firing		
CO	13	58
VOC	3	7
B. With Duct Burner Firing, Without Steam Power Augmentation		
CO	16	79
VOC	4	10
C. With Duct Burner Firing and Steam Power Augmentation		
CO	23	117
VOC	6	17

*Maximum rates for each operating scenario.

Sources: ECT, 1999.
GE, 1999.
Gulf, 1999.

are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

Treatment of natural gas to remove sulfur compounds is conducted by the fuel supplier, when necessary, prior to distribution by pipeline. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas sulfur content has already been reduced to very low levels.

There have been no applications of FGD technology to natural gas-fired CTGs or DBs due to the low sulfur content of natural gas. The Smith Unit 3 CTGs and DBs will be fired exclusively with natural gas. The sulfur content of natural gas is more than 100 times lower than the fuels (e.g., coal) employed in boilers utilizing FGD systems. In addition, CTGs operate with a significant amount of excess air which generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of a FGD system to a CTG/HRSG exhaust stream will result in unreasonably low SO_2 removal efficiencies. Due to low SO_2 exhaust stream concentrations, FGD technology is not considered to be technically feasible for CTGs or DBs because removal efficiencies would be unreasonably low. Similarly, use of mist eliminators to control H_2SO_4 mist emissions is not technically feasible due to the very low CTG and DB H_2SO_4 mist exhaust concentrations. For example, the Smith Unit 3 CTGs and DBs will have a H_2SO_4 mist exhaust concentration of 0.0002 grains per actual cubic foot at 100 percent load, 0°F operating conditions per CTG/HRSG unit.

5.5.2 PROPOSED BACT EMISSION LIMITATIONS

Because post-combustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the Smith Unit 3 CTGs and DBs. Natural gas utilized at Smith Unit 3 will be pipeline-quality. Emissions of H_2SO_4 mist were estimated based on a 7.5 percent conversion rate of SO_2 to H_2SO_4 mist. BACT for SO_2 and H_2SO_4 mist for Smith Unit 3 is the use of pipeline quality natural gas.

5.6 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Control technologies proposed as BACT for each pollutant subject to review are summarized in Table 5-16. Specific proposed BACT emission limits for each pollutant are summarized in Table 5-16.

Table 5-16. Summary of BACT Control Technologies

Pollutant	Control Technology
A. GE PG7241 (FA) CTGs and DBs	
PM/PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas • Efficient combustion
CO and VOC	• Efficient combustion
SO_2/H_2SO_4 mist	• Exclusive use of low-sulfur natural gas
B. Cooling Tower	
PM/PM_{10}	• Efficient mist eliminators

Source: ECT, 1999.

Table 5-17. Summary of Proposed BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits* (ppmvd) †	(lb/hr)
GE PG7241 (FA) CTGs and DBs (Per CTG/HRSG Unit)			
A. All Operating Scenarios			
	PM/PM_{10}	10% opacity	
	SO_2	Pipeline quality natural gas	
	H_2SO_4 mist	Pipeline quality natural gas	
B. With or Without Steam Power Augmentation, Without Duct Burner Firing			
	CO	13	58
	VOC	3	7
C. With Duct Burner Firing, Without Steam Power Augmentation			
	CO	16	79
	VOC	4	10
D. With Duct Burner Firing and Steam Power Augmentation			
	CO	23	117
	VOC	6	17
2.1.1.1.1 Cooling Tower			
	PM/PM_{10}	Drift eliminators	

*Maximum rates for each operating scenario.
†Corrected to 15 percent oxygen.

Sources: ECT, 1999.
GE, 1999.
Gulf, 1999.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

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 regulatory agency practice. Guidance contained in EPA manuals and users' guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, Smith Unit 3 will have the potential to emit 757 tpy NO_x; 701 tpy of CO; 253 tpy of PM/PM_{10}; 105 tpy of SO_2; 93 tpy of VOCs; and 12 tpy of H_2SO_4 mist. Due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit No. 1, a federally enforceable NO_x emissions cap of 3,587 tpy, using CEMS to demonstrate compliance, for Smith Units 1 and 3 is requested to achieve a net reduction of 9 tpy in NO_x emissions from the Lansing Smith Plant following construction of Smith Unit 3. Accordingly, total annual Lansing Smith Plant NO_x emissions will be decreased from historical levels following installation of Unit 3. A comparison of estimated potential annual emission rates for Smith Unit 3 and the PSD significant emission rate thresholds was previously provided in Table 3-2. As shown in that table, potential emissions of PM, PM_{10}, SO_2, CO, VOC, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR air quality impact analysis requirements of Rule 62-212. 400(5)(d), F.A.C.

The ambient impact analysis addresses PM, PM_{10}, SO_2, CO, and H_2SO_4 mist. Modeled impacts of H_2SO_4 mist were compared to FDEP's 8- and 24-hour draft ambient reference concentrations (ARCs) for this pollutant. Because VOCs contribute to the formation of ground-level ozone and because ozone modeling is conducted on a regional scale, modeling of VOC emissions resulting from the operation of Smith Unit 3 was not conducted.

6.3 MODEL SELECTION AND USE

For this study, air quality models were applied at two levels. The first, or screening, level provided conservative estimates of impacts from the cogeneration units. The purposes of the screening modeling were to:

- Eliminate the need for more sophisticated analysis in situations with low predicted impacts and no threat to any standard.
- Provide information to guide the more rigorous refined analysis, including the operating mode (load and ambient temperature) which caused the highest ambient impact for each criteria pollutant.

The second, or refined, level encompassed a more detailed treatment of atmospheric processes. Refined modeling required more detailed and precise input data, but is presumed to have provided more accurate estimates of source impacts.

6.3.1 SCREENING MODELS

For screening purposes, the SCREEN3 model, Version 96043, is recommended and was used in this analysis. SCREEN3 is a simple model that calculates 1-hour average concentrations over a range of pre-defined worst-case meteorological conditions. SCREEN3 also includes algorithms to assess building wake downwash. SCREEN3 also includes algorithms for analyzing concentrations on simple and complex terrain.

The proposed CTG/HRSG units may operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and the use of evaporative coolers, supplemental duct burner firing, and steam power augmentation. Plume dispersion and, therefore, ground-level impacts, will be affected by these different operating scenarios because emission rates, exit temperatures, and exhaust gas velocities will change. Each of the operating scenarios was evaluated for each pollutant of concern to identify the scenario which caused the highest impact. These worst-case operating scenarios were then subsequently evaluated using the refined ISC dispersion model. The two CTG/HRSG stacks were collocated for screening modeling purposes since: (1) the two point sources will emit the same pollutant(s); (2) they both will have identical stack heights, volumetric flow rates, and stack gas exit temperatures; and (3) the stacks are situated relatively close to each other. A nominal emission rate of 10.0 grams per second (g/s) was used for all SCREEN3 model runs. The SCREEN3 model results were then adjusted to reflect maximum emission rates for each operating case; i.e., model results were multiplied by the ratio of maximum emission rates (in g/s) to 10.0 g/s. Screening modeling results are summarized in Section 7.0, Table 7-1 through 7-5. These tables show, for each operating scenario and pollutant evaluated, the SCREEN3 unadjusted 1-hour average maximum impact, emission rate adjustment ratio, and the adjusted SCREEN3 1-hour average maximum impact.

6.3.2 REFINED MODELS

The most recent regulatory version of the Industrial Source Complex (ISC) models (EPA, 1998) is recommended and was used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISC3 short-term (ISCST3, Version 98356) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

Procedures applicable to the ISCST3 dispersion model specified in EPA's *Guideline for Air Quality Models* (GAQM) were followed in conducting the refined dispersion modeling. The GAQM is codified in Appendix W of 40 CFR Part 51. In particular, the ISCST3 model control pathway MODELOPT keyword parameters DFAULT, CONC, RURAL, and NOCMPL were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC, RURAL, and NOCMPL parameters specify calculation of concentrations, use of rural dispersion, and suppression of complex terrain calculations, respectively. As previously mentioned, the ISCST3 model was also used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

6.4 DISPERSION OPTION SELECTION

Area characteristics in the vicinity of proposed emission sources are important in determining model selection and use. One important consideration is whether the area is rural or urban, since dispersion rates differ between these two classifications. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing and the other is based on population density. The land use typing method utilizes the work of Auer (Auer, 1978) and is preferred by EPA and FDEP 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 these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

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. Accurate classification of the residential areas into proper groupings is important to determine the most appropriate land use classification for the study area.

USGS 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. Based on this analysis, more than 50 percent of the land use surrounding the plant was determined to be rural under the Auer land use classification technique. Therefore, rural dispersion coefficients and mixing heights were used for the Ambient Impact Analysis.

6.5 TERRAIN CONSIDERATION

The GAQM defines *flat terrain* as terrain equal to the elevation of the stack base, *simple terrain* as terrain lower than the height of the stack top, and *complex terrain* as terrain above the height of the plume center line (for screening modeling, *complex terrain* is terrain above the height of the stack top). Terrain above the height of the stack top but below the height of the plume center line is defined as *intermediate terrain.*

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the proposed Smith Unit 3 (i.e., within an approximate 10-km radius). Base elevation of the site is approximately 10 feet above mean sea level (ft-msl). Highest elevations in the vicinity of the site are approximately 20 ft-msl. Site base elevation plus CTG/HRSG stack height (i.e., 10 + 125) is 135 ft-msl. Accordingly, terrain in the vicinity of the site would be classified as ranging from *flat* to *simple terrain*. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted; i.e., all receptors were assumed to be at the same elevation as the CTG/HRSG stack base for modeling purposes.

6.6 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

The CAA Amendments of 1990 require 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). GEP stack height is defined as the highest of 65 meters, or 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.

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 stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for the CTG/HRSG units (125 ft) is less than the *de minimis* GEP height of 65 meters (213 ft) and, therefore, complies with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height which can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The ISC dispersion models contain two algorithms that assess the effect of building downwash; these algorithms are referred to as the Huber-Snyder and Schulman-Scire methods. The following steps are employed in determining the effects of building downwash:

- A determination is made as to whether a particular stack is located in the area of influence of a building (i.e., within five times the lesser of the building's height or projected width). If the stack is not within this area, it will not be subject to downwash from that building.

- If a stack is within a building's area of influence, a determination is made as to whether it will be subject to downwash based on the heights of the stack and building. If the stack height to building height ratio is equal to or greater than 2.5, the stack will not be subject to downwash from that building.
- If both conditions in Items 1 and 2 are satisfied (a stack is within the area of influence of a building and has a stack height to building height ratio of less than 2.5), the stack will be subject to building downwash. The determination is then made as to whether the Huber-Snyder or Schulman-Scire downwash method applies. If the stack height is less than or equal to the building height plus one-half the lesser of the building height or width, the Schulman-Scire method is used. Conversely, if the stack height is greater than this criterion, the Huber-Snyder method is employed.
- The ISCST3 downwash input data consists of an array of 36 wind direction-specific building heights and projected widths for each stack. LB is defined as the lesser of the height and projected width of the building. For directionally dependent building downwash, wake effects are assumed to occur if a stack is situated within a rectangle composed of two lines perpendicular to the wind direction, one line at 5 LB downwind of the building and the other at 2 LB upwind of the building, and by two lines parallel to the wind, each at 0.5 LB away from the side of the building.

For the ambient impact analysis, the complex downwash analysis described above was performed using the current version of EPA's Building Profile Input Program (BPIP—Version 95086). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. Dimensions of the building/structures evaluated for wake effects are shown in Table 6-1; the locations of these buildings/structures were previously provided on Figure 2-2. BPIP output consists of an

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meter)	Length (meter)	Height (meter)
Heat Recovery Steam Generators	18.3	30.5	33.5
Cooling Tower	34.7	81.4	17.4

Sources: ECT, 1999.
Gulf, 1999.

array of 36 direction-specific (10 to 360°) building heights and projected building widths for each stack suitable for use as input to the ISCST3 model.

6.7 <u>RECEPTOR GRIDS</u>

Receptors were placed at locations considered to be *ambient air*, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." The entire perimeter of the plant site, excluding natural barriers, will be fenced; therefore, the nearest locations of general public access are at the facility property lines.

Consistent with GAQM recommendations, the ambient impact analysis utilized the following receptor grids:

- Fence Line Receptors: Receptors placed on the site boundary spaced 100 meters apart.
- Near-Field Discrete Receptors: Cartesian receptors placed at 100-meter spacings from the site to the first near-field polar receptor ring
- Near-Field Polar Receptors: Receptor rings (with 36 receptors per ring at 10° intervals) starting from the site and extending to 2.9 km at 100-meter spacings.
- Mid-Field Polar Receptors: Receptor rings (with 36 receptors per ring at 10° intervals) starting 3 km from the site and extending to 5 km at 250-meter spacings.
- Far-Field Polar Receptors: Receptor rings (with 36 receptors per ring at 10° intervals) starting 5.5 km from the site and extending to 10 km at 500-meter spacings.

Each polar receptor ring was offset 5° from the previous ring to improve the spatial distribution.

A graphical representation of the receptor grids (out to a distance of 3 km) is provided in Figure 6-1. A depiction of the receptor grids (from 3 to 10 km) is shown in Figure 6-2.

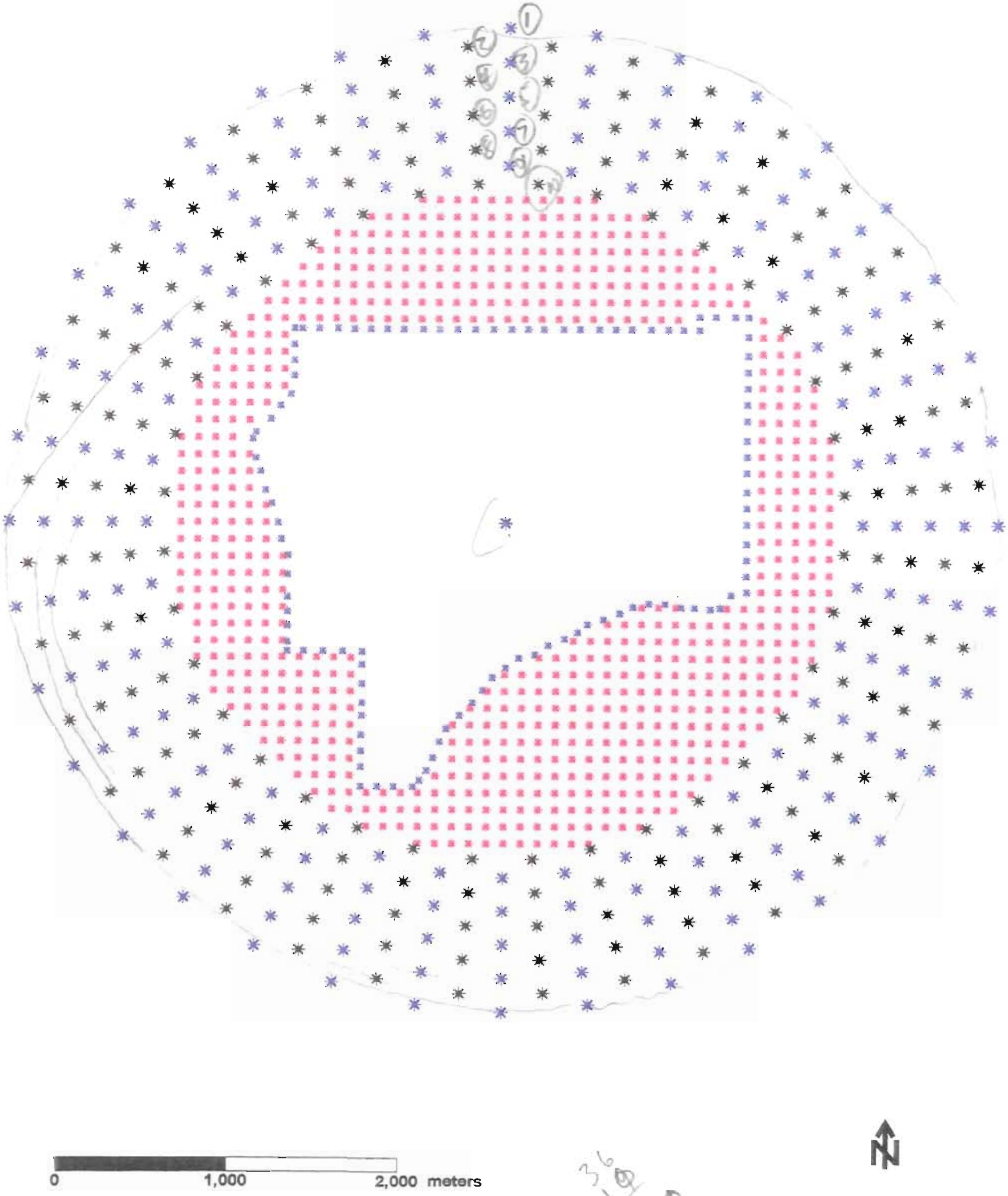
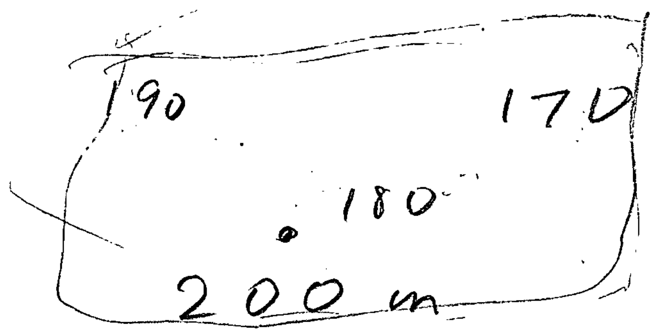


FIGURE 6-1.

RECEPTOR LOCATIONS (WITHIN 1 KM)

Source: ECT, 1999.

Environmental Consulting & Technology, Inc.



360

500 m

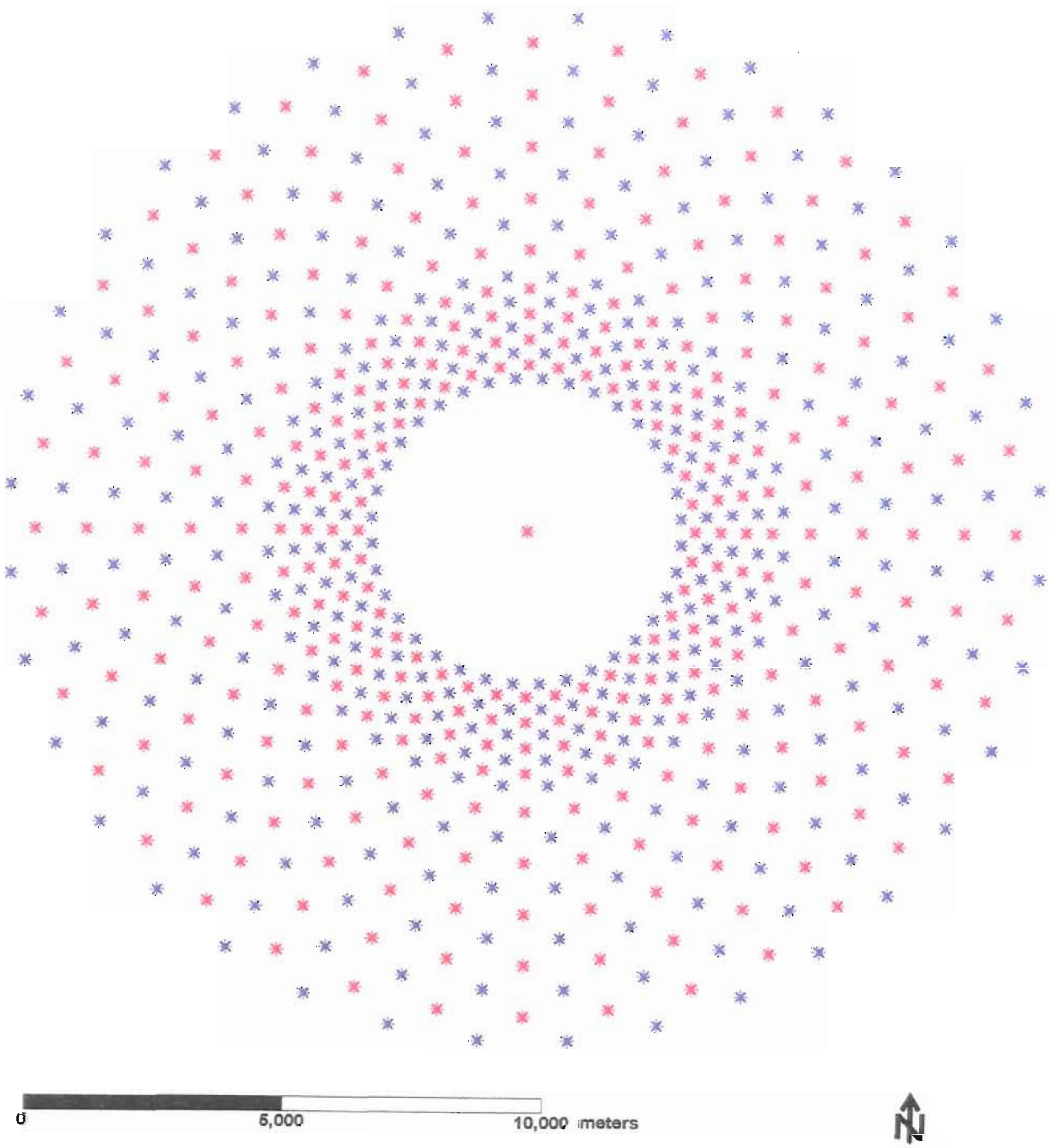


FIGURE 6-2.

RECEPTOR LOCATIONS (FROM 3 TO 10 KM)

Source: ECT, 1999.

ECT

Environmental Consulting & Technology, Inc.

6.8 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC dispersion models. The ISCST3 model requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings (i.e., mixing height data).

There are no onsite surface or upper meteorological stations. The nearest offsite surface meteorological station is located at the Apalachicola Municipal Airport approximately 88 km (55 miles) southeast of Smith Unit 3 site. The nearest offsite upper air meteorological station is also located at the Apalachicola Municipal Airport. The surface meteorological station at Pensacola Regional Airport is located approximately 145 km (90 miles) west, northwest of Smith Unit 3 site.

Short-Term Meteorological Data

Consistent with the GAQM and FDEP guidance, 5 consecutive years of the most recent, readily available, representative meteorological data were processed for the ambient impact analysis. For Bay County, FDEP recommends use of Pensacola and Apalachicola surface and Apalachicola upper air meteorological data in conducting the air quality analyses. As recommended by FDEP, 1986 and 1987 Pensacola surface (Pensacola Regional Airport—Station No. 13899), 1988 through 1990 Apalachicola surface (Apalachicola Municipal Airport—Station No. 12832), and 1986 through 1990 Apalachicola upper air meteorological data were used in the Ambient Impact Analysis.

The surface and mixing height data for each of the 5 years were processed using the current version of EPA's PCRAMMET (Version 95300) meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model. PCRAMMET input files consist of the surface and mixing height files as obtained from the EPA SCRAM website. The mixing height file for each year must include mixing height records for December 31 of the year preceding the year of record and for January 1 of the year following the year of record. If records for these 2 days are unavailable, duplicate mixing height records are used with the year, month, and day changed appropriately.

In addition to the surface and mixing height meteorological data files, PCRAMMET requires input with respect to: (a) the use of dry or wet deposition calculations; (b) output filename; (c) output file type (UNFORM or ASCII); (d) surface data format (CD144, SAMSON, or SCRAM); and (e) latitude, longitude, and time zone of the surface meteorological station. In processing the Apalachicola and Pensacola meteorological data, the NONE deposition option was selected, ASCII output file chosen, and the SCRAM surface data format utilized. As obtained from the EPA SCRAM web site, Apalachicola surface station latitude and longitude coordinates (in decimal degrees) are 29.733 and 85.033, respectively. The Pensacola surface station latitude and longitude coordinates (in decimal degrees) are 30.467 and 87.200, respectively. The Apalachicola and Pensacola surface stations are located in time zones 5 and 6, respectively.

Actual anemometer height for the Apalachicola surface station, obtained from the National Climatic Data Center (NCDC), is 30 ft (9.1 meters) for the time period of interest (i.e., 1988 through 1990). Actual anemometer height for the Pensacola surface station is 22 ft (6.7 meters) for the time period of interest (i.e., 1986 and 1987).

Processing of the Apalachicola and Pensacola station meteorological data did not require any data replacement or substitution.

6.9 MODELED EMISSION INVENTORY

6.9.1 ON-PROPERTY SOURCES

On-property emission sources addressed in the ambient impact analysis consisted of the two CTG/HRSG units and the mechanical draft cooling tower.

Emission rates and stack parameters for the CTG/HRSG units were previously presented in Tables 2-1 through 2-4. Model input parameters for the mechanical draft cooling tower include a PM/PM_{10} emission rate of 15.7 lb/hr (1.98 g/s), stack height of 57 ft (17.4 meters), equivalent stack diameter of 104. 4 ft (31.8 meters), exhaust temperature of 68°F (293 Kelvin), and an exhaust velocity of 22.9 feet per second (7.0 meters per second).

6.9.2 OFF-PROPERTY SOURCES

As will be discussed in Section 7.0, maximum air quality impacts are projected to be below the PSD significant impact levels for all pollutants defined in Rule 62-210.200(259), F.A.C., with the exception of PM/PM_{10}. Accordingly, a full, multi-source interactive assessment of PM_{10} NAAQS attainment and PSD Class II increment consumption was not required for Smith Unit 3.

An inventory of PM/PM_{10} emission sources within approximately 75 km of Smith Unit 3 was obtained from FDEP. A summary of the FDEP off-property PM_{10} emission sources is provided on Table 6-2.

Off-property PM/PM_{10} emission sources included in the dispersion modeling analysis for the Smith Unit 3 consisted of all emission sources listed on Table 6-2 located within 53 km of the project site; i.e., within the 2.2-km area of impact (AOI) distance plus 50 km, having data available for modeling purposes. Smith Units 1 and 2 are ducted to a common stack. Emission source data for Smith Units 1 and 2 and the existing combustion turbine were revised to reflect current data as obtained from Gulf's Title V permit application and recent stack test data. A summary of the modeled off-property PM/PM_{10} emission sources is provided on Table 6-3.

Table 6-2. FDEP Off-Property PM_{10} Emission Inventory

Company Name	EU ID	UTM Coordinates (km) Northing (km)	UTM Coordinates (km) Easting (km)	Distance From Unit 3 (km)	Relative Coordinates Y (m)	Relative Coordinates X (m)	PM Emission Rates (lb/hr)	PM Emission Rates (g/s)	PM Emission Rates (tpy)	Stack Parameters Height (m)	Stack Parameters Temperature (K)	Stack Parameters Velocity (m/s)	Stack Parameters Diameter (m)	
ALABAMA ELECTRIC COOPERATIVE	1	3,383.5	575.1	61.1	-34,500	50,400			2.40	7.6	824.8	64.61	0.30	
ANDERSON COLUMBIA CO INC #6	1	3,362.8	648.8	27.1	-13,780	-23,290	18.000	2.268	27.00	9.8	435.9	21.03	1.22	
ANDERSON COLUMBIA CO., INC.	1	3,401.2	672.1	70.0	-52,190	-46,620	14.360	1.809	7.98	7.0	366.5	29.59	1.16	
ANDERSON COLUMBIA COMPANY, INC.	1	3,404.5	677.0	75.7	-55,500	-51,500	38.590	4.862	40.13	10.7	322.0		1.31	
ANDERSON MATERIALS CO., INC.	1	3,401.3	672.3	70.2	-52,250	-46,810			49.00					
ARIZONA CHEMICAL COMPANY	14	3,335.4	633.1	15.6	13,600	-7,600	17.500	2.205	76.65	30.5	510.9	22.55	1.22	
ARIZONA CHEMICAL COMPANY	15	3,335.4	633.1	15.6	13,600	-7,600	17.500	2.205	76.65	30.5	466.5	17.37	1.22	
ARIZONA CHEMICAL COMPANY	19	3,335.4	633.1	15.6	13,600	-7,600	0.073	0.009	0.32	6.1	298.2		6.71	
ARIZONA CHEMICAL COMPANY	28	3,335.4	633.1	15.6	13,600	-7,600				5.2	298.2	5.70	0.99	
ARIZONA CHEMICAL COMPANY	30	3,335.4	633.1	15.6	13,600	-7,600								
BAXTER'S ASPHALT & CONCRETE, INC. DBA DO	1	3,392.9	673.9	65.4	-43,930	-48,420			0.30					
BAY COUNTY ENERGY SYSTEMS, INC.	1	3,348.9	644.0	18.5	100	-18,500	6.800	0.857	29.55	38.1	477.6	17.37	1.37	
BAY COUNTY ENERGY SYSTEMS, INC.	2	3,348.9	644.0	18.5	100	-18,500	6.800	0.857	29.80	38.1	497.0	17.37	1.37	
COASTAL METALS,INC.	1	3,338.7	630.8	11.6	10,300	-5,300								
COUCH CONSTRUCTION, L.P.	1	3,338.8	630.1	11.2	10,230	-4,570			0.03					
COUCH CONSTRUCTION, L.P.	2	3,360.3	573.1	53.6	-11,300	52,400	8.170	1.029	8.50	6.1	366.5	15.30	1.19	
COUCH CONSTRUCTION, L.P.	3	3,360.3	573.1	53.6	-11,300	52,400								
COUCH CONSTRUCTION, L.P.	1	3,400.7	577.2	70.8	-51,670	48,330	7.340	0.925	32.15	18.3	338.7	24.69	1.07	
COUCH CONSTRUCTION, L.P.	3	3,400.7	577.2	70.8	-51,670	48,330			1.80					
COUCH, INCORPORATED	1	3,401.4	580.6	69.0	-52,400	44,900				11.9	303.2	2.74	0.40	
COX BUILDING CORPORATION	1	3,342.3	613.0	14.2	6,700	12,500				15.2	303.2	25.60	0.15	
EAGLE RECYCLING, INC.	1	3,333.9	669.1	46.2	15,120	-43,640	3.800	0.479	16.80	9.1		12.92	0.91	
EB PIPE COATING INC.	1	3,339.1	622.1	10.5	9,900	3,400				3.7	305.4	33.01	0.43	
EB PIPE COATING INC.	2	3,339.1	622.1	10.5	9,900	3,400				4.0	305.4	56.72	0.34	
EB PIPE COATING INC.	3	3,339.1	622.1	10.5	9,900	3,400				4.9	305.4	31.61	0.46	
EB PIPE COATING INC.	4	3,339.1	622.1	10.5	9,900	3,400				5.8	305.4	15.33	0.69	
EB PIPE COATING INC.	5	3,339.1	622.1	10.5	9,900	3,400				4.0	305.4	32.34	0.30	
EB PIPE COATING INC.	6	3,339.1	622.1	10.5	9,900	3,400				7.9	305.4	19.23	0.56	
EB PIPE COATING INC.	7	3,339.1	622.1	10.5	9,900	3,400					305.4			
EWELL INDUSTRIES, INC.	1	3,345.5	605.2	20.6	3,500	20,300				12.2	303.2	25.60	0.15	
EWELL INDUSTRIES, INC.	2	3,345.5	605.2	20.6	3,500	20,300								
EWELL INDUSTRIES, INC.	1	3,359.9	585.5	41.5	-10,940	40,030				18.9	303.2	25.60	0.15	
FLORIDA ASPHALT PAVING COMPANY	1	3,338.3	631.4	12.2	10,700	-5,900	14.400	1.814	28.80	7.0	302.6	9.14	1.86	
FLORIDA ASPHALT PAVING COMPANY	1	3,399.8	624.4	50.8	-50,800	1,100	10.000	1.260	43.80	11.0	435.9	22.25	1.16	
FLORIDA COAST PAPER COMPANY, L.L.C.	2	3,299.0	662.8	62.4	50,000	-37,300	10.290	1.297	45.10	33.8	352.6	19.81	1.22	
FLORIDA COAST PAPER COMPANY, L.L.C.	3	3,299.0	662.8	62.4	50,000	-37,300	10.290	1.297	45.1	33.5	352.6	18.29	1.22	3.89
FLORIDA COAST PAPER COMPANY, L.L.C.	4	3,299.0	662.8	62.4	50,000	-37,300	10.290	1.297	45.10	33.8	352.6	20.73	1.22	
FLORIDA COAST PAPER COMPANY, L.L.C.	5	3,299.0	662.8	62.4	50,000	-37,300			1.63					
FLORIDA COAST PAPER COMPANY, L.L.C.	17	3,299.0	662.8	62.4	50,000	-37,300	25.670	3.234	112.43	12.2	355.4	1.22	0.76	6.47
FLORIDA COAST PAPER COMPANY, L.L.C.	18	3,299.0	662.8	62.4	50,000	-37,300	25.670	3.234	112.43	12.2	355.4	1.22	0.76	
FLORIDA COAST PAPER COMPANY, L.L.C.	21	3,299.0	662.8	62.4	50,000	-37,300	5.000	0.630	21.90	38.1	360.4	7.62	1.07	
FLORIDA COAST PAPER COMPANY, L.L.C.	22	3,299.0	662.8	62.4	50,000	-37,300	37.500	4.725	164.25	38.1	460.9	14.63	2.56	10.71
FLORIDA COAST PAPER COMPANY, L.L.C.	23	3,299.0	662.8	62.4	50,000	-37,300	5.000	0.630	21.90	38.1	355.4		1.07	
FLORIDA COAST PAPER COMPANY, L.L.C.	24	3,299.0	662.8	62.4	50,000	-37,300	37.500	4.725	164.25	38.1	394.3	2.74	2.56	
FLORIDA COAST PAPER COMPANY, L.L.C.	25	3,299.0	662.8	62.4	50,000	-37,300	88.200	11.113	386.32	51.8	343.2	10.06	4.27	11.13
FLORIDA COAST PAPER COMPANY, L.L.C.	26	3,299.0	662.8	62.4	50,000	-37,300	152.380	19.200	667.42	57.9	444.3	14.63	2.68	19.2
FLORIDA COAST PAPER COMPANY, L.L.C.	27	3,299.0	662.8	62.4	50,000	-37,300	19.900	2.507	87.20	30.5	367.6	2.13	2.38	2.51
FLORIDA COAST PAPER COMPANY, L.L.C.	31	3,299.0	662.8	62.4	50,000	-37,300				19.8	303.2	71.62	0.09	
FLORIDA COAST PAPER COMPANY, L.L.C.	35	3,299.0	662.8	62.4	50,000	-37,300				33.5	352.6	18.29	1.22	
FLORIDA COAST PAPER COMPANY, L.L.C.	36	3,299.0	662.8	62.4	50,000	-37,300	0.690	0.087	0.54					

Table 6-2. FDEP Off-Property PM_{10} Emission Inventory (Page 2 of 2)

Company Name	EU ID	UTM Coordinates (km) Northing (km)	UTM Coordinates (km) Easting (km)	Distance From Unit 3 (km)	Relative Coordinates Y (m)	Relative Coordinates X (m)	PM Emission Rates (lb/hr)	PM Emission Rates (g/s)	PM Emission Rates (tpy)	Stack Parameters Height (m)	Stack Parameters Temperature (K)	Stack Parameters Velocity (m/s)	Stack Parameters Diameter (m)
FLORIDA GAS TRANSMISSION CO.	6	3,394.2	610.6	47.6	-45,200	14,900	0.080	0.010	0.35	15.2	560.9	71.01	0.37
FLORIDA GAS TRANSMISSION CO.	7	3,394.2	610.6	47.6	-45,200	14,900							
FLORIDA MINING & MATERIALS	1	3,339.5	629.0	10.1	9,510	-3,500				20.7	303.2	0.30	1.04
FLORIDA MINING & MATERIALS	2	3,339.5	629.0	10.1	9,510	-3,500				20.7	303.2	0.30	1.04
FLORIDA MINING & MATERIALS	3	3,339.5	629.0	10.1	9,510	-3,500				12.5	303.2	1.83	0.49
FLORIDA MINING & MATERIALS	1	3,342.3	613.0	14.2	6,700	12,500							
FLORIDA MINING & MATERIALS	2	3,342.3	613.0	14.2	6,700	12,500							
FLORIDA MINING & MATERIALS CONCRETE	1	3,299.5	662.9	62.0	49,490	-37,410				13.7	305.4	13.41	0.18
FLORIDA MINING & MATERIALS CONCRETE	2	3,299.5	662.9	62.0	49,490	-37,410	10.000	1.260	0.13				
G.A.C. CONTRACTORS INC.	1	3,343.7	634.9	10.8	5,300	-9,400	35.430	4.464	44.29	7.6	327.6	11.28	1.22
GRANGER ASPHALT PAVING, INC.	1	3,340.3	628.1	9.1	8,720	-2,590	8.300	1.046	15.10	8.5	405.4	2.44	3.05
GULF COAST CREMATORY SERVICE	1	3,343.9	634.3	10.2	5,100	-8,800				6.1	588.7	3.35	0.61
GULF POWER COMPANY	1	3,349.1	625.2	0.3	-100	300	176.800	22.277	774.00	61.0	399.8	19.51	5.49
GULF POWER COMPANY	1	3,349.1	625.2	0.3	-100	300	176.800	22.277	774.00	61.0	399.8	19.51	5.49
GULF POWER COMPANY	2	3,349.1	625.2	0.3	-100	300	204.200	25.729	894.40	61.0	399.8	19.51	5.49
GULF POWER COMPANY	2	3,349.1	625.2	0.3	-100	300	204.200	25.729	894.40	61.0	399.8	19.51	5.49
GULF POWER COMPANY	3	3,349.1	625.2	0.3	-100	300	33.090	4.169	144.80	7.6	922.0	124.05	1.52
HUMANE SOCIETY OF BAY COUNTY.	1	3,338.8	630.7	11.4	10,200	-5,200	0.600	0.076	2.63	4.9	669.3	8.23	0.52
JERKINS, INCORPORATED	1	3,383.7	635.6	36.2	-34,720	-10,070	0.148	0.019	0.65	4.6	298.2	2.13	0.37
LOUISIANA PACIFIC CORP	1	3,355.2	608.8	17.8	-6,160	16,700	8.400	1.058	36.79	15.5	344.3	14.93	0.91
LOUISIANA PACIFIC CORP	2	3,355.2	608.8	17.8	-6,160	16,700							
PARTHENON PRINTS	1	3,343.5	627.5	5.9	5,500	-2,000				10.7	322.0	85.95	0.46
PERDUE FARMS INCORPORATED	2	3,399.3	590.1	61.5	-50,300	35,400	0.530	0.067	1.66		508.2		
PERDUE FARMS INCORPORATED	3	3,399.3	590.1	61.5	-50,300	35,400	0.190	0.024	0.58		508.2		
PERDUE FARMS INCORPORATED	4	3,399.3	590.1	61.5	-50,300	35,400	0.260	0.033	0.80		508.2		
PERDUE FARMS INCORPORATED	5	3,399.3	590.1	61.5	-50,300	35,400	0.130	0.016	0.42		508.2		
PERDUE FARMS INCORPORATED	6	3,399.3	590.1	61.5	-50,300	35,400	16.000	2.016	41.60	44.2	305.4	19.81	0.88
PERDUE FARMS INCORPORATED	7	3,399.3	590.1	61.5	-50,300	35,400	16.000	2.016	41.60	44.2	305.4	23.47	0.88
PERDUE FARMS INCORPORATED	8	3,399.3	590.1	61.5	-50,300	35,400							
PREMIER REFRACTORIES, INC.	2	3,302.8	664.7	60.6	46,200	-39,200	9.490	1.196	41.57	21.6	463.7	3.05	1.83
PREMIER REFRACTORIES, INC.	3	3,302.8	664.7	60.6	46,200	-39,200	11.060	1.394	48.45	36.6	300.4	8.23	0.52
PREMIER REFRACTORIES, INC.	6	3,302.8	664.7	60.6	46,200	-39,200	9.490	1.196	41.57	19.5	449.8	4.57	1.83
PREMIER REFRACTORIES, INC.	7	3,302.8	664.7	60.6	46,200	-39,200	9.490	1.196	41.57	19.5	439.3	5.49	1.83
PREMIER REFRACTORIES, INC.	8	3,302.8	664.7	60.6	46,200	-39,200	10.380	1.308	45.47	20.1	338.7	7.01	1.22
PREMIER REFRACTORIES, INC.	9	3,302.8	664.7	60.6	46,200	-39,200	0.190	0.024	0.82	15.2	355.4	14.51	0.21
SIKES CONCRETE PIPE CO	4	3,339.3	630.9	11.1	9,700	-5,400				11.0	303.2	12.80	0.15
SIKES CONCRETE PIPE CO.	1	3.338.7	630.7	11.5	10,300	-5,200				9.8	303.2	12.80	0.15
STEPHEN MILEY	1	3,373.2	581.1	50.6	-24,210	44,410	16.000	2.016	32.20				
STONE CONTAINER CORPORATION	1	3,335.1	632.8	15.7	13,900	-7,300	112.500	14.175	472.50	70.1	435.9	23.44	2.77
STONE CONTAINER CORPORATION	4	3,335.1	632.8	15.7	13,900	-7,300	29.830	3.759	130.66	18.3	348.7	6.71	2.04
STONE CONTAINER CORPORATION	5	3,335.1	632.8	15.7	13,900	-7,300	32.300	4.070	141.91	19.8	352.6	4.57	0.88
STONE CONTAINER CORPORATION	15	3,335.1	632.8	15.7	13,900	-7,300	109.500	13.797	479.61	62.8	327.0	23.16	2.38
STONE CONTAINER CORPORATION	16	3,335.1	632.8	15.7	13,900	-7,300	86.600	10.912	379.30	62.8	324.8	24.99	2.38
STONE CONTAINER CORPORATION	19	3,335.1	632.8	15.7	13,900	-7,300	112.500	14.175	492.75	70.1	435.9	23.16	2.77
STONE CONTAINER CORPORATION	20	3,335.1	632.8	15.7	13,900	-7,300	28.520	3.594	130.10	73.1	338.7	4.27	1.80
STONE CONTAINER CORPORATION	21	3,335.1	632.8	15.7	13,900	-7,300	29.710	3.743	130.10	73.1	338.7	3.96	1.80
STONE CONTAINER CORPORATION	30	3,335.1	632.8	15.7	13,900	-7,300			24.00		293.7		
SYLVACHEM CORPORATION	2	3,299.6	661.9	61.3	49,380	-36,350	0.986	0.124	4.32	16.5	515.9	14.02	1.22
SYLVACHEM CORPORATION	5	3,299.6	661.9	61.3	49,380	-36,350	7.000	0.882	30.66	6.1	310.9	25.60	0.30
SYLVACHEM CORPORATION	6	3,299.6	661.9	61.3	49,380	-36,350	12.800	1.613	55.26	9.1	302.6	0.91	1.52
SYLVACHEM CORPORATION	15	3,299.6	661.9	61.3	49,380	-36,350							
TEXTURED COATINGS OF AMERICA,INC.	1	3,338.5	631.3	12.0	10,500	-5,800	0.004	0.001	0.00	6.1	294.3	7.01	0.82
TRIANGLE CONSTRUCTION ROAD BUILDING INC.	1	3,347.0	638.8	13.4	2,000	-13,300	7.370	0.929	11.50	10.7	349.8	14.02	1.01
UNITED STATES AIR FORCE	9	3,326.8	635.6	24.4	22,200	-10,100	0.700	0.088	1.02	6.1	549.8	2.13	0.21
WHITE CONSTRUCTION COMPANY	1	3,403.5	654.2	61.6	-54,500	-28,700	6.990	0.881	30.62	10.7	449.8	32.92	1.10
WHITE CONSTRUCTION COMPANY	2	3,403.5	654.2	61.6	-54,500	-28,700							
WHITE CONSTRUCTION COMPANY, INC.	1	3,397.5	633.9	49.2	-48,470	-8,430			2.40		298.2		
WHITE CONSTRUCTION COMPANY, INC.	2	3,397.5	633.9	49.2	-48,470	-8,430			1.10				
WHITE CONSTRUCTION COMPANY, INC.	3	3,397.5	633.9	49.2	-48,470	-8,430			9.00				
WHITE CONSTRUCTION COMPANY, INC.	1	3,400.5	579.5	69.1	-51,500	46,000	12.810	1.614	55.90	7.0	410.9	29.08	1.16
WHITE CONSTRUCTION COMPANY, INC.	3	3,400.5	579.5	69.1	-51,500	46,000					298.2		

Source: FDEP, 1999.

Table 6-3. FDEP Off-Property PM_{10} Emission Inventory - Modeled Emission Sources

Company Name	ISC ID	EU ID	UTM Coordinates (km) Easting (km)	UTM Coordinates (km) Northing (km)	Distance From Smith Unit 3 (km)	PM Emission Rates (lb/hr)	PM Emission Rates (g/s)	Stack Parameters Height (m)	Stack Parameters Temperature (K)	Stack Parameters Velocity (m/s)	Stack Parameters Diameter (m)
GULF POWER COMPANY	1	3	625.2	3,349.1	0.3	33.090	4.169	10.1	922.0	36.90	4.20
GULF POWER COMPANY	2	1	625.2	3,349.1	0.3	381.746	48.100	60.7	441.0	31.30	5.49
GRANGER ASPHALT PAVING, INC.	6	1	628.1	3,340.3	9.1	8.300	1.046	8.5	405.4	2.44	3.05
G.A.C. CONTRACTORS INC.	7	1	634.9	3,343.7	10.8	35.430	4.464	7.6	327.6	11.28	1.22
HUMANE SOCIETY OF BAY COUNTY.	8	1	630.7	3,338.8	11.4	0.600	0.076	4.9	669.3	8.23	0.52
TEXTURED COATINGS OF AMERICA,INC.	9	1	631.3	3,338.5	12.0	0.004	0.001	6.1	294.3	7.01	0.82
FLORIDA ASPHALT PAVING COMPANY	10	1	631.4	3,338.3	12.2	14.400	1.814	7.0	302.6	9.14	1.86
TRIANGLE CONSTRUCTION ROAD BUILDING INC.	11	1	638.8	3,347.0	13.4	7.370	0.929	10.7	349.8	14.02	1.01
ARIZONA CHEMICAL COMPANY	12	19	633.1	3,335.4	15.6	0.073	0.009	6.1	298.2	0.01	6.71
ARIZONA CHEMICAL COMPANY	13	14	633.1	3,335.4	15.6	17.500	2.205	30.5	510.9	22.55	1.22
ARIZONA CHEMICAL COMPANY	14	15	633.1	3,335.4	15.6	17.500	2.205	30.5	466.5	17.37	1.22
STONE CONTAINER CORPORATION	15	20	632.8	3,335.1	15.7	28.520	3.594	73.1	338.7	4.27	1.80
STONE CONTAINER CORPORATION	16	21	632.8	3,335.1	15.7	29.710	3.743	73.1	338.7	3.96	1.80
STONE CONTAINER CORPORATION	17	4	632.8	3,335.1	15.7	29.830	3.759	18.3	348.7	6.71	2.04
STONE CONTAINER CORPORATION	18	5	632.8	3,335.1	15.7	32.300	4.070	19.8	352.6	4.57	0.88
STONE CONTAINER CORPORATION	19	16	632.8	3,335.1	15.7	86.600	10.912	62.8	324.8	24.99	2.38
STONE CONTAINER CORPORATION	20	15	632.8	3,335.1	15.7	109.500	13.797	62.8	327.0	23.16	2.38
STONE CONTAINER CORPORATION	21	1	632.8	3,335.1	15.7	112.500	14.175	70.1	435.9	23.44	2.77
STONE CONTAINER CORPORATION	22	19	632.8	3,335.1	15.7	112.500	14.175	70.1	435.9	23.16	2.77
LOUISIANA PACIFIC CORP	23	1	608.8	3,355.2	17.8	8.400	1.058	15.5	344.3	14.93	0.91
BAY COUNTY ENERGY SYSTEMS, INC.	24	1	644.0	3,348.9	18.5	6.800	0.857	38.1	477.6	17.37	1.37
BAY COUNTY ENERGY SYSTEMS, INC.	25	2	644.0	3,348.9	18.5	6.800	0.857	38.1	497.0	17.37	1.37
UNITED STATES AIR FORCE	26	9	635.6	3,326.8	24.4	0.700	0.088	6.1	549.8	2.13	0.21
ANDERSON COLUMBIA CO INC #6	27	1	648.8	3,362.8	27.1	18.000	2.268	9.8	435.9	21.03	1.22
JERKINS, INCORPORATED	28	1	635.6	3,383.7	36.2	0.148	0.019	4.6	298.2	2.13	0.37
EAGLE RECYCLING, INC.	29	1	669.1	3,333.9	46.2	3.800	0.479	9.1	255.4	12.92	0.91
FLORIDA GAS TRANSMISSION CO.	30	6	610.6	3,394.2	47.6	0.080	0.010	15.2	560.9	71.01	0.37
FLORIDA ASPHALT PAVING COMPANY	32	1	624.4	3,399.8	50.8	10.000	1.260	11.0	435.9	22.25	1.16
COUCH CONSTRUCTION, L.P.	33	2	573.1	3,360.3	53.6	8.170	1.029	6.1	366.5	15.30	1.19

Sources: FDEP, 1999.
Gulf, 1999.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The SCREEN3 dispersion model was used to assess each of the 14 CTG operating cases; i.e., a matrix of three CTG loads (100-, 75-, and 50-percent); three ambient temperatures (0, 65, and 95°F); and optional use of evaporative cooling, duct burner firing, and steam power augmentation, for each pollutant subject to PSD review (SO_2, PM/PM_{10}, CO, and H_2SO_4 mist). The worst-case operating mode identified by the SCREEN3 model for each pollutant was then carried forward to the refined modeling for further analysis.

SCREEN3 model runs employed the specific stack exit temperature and exhaust gas velocity appropriate for each operating case. A nominal emission rate of 1.0 g/s was used for each case; model results were then scaled to reflect the maximum emission rates for each pollutant. Because the SCREEN3 model is a single-source model, the scaling procedure was based on maximum emissions from both CTGs. SCREEN3 model options used include rural dispersion, building downwash, full meteorology, and automated receptors extending from 725 (distance to the nearest boundary) to 10,000 meters.

SCREEN3 model maximum 1-hour impacts for each CTG operating case are provided on Tables 7-1 through 7-4 for SO_2, PM/PM_{10}, CO, and H_2SO_4 mist, respectively. These tables indicate, for each operating case, the maximum emission rate for both CTGs, SCREEN3 model results based on a nominal 1.0 g/s emission rate, emission rate scaling factor, scaled SCREEN3 model result, and location of maximum impact.

As shown in Tables 7-1, 7-3, and 7-4, the maximum impacts for SO_2, CO, and H_2SO_4 mist all occurred for Case 11 (100 percent load, 95°F ambient temperature, evaporative cooling, duct burner firing, and steam power augmentation). For PM/PM_{10}, the maximum SCREEN3 impact occurred for Case 14 (50 percent load and 95°F ambient temperature). These worst-case operating cases were then analyzed using the refined ISCST3 dispersion model.

Table 7-1. SCREEN3 Model Results - SO_2 Impacts, Two CTG/HRSGs

								Sulfur Dioxide			
Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temper-ature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact ($\mu g/m^3$)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact ($\mu g/m^3$)	Down Wind Distance (m)
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	2.92	2.92	9.71	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	3.20	3.20	10.65	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	2.35	2.35	8.98	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	1.87	1.87	7.98	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	2.68	2.68	10.44	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	2.99	2.99	11.68	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	2.18	2.18	9.75	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	1.75	1.75	8.99	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	2.53	2.53	11.30	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	2.68	2.68	11.89	725
11	**Natural Gas**	**CTG+ EC + PA + DB**	**Yes**	**100**	**95**	**1.0**	**4.43**	**3.13**	**3.13**	**13.89**	**725**
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	3.00	3.00	13.07	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	2.07	2.07	9.67	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	1.66	1.66	9.57	725
									Maximum	13.89	

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PA = power augmentation.

Source: ECT, 1999.

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Table 7-2. SCREEN3 Model Results - PM/PM_{10} Impacts, Two CTG/HRSGs

								PM/PM_{10}			
Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temper-ature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact ($\mu g/m^3$)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact ($\mu g/m^3$)	Down Wind Distance (m)
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	4.99	4.99	16.59	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	5.24	5.24	17.44	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	4.99	4.99	19.05	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	4.99	4.99	21.25	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	4.99	4.99	19.42	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	5.27	5.27	20.58	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	4.99	4.99	22.34	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	4.99	4.99	25.69	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	4.99	4.99	22.24	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	4.99	4.99	22.16	725
11	Natural Gas	CTG+ EC + PA + DB	Yes	100	95	1.0	4.43	5.41	5.41	23.96	725
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	5.29	5.29	23.06	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	4.99	4.99	23.31	725
14	**Natural Gas**	**CTG**	**Yes**	**50**	**95**	**1.0**	**5.76**	**4.99**	**4.99**	**28.76**	**725**
									Max.	**28.76**	

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PA = power augmentation.

Source: ECT, 1999.

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Table 7-3. SCREEN3 Model Results - CO Impacts, Two CTG/HRSGs

Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temper-ature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact ($\mu g/m^3$)	Carbon Monoxide Emission Rate (g/sec)	Carbon Monoxide Emission Rate Ratio	Carbon Monoxide Maximum Impact ($\mu g/m^3$)	Down Wind Distance (m)
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	14.69	14.69	48.83	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	19.82	19.82	65.96	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	11.64	11.64	44.45	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	9.42	9.42	40.14	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	13.31	13.31	51.80	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	18.99	18.99	74.21	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	10.81	10.81	48.40	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	8.87	8.87	45.67	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	12.47	12.47	55.61	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	12.47	12.47	55.40	725
11	**Natural Gas**	**CTG+ EC + PA + DB**	**Yes**	**100**	**95**	**1.0**	**4.43**	**29.38**	**29.38**	**130.26**	**725**
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	18.46	18.46	80.42	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	10.26	10.26	47.92	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	8.59	8.59	49.52	725
									Max.	**130.26**	

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PA = power augmentation.

Source: ECT, 1999.

Table 7-4. SCREEN3 Model Results - H_2SO_4 Impacts, Two CTG/HRSGs

								Sulfuric Acid Mist			
Case	CTG Fuel	Operating Scenario	Down-wash	Load (%)	Ambient Temper-ature (°F)	SCREEN3 Emission Rate (g/sec)	SCREEN3 Maximum Impact ($\mu g/m^3$)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum Impact ($\mu g/m^3$)	Down Wind Distance (m)
1	Natural Gas	CTG	Yes	100	0	1.0	3.32	0.336	0.34	1.12	725
2	Natural Gas	CTG + DB	Yes	100	0	1.0	3.33	0.368	0.37	1.22	725
3	Natural Gas	CTG	Yes	75	0	1.0	3.82	0.270	0.27	1.03	725
4	Natural Gas	CTG	Yes	50	0	1.0	4.26	0.215	0.22	0.92	725
5	Natural Gas	CTG + EC	Yes	100	65	1.0	3.89	0.308	0.31	1.20	725
6	Natural Gas	CTG + EC + DB	Yes	100	65	1.0	3.91	0.343	0.34	1.34	725
7	Natural Gas	CTG	Yes	75	65	1.0	4.48	0.250	0.25	1.12	725
8	Natural Gas	CTG	Yes	50	65	1.0	5.15	0.200	0.20	1.03	725
9	Natural Gas	CTG + EC	Yes	100	95	1.0	4.46	0.291	0.29	1.30	725
10	Natural Gas	CTG + EC + PA	Yes	100	95	1.0	4.44	0.307	0.31	1.37	725
11	**Natural Gas**	**CTG+ EC + PA + DB**	**Yes**	**100**	**95**	**1.0**	**4.43**	**0.36**	**0.36**	**1.59**	**725**
12	Natural Gas	CTG + EC + DB	Yes	100	95	1.0	4.36	0.345	0.34	1.50	725
13	Natural Gas	CTG	Yes	75	95	1.0	4.67	0.238	0.24	1.11	725
14	Natural Gas	CTG	Yes	50	95	1.0	5.76	0.191	0.19	1.10	725
									Max.	**1.59**	

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PA = power augmentation.

Source: ECT, 1999.

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7.2 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The refined ISCST model was used to model the operating cases identified by the SCREEN3 model to cause maximum impacts. ISCST3 model results for each year of meteorology evaluated (1986—1990) are summarized on Table 7-5 (annual SO_2 impacts), Table 7-6 (3-hour SO_2 impacts), Table 7-7 (24-hour SO_2 impacts), Table 7-8 (annual PM/PM_{10} impacts), Table 7-9 (24-hour PM/PM_{10} impacts), Table 7-10 (1-hour CO impacts), and Table 7-11 (8-hour CO impacts).

Tables 7-5 through 7-11 demonstrate that Smith Unit 3 impacts, for all pollutants and all averaging times, are below the PSD significant impact levels previously shown in Table 4-2 with the exception of PM_{10}. A summary of maximum Smith Unit 3 impacts and PSD significant impact levels is provided on Table 7-12.

7.3 NAAQS ANALYSIS

An assessment of Smith Unit 3 impacts, together with other sources within 54 km, was performed for comparison to the annual and 24-hour average PM_{10} NAAQS. The modeled emission inventory included the two Smith Unit 3 CTG/HRSG units (operating under Case 14 conditions) and cooling tower, and all other sources contained in the FDEP PM emission inventory retrieval that are located within 54 km of the Smith Unit 3 site. Conservatively, the PM emission rates provided by FDEP were assumed to be equal to PM_{10} emission rates.

The receptor grids for the refined NAAQS analysis consisted of the fence line and natural barrier receptors, and near-field grid receptors consistent with the approximate 2.4 km AOI; i.e., the grid extended from Smith Unit 3 site out to 2.4 km. The results of the annual and 24-hour average PM_{10} NAAQS modeling are provided on Tables 7-13 and 7-14, respectively. This table demonstrates that Smith Unit 3 emission source impacts, together with all other off-property PM emission sources and including background, are well below the annual and 24-hour average PM_{10} NAAQS.

Table 7-5. ISCST3 Model Results - Maximum Annual Average SO_2 Impacts

Maximum Annual Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	0.37	0.39	0.41	0.37	**0.60**
Emission Rate Scaling Factor[2]	0.1566	0.1566	0.1566	0.1566	**0.1566**
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	0.06	0.06	0.06	0.06	**0.09**
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	**1.0**
Exceed PSD Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	5.7	6.2	6.4	5.8	**9.3**
Receptor UTM Easting (m)	625,500.0	625,761.4	623,278.5	623,520.1	**623,278.5**
Receptor UTM Northing (m)	3,346,300.0	3,346,011.5	3,350,864.0	3,350,980.0	**3,350,864.0**
Distance From Grid Origin (m)	2,700	3,000	2,900	2,800	**2,900**
Direction From Grid Origin (Vector °)	180	175	310	315	**310**

[1] Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-6. ISCST3 Model Results - Maximum 24-Hour Average SO_2 Impacts

Maximum 24-Hour Impacts	**1986**	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	**10.85**	8.73	4.21	4.45	6.35
Emission Rate Scaling Factor[2]	**0.1566**	0.1566	0.1566	0.1566	0.1566
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	**1.70**	1.37	0.66	0.70	0.99
PSD Significant Impact ($\mu g/m^3$)	**5.0**	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	**N**	N	N	N	N
Percent of PSD Significant Impact (%)	**34.0**	27.3	13.2	13.9	19.9
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	**13.0**	13.0	13.0	13.0	13.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	**N**	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	**13.1**	10.5	5.1	5.4	7.6
Receptor UTM Easting (m)	**625,714.2**	625,104.6	626,991.3	623,228.7	623,206.4
Receptor UTM Northing (m)	**3,350,143.0**	3,350,143.0	3,346,870.3	3,349,786.8	3,350,606.0
Distance From Grid Origin (m)	**1,163**	1,209	2,600	2,404	2,800
Direction From Grid Origin (Vector °)	**11**	341	145	289	305
Date of Maximum Impact	**2/26/86**	4/14/87	11/28/88	5/18/89	5/26/90
Julian Date of Maximum Impact	**57**	104	333	138	146

[1] Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-7. ISCST3 Model Results - Maximum 3-Hour Average SO_2 Impacts

Maximum 3-Hour Impacts	1986	1987	1988	1989	1990
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	**48.76**	41.82	16.84	18.76	18.18
Emission Rate Scaling Factor[2]	**0.1566**	0.1566	0.1566	0.1566	0.1566
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	**7.64**	6.55	2.64	2.94	2.85
PSD Significant Impact ($\mu g/m^3$)	**25.0**	25.0	25.0	25.0	25.0
Exceed PSD Significant Impact (Y/N)	**N**	N	N	N	N
Percent of PSD Significant Impact (%)	**30.5**	26.2	10.5	11.8	11.4
Receptor UTM Easting (m)	**625,009.4**	625,104.6	623,431.9	623,944.4	626,438.2
Receptor UTM Northing (m)	**3,350,143.0**	3,350,143.0	3,349,364.8	3,350,555.8	3,348,523.8
Distance From Grid Origin (m)	**1,244**	1,209	2,100	2,200	1,052
Direction From Grid Origin (Vector °)	**337**	341	280	315	117
Date of Maximum Impact	**3/13/86**	4/14/87	8/13/88	7/26/89	10/25/90
Julian Date of Maximum Impact	**72**	104	226	207	298
Ending Hour of Maximum Impact	**0300**	1200	1200	1500	2100

[1] Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-8. ISCST3 Model Results - Maximum Annual Average PM/PM_{10} Impacts

Maximum Annual Impacts	1986	1987	1988	1989	**1990**
ISCST3 Impact ($\mu g/m^3$)	0.38	0.33	0.32	0.28	**0.47**
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	**1.0**
Exceed PSD Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	38.0	33.0	32.0	28.0	**47.0**
Receptor UTM Easting (m)	626,228.6	625,923.8	623,891.3	623,944.4	**623,891.3**
Receptor UTM Northing (m)	3,350,143.0	3,350,143.0	3,350,349.8	3,350,555.8	**3,350,349.8**
Distance From Grid Origin (m)	1,355	1,219	2,100	2,200	**2,100**
Direction From Grid Origin (Vector °)	33	20	310	315	**310**

Source: ECT, 1999.

Table 7-9. ISCST3 Model Results - Maximum 24-Hour Average PM/PM_{10} Impacts

Maximum 24-Hour Impacts	**1986**	1987	1988	1989	1990
ISCST3 Impact (µg/m³)	**13.44**	8.13	6.06	3.43	4.68
PSD Significant Impact (µg/m³)	**5.0**	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	**Y**	Y	Y	N	N
Percent of PSD Significant Impact (%)	**268.8**	162.6	121.2	68.6	93.6
PSD *de minimis* Ambient Impact Threshold (µg/m³)	**10.0**	10.0	10.0	10.0	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)*	**Y**	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)*	**134.4**	81.3	60.6	34.3	46.8
Receptor UTM Easting (m)	**625,800.0**	625,828.5	625,923.8	625,900.0	623,370.2
Receptor UTM Northing (m)	**3,350,200.0**	330,143.0	3,350,143.0	3,350,300.0	3,350,491.3
Distance From Grid Origin (m)	**1,237**	3,018,857	1,219	1,360	2,600
Direction From Grid Origin (Vector °)	**14**	180	20	17	305
Date of Maximum Impact	**2/26/86**	1/29/87	6/9/88	5/18/89	5/26/90
Julian Date of Maximum Impact	**57**	29	161	138	146

*An "exceedance" of the *de minimis* ambient impact threshold simply requires that more refined modeling be performed.

Source: ECT, 1999.

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Table 7-10. ISCST3 Model Results - Maximum 1-Hour Average CO Impacts

Maximum 1-Hour Impacts	1986	**1987**	1988	1989	1990
Unadjusted ISCST3 Impact (μg/m^3)[1]	74.51	**75.68**	35.29	34.43	51.00
Emission Rate Scaling Factor[2]	1.47	**1.47**	1.47	1.47	1.47
Adjusted ISCST3 Impact (μg/m^3)[3]	109.47	**111.19**	51.85	50.58	74.93
PSD Significant Impact (μg/m^3)	2,000.0	**2,000.0**	2,000.0	2,000.0	2,000.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	5.5	**5.6**	2.6	2.5	3.7
Receptor UTM Easting (m)	625,009.4	**625,419.0**	625,752.3	626,171.5	624,238.3
Receptor UTM Northing (m)	3,350,143.0	**3,350,143.0**	3,348,275.8	3,348,466.5	3,349,756.0
Distance From Grid Origin (m)	1,244	**1,146**	767	858	1,471
Direction From Grid Origin (Vector °)	337	**356**	161	128	301
Date of Maximum Impact	3/13/86	**2/2/87**	7/2/88	11/16/89	2/5/90
Julian Date of Maximum Impact	72	**33**	184	320	36
Ending Hour of Maximum Impact	0300	**0500**	2200	0600	2400

[1] Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-11. ISCST3 Model Results - Maximum 8-Hour Average CO Impacts

Maximum 8-Hour Impacts	1986	**1987**	1988	1989	1990
Unadjusted ISCST3 Impact (μg/m^3)[1]	21.83	**26.12**	11.24	10.20	12.64
Emission Rate Scaling Factor[2]	1.47	**1.47**	1.47	1.47	1.47
Adjusted ISCST3 Impact (μg/m^3)[3]	32.07	**38.38**	16.52	14.98	18.57
PSD Significant Impact (μg/m^3)	500.0	**500.0**	500.0	500.0	500.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	6.4	**7.7**	3.3	3.0	3.7
PSD *de minimis* Ambient Impact Threshold (μg/m^3)	575.0	**575.0**	575.0	575.0	575.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	**N**	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	5.6	**6.7**	2.9	2.6	3.2
Receptor UTM Easting (m)	624,895.1	**625,104.6**	627,691.6	623,944.4	623,738.1
Receptor UTM Northing (m)	3,350,143.0	**3,350,143.0**	3,348,808.3	3,350,555.8	3,350,478.5
Distance From Grid Origin (m)	1,293	**1,209**	2,200	2,200	2,300
Direction From Grid Origin (Vector °)	332	**341**	95	315	310
Date of Maximum Impact	3/12/86	**4/14/87**	11/5/88	6/1/89	6/12/90
Julian Date of Maximum Impact	71	**104**	310	153	164
Ending Hour of Maximum Impact	2400	**1600**	1600	1600	1600

[1] Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

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Table 7-12. Smith Unit 3 Emission Sources—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
CO	8-hour	38.4	500
	1-hour	111.2	2,000
PM/PM_{10}	Annual	0.5	1.0
	24-hour	13.4	5.0
SO_2	Annual	0.1	1.0
	24-hour	1.7	5.0
	3-hour	7.6	25.0

Source: ECT, 1999.

Table 7-13. ISCST3 Model Results - Maximum Annual Average PM_{10} Impacts; NAAQS Analysis

Maximum Annual Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu g/m^3$)	0.96	0.93	1.02	1.13	**1.27**
Background ($\mu g/m^3$)	28.0	28.0	28.0	28.0	**28.0**
Total Impact ($\mu g/m^3$)	29.0	28.93	29.20	29.13	**29.27**
NAAQS ($\mu g/m^3$)	50.0	50.0	50.0	50.0	**50.0**
Exceed NAAQS (Y/N)	N	N	N	N	**N**
Percent of NAAQS (%)	57.9	57.9	58.0	58.3	**58.5**
Receptor UTM Easting (m)	625,500.0	625,709.2	627,197.1	625,290.8	**623,738.1**
Receptor UTM Northing (m)	3,346,700.0	3,346,609.3	3,347,303.0	3,346,609.3	**3,350,478.5**
Distance From Grid Origin (m)	2,300	2,400	2,400	2,400	**2,300**
Direction From Grid Origin (Vector °)	180	175	135	185	**310**

Source: ECT, 1999.

Table 7-14. ISCST3 Model Results - High, Second Highest 24-Hour Average PM_{10} Impacts; NAAQS Analysis

High, Second Highest 24-Hour Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu g/m^3$)	8.2	7.3	7.9	$\boxed{9.1}$	7.9
Background ($\mu g/m^3$)	73.0	73.0	73.0	**73.0**	73.0
Total Impact ($\mu g/m^3$)	81.2	80.30	80.85	**82.10**	80.90
NAAQS ($\mu g/m^3$)	150.0	150.0	150.0	**150.0**	150.0
Exceed NAAQS (Y/N)	N	N	N	**N**	N
Percent of NAAQS (%)	54.1	53.5	53.9	**54.7**	53.9
Receptor UTM Easting (m)	625,800.0	626,038.1	626,038.1	**626,800.0**	626,038.1
Receptor UTM Northing (m)	3,350,200.0	3,350,143.0	3,350,143.0	**3,350,200.0**	3,350,143.0
Distance From Grid Origin (m)	1,237	1,263	1,263	**1,237**	1,263
Direction From Grid Origin (Vector °)	14	25	25	**14**	25
Date of Maximum Impact	6/30/86	8/4/87	5/4/88	**1/8/89**	1/24/90
Julian Date of Maximum Impact	181	216	125	**8**	24

Source: ECT, 1999.

The NAAQS impact analyses was conducted using conservative premises for background PM_{10} levels, off-property source PM_{10} emission rates, and Smith Unit 3 cooling tower PM_{10} emission rates. The *highest* 24-hour and annual average PM_{10} values obtained from the FDEP PM_{10} monitoring site located in Panama City, Bay County for 1997 and 1998 were used as background. This approach results in an over-estimation of total impacts due to "double-counting"; i.e., a portion of the FDEP monitored ambient PM_{10} data would be expected to have been caused by the same PM_{10} emission sources which are also included in the modeled emission inventory. As noted above, all PM emission rates provided by FDEP for the off-property sources were conservatively assumed to be equal to PM_{10} emission rates.

More significantly, Smith Unit 3 cooling tower PM_{10} emission rates were estimated using EPA AP-42 procedures. As noted, and emphasized in AP-42, these emission estimation procedures result in "conservatively high" PM_{10} emission rates. Analysis of the dispersion model PM_{10} results shows that the Smith Unit 3 cooling tower was one of the principal contributors to the highest impacts. With respect to 24-hour average PM_{10} impacts, Smith Unit 3 cooling tower emissions were responsible for approximately 55 percent of the total impact. For maximum annual average PM_{10} impacts, Smith Unit 3 cooling tower emissions contributed approximately 25 percent of the total impact. Note that PM_{10} emissions from the primary Smith Unit 3 emission sources, the two CTG/HRSG units, result in maximum PM_{10} impacts which are well below the PSD significant impact levels.

Because of the conservative approach used in conducting the air quality analysis for PM_{10} NAAQS impacts, there is reasonable assurance that Smith Unit 3 will not cause nor contribute to an exceedance of the PM_{10} NAAQS.

7.4 PSD CLASS II INCREMENT ANALYSIS

An assessment of Smith Unit 3 impacts, together with other sources within 54 km, was performed for comparison to the annual and 24-hour average PSD Class II PM_{10} increments. The modeled emission inventory included the two Smith Unit 3 CTG/HRSG units (operating under Case 14 conditions) and cooling tower, and all other sources contained in the FDEP PM emission inventory retrieval that are located within 54 km of Smith Unit 3 site. The FDEP PM_{10} emission inventory did not identify the specific emission sources which consume PSD PM_{10} increment. Conservatively, *all* off-property PM_{10} emission sources located within 54 km of Smith Unit 3 site were assumed to consume PSD increment. In addition, the PM emission rates provided by FDEP were conservatively assumed to be equal to PM_{10} emission rates.

The receptor grids for the refined PSD Class II PM_{10} increment analysis consisted of the fence line receptors, and near-field grid receptors consistent with the approximate 2.4 km AOI; i.e., the grid extended from Smith Unit 3 site out to 2.4 km. The results of the 24-hour and annual average PSD Class II PM_{10} increment modeling are provided in Table 7-15 and 7-16, respectively. These tables demonstrate that maximum Smith Unit 3 impacts, together with all other PSD PM_{10} increment consuming emission sources, are below the 24-hour and annual average PSD Class II PM_{10} increments.

Similar to the NAAQS air quality analysis, the assessment of PSD Class II PM_{10} increment consumption was conducted using several conservative premises. As noted above, *all* off-property PM emission sources were assumed to consume PSD PM_{10} increment. In addition, the PM emission rates provided by FDEP for the off-property sources were assumed to be equal to PM_{10} emission rates. The same conservatively high PM_{10} emission rates used for Smith Unit 3 cooling tower in the NAAQS analysis were also used in the PSD Class II PM_{10} increment consumption analysis. Accordingly, the Smith Unit 3 cooling tower was also one of the principal contributors to PSD Class II PM_{10} increment consumption; i.e., accounting for approximately 57 and 26 percent of the total impact for the 24-hour and annual averaging periods, respectively.

Because of the conservative approach used in conducting the air quality analysis for PM_{10} PSD Class II increment consumption, there is reasonable assurance that Smith Unit 3 will not cause nor contribute to an exceedance of the PSD Class II PM_{10} increments.

Table 7-15. ISCST3 Model Results - Maximum Annual PM_{10} Impacts; PSD Class II Increment Analysis

Maximum Annual Impacts	1986	1987	1988	1989	1990
ISCST3 Impact ($\mu g/m^3$)	0.96	0.93	1.02	1.13	**1.27**
PSD Class II Increment ($\mu g/m^3$)	17.0	17.0	17.0	17.0	**17.0**
Exceed PSD Class II Increment (Y/N)	N	N	N	N	**N**
Percent of PSD Class II Increment (%)	5.6	5.5	6.0	6.6	**7.5**
Receptor UTM Easting (m)	625,500.0	625,709.2	627,197.1	625,290.8	**623,738.1**
Receptor UTM Northing (m)	3,346,700.0	3,346,609.3	3,347,303.0	3,346,609.3	**3,350,478.5**
Distance From Grid Origin (m)	2,300	2,400	2,400	2,400	**2,300**
Direction From Grid Origin (Vector °)	180	175	135	185	**310**

Source: ECT, 1999.

Table 7-16. ISCST3 Model Results - High, Second Highest 24-Hour Average PM_{10} Impacts; PSD Class II Increment Analysis

High, Second Highest 24-Hour Impacts	1986	1987	1988	**1989**	1990
ISCST3 Impact ($\mu g/m^3$)	8.2	7.3	7.9	**9.1**	7.9
PSD Class II Increment ($\mu g/m^3$)	30.0	30.0	30.0	**30.0**	30.0
Exceed PSD Class II Increment (Y/N)	N	N	N	**N**	N
Percent of PSD Class II Increment (%)	27.3	24.3	26.2	**30.3**	26.3
Receptor UTM Easting (m)	625,800.0	626,038.1	626,038.1	**626,800.0**	626,038.1
Receptor UTM Northing (m)	3,350,200.0	3,350,143.0	3,350,143.0	**3,350,200.0**	3,350,143.0
Distance From Grid Origin (m)	1,237	1,263	1,263	**1,237**	1,263
Direction From Grid Origin (Vector °)	14	25	25	**14**	25
Date of Maximum Impact	6/30/86	8/4/87	5/4/88	**1/8/89**	1/24/90
Julian Date of Maximum Impact	181	216	125	**8**	24

Source: ECT, 1999.

7.5 SULFURIC ACID MIST

The maximum 1-hour average SCREEN3 model impact was 1.59 $\mu g/m^3$ for H_2SO_4 mist. Recommended EPA (EPA, 1992) multiplying factors for converting 1-hour averages to 8- and 24-hour averages are 0.7 and 0.4, respectively. Use of these factors yields maximum 8- and 24-hour average H_2SO_4 mist impacts of 1.11 and 0.64 $\mu g/m^3$, respectively. These impacts are well below the FDEP draft ARCs for H_2SO_4 mist of 10.0 and 2.4 $\mu g/m^3$ for 8- and 24-hour average periods, respectively. A summary of Smith Unit 3 H_2SO_4 impacts and the FDEP draft ARC levels is provided on Table 7-17.

7.6 CONCLUSIONS

Comprehensive dispersion modeling using the SCREEN3 and refined ISCST3 models demonstrates that Smith Unit 3 emission sources will result in ambient air quality impacts that are:

- Below the PSD significant impact levels for all pollutants and all averaging periods with the exception of PM_{10}.
- Below the PSD *de-minimis* ambient impact levels for all pollutants and all averaging periods with the exception of PM_{10}.
- Below the FDEP draft ARCs for H_2SO_4 mist.

Comprehensive dispersion modeling using the refined ISCST3 model demonstrates that Project emission sources, together with all off-property PM emission sources located within 54 km of Smith Unit 3 site and including background concentrations, will result in ambient air quality impacts that are:

- Below the NAAQS for PM_{10}; and
- Below the PSD Class II increment for PM_{10}.

Table 7-17. Summary of Worst-Case Estimates of H_2SO_4 Mist Impacts Compared to FDEP Ambient Reference Concentrations

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Ambient Reference Concentration ($\mu g/m^3$)
H_2SO_4 mist	8-hour	1.11	10
	24-hour	0.64	2.4

Source: ECT, 1999.

Based on the conservative nature of the air quality analysis, there is reasonable assurance that Smith Unit 3 will:

- Not cause nor contribute to an exceedance of any NAAQS or Florida AAQS.
- Not cause nor contribute to an exceedance of any PSD Class I or Class II increment.
- Not cause nor contribute to an exceedance of any FDEP draft ARC.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring station is located in Panama City, Bay County, approximately 13 km southeast of the Smith Unit 3 site. The FDEP monitoring station at Panama City monitors PM_{10}. The nearest FDEP stations that monitor SO_2 and NO_2 are located in Pensacola, Escambia County, approximately 161 km west of the Smith Unit 3 site. The nearest FDEP stations monitoring for CO and lead are situated in Jacksonville, Duval County, approximately 441 km east of the Smith Unit 3 site. The nearest FDEP station that monitors ozone is located in Tallahassee, Leon County, approximately 158 km northeast of the Smith Unit 3 site. A summary of 1997 and 1998 ambient air quality data for these FDEP monitoring stations is provided in Tables 8-1 and 8-2.

In addition to the FDEP ambient air monitoring stations, Gulf also conducts ambient air monitoring for TSP, SO_2, and NO_2. Gulf currently operates two SO_2 monitoring stations in Bay County (East and North Remote Lynn Haven Stations), and one NO_2 monitoring station in Bay County (North Remote Lynn Haven Station). A summary of 1993—1995 and 1996—1998 ambient air quality data for these Gulf monitoring stations is provided in Tables 8-3 and 8-4.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 4.2, 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. Because several pollutants will be emitted from Smith Unit 3 in excess of their respective significant emission rates, preconstruction monitoring is generally required. However, the FDEP Rule 62-212.400(2)(e), F.A.C. provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 4-1. To assess the

Table 8-1. Summary of 1997 FDEP Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site No.	Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m³): 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Bay	Panama City	3480-004-F02	13 SE	24-Hr	Jan-Dec	56	62	52	62		150[1]
					Annual						25	50[2]
	Gulf	Port St. Joe	3740-003-F02	60 SE	24-Hr	Jan-Dec	53	65	54	65		
					Annual						23	
SO_2	Escambia	Pensacola	3540-004-F01	161 W	1-Hr	Jan-Dec	8,715	291	254			
					3-Hr			233	191			1,300[3]
					24-Hr			98	76			260[3]
					Annual						11	60[2]
	Escambia	Pensacola	3540-022-F02	161 W	1-Hr	Jan-Dec	8,657	432	403			
					3-Hr			333	322			1,300[3]
					24-Hr			114	86			260[3]
					Annual						12	60[2]
NO_2	Escambia	Pensacola	3540-004-F01	161 W	1-Hr	Jan-Sep	6,161	105	98			
					Annual						16	100[2]
CO	Duval	Jacksonville	1960-080-H01	441 E	1-Hr	Jan-Dec	8,519	3,420	3,420			40,000[3]
					8-Hr			2,280	2,280			10,000[3]
CO	Duval	Jacksonville	1960-083-H01	441 E	1-Hr	Jan-Dec	8,544	7,980	5,700			40,000[3]
					8-Hr			3,420	3,420			10,000[3]
CO	Duval	Jacksonville	1960-084-H01	441 E	1-Hr	Jan-Dec	8,576	6,840	6,840			40,000[3]
					8-Hr			4,560	3,420			10,000[3]
CO	Duval	Jacksonville	1960-095-H01	441 E	1-Hr	Jan-Dec	8,074	7,980	5,700			40,000[3]
					8-Hr			3,420	3,420			10,000[3]
Ozone	Leon	Tallahassee	2340-003-F01	158 NE	1-Hr	Mar-Mar	345	135	110			235[4]
Lead	Duval	Jacksonville	1960-032-H01	441 E	24-Hr							
						Jan-Mar	15				0.0	1.5[2]
						Apr-Jun	15				0.0	
						Jul-Sep	15				0.0	
						Oct-Dec	13				0.0	
Lead	Duval	Jacksonville	1960-084-H01	441 E	24-Hr							
						Jan-Mar	15				0.0	1.5[2]
						Apr-Jun	15				0.0	
						Jul-Sep	14				0.0	
						Oct-Dec	14				0.0	

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period

Sources: FDEP, 1998 and 1999.
ECT, 1999.

Table 8-2. Summary of 1998 FDEP Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site No.	Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m³): 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Bay	Panama City	12-005-004	13 SE	24-Hr	Jan-Dec	54	73	64	73		150[1]
					Annual						28	50[2]
	Gulf	Port St. Joe	12-045-1003	60 SE	24-Hr	Jan-Dec	61	73	65	73		
					Annual						26	
SO_2	Escambia	Pensacola	12-033-0004	161 W	1-Hr	Jan-Dec	8,707	334	310			
					3-Hr			253	214			1,300[3]
					24-Hr			60	57			260[3]
					Annual						10	60[2]
	Escambia	Pensacola	12-033-0022	161 W	1-Hr	Jan-Dec	8,595	477	360			
					3-Hr			264	211			1,300[3]
					24-Hr			63	63			260[3]
					Annual						10	60[2]
NO_2	Duval	Jacksonville	12-031-0032	441 E	1-Hr	Jan-Dec	8,204	124	124			
					Annual						28	100[2]
CO	Duval	Jacksonville	12-031-0080	441 E	1-Hr	Jan-Dec	8,311	9,576	7,296			40,000[3]
					8-Hr			5,130	3,306			10,000[3]
CO	Duval	Jacksonville	12-031-0083	441 E	1-Hr	Jan-Dec	8,013	5,586	5,472			40,000[3]
					8-Hr			3,534	3,306			10,000[3]
CO	Duval	Jacksonville	12-031-0084	441 E	1-Hr	Jan-Dec	8,417	6,954	6,270			40,000[3]
					8-Hr			3,762	3,762			10,000[3]
CO	Duval	Jacksonville	12-031-0095	441 E	1-Hr	Jan-Dec	2,111	5,016	4,218			40,000[3]
					8-Hr			2,280	2166			10,000[3]
Ozone	Leon	Tallahassee	12-073-0012	158 NE	1-Hr	Jan-Dec	199	202	190			235[4]
Lead	Duval	Jacksonville	12-031-0032	441 E	24-Hr		50					
						Jan-Mar					0.01	1.5[2]
						Apr-Jun					0.02	
						Jul-Sep					0.01	
						Oct-Dec					0.02	
Lead	Duval	Jacksonville	12-031-0084	441 E	24-Hr		62					
						Jan-Mar					0.01	1.5[2]
						Apr-Jun					0.01	
						Jul-Sep					0.01	
						Oct-Dec					0.02	

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period

Sources: FDEP, 1998 and 1999.
ECT, 1999.

GDP99/GULF-SMITH/SCA/PSD8.XLS--052899

Table 8-3. Summary of 1993 - 1995 Gulf Power Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: Name	Year	Site No.	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
TSP	Bay	Smith Plant	1993		Annual	Jan-Dec				22.26*	50[1]
			1994		Annual	Jan-Dec				22.23*	50[1]
			1995		Annual	Jan-Dec				22.53*	50[1]
SO_2	Bay	North Remote	1993	2420-004J02	1-Hr	Jul-Sep	1,722	296	212		
		Lynn Haven			3-Hr			138	138		1,300[2]
					24-Hr			47	32		260[2]
			1994		1-Hr	Jan-Dec	6,884	479	401		
					3-Hr			238	199		1,300[2]
					24-Hr			44	44		260[2]
			1995		1-Hr	Jan-Dec	7,060	956	736		
					3-Hr			700	465		1,300[2]
					24-Hr			154	136		260[2]
	Bay	East Remote	1993	2420-005J02	1-Hr	Jul-Sep	1,487	207	186		
		Lynn Haven			3-Hr			183	97		1,300[2]
					24-Hr			27	26		260[2]
			1994		1-Hr	Jan-Dec	7,672	789	574		
					3-Hr			597	407		1,300[2]
					24-Hr			166	102		260[2]
			1995		1-Hr	Jan-Dec	6,095	1,138	778		
					3-Hr			504	475		1,300[2]
					24-Hr			256	157		260[2]
NO_2	Bay	North Remote	1993	2420-004J02	Annual	Jan-Dec				5.13*	100[1]
		Lynn Haven	1994		Annual	Jan-Dec				4.59*	100[1]
			1995		Annual	Jan-Dec				5.02*	100[1]

[1] Arithmetic mean

[2] 2nd high

*Average of four quarterly geometric means.

Sources: Gulf Power, 1999.
ECT, 1999.

Table 8-4. Summary of 1996 -1998 Gulf Power Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: Name	Year	Site No.	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m³): 1st High	2nd High	Arithmetic Mean	Standard
TSP	Bay	Smith Plant	1996		Annual	Jan-Dec				19.24*	50[1]
			1997		Annual	Jan-Dec				18.56*	50[1]
			1998		Annual	Jan-Dec				25.0*	50[1]
SO_2	Bay	North Remote	1996	2420-004J02	1-Hr	Jan-Dec	7,232	1,107	1,005		
		Lynn Haven			3-Hr			1,005	961		1,300[2]
					24-Hr			76	63		260[2]
			1997		1-Hr	Jan-Dec	5,252	948	741		
					3-Hr			529	527		1,300[2]
					24-Hr			152	149		260[2]
					Annual					16.3	60[1]
			1998		1-Hr	Jan-Dec	6,328	697	697		
					3-Hr			584	545		1,300[2]
					24-Hr			199	105		260[2]
					Annual					6.3	60[1]
	Bay	East Remote	1996	2420-005J02	1-Hr	Jan-Dec	5,674	919	888		
		Lynn Haven			3-Hr			721	708		1,300[2]
					24-Hr			248	167		260[2]
			1997		1-Hr	Jan-Dec	6,495	582	537		
					3-Hr			490	461		1,300[2]
					24-Hr			178	157		260[2]
					Annual					17.1	60[1]
			1998		1-Hr	Jan-Dec	6,112	1035	838		
					3-Hr			629	587		1,300[2]
					24-Hr			202	181		260[2]
					Annual					10.7	60[1]
NO_2	Bay	North Remote	1996	2420-004J02	Annual	Jan-Dec				6.11*	100[1]
		Lynn Haven	1997		Annual	Jan-Dec				13.43*	100[1]
			1998		Annual	Jan-Dec				3.49*	100[1]

[1] Arithmetic mean

[2] 2nd high

*Average of four quarterly geometric means.

Sources: Gulf Power, 1999.
ECT, 1999.

GDP99/GULF-SMITH/SCA/PSD8.XLS--052899

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. The following paragraphs summarize the analyses results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 13.4 micrograms per cubic meter ($\mu g/m^3$). This concentration is above the 10 $\mu g/m^3$ *de minimis* level. In accordance with EPA guidance (EPA, 1992a), representative, current (1997 and 1998) quality-assured ambient PM_{10} data collected at the FDEP's PM_{10} monitoring site located in Panama City, Bay County was used to satisfy the PSD pre-construction ambient air monitoring requirements for PM_{10}. A summary of the FDEP monitored PM_{10} ambient air quality data is provided on Tables 8-1 and 8-2.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 38.4 $\mu g/m^3$. This concentration is well below the 575 $\mu g/m^3$ *de minimis* ambient impact level for CO. Therefore, a preconstruction monitoring exemption is appropriate in accordance with the PSD regulations.

8.2.3 SO_2

The maximum 24-hour SO_2 impact was predicted to be 1.7 $\mu g/m^3$. This concentration is well below the 13 $\mu g/m^3$ *de minimis* ambient impact level for SO_2. Therefore, a preconstruction monitoring exemption is appropriate in accordance with the FDEP PSD regulations.

8.2.4 OZONE

Because the proposed Smith Unit 3 will not exceed the PSD monitoring significance level (i.e., potential VOC emissions are less than 100 tpy), preconstruction monitoring for ozone is not required in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to: (a) associated growth, (b) soils, vegetation, and wildlife, and (c) visibility impairment. Each of these topics is discussed in the following sections.

9.1 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.

Impacts associated with construction of the Smith Unit 3 Project and ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The Smith Unit 3 Project is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of Smith Unit 3 are anticipated. When operational, Smith Unit 3 is projected to generate approximately 29 new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas fuel demand due to operation of Smith Unit 3 CT/HRSGs will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

9.2.1 IMPACTS ON SOILS

All the soil types present on the site and in the immediate vicinity are nearly level, poorly drained soils and are described as very strongly acid (see Section 2.3.1.3 of the SCA for soil descriptions). The components of emissions from the power plant of potential impact to soils are SO_2 (including acid rain) and NO_x. However, there will be a net decrease in

NO_x emissions from the Lansing Smith Plant following installation of Unit 3 due to the contemporaneous installation of low-NO_x burners and an improved burner management system for Lansing Smith Unit 1. The primary effect of SO_2 and NO_x deposition and adsorption by soils is the resultant lowering of soil pH. Low soil pH will have an influence on most chemical and biological reactions in the soil including the level and availability of most plant nutrients in the soil. Based on the extremely low maximum incremental and total SO_2 impacts predicted and the ambient acidic nature of the soils, no impacts to soils resources at the plant site or the vicinity are expected.

9.2.2 IMPACTS ON VEGETATION

As described in Section 2.3.5 of the SCA, the vegetation on the proposed power plant site consists of relatively natural and planted vegetation represented mostly by pine plantation and cypress titi-swamp, as well as ruderal or remnant upland and wetland vegetation in areas previously cleared for construction of the existing transmission line right-of-way. The land use and vegetative cover in the immediate area surrounding the project area is a combination of pine plantation/cypress titi-swamp and developed land. The developed land mostly consists of the existing Smith Generating Plant to the south of the site. The vegetated areas in the immediate vicinity of the project site consists of pine plantation planted with slash pine and forested wetlands represented by cypress titi-swamps and hydric slash pine plantation.

Potential impacts to vegetation from SO_2, acid rain, and CO have been evaluated with respect to dose response curves that have been developed for various plant species and their sensitivity to these pollutants. Vegetation damages are described as impacts which result 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 are usually manifested by internal physical damage to foliar tissues which have both functional and visible consequences. 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 pollutants of concern with the proposed power plant project.

SO_2

Natural (ambient) background concentrations of SO_2 range between 0.28 and 2.8 μg/m^3 of SO_2 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 upon plants from SO_2 are primarily due to impacts to photosynthetic processes. SO_2 can react with chlorophyll by causing bleaching or by 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 μg/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 μg/m^3 (ibid.). Caribbean pine (*Pinus caribaea*) seedlings similar in ecology and appearance to slash pine (*Pinus elliotti*) exhibited up to 5 percent needle necrosis when exposed to

1,310 μg/m^3 SO_2 for 4 hours (Umbach and Davis, 1988). 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; U.S. Department of Agriculture, 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).

Because of relative low chlorophyll content and the absence of a protective covering of the cuticle common in the leaves of higher plants, nonvascular plants such as lichens and bryophytes are relatively more sensitive to SO_2 injury and have been documented on those primitive plants at levels as low as 88 μg/m^3 (U.S. Department of Health, Education, and Welfare, 1971). Hart *et al.* (1976) showed that *Ramalina* spp., a lichen genus, exhibited a reduction of carbon dioxide uptake and biomass gain at SO_2 exposures of 400 μg/m^3 for 6 weeks. Tolerant lichens can resist SO_2 concentrations in the range of 79 to 157 μg/m^3; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975).

The maximum total 3-hour average SO_2 concentration for the Smith Unit 3 Project is projected to be 7.6 μg/m^3. The maximum total predicted 24-hour average SO_2 concentration is 1.7 μg/m^3. Annually, the concentration is predicted to be 0.1 μg/m^3. All of these estimates are lower than doses known to cause vegetative injury.

H_2SO_4 Mist

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

Since the concentration of H_2SO_4 mist from the proposed power generating facility is directly dependent upon the availability of SO_2 and SO_2 concentrations are predicted to be well below levels which have been documented as negatively affecting vegetation, 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 is lacking (Gholz, 1985; Charles, 1991).

CO

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.

9.2.3 IMPACTS ON WILDLIFE

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.

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 (ibid.). Florida lakes have a wide natural range of pH (from 4 to 8.8 pH units). According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degradation of aquatic systems have occurred as a direct result of acid precipitation in Florida. The projected air emissions from the Smith Unit 3 Project which contribute to formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife.

In conclusion, it is unlikely that the projected air emission levels from the proposed power plant will have any measurable direct or indirect effects on wildlife using the site or vicinity.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the Project. Opacity of the Project CTG/HRSG unit exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the Project CTG/HRSGs will be low due to the exclusive use of pipeline quality natural gas. The Smith Unit 3 Project will comply with all applicable FDEP requirements pertaining to visible emissions.

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Gulf Power – Smith Unit #3

Rec'd 7 June '99

PA 99-40

PSD-FL-269

ATTACHMENT A—

APPLICATION FOR AIR PERMIT – TITLE V SOURCE

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Gulf Power Company**	
2. Site Name: **Lansing Smith Electric Generating Plant – Smith Unit 3**	
3. Facility Identification Number: **0050014** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **4300 Highway 2300** City: **Southport** County: **Bay** Zip Code: **32409**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [✔] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **G. Dwain Waters** **Air Quality Programs Coordinator**
2. Application Contact Mailing Address: Organization/Firm: **Gulf Power Company** Street Address: **One Energy Place** City: **Pensacola** State: **FL** Zip Code: **32520-0328**
3. Application Contact Telephone Numbers: Telephone: **(850)444 – 6527** Fax: **(850) 444-6217**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:____________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:____________________

Operation permit number to be revised:____________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:____________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:____________________

Reason for revision:____________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[✔] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : Robert G. Moore
Title : V. P. Power Generation/Transmission

2. Owner or Authorized Representative or Responsible Official Mailing Address :

Organization/Firm : Gulf Power Company
Street Address : One Energy Place
City : Pensacola
State : FL Zip Code : 32520-0100

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (850)444-6383 Fax : (850)444-6744

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*

Robert G. Moore
Signature

5/27/99
Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address: Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444** Fax: **(352) 332-6722**

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [✔], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [✔], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Thomas W. Davis   6/5/99

Signature   Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
006	Combined Cycle Combustion Turbine Generator Unit No. 1 (CC-1)	AC1A	N/A
007	Combined Cycle Combustion Turbine Generator Unit No. 2 (CC-2)	AC1A	N/A
008	Salt Water Cooling Tower	AC1A	N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $ ________ [✔] Not Applicable

Note: Application processing fee will be submitted pursuant to the FPPSA.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Project consists of the addition of two nominal 170-MW General Electric 7241 FA combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs) equipped with supplemental duct burners (DBs), one nominal 200-MW steam turbine generator (STG), and one, 10 cell, mechanical draft salt water cooling tower. At average annual site conditions with duct burner firing, Unit 3 will generate 566 MW. At summer peaking site conditions with duct burner firing and steam power augmentation, Unit 3 will generate 574 MW. The CTGs and DBs will be fired exclusively with pipeline quality natural gas. The CTGs will include provisions for the optional use of evaporative coolers and steam power augmentation. The new combined-cycle CTG/HRSGs will be capable of operating at base load for up to 8,760 hours per year. The CTGs will normally operate between 50- and 100-percent load, with commensurate STG load.**
2. Projected or Actual Date of Commencement of Construction: **November 1, 2000**
3. Projected Date of Completion of Construction: **February 1, 2002**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **16** East (km): **625.03** North (km): **3,349.08**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Richard Kraynak, Group Leader Operations**
2. Facility Contact Mailing Address: Organization/Firm: **Gulf Power Company – Lansing Smith** Street Address: **4300 Highway 2300** City: **Southport** State: **FL** Zip Code: **32409**
3. Facility Contact Telephone Numbers: Telephone: **(850) 265-2318** Fax: **(850) 271-1697**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [✔] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [✔] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [✔] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

See Attachment A-1	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**	**N/A**	**3,587**	**ESCPSD**	**Cap for Unit 1 and Unit 3**
SO2	**A**	**N/A**	**N/A**	**N/A**	
CO	**A**	**N/A**	**N/A**	**N/A**	
PM10	**A**	**N/A**	**N/A**	**N/A**	
PM	**A**	**N/A**	**N/A**	**N/A**	
SAM	**A**	**N/A**	**N/A**	**N/A**	
VOC	**A**	**N/A**	**N/A**	**N/A**	
HCL	**A**	**N/A**	**N/A**	**N/A**	
H107	**A**	**N/A**	**N/A**	**N/A**	
HAPs	**A**	**N/A**	**N/A**	**N/A**	

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [✔] Attached, Document ID: **Fig. 2-3** [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [✔] Attached, Document ID: **Fig. 2-4** [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [✔] Attached, Document ID: **Fig. 2-5** [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [✔] Attached, Document ID: **Att. A-2** [ ] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [✔] Attached, Document ID: **PSD App.** [ ] Not Applicable
7. Supplemental Requirements Comment: **Items 1, 2, 3, 4, and 6 above are specific for the Smith Unit 3 project.** **See previously submitted Smith Electric Generating Plant Title V permit application for existing facility information.**

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:________________________) [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable

Items 8. through 15. above previously submitted – see Smith Electric Generating Plant Title V permit application.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[✔] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator (CTG) having a nominal rating of 170 megawatts (MW) and one fired heat recovery steam generator (HRSG). The CTG/HRSG unit will be fired exclusively with pipeline quality natural gas.

4. Emissions Unit Identification Number: [ ] No ID
ID: **006 (CC-1)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[✔]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **NO$_x$ Controls** **Dry low-NO$_x$ combustors**
2. Control Device or Method Code(s): **25 (dry low-NO$_x$)**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **PG7241(FA)**
2. Generator Nameplate Rating: **170** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,751 (LHV)** mmBtu/hr **(CTG only)**			
2. Maximum Incineration Rate:	lb/hr		tons/day	
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

CTG maximum heat input is lower heating value (LHV) at 100 percent load, 0°F operating conditions. Heat input will vary with load and ambient temperature.

HRSG duct burner maximum heat input is a nominal 275 MMBtu/hr (LHV).

At average annual site conditions with duct burner firing, Unit 3 will generate 566 MW. At summer peaking site conditions with duct burner firing and steam power augmentation, Unit 3 will generate 574 MW.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CC-1**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

N/A

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

5. Discharge Type Code: **V**	6. Stack Height: **121** feet	7. Exit Diameter: **16.8** feet
8. Exit Temperature: **186** °F	9. Actual Volumetric Flow Rate: **981,334** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

Stack temperature and flow rate are at 100 percent load, 65°F, evaporative cooling, and duct burner firing operating conditions (Case 6). Stack temperature and flow rate will vary with load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine generator fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.845**	5. Maximum Annual Rate: **16,162.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV).**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **HRSG duct burner fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **10100601**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.290**	5. Maximum Annual Rate: **2,540.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Maximum hourly rate (Field 4) based on nominal heat input of 275 MMBtu/hr (LHV) Maximum Annual Rate (Field 5) based on 8,760 hours per year. Fuel heat content (Field 9) represents lower heating value (LHV).**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	025		EL
2 – CO			EL
3 – PM			WP
4 – PM10			WP
5 – SO2			WP
6 – SAM			WP
7 – VOC			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **113.3** lb/hour **378.5** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **113.3 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**

8. Calculation of Emissions (limit to 600 characters):

Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 82.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 113.3 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions
Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year

5. Method of Compliance (limit to 60 characters):
NO_x CEMS

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
An annual, multi-unit NO_x emissions cap of 3,587 tpy is requested for Smith Units 1 and 3.

CTG is subject to NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). DB is subject to NO_x limits of 40 CFR Part 60, Subpart Da (NSPS).

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **116.6** lb/hour **350.7** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **116.6 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 75.4 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 116.6 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **13 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **58.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **23 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **116.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **16 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **78.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **21.5** lb/hour **91.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **21.5 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **21.5** lb/hour **91.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable for all CTG/HRSG operating modes.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 5, 5B, or 17 (Initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **40 CFR Part 60, §60.42a(a)(1), Subpart Da (NSPS); applicable to DB only.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **21.5** lb/hour **91.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **21.5 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **21.5** lb/hour **91.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable for all CTG/HRSG operating modes.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.7** lb/hour **52.3** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **12.7 lb/hr** Reference: **GE data**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **(2.0 gr S/100 ft^3 gas) x (2,223,100 ft^3 gas/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 12.7 lb/hr SO_2** **Annual emissions based on 11.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 12.4 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **55.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to DB only per 40 CFR Part 60, §60.43a(b)(2), NSPS.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.8 weight % S fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG only per 40 CFR Part 60, §60.333(b), NSPS.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.46** lb/hour **6.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.46 lb/hr** Reference: **GE data**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **(12.7 lb/hr SO_2) x (7.5/100) x (98 lb H_2SO_4/64 lb SO_2 = 1.46 lb/hr H_2SO_4** **Annual emissions based on 1.36 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 1.43 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.8** lb/hour **46.4** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **16.8 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 9.8 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 16.8 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **6.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **16.8** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **4 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **10.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Rule 62-212.400(5)(c), F.A.C. (BACT)**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Reference Method 9 (every 5 years)**	
5. Visible Emissions Comment (limit to 200 characters): **Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C. Applicant has requested up to 4 hours for cold startups and all shutdowns.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✓] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement:	[✓] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-5** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **Att. A-3** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Sect. 5.0** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities **To be provided** [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [✔] Attached, Document ID: **Att. A-4** [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

Above items previously submitted, see Smith Electric Generating Plant Title V permit application.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[✔] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

4. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one General Electric (GE) 7241 FA combustion turbine generator (CTG) having a nominal rating of 170 megawatts (MW) and one fired heat recovery steam generator (HRSG). The CTG/HRSG unit will be fired exclusively with pipeline quality natural gas.

4. Emissions Unit Identification Number: [ ] No ID
ID: **007 (CC-2)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[✔]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

6. Control Equipment/Method Description (Limit to 200 characters per device or method): **NO_x Controls** **Dry low-NO_x combustors**
2. Control Device or Method Code(s): **25 (dry low-NO_x)**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **PG7241(FA)**
2. Generator Nameplate Rating: **170** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,751 (LHV)** mmBtu/hr **(CTG only)**		
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	24 hours/day		**7** days/week
	52 weeks/year		**8,760** hours/year

7. Operating Capacity/Schedule Comment (limit to 200 characters):

CTG maximum heat input is lower heating value (LHV) at 100 percent load, 0°F operating conditions. Heat input will vary with load and ambient temperature.

HRSG duct burner maximum heat input is a nominal 275 MMBtu/hr (LHV).

At average annual site conditions with duct burner firing, Unit 3 will generate 566 MW. At summer peaking site conditions with duct burner firing and steam power augmentation, Unit 3 will generate 574 MW.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CC-2**	7. Emission Point Type Code: **1**

8. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

N/A

9. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

10. Discharge Type Code: **V**	6. Stack Height: **121** feet	7. Exit Diameter: **16.8** feet
8. Exit Temperature: **186** °F	9. Actual Volumetric Flow Rate: **981,334** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

Stack temperature and flow rate are at 100 percent load, 65°F, evaporative cooling, and duct burner firing operating conditions (Case 6). Stack temperature and flow rate will vary with load, ambient temperature, and use of optional evaporative cooling, duct burner firing, and steam power augmentation.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine generator fired with pipeline quality natural gas.**		
3. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
6. Maximum Hourly Rate: **1.845**	7. Maximum Annual Rate: **16,162.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	10. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV).**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **HRSG duct burner fired with pipeline quality natural gas.**		
3. Source Classification Code (SCC): **10100601**	3. SCC Units: **Million Cubic Feet Burned**	
6. Maximum Hourly Rate: **0.290**	7. Maximum Annual Rate: **2,540.4**	6. Estimated Annual Activity Factor:
11. Maximum % Sulfur:	12. Maximum % Ash:	13. Million Btu per SCC Unit: **950**
14. Segment Comment (limit to 200 characters): **Maximum hourly rate (Field 4) based on nominal heat input of 275 MMBtu/hr (LHV)** **Maximum Annual Rate (Field 5) based on 8,760 hours per year.** **Fuel heat content (Field 9) represents lower heating value (LHV).**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	025		EL
2 – CO			EL
3 – PM			WP
4 – PM10			WP
5 – SO2			WP
6 – SAM			WP
7 – VOC			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **113.3** lb/hour **378.5** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **113.3 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 82.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 113.3 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters): **NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **An annual, multi-unit NO_x emissions cap of 3,587 tpy is requested for Smith Units 1 and 3.** **CTG is subject to NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). DB is subject to NO_x limits of 40 CFR Part 60, Subpart Da (NSPS).**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **116.6** lb/hour **350.7** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **116.6 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 75.4 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 116.6 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **13 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **58.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
5. Requested Allowable Emissions and Units: **23 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **116.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
6. Requested Allowable Emissions and Units: **16 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **78.7** lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **21.5** lb/hour **91.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **21.5 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **21.5** lb/hour **91.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable for all CTG/HRSG operating modes.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Methods 5, 5B, or 17 (Initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **40 CFR Part 60, §60.42a(a)(1), Subpart Da (NSPS); applicable to DB only.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **21.5** lb/hour **91.8** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **21.5 lb/hr** Reference: **GE data**		7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 20.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 21.5 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **21.5** lb/hour **91.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable for all CTG/HRSG operating modes.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.7** lb/hour **52.3** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **12.7 lb/hr** Reference: **GE data**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

(2.0 gr S/100 ft^3 gas) x (2,223,100 ft^3 gas/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 12.7 lb/hr SO_2

Annual emissions based on 11.9 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 12.4 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **55.0** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
Fuel analysis for sulfur content

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Limit applicable to DB only per 40 CFR Part 60, §60.43a(b)(2), NSPS.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **0.8 weight % S fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG only per 40 CFR Part 60, §60.333(b), NSPS.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **1.46** lb/hour **6.0** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **1.46 lb/hr** Reference: **GE data**		7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

(12.7 lb/hr SO_2) x (7.5/100) x (98 lb H_2SO_4/64 lb SO_2 = 1.46 lb/hr H_2SO_4

Annual emissions based on 1.36 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 1.43 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year

5. Method of Compliance (limit to 60 characters):

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **16.8** lb/hour **46.4** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **16.8 lb/hr** Reference: **GE data**		7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11). Annual emissions based on 9.8 lb/hr (100 percent load, 65°F, evaporative cooling, duct burner firing [Case 6]) for 7,760 hrs/yr and 16.8 lb/hr (100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation [Case 11]) for 1,000 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions __1__ of __3__

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **3 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **6.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG/HRSG operations without duct burner firing or steam power augmentation.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
5. Requested Allowable Emissions and Units: **6 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **16.8** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG/HRSG operations at 100 percent load, 95°F, evaporative cooling, duct burner firing, and steam power augmentation (Case 11).**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
6. Requested Allowable Emissions and Units: **4 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **10.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25 (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Limit applicable to CTG/HRSG operations with duct burner firing and without steam augmentation.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

2. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
6. Method of Compliance: **EPA Reference Method 9**	
7. Visible Emissions Comment (limit to 200 characters): **Rule 62-212.400(5)(c), F.A.C. (BACT)**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

2. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
6. Method of Compliance: **EPA Reference Method 9 (every 5 years)**	
7. Visible Emissions Comment (limit to 200 characters): **Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C. Applicant has requested up to 4 hours for cold startups and all shutdowns.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

<u>**Continuous Monitoring System:**</u> Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.**	

<u>**Continuous Monitoring System:**</u> Continuous Monitor 2 of 2

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Subpart Da. Specific CEMS information will be provided to FDEP when available.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-5** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **Att. A-3** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Sect. 5.0** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities **To be provided** [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [✔] Attached, Document ID: Att. A-4 [ ] Not Applicable	
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable	
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable	
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable	
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable	

Above items previously submitted, see Smith Electric Generating Plant Title V permit application.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[✔] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Salt water cooling tower. Tower is equipped with drift eliminators for control of PM/PM_{10} emissions.

4. Emissions Unit Identification Number: [ ] No ID
ID: **008 (Cooling Tower)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Drift eliminators**
2. Control Device or Method Code(s): **15**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating: MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	mmBtu/hr			
2. Maximum Incineration Rate:	lb/hr		tons/day	
3. Maximum Process or Throughput Rate: **125,000 gal/min**				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum process rate (Field 3) is cooling tower water recirculation rate.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **TC-1 thru TC-10**	2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Cooling tower consists of ten cells.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **57** feet	7. Exit Diameter: **33.0** feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Cooling tower consists of 10 cells with 10 individual exhaust fans. Stack height and diameter provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperature.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Salt water cooling tower recirculation water flow rate.**		
2. Source Classification Code (SCC):	3. SCC Units: **Thousand gallons transferred**	
4. Maximum Hourly Rate: **7,500.0**	5. Maximum Annual Rate: **65,700,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ___ of ___

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – PM	**015**		**NS**
2 – PM10	**015**		**NS**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **18.2** lb/hour **79.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **18.2 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(125,000 gal/min) x (0.001 gal/100 gal) x (29,000 lb PM/10^6 lb water) x (8.345 lb/gal water) x (60 min/hr) = 18.15 lb/hr PM** **(18.15 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 79.5 ton/yr PM**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **18.2** lb/hour **79.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **18.2 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(125,000 gal/min) x (0.001 gal/100 gal) x (29,000 lb PM/10^6 lb water) x (8.345 lb/gal water) x (60 min/hr) = 18.15 lb/hr PM** **(18.15 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 79.5 ton/yr PM**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

<u>Allowable Emissions</u> Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

Visible Emissions Limitation: Visible Emissions Limitation ____of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION – Not Applicable
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
6. Continuous Monitor Comment (limit to 200 characters):	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-5** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: _______ [✔] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Sect. 5.0** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [✔] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

Above items previously submitted, see Smith Electric Generating Plant Title V permit application.

Rest of Application
PSD-FL-269
6-7-99

ATTACHMENT A-1

REGULATORY APPLICABILITY ANALYSES

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	§60.7		CC-1, CC-2 Gas Turbines Duct Burners	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CC-1, CC-2 Gas Turbines Duct Burners	Conduct performance tests as required by EPA or FDEP.
Compliance with Standards	§60.11		CC-1, CC-2 Gas Turbines Duct Burners	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CC-1, CC-2 Gas Turbines Duct Burners	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13		CC-1, CC-2 Gas Turbines Duct Burners	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CC-1, CC-2 Gas Turbines Duct Burners	General procedures regarding reporting deadlines.
Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978				
Standards for Particulate Matter	§60.42a(a) and (b)		CC-1, CC-2 Duct Burners	Establishes PM limit of 13 ng/J (0.03 lb/MMBtu). Opacity shall not be greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978 (continued)				
Standards for Sulfur Dioxide	§60.43a(b)(2)		CC-1, CC-2 Duct Burners	Establishes SO_2 limit of 86 ng/J (0.20 lb/MMBtu), 30-day rolling average.
Standards for Nitrogen Oxides	§60.44a(d)(1)		CC-1, CC-2 Duct Burners	For sources which commence construction after July 9, 1997, establishes NO_x limit of 1.6 lb/MWh, 30-day rolling average.
Compliance Provisions	§60.46a, all except (d)		CC-1, CC-2 Duct Burners	Describes compliance provisions for PM, SO_2, and NO_x standards. Paragraph (d) applies to FGD systems.
Emission Monitoring	§60.47a, all except (a) and (b)		CC-1, CC-2 Duct Burners	Continuous emissions monitoring requirements. NO_x CEM required. Continuous emissions monitoring of opacity [Paragraph (a)] and SO_2 [Paragraph (b)]is not required where gaseous fuel is the only fuel combusted.
Compliance Determination Procedures and Methods	§60.48a (a) and (f)		CC-1, CC-2 Duct Burners	Initial performance testing requirements for electric utility combined cycle gas turbines.
Reporting Requirements	§60.49a		CC-1, CC-2 Duct Burners	Periodic reporting requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	§60.332(a)(1) and (3), (b), and (f)		CC-1, CC-2 Gas Turbines	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		CC-1, CC-2 Gas Turbines	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.
Monitoring Requirements	§60.334(a)	X		Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ±5.0 percent. Applicable only to CTGs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CC-1, CC-2 Gas Turbines	Requires daily monitoring of fuel sulfur and nitrogen content unless custom schedule requested and approved. Defines excess emissions
Test Methods and Procedures	§60.335		CC-1, CC-2 Gas Turbines	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to Smith Unit 3.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, II, JJ, KK, LL, OO, PP, QQ, RR, VV, EEE, GGG, III, and JJJ		X		None of the listed NESHAPS' contain requirements which are applicable to the Smith Unit 3 CTGs.
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CC-1, CC-2	General Acid Rain Program requirements.
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		CC-1, CC-2	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CC-1, CC-2	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. **(future requirement).**

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Acid Rain permit information requirements	§72.31		CC-1, CC-2	Lists information required for Acid Rain permit applications.
Permit Application Shield	§72.32		CC-1, CC-2	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CC-1, CC-2	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to Smith Unit 3.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CC-1, CC-2	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
General Permit Revision Procedures Including Fast-Track Modifications	§72.80, §72.81, §72.82(a) and (c), §72.83, and §72.84		CC-1, CC-2	Procedures for permit revisions including fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CC-1, CC-2	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CC-1, CC-2	General monitoring prohibitions.
Subpart B - Monitoring Provisions				

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Operating Requirements	§75.10		CC-1, CC-2	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CC-1, CC-2	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CC-1, CC-2	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CC-1, CC-2	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(c)		CC-1, CC-2	Opacity continuous monitoring exemption for gas-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CC-1, CC-2	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CC-1, CC-2	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CC-1, CC-2	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CC-1, CC-2	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CC-1, CC-2	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		CC-1, CC-2	General missing data requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CC-1, CC-2	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CC-1, CC-2	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CC-1, CC-2	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CC-1, CC-2	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CC-1, CC-2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CC-1, CC-2	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CC-1, CC-2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CC-1, CC-2	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CC-1, CC-2	General reporting requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CC-1, CC-2	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Monitoring Plan	§75.62		CC-1, CC-2	Requires submittal of a monitoring plan no later than 45 days prior to the first scheduled certification test.
Recertification Application	§75.63		CC-1, CC-2	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CC-1, CC-2	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CC-1, CC-2	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CC-1, CC-2	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CC-1, CC-2	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 78 - Appeals Procedures				
Appeals Procedures for Acid Rain Program	§78		CC-1, CC-2	General Acid Rain Program appeals procedures. **(potential future requirement)**
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		Smith Unit 3 will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Gulf personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Gulf will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Smith Unit 3 will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Gulf personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Gulf personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		Gulf personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Compliance Assurance Monitoring		X		Program only applies to emission units which are equipped with control devices, excluding inherent process equipment.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 57, 58, 59, 66, 67, 68, 69, 71, 73, 76, 77, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 95, and 96		X		The listed regulations do not contain any requirements which are applicable to Smith Unit 3.

Source: ECT, 1999.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	**62-4.030, F.A.C[1]**		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	**62-4.040, F.A.C[1]**		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	**62-4.050, F.A.C.[1]**		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to Smith Unit 3.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial construction permit. Modification of permit conditions is not being requested.
Renewals	**62-4.090, F.A.C.[1]**		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.-430(3), F.A.C. **(future requirement)**
Suspension and Revocation	**62-4.100, F.A.C.[1]**		X		Establishes permit suspension and revocation criteria.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	**62-4.130, F.A.C.**[1]		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Review	62-4.150, F.A.C.	X			Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.	X			Contains no applicable requirements.
Scope of Part II	62-4.200, F.A.C.	X			Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits. **(future requirement)**
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting				Unit 3	Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	**62-204.800(7)(a), (b)2. and 39., (c), (d), and (e), F.A.C.[1]**			CC1, CC-2	NSPS Subpart Da and GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.			CC1, CC-2	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	**62-204.800(21), F.A.C.[1]**		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required	62-210.300(1) and (3), F.A.C.		X		Air construction permit required. Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required. **(future requirement)**
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to Smith Unit 3.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement)**
Public Notice and Comment Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.		X		Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants **(future requirement)**.
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to Smith Unit 3.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports					
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. **(future requirement)**.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.			Units with control equipment	An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration. **Excess emissions for more than two hours in a 24 hour period are specifically requested for Smith Unit 3. See Section 2.2 of the PSD permit application for details.**
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to Smith Unit 3.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited. **(potential future requirement)**.
Excess Emissions	62-210.700(5), F.A.C.	X			Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. **(potential future requirement)**.
Forms and Instructions	62-210.900(5), F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.		X		General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit required prior to construction of Smith Unit 3.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Smith Unit 3 is not located in a nonattainment area or a nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to Smith Unit 3.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), and (4), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implement-ed pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CC1, CC-2	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.		X		Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900(1), F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	§62-214.300, F.A.C.		X		Smith Unit 3 includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CC1, CC-2	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CC1, CC-2	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			CC1, CC-2	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	§62-214.370, F.A.C.			CC1, CC-2	Defines revision procedures and automatic amendments **(potential future requirement)**..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CC1, CC-2	Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning
Open Burning allowed	**62-256.700, F.A.C.**[1]		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	**62-256.800, F.A.C.**[1]	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to Smith Unit 3.
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	**62-296.320(2), F.A.C.**[1]		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.**[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Smith Unit 3 does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to Smith Unit 3.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Smith Unit 3 is not located in an ozone nonattainment area or an ozone air quality maintenance area.
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Smith Unit 3 is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm. Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Smith Unit 3 is not located in a lead non-attainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Smith Unit 3 is not located in a PM non-attainment area or a PM air quality maintenance area.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
General Compliance Test Requirements	62-297.310, F.A.C.			CC-1, CC-2	Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to Smith Unit 3.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

[1] - State requirement only; not federally enforceable.

Source: ECT, 1999.

ATTACHMENT A-2

II.E.4—PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from Smith Unit 3 operations include:

- Vehicular traffic on paved and unpaved roads.
- Wind-blown dust from yard areas.
- Periodic abrasive blasting.

The following techniques may be used to control unconfined particulate matter emissions on an as-needed basis:

- Chemical or water application to:
  - Unpaved roads
  - Unpaved yard areas
- Paving and maintenance of roads, parking areas, and yards.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary.

ATTACHMENT A-3

III.L.2—FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.061
Propane	0.890
I-butane	0.189
N-butane	0.168
I-pentane	0.038
N-pentane	0.026
Nitrogen	0.527
Methane	93.813
CO_2	1.024
Ethane	3.2820
Other Characteristics	
Heat content (HHV)	1,050 Btu/ft^3 at 14.73 psia, dry
Real specific gravity	0.5999
Sulfur content (maximum)	2.0 gr/100 scf

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

Source: Koch, 1999.
Gulf, 1999.

ATTACHMENT A-4

ALTERNATE METHODS OF OPERATION

Gulf Power – Smith Unit 3
Alternate Methods of Operation

Emission Source	Method No.	Evaporative Cooling	Duct Burner Firing	Steam Power Augmentation	Annual Operating Hours (Hrs/Yr)
CC/HRSG-1, 2	1				8,760
	2	X			8,760
	3		X		8,760
	4	X	X		8,760
	5	X	X	X	1,000

Source: Gulf, 1999.

ATTACHMENT B—

CTG VENDOR INFORMATION

Southern Company
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,869	20,869	20,869
Fuel Temperature	Deg F	80	80	80
Output	kW	189,300.	142,000.	94,700.
Heat Rate (LHV)	Btu/kWh	9,250.	9,920.	11,850.
Heat Cons. (LHV) X 10^6	Btu/h	1,751.	1,408.6	1,122.2
Exhaust Flow X 10^3	lb/h	3867.	3079.	2515.
Exhaust Temp.	Deg F.	1071.	1106.	1155.
Exhaust Heat (LHV) X 10^6	Btu/h	1054.7	882.9	765.0

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	64.	51.	40.
CO	ppmvd	15.	15.	15.
CO	lb/h	53.	42.	34.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
Particulates	lb/h	9.	9.	9.

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.89	0.91
Nitrogen	75.09	75.09	75.19
Oxygen	12.58	12.58	12.87
Carbon Dioxide	3.88	3.89	3.75
Water	7.55	7.55	7.29

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.04
Exhaust Loss	in Water	16.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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Southern Company
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Inlet Loss	in. H2O	4.	4.	4.
Exhaust Loss	in. H2O	16.5	16.5	16.5
Ambient Temp.	Deg F.	65.	65.	65.
Evap. Cooler Status		On	Off	Off
Evap. Cooler Effectiveness	%	85		
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,869	20,869	20,869
Fuel Temperature	Deg F	80	80	80
Output	kW	172,400.	129,300.	86,200.
Heat Rate (LHV)	Btu/kWh	9,320.	10,090.	12,130.
Heat Cons. (LHV) X 10^6	Btu/h	1,606.8	1,304.6	1,045.6
Exhaust Flow X 10^3	lb/h	3524.	2894.	2390.
Exhaust Temp.	Deg F.	1122.	1148.	1192.
Exhaust Heat (LHV) X 10^6	Btu/h	972.2	825.1	719.6

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	38.
CO	ppmvd	15.	15.	15.
CO	lb/h	48.	39.	32.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
Particulates	lb/h	9.	9.	9.

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.89	0.89
Nitrogen	74.03	74.26	74.37
Oxygen	12.29	12.50	12.81
Carbon Dioxide	3.89	3.81	3.67
Water	8.91	8.54	8.26

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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Southern Company

ESTIMATED PERFORMANCE PG7241(FA) 100% upgrd 75% 50%

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Evap. Cooler Status		On	Off	Off
Evap. Cooler Effectiveness	%	85		
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,869	20,869	20,869
Fuel Temperature	Deg F	80	80	80
Output	kW	159,000.	119,300.	79,500.
Heat Rate (LHV)	Btu/kWh	9,550.	10,400.	12,510.
Heat Cons. (LHV) X 10^6	Btu/h	1,518.5	1,240.7	994.5
Exhaust Flow X 10^3	lb/h	3353.	2787.	2326.
Exhaust Temp.	Deg F.	1140.	1169.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	931.9	796.9	692.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	56.	45.	36.
CO	ppmvd	15.	15.	15.
CO	lb/h	45.	37.	31.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
Particulates	lb/h	9.	9.	9.

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.87	0.89
Nitrogen	72.91	73.37	73.50
Oxygen	12.08	12.39	12.77
Carbon Dioxide	3.84	3.75	3.57
Water	10.31	9.62	9.28

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Inlet Loss	in Water	4.04
Exhaust Loss	in Water	16.5
Relative Humidity	%	45
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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Southern Company
ESTIMATED PERFORMANCE PG7241(FA) 100% w/PA

Load Condition		BASE
Inlet Loss	in. H2O	4.
Exhaust Loss	in. H2O	16.5
Ambient Temp.	Deg F.	95.
Evap. Cooler Status		On
Evap. Cooler Effectiveness	%	85
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,869
Fuel Temperature	Deg F	80
Output	kW	175,300.
Heat Rate (LHV)	Btu/kWh	9,150.
Heat Cons. (LHV) X 10^6	Btu/h	1,604.
Exhaust Flow X 10^3	lb/h	3471.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	975.7
Steam Flow	lb/h	113,450.

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	79
CO	ppmvd	15.
CO	lb/h	45.
UHC	ppmvw	7.
UHC	lb/h	14.
Particulates	lb/h	9.

EXHAUST ANALYSIS % VOL.

Argon	0.82
Nitrogen	69.06
Oxygen	11.04
Carbon Dioxide	3.84
Water	15.24

SITE CONDITIONS

Elevation	ft.	96.0
Site Pressure	psia	14.65
Relative Humidity	%	45
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(a)(1)(i). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

ATTACHMENT C—

EMISSION RATE CALCULATIONS

Table C-1. Plant Smith Unit 3
CTG Operating Scenarios

Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Steam Power Augmentation	Duct Burner Firing
1	0	100	X	X			
2	0	100	X	X			X
3	0	75	X	X			
4	0	50	X	X			
5	65	100	X	X	X		
6	65	100	X	X	X		X
7	65	75	X	X			
8	65	50	X	X			
9	95	100	X	X	X		
10	95	100	X	X	X	X	
11	95	100	X	X	X	X	X
12	95	100	X	X	X		X
13	95	75	X	X			
14	95	50	X	X			

Sources: ECT, 1999.
Gulf Power, 1999.

Table C-2. Plant Smith Unit 3
CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Temp. (^{o}F)	Case	Load (%)	PM_{10}[1] (lb/hr)	PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
0	1	100	19.8	2.495	11.6	1.461	1.33	0.168	0.00077	0.00010
	2	100	20.8	2.620	12.7	1.600	1.46	0.184	0.00084	0.00011
	3	75	19.8	2.495	9.3	1.175	1.07	0.135	0.00062	0.00008
	4	50	19.8	2.495	7.4	0.936	0.85	0.108	0.00049	0.00006
65	5	100	19.8	2.495	10.6	1.341	1.22	0.154	0.00070	0.00009
	6	100	20.9	2.633	11.9	1.495	1.36	0.172	0.00078	0.00010
	7	75	19.8	2.495	8.6	1.089	0.99	0.125	0.00057	0.00007
	8	50	19.8	2.495	6.9	0.873	0.80	0.100	0.00046	0.00006
95	9	100	19.8	2.495	10.1	1.267	1.15	0.146	0.00066	0.00008
	10	100	19.8	2.495	10.6	1.338	1.22	0.154	0.00070	0.00009
	11	100	21.5	2.703	12.4	1.566	1.43	0.180	0.00082	0.00010
	12	100	21.0	2.647	11.9	1.501	1.37	0.172	0.00079	0.00010
	13	75	19.8	2.495	8.2	1.035	0.94	0.119	0.00054	0.00007
	14	50	19.8	2.495	6.6	0.830	0.76	0.095	0.00043	0.00005
		Maximums	**21.5**	**2.703**	**12.7**	**1.600**	**1.46**	**0.184**	**0.00084**	**0.00011**

Temp. (^{o}F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)	VOC (g/sec)
0	1	100	9.0	70.4	8.870	12.1	58.3	7.346	2.50	6.6	0.832
	2	100	10.1	78.7	9.910	15.0	78.7	9.910	3.40	10.2	1.289
	3	75	9.0	56.1	7.069	12.1	46.2	5.821	2.50	5.2	0.660
	4	50	9.0	44.0	5.544	12.6	37.4	4.712	2.59	4.4	0.550
65	5	100	9.0	64.9	8.177	11.9	52.8	6.653	2.50	6.2	0.776
	6	100	10.4	82.9	10.460	15.5	75.4	9.494	3.50	9.8	1.234
	7	75	9.0	51.7	6.514	12.2	42.9	5.405	2.55	5.2	0.651
	8	50	9.0	41.8	5.267	12.8	35.2	4.435	2.65	4.4	0.549
95	9	100	9.0	61.6	7.762	11.9	49.5	6.237	2.40	5.7	0.721
	10	100	9.0	86.9	10.949	11.2	49.5	6.237	2.53	5.0	0.632
	11	100	13.6	113.3	14.276	22.9	116.6	14.692	5.80	16.8	2.121
	12	100	10.6	80.6	10.159	15.8	73.3	9.231	3.60	9.6	1.206
	13	75	9.0	49.5	6.237	12.3	40.7	5.128	2.60	4.2	0.529
	14	50	9.0	39.6	4.990	13.0	34.1	4.297	2.73	5.0	0.632
		Maximums	**13.6**	**113.3**	**14.276**	**22.9**	**116.6**	**14.692**	**5.80**	**16.8**	**2.121**

[1] Excludes sulfuric acid mist.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Based on EPA Electric Utility HAP emission factor of 3.70 x 10^{-1} lb/10^{12} Btu and natural gas heat content of 1,020 Btu/ft^3.
[5] Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-3. Plant Smith Unit 3
CTG/HRSG Annual Emission Rates
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates NO$_x$ (lb/hr)	NO$_x$ (tpy)	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)
CTG/HRSG1,2	6	2	7,760	165.9	643.6	150.70	584.7	19.6	76.0
CTG/HRSG1,2	11	2	1,000	226.6	113.3	233.2	116.6	33.7	16.8
			Totals	**N/A**	**756.9**	**N/A**	**701.3**	**N/A**	**92.8**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates PM/PM$_{10}$ (lb/hr)	PM/PM$_{10}$ (tpy)	SO$_2$ (lb/hr)	SO$_2$ (tpy)	Lead (lb/hr)	Lead (tpy)	H$_2$SO$_4$ (lb/hr)	H$_2$SO$_4$ (tpy)
CTG/HRSG1,2	6	2	7,760	41.8	162.2	23.7	92.1	0.0016	0.00000	2.7	10.6
CTG/HRSG1,2	11	2	1,000	42.9	21.5	24.9	12.4	0.0016	0.00001	2.9	1.4
			Totals	**N/A**	**183.6**	**N/A**	**104.5**	**N/A**	**0.00001**	**N/A**	**12.0**

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-4. Plant Smith Unit 3
CTG/HRSG Exhaust Flow Rates (Per CTG/HRSG)

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole)	Exhaust Gas Composition - Volume % 100 % Load								75 % Load			50 % Load		
		0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	59 °F	95 °F
	Case	1	2	5	6	9	10	11	12	3	7	13	4	8	14
Ar	39.944	0.90	0.90	0.88	0.88	0.87	0.82	0.81	0.87	0.89	0.89	0.87	0.91	0.89	0.89
N_2	28.013	75.09	74.82	74.03	73.70	72.91	69.06	68.61	72.54	75.09	74.26	73.37	75.19	74.37	73.50
O_2	31.999	12.58	11.80	12.29	11.35	12.08	11.04	9.68	11.03	12.58	12.50	12.39	12.87	12.81	12.77
CO_2	44.010	3.88	4.23	3.89	4.31	3.84	3.84	4.46	4.32	3.89	3.81	3.75	3.75	3.67	3.57
H_2O	18.015	7.55	8.25	8.91	9.75	10.31	15.24	16.43	11.25	7.55	8.54	9.62	7.29	8.26	9.28
	Totals	100.00	100.00	100.00	100.00	100.01	100.00	100.00	100.00	100.00	100.00	100.00	100.01	100.00	100.01
Exhaust MW (lb/mole)		28.49	28.44	28.34	28.29	28.18	27.64	27.57	28.12	28.49	28.37	28.25	28.51	28.39	28.27
Exhaust Flow (lb/sec)		1,074.17	1,076.39	978.89	981.25	931.39	964.17	968.06	935.14	855.28	803.89	774.17	698.61	663.89	646.11
Exhaust Temp. (°F)		192	190	188	186	175	170	170	183	170	166	180	159	155	173
(K)		362	361	360	359	353	350	350	357	350	348	355	344	341	351
Ambient Temp. (°F)		0	0	65	65	95	95	95	95	0	65	95	0	65	95
(K)		255	255	291	291	308	308	308	308	255	291	308	255	291	308
Exhaust O_2 (Vol %, Dry)		13.61	12.86	13.49	12.58	13.47	13.03	11.58	12.43	13.61	13.67	13.71	13.88	13.96	14.08

B. Exhaust Flow Rates

	100 % Load								75 % Load			50 % Load		
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	59 °F	95 °F
Case	1	2	5	6	9	10	11	12	3	7	13	4	8	14
ACFM	1,076,530	1,077,167	980,124	981,334	918,862	962,248	968,750	936,283	828,210	776,637	768,024	664,209	629,708	633,397
Velocity (fps)	81.4	81.5	74.1	74.2	69.5	72.8	73.3	70.8	62.6	58.7	58.1	50.2	47.6	47.9
Velocity (m/s)	24.8	24.8	22.6	22.6	21.2	22.2	22.3	21.6	19.1	17.9	17.7	15.3	14.5	14.6
SCFM, Dry[1]	805,875	802,674	727,378	723,767	685,187	683,482	678,430	682,268	641,648	599,054	572,603	525,212	495,928	479,253

[1] At 68 °F.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-4. Plant Smith Unit 3
CTG/HRSG Exhaust Data (Per CTG/HRSG)

C. Correction of VOC Concentrations to 15% O_2, dry

	100 % Load								75 % Load			50 % Load		
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	59 °F	95 °F
Case	1	2	5	6	9	10	11	12	3	7	13	4	8	14
VOC ($ppmv_w$)	2.86	4.25	2.86	4.46	2.71	2.86	7.65	4.59	2.86	2.86	2.86	2.86	2.86	2.86
VOC ($ppmv_d$)	3.09	4.63	3.14	4.94	3.02	3.37	9.16	5.17	3.09	3.13	3.16	3.08	3.12	3.15
VOC (15% O_2)	2.50	3.40	2.50	3.50	2.40	2.53	5.80	3.60	2.50	2.55	2.60	2.59	2.65	2.73

D. Correction of CO Concentrations to 15% O_2, dry

	100 % Load								75 % Load			50 % Load		
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	59 °F	95 °F
Case	1	2	5	6	9	10	11	12	3	7	13	4	8	14
CO ($ppmv_d$)	15.00	20.43	15.00	21.86	15.00	15.00	36.16	22.69	15.00	15.00	15.00	15.00	15.00	15.00
CO (15% O_2)	12.14	15.00	11.95	15.50	11.91	11.24	22.90	15.80	12.14	12.24	12.31	12.61	12.76	12.97

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-5. Plant Smith Unit 3

Natural Gas Fuel Flow Rates; Per CTG/HRSG Unit

	100 % Load								75 % Load			50 % Load		
	0 °F	0 °F	65 °F	65 °F	95 °F	95 °F	95 °F	95 °F	0 °F	65 °F	95 °F	0 °F	65 °F	95 °F
Case	1	2	5	6	9	10	11	12	3	7	13	4	8	14
Heat Input - LHV (MMBtu/hr)	1,751.0	1,917.9	1,606.8	1,791.4	1,518.5	1,604.0	1,876.9	1,798.4	1,408.6	1,304.6	1,240.7	1,122.2	1,045.6	994.5
Fuel Rate[1] (lb/hr)	83,904	91,902	76,995	85,841	72,763	76,860	89,935	86,176	67,497	62,514	59,452	53,774	50,103	47,654
Fuel Rate (lb/sec)	23.307	25.528	21.387	23.845	20.212	21.350	24.982	23.938	18.749	17.365	16.514	14.937	13.918	13.237
Fuel Rate[2] (10^6 ft^3/hr)	1.845	2.021	1.693	1.887	1.600	1.690	1.977	1.895	1.484	1.375	1.307	1.182	1.102	1.048

[1] Based on natural gas heat content of 20,869 Btu/lb (LHV).
[2] Based on natural gas density of 0.04548 lb/ft^3.

Sources: ECT, 1999.
GE, 1999.
Gulf Power, 1999.

Table C-6. Plant Smith Unit 3
CTG NSPS Subpart GG Limit (Per CTG)

Fuel	PG7241FA Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,150	9.654	0.0	111.9

Sources: ECT, 1999.
GE, 1999.

COOLING TOWER EMISSION RATE ESTIMATES

Particulate matter (PM/PM_{10}) emissions from the induced draft mechanical cooling tower were estimated using procedures found in AP42, Section 13.4, Wet Cooling Towers.

A. Cooling Tower Data

Total Liquid Drift = 0.001% of recirculation water flow rate
Total Liquid Drift = 0.001 gal / 100 gal recirculation water flow rate

Recirculation Water Flow Rate = 125,000 gal/min

Recirculation Water Total Dissolved Solids (TDS) = 29,000 ppmw

B. PM/PM_{10} Emission Rate Calculations

$$PM/PM_{10} = (125{,}000 \text{ gal/min}) \times (0.001 \text{ gal} / 100 \text{ gal}) \times (8.345 \text{ lb} / \text{gal water}) \times (29{,}000 \text{ lb } PM/PM_{10} / 10^6 \text{ lb water}) \times (60 \text{ min/hr})$$

PM/PM_{10} = 18.15 lb/hr

PM/PM_{10} = 79.5 ton/yr (8,760 hours/year operation)

ATTACHMENT D—

NO_x NETTING ANALYSIS

Gulf Power Plant Smith Unit 3
NO_x Netting Analysis

A. Unit 1 Baseline NO_x Emissions

Year	Fuel Usage Coal (ton/yr)	Fuel Usage Oil (gal/yr)	Fuel Heat Content Coal (Btu/lb)	Fuel Heat Content Oil (Btu/gal)	Total Heat Input (10^6 Btu/yr)	CEMS NO_x Emission Rate (lb/10^6 Btu)	NO_x Emission Rate (ton/yr)
1996[a]	520,766.0	65,900	11,775	138,500	12,273,166	0.614	3,767.9
1998	522,256.5	70,760	11,765	138,480	12,298,494	0.557	3,425.1
2-Yr Average	521,511.3	68,330	11,770	138,490	12,285,830	0.586	3,596.5

B. Unit 3 NO_x Emissions (Two CTG/HRSG Units)

Operating Case	NO_x Emissions (lb/hr)	Operations (hr/yr)	NO_x Emissions (ton/yr)
6[b]	165.9	7,760	643.6
11[c]	226.6	1,000	113.3
Totals	N/A	8,760	756.9

C. Net Change in NO_x Emissions

Emission Source	'96, '98 Baseline (ton/yr) [lb/10^6 Btu]	Following Unit 3 Installation (ton/yr) [lb/10^6 Btu][d]	Emission Rate Change (ton/yr)
Unit 1	3,596.5 [0.586]	2,830.4 [0.461]	-766.1
Unit 3	0.0	756.9	756.9
		Net Change	-9.1
Annual Cap for Unit 1 and Unit 3[e]		**3,587.4**	

Notes:

a - 1997 not used for averaging purposes due to 37 day outage occurring during 1997 per agreement with Clair Fancy/Al Linero (FDEP Division of Air Resources Management) on 1/25/99.
b - Base load, 65 °F, evaporative cooling, duct burner firing.
c - Base load, 95 °F, evaporative cooling, duct burner firing, and steam power augmentation.
d - Based on installation of low-NO_x burners and improved burner management system.
e - A federally enforceable annual NO_x emissions cap of 3,587 tpy for Unit 1 and Unit 3 is requested.

Sources: Gulf, 1999.
ECT, 1999.

June 3, 1999

SOUTHERN COMPANY
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Estimates of Changes in CO, VOC, and Particulate Emissions From Low NOx Firing at Gulf Power's Lansing Smith Unit 1

A substantial amount of information has been published regarding possible changes in emissions from coal-fired utility boilers resulting from the installation of low NOx combustion modifications. Some of the best information available was developed at Gulf Power's Plant Smith Unit 2, during the U. S. DOE's Clean Coal Project (CCP). The information developed during that program, along with other relevant published information, is discussed in the following paragraphs.

Carbon Monoxide (CO) – Data taken at the Smith Unit 2 CCP demonstration indicated that the CO emissions, starting at 10 to 15 ppm for the original burners, were slightly decreased (10 ppm) with the NOx burner modifications that closely match those proposed for Smith Unit 1[1].

Volatile Organic Compounds (VOC) – VOC's, like CO, are the result of incomplete combustion of the coal. Because of this relationship, normally VOC and CO emissions will track, with CO rising to several hundred ppm before significant VOC's appear. A study of air toxics was preformed as part of the Smith Unit 2 CCP[2]. In this report, all but one of the 19 identified compounds in the volatile organic sampling train (VOST) were lower in the low NOx firing test than in the baseline testing, with 10 of the 19 compounds not detected in the low NOx testing. (Even though the authors speculate that the baseline test samples may have been contaminated, most of the compounds were not detected in the low NOx firing case.) As further evidence of minimal impact from these burner changes, EPRI's Emission Factor Handbook[3] makes no distinction between uncontrolled and low NOx firing for coal-fired boilers when estimating organic emissions. In summary, no changes are expected in the already low emissions of VOC's as a result of installing low NOx burner tips at Smith Unit 1.

Particulate Emissions – After the numerous low NOx modifications made to coal-fired boilers in the Southern Company electric system, the only impact on particulate emissions that has been seen is due to increased unburned carbon in the fly ash. This added carbon load, because it is not collected as efficiently as fly ash, can lead to increased mass emissions if the existing ESP is marginal. However, after the utility industry discovered these initial problems with unburned carbon, it was recognized that pulverizer performance can control the top coal particle size, and therefore the unburned carbon, and these problems have been mostly resolved. Even though the study of Smith Unit 2 described previously[2] found a slight increase in ESP outlet mass emissions from the base case to the most extreme low NOx test case, it is expected that the new low NOx burner modifications at Smith Unit 1 will not cause any measurable increase in particulate emissions. The reason for this assertion is that the low NOx retrofit proposed uses a more advanced burner tip, without resorting to the extreme air staging that seems to cause the increase in unburned carbon in fly ash.

Larry S. Monroe

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References

[1]R. R. Hardman, L. L. Smith, and S. Tavoulareas, "Results from the ICCT T-Fired Demonstration Project Including the Effect of Coal Fineness on NOx Emissions and Unburned Carbon Levels," presented at the EPRI/EPA 1993 Joint Symposium on Stationary Combustion NOx Control, Miami Beach, Florida, May 1993.

[2]E. B. Dismukes, **Measurement of Chemical Emissions Under the Influence of Low NOx Combustion Modifications**, Final Report to Southern Company Service, Inc., Contract C-91-000017, October 1993.

[3]**Emissions Factors Handbook: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Plant**, EPRI, Palo Alto, CA, TR-105611, November 1995.

TOTAL P.03

APPENDIX E—

DISPERSION MODELING FILES

(One set of diskettes provided to FDEP)

APPENDIX 10.2.8

FEDERAL AVIATION

ADMINISTRATION APPLICATION

10.2.8

FAA Stack Height Application

will be Submitted Later