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HARDEE COUNTY GENERATION FACILITY
AIR CONSTRUCTION
PERMIT APPLICATION

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BUREAU OF AIR REGULATION

Prepared for:

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January 2000

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued, Page 2 of 3)

TABLE OF CONTENTS
(Continued, Page 3 of 3)

LIST OF TABLES

LIST OF TABLES
(Continued, Page 2 of 5)

LIST OF TABLES
(Continued, Page 3 of 5)

LIST OF TABLES
(Continued, Page 4 of 5)

LIST OF TABLES
(Continued, Page 5 of 5)

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Granite Power Partners II, L.P. (GPP), is planning to construct and operate three simple-cycle combustion turbine generators (CTGs) at a site located in Hardee County, Florida. The proposed power plant, called the Hardee County Generation Facility (HCGF), will be situated approximately 5 miles west of Wachula near the intersection of Vandolah Road and Fort Green Ona Road, adjacent to the existing Vandolah Substation. Selection of the particular CTGs that will be installed at the HCGF has not been finalized. The specific CTGs under consideration, and for which permit approval is requested, include nominal 170-megawatt (MW) General Electric (GE) 7FA units, nominal 170-MW Siemens Westinghouse 501F units, nominal 120-MW Siemens Westinghouse 501D5A units, and nominal 180-MW ABB Power Generation GT-24 units. The HCGF simple-cycle CTGs will be fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source.

Compared to baseload operations, CTG air exhaust emission levels can increase at low-load conditions. HCGF emissions associated with low-load operation will be mitigated by operating the CTGs at loads no lower than 50 percent, excluding periods of startups, shutdowns, and malfunctions. The simple-cycle CTGs will each operate a total of 3,000 hours per year (hr/yr) at baseload operation for natural gas and oil firing, with a maximum of 500 hr/yr for oil firing. Part load operation will be conducted for the Siemens Westinghouse and ABB Power Generation units at partial loads as low as 50 percent for no greater than 500 hr/yr while natural gas firing.

Operation of the proposed project will result in airborne emissions. 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 GPP's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, *et seq.*, F.A.C.

The HCGF will be located in an area classified as attainment for all criteria pollutents and will have potential emissions of a regulated pollutant in excess of 250 tons per year (tpy). Accordingly, the HCGF is classified as a new major source and is subject to the prevention of significant deterioration (PSD) new source review (NSR) requirements of Section 62-212.400, F.A.C. Therefore, this report and application are 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 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 the HCGF and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 lists the references used in preparing the report.

Appendices A through D provide the FDEP Application for Air Permit—Long Form, CTG vendor emissions data, control system vendor quote, and emission rate calculations, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in diskette format in Appendix E.

1.2 SUMMARY

The HCGF will consist of three simple-cycle CTGs. The CTGs will be fired primarily with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per 100 standard cubic feet (gr S/100 scf). Low sulfur (containing no more than 0.05 weight percent sulfur [wt%S]) will serve as a back-up fuel source.

The planned construction start date for the HCGF is 4th quarter 2000. The projected date for the facility to begin commercial operation is 4th quarter 2001, following initial equipment start-up and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios for all CTGs under consideration, the HCGF will have the potential to emit 946 tpy of nitrogen oxides (NO_x), 515 tpy of carbon monoxide (CO), 125 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM/PM_{10}), 108 tpy of sulfur dioxide (SO_2), and 73 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, the HCGF will potentially emit 14.0 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of heavy metals and organic compounds associated with distillate fuel oil combustion. Based on these annual emission rate potentials, NO_x, CO, PM/PM_{10}, SO_2, VOCs, 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 will use the latest commercially proven burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emission rates and will be fired with pipeline-quality natural gas and low-sulfur, low-ash distillate fuel oil.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO. At baseload operation during natural gas and distillate fuel oil firing, the CT CO exhaust concentrations are projected to be 12 and 23 parts per million by dry volume (ppmvd), respectively, for the GE 7FA units. For the Siemens Westing-

house 501F units, CT CO exhaust concentrations are projected to be 16 and 20 ppmvd, respectively, during natural gas and distillate fuel oil firing at baseload operations. For the Siemens Westinghouse 501D5A units, CT CO exhaust concentrations are projected to be 10 and 28 ppmvd, respectively, during natural gas and distillate fuel oil firing at baseload operations. At baseload operation during natural gas and distillate fuel oil firing, CT CO exhaust concentrations are projected to be 6 and 25 ppmvd, respectively, for the ABB GT-24 units. These concentrations are consistent with prior FDEP BACT determinations for CTGs. The cost effectiveness of CO oxidation catalyst control systems was determined to be $3,312 per ton of CO controlled. Because this cost exceeds levels previously determined by FDEP to be cost effective, installation of a CO oxidation catalyst control system is considered economically unreasonable.

- BACT for SO_2 and H_2SO_4 mist will be achieved through the use of low-sulfur, pipeline-quality natural gas containing no more than 2.0 gr S/100 scf and distillate fuel oil containing no more than 0.05 wt%S.
- Dry low-NO_x (DLN) burner technology is proposed as BACT for NO_x for the HCGF CTGs during natural gas firing. For all normal operating loads, the CT NO_x exhaust concentration will not exceed 10.5 ppmvd, corrected to 15-percent oxygen for the GE 7FA units. For the Siemens Westinghouse 501F and 501D5A units, the CT NO_x exhaust concentration will not exceed 15 ppmvd, corrected to 15-percent oxygen for all normal operating loads. For all normal operating loads, the CT NO_x exhaust concentration will not exceed 25 ppmvd, corrected to 15-percent oxygen for the ABB GT-24 units. These concentrations are consistent with prior FDEP BACT determinations for simple cycle CTGs fired with natural gas.
- During distillate fuel oil firing, wet injection will be employed to reduce the CT NO_x exhaust concentration to 42 ppmvd, corrected to 15-percent oxygen, for all CTGs under consideration. This concentration is consistent with prior FDEP BACT determinations for simple-cycle CTGs fired with distillate fuel oil.

- The cost effectiveness of high temperature selective catalytic reduction (SCR) control systems was determined to be \$9,394 per ton of NO_x controlled. Because this cost exceeds levels previously determined by FDEP to be cost effective, installation of high temperature SCR control systems is considered economically unreasonable.
- The HCGF is projected to emit NO_x, CO, PM/PM_{10}, SO_2, VOC, 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. Accordingly, the HCGF 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.
- 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 62-210.200(260), F.A.C. Accordingly, a multisource interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class I and II increment consumption was not required.
- Based on refined dispersion modeling, the HCGF 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.
- 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 (Chassahowitzka National Wildlife Refuge [NWR]) is located approximately 138 kilometers (km) northwest of the project 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

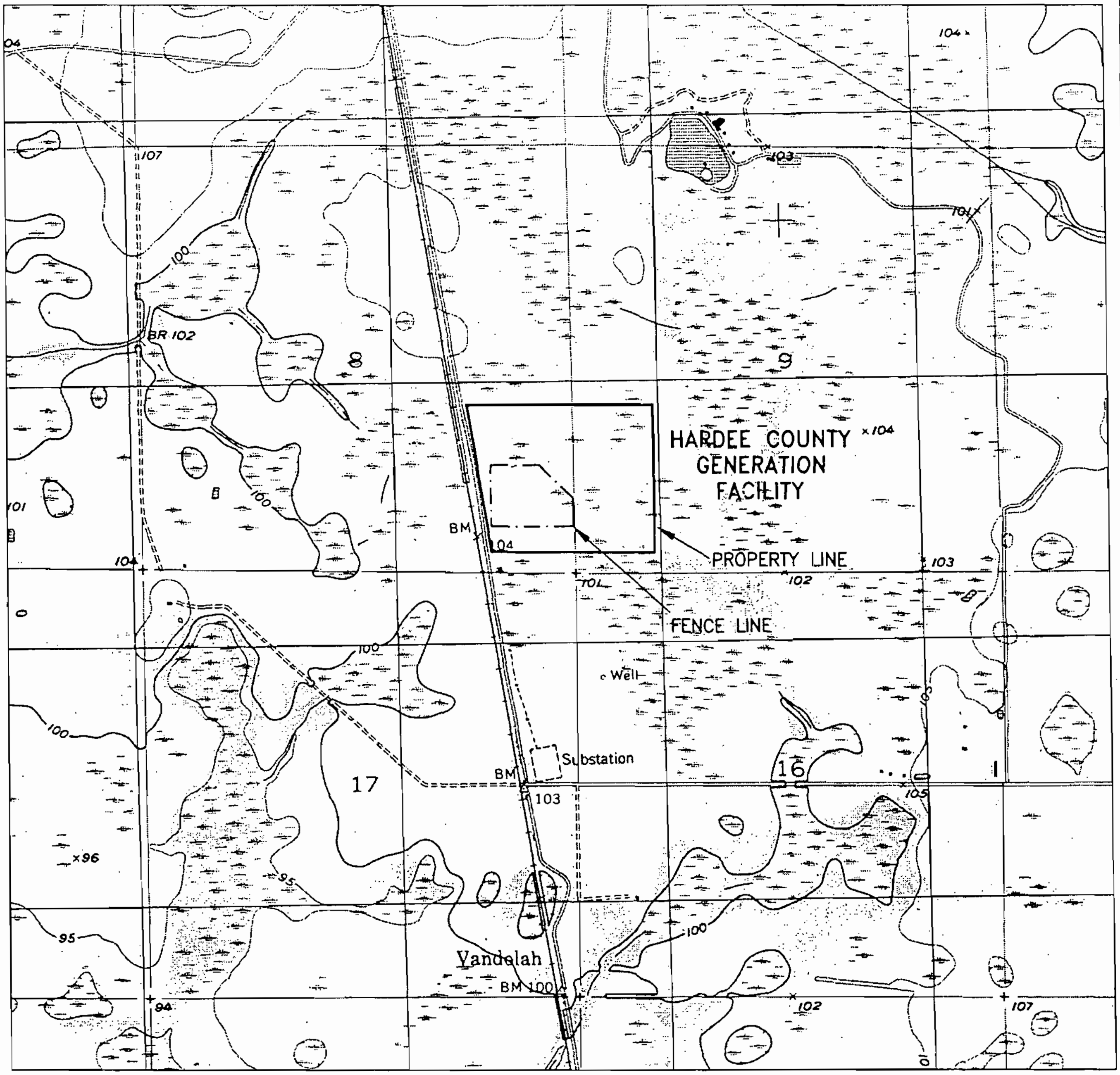
The HCGF is situated approximately 5 miles west of Wauchula in northwestern Hardee County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the HCGF site location, property boundaries, and nearby prominent geographical features.

The proposed Project consists of three, simple-cycle CTGs capable of producing a net nominal generating capacity of 540 MW of electricity. The CTGs will be fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. Ancillary equipment includes one 10 million British thermal units per hour (MMBtu/hr) natural gas-fired heater and a 1.5-million-gallon No. 2 fuel oil storage tank.

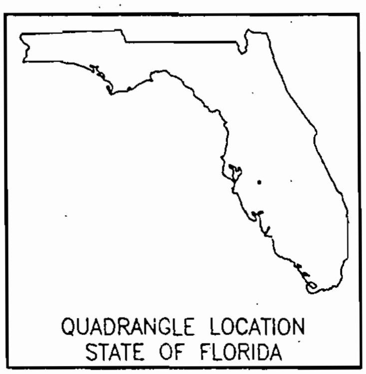
The simple-cycle CTGs will operate a total of 3,000 hr/yr at baseload operation for natural gas and oil firing, with a maximum of 500 hr/yr for oil firing. Part load operation will be conducted for the Siemens Westinghouse and ABB Power Generation units at partial loads as low as 50 percent for no greater than 500 hr/yr while natural gas firing. Compared to baseload operations, CTG air contaminant exhaust concentrations can increase at low-load conditions. HCGF emissions associated with low-load operation will be mitigated by operating the CTGs at loads no lower than 50 percent, excluding periods of startups, shutdowns, and malfunctions.

Combustion of natural gas and distillate fuel oil in the CTGs will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Emission control systems proposed for the simple-cycle CTGs include the use of DLN combustors (natural gas firing) and water injection (distillate fuel oil firing) for control of NO_x; good combustion practices for abatement of CO and VOCs; and use of clean, low-sulfur, low-ash natural gas and distillate fuel oil to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

A site plan showing the existing CTGs, major process equipment and structures, and the emission points are provided in Figure 2-2. Primary access to the HCGF is from Fort



SOURCE: USGS Quad: FT Green, FL, 1987.



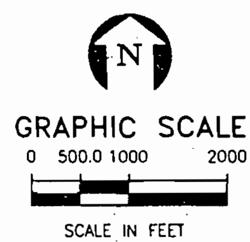


FIGURE 2-1.

HARDEE COUNTY GENERATION FACILITY

Source: USGS Quad: Fort Green, FL, 1987.

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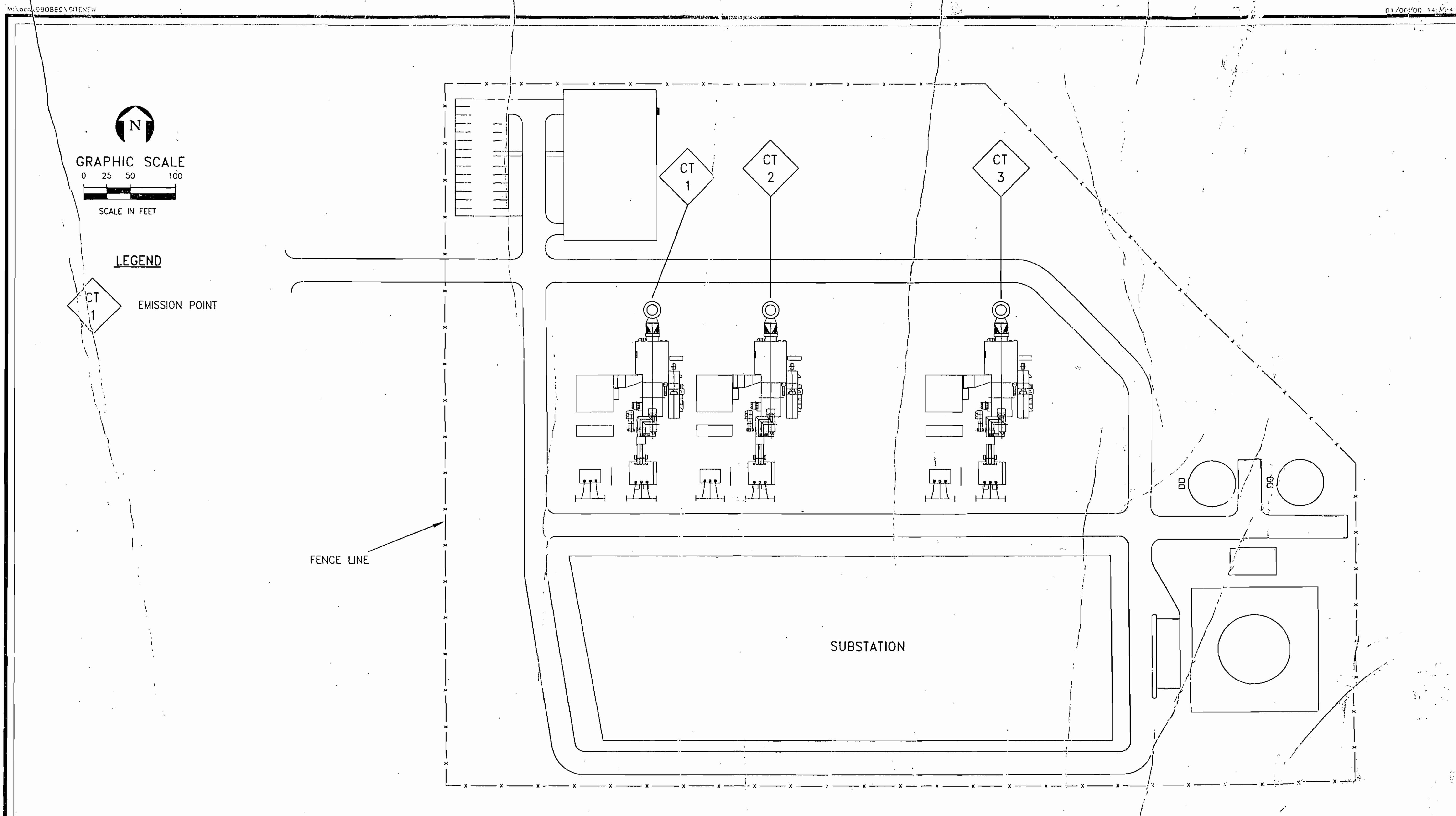

FIGURE 2-2.

HARDEE COUNTY GENERATION FACILITY SITE PLAN

Source: ECT, 1999.

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Green Ona Road on the west side of the site. The HCGF entrance will have security to control site access.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed Project will include three nominal 170-MW GE 7FA or Siemens Westinghouse 501F, nominal 120-MW Siemens Westinghouse 501D5A, or nominal 180-MW ABB Power Generation GT-24 simple-cycle CTGs. Figure 2-3 presents a process flow diagram of the Project.

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 used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTGs' compressors. The CTGs' compressors increase the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with natural gas fuel or distillate fuel oil and burned in the CTGs' high-pressure combustors to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CTGs' turbines to produce rotary shaft power, which is used to drive an electric generator as well as the CTGs combustion air compressor.

Normal operation is expected to consist of the CTGs operating at baseload. HCGF emissions associated with low-load operation will be mitigated by operating the CTGs at loads no lower than 50 percent, excluding periods of startups, shutdowns, and malfunctions.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to start-up, shut-down, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration.

The CTGs will utilize DLN combustion technology and water injection to control NO_x air emissions. The use of low-sulfur natural gas and distillate fuel oil in the CTGs will

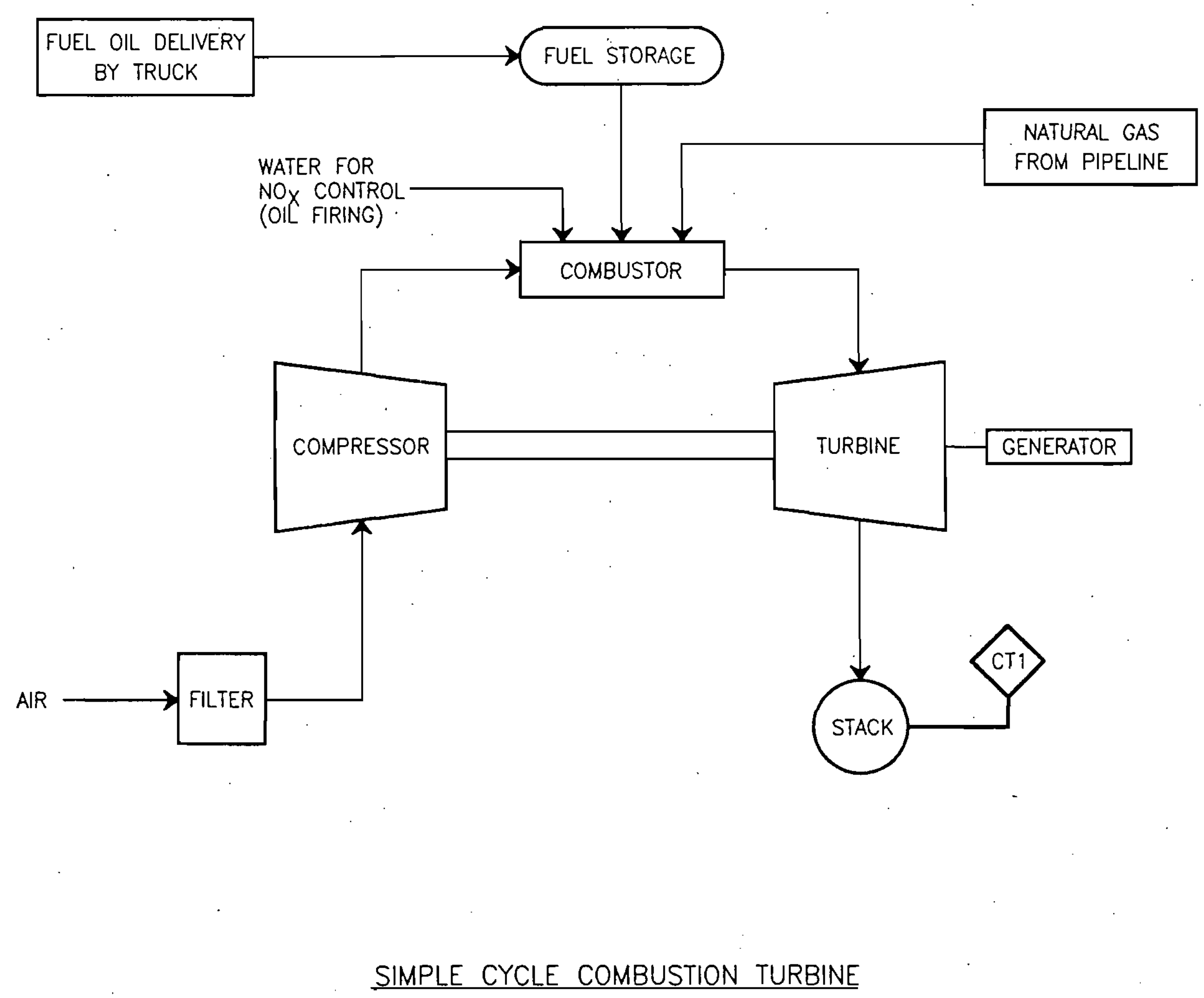

FIGURE 2-3.

HARDEE COUNTY GENTERATION FACILITY

PROCESS FLOW DIAGRAM

Source: ECT, 1999.

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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.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1, 2-2, 2-5, 2-6, 2-9, 2-10, 2-13, and 2-14 provide maximum hourly criteria pollutant CTG emission rates for natural gas and distillate fuel oil firing, respectively. Maximum hourly H_2SO_4 mist emission rates for natural gas and distillate fuel oil firing are summarized in Table 2-17. Maximum hourly noncriteria pollutant rates for natural gas and distillate fuel oil firing are provided in Tables 2-3, 2-4, 2-7, 2-8, 2-11, 2-12, 2-15, and 2-16, respectively. The highest hourly emission rates for each pollutant are prescribed, taking into account load and ambient temperature to develop maximum hourly emission estimates for each CTG. Noncriteria pollutants consist primarily of trace amounts of organic and inorganic compounds associated with the combustion of distillate fuel oil.

Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for CTG operations at low ambient temperature (i.e., 32 degrees Fahrenheit [°F]), baseload, and fuel oil firing. The bases for these emission rates are provided in Appendix D. Table 2-18 presents projected maximum annualized criteria and noncriteria emissions for the Project. The maximum annualized rates were conservatively estimated assuming baseload operation for 2,500 hr/yr (natural gas firing), baseload operation for 500 hr/yr (fuel oil firing), and an ambient temperature of 59°F.

Maximum annualized rates were also evaluated for the Siemens Westinghouse and ABB Power Generation units at a partial load of 50 percent for 500 hr/yr while natural gas firing.

Stack parameters for the simple-cycle CTGs are provided in Tables 2-19 and 2-26 for natural gas and distillate fuel oil firing, respectively.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas GE 7241 FA CT (Per CT)

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	20	9.9	1.25	9.8	1.24	80.9	10.19	56.1	7.07	3.3	0.42	Neg.	Neg.
	59	9.9	1.25	9.2	1.16	75.7	9.54	52.8	6.65	3.1	0.39	Neg.	Neg.
	90†	9.9	1.25	8.5	1.07	69.3	8.73	47.3	5.96	2.9	0.36	Neg.	Neg.
75	20	9.9	1.25	7.9	0.99	64.2	8.09	45.1	5.68	2.6	0.33	Neg.	Neg.
	59	9.9	1.25	7.5	0.94	60.3	7.60	42.9	5.41	2.4	0.30	Neg.	Neg.
	90†	9.9	1.25	6.9	0.87	56.5	7.11	39.6	4.99	2.4	0.30	Neg.	Neg.
50	20	9.9	1.25	6.3	0.79	50.1	6.31	37.4	4.71	2.2	0.28	Neg.	Neg.
	59	9.9	1.25	6.0	0.75	47.5	5.98	35.2	4.44	2.0	0.25	Neg.	Neg.
	90†	9.9	1.25	5.6	0.71	44.9	5.66	33.0	4.16	2.0	0.25	Neg.	Neg.

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

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
GE, 1998.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil GE 7241 FA CT (Per CT)

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	20	18.7	2.36	104.1	13.12	371.8	46.85	124.3	15.66	8.3	1.04	Neg.	Neg.
	59	18.7	2.36	98.1	12.36	350.9	44.21	116.6	14.69	7.7	0.97	Neg.	Neg.
	90†	18.7	2.36	89.2	11.24	319.0	40.19	106.7	13.44	7.2	0.90	Neg.	Neg.
75	20	18.7	2.36	84.5	10.64	299.2	37.70	92.4	11.64	6.1	0.76	Neg.	Neg.
	59	18.7	2.36	79.7	10.05	282.7	35.62	89.1	11.23	6.1	0.76	Neg.	Neg.
	90†	18.7	2.36	73.1	9.20	258.5	32.57	84.7	10.67	6.1	0.76	Neg.	Neg.
50	20	18.7	2.36	65.9	8.30	231.0	29.11	78.1	9.84	5.5	0.69	Neg.	Neg.
	59	18.7	2.36	62.7	7.90	220.0	27.72	77.0	9.70	5.0	0.62	Neg.	Neg.
	90†	18.7	2.36	57.8	7.28	202.4	25.50	73.7	9.29	5.0	0.62	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
GE, 1998.

Table 2-3. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas GE 7241 FA CT (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Arsenic		Benzene		Beryllium		Cadmium		Chromium		Cobalt	
		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	20	3.70E-04	4.66E-05	3.88E-03	4.89E-04	2.22E-05	2.80E-06	2.03E-03	2.56E-04	2.59E-03	3.26E-04	1.55E-04	1.95E-05
	59	3.46E-04	4.36E-05	3.63E-03	4.57E-04	2.07E-05	2.61E-06	1.90E-03	2.39E-04	2.42E-03	3.05E-04	1.45E-04	1.83E-05
	90†	3.18E-04	4.01E-05	3.34E-03	4.21E-04	1.91E-05	2.41E-06	1.75E-03	2.21E-04	2.23E-03	2.81E-04	1.34E-04	1.69E-05

Unit Load (%)	Ambient Temp. (°F)	Dichlorobenzene		Formaldehyde		Lead		Manganese		Mercury		Naphthalene	
		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	20	2.22E-03	2.81E-04	1.39E-01	1.75E-02	9.24E-04	1.16E-04	7.02E-04	8.85E-05	4.81E-04	6.06E-05	1.13E-03	1.42E-04
	59	2.07E-03	2.61E-04	1.30E-01	1.64E-02	8.65E-04	1.09E-04	6.57E-04	8.28E-05	4.50E-04	5.67E-05	1.05E-03	1.32E-04
	90†	1.91E-03	2.41E-04	1.19E-01	1.50E-02	7.96E-04	1.00E-04	6.05E-04	7.62E-05	4.14E-04	5.22E-05	9.71E-04	1.22E-04

Unit Load (%)	Ambient Temp. (°F)	Nickel		Polycyclic Organic Matter		Selenium		Toluene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	3.88E-03	4.89E-04	1.63E-04	2.05E-05	4.44E-05	5.59E-06	6.28E-03	7.91E-04
	59	3.63E-03	4.57E-04	1.53E-04	1.93E-05	4.15E-05	5.23E-06	5.88E-03	7.41E-04
	90†	3.34E-03	4.21E-04	1.40E-04	1.76E-05	3.82E-05	4.81E-06	5.41E-03	6.82E-04

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2000.

Table 2-4. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil GE 7241 FA CT (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Antimony		Arsenic		Beryllium		Cadmium		Chromium		Cobalt	
		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	20	4.19E-02	5.28E-03	9.34E-03	1.18E-04	6.29E-04	7.93E-05	8.00E-03	1.01E-03	8.96E-02	1.13E-03	1.73E-02	2.18E-03
	59	3.95E-02	4.98E-03	8.80E-03	1.11E-04	5.92E-04	7.46E-05	7.54E-03	9.50E-04	8.44E-02	1.06E-03	1.63E-02	2.05E-03
	90†	3.59E-02	4.52E-03	8.00E-03	1.01E-04	5.39E-04	6.79E-05	6.86E-03	8.64E-04	7.67E-02	9.66E-04	1.49E-02	1.88E-03

Unit Load (%)	Ambient Temp. (°F)	Lead		Manganese		Mercury		Nickel		Phosphorus		Selenium	
		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	20	1.11E-01	1.40E-02	6.48E-01	8.16E-02	1.73E-03	2.18E-04	2.29E-00	2.89E-01	5.72E-01	7.21E-02	1.01E-02	1.27E-03
	59	1.04E-01	1.31E-02	6.10E-01	7.69E-02	1.63E-03	2.05E-04	2.15E-00	2.71E-01	5.39E-01	6.79E-02	9.51E-03	1.20E-03
	90†	9.47E-02	1.19E-02	5.55E-01	6.99E-02	1.49E-03	1.88E-04	1.96E-00	2.47E-01	4.90E-01	6.17E-02	8.65E-03	1.09E-03

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2000.

Table 2-5. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas Westinghouse 501F CT (Per CT)

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	32	9.5	1.19	9.9	1.25	125.1	15.77	80.3	10.12	8.8	1.11	Neg.	Neg.
	59	9.5	1.19	9.3	1.17	116.9	14.73	75.9	9.56	8.8	1.11	Neg.	Neg.
	95†	9.5	1.19	8.5	1.08	107.3	13.51	68.2	8.59	7.7	0.97	Neg.	Neg.
70	32	9.5	1.19	7.6	0.96	94.9	11.95	61.6	7.76	6.6	0.83	Neg.	Neg.
	59	9.5	1.19	7.2	0.91	89.4	11.26	58.3	7.35	6.6	0.83	Neg.	Neg.
	95†	9.5	1.19	6.7	0.84	82.5	10.40	55.0	6.93	6.6	0.83	Neg.	Neg.
50	32	9.5	1.19	5.9	0.75	74.3	9.36	245.3	30.91	34.1	4.30	Neg.	Neg.
	59	9.5	1.19	5.6	0.71	70.1	8.84	234.3	29.52	33.0	4.16	Neg.	Neg.
	95†	9.5	1.19	5.3	0.66	64.6	8.14	217.8	27.44	29.7	3.74	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
Westinghouse, 1998.

Table 2-6. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil Westinghouse 501F (Per CT)

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	32	21.0	2.65	95.2	11.99	352.0	44.35	101.2	12.75	29.7	3.74	Neg.	Neg.
	59	19.8	2.49	89.1	11.23	328.9	41.44	95.7	12.06	28.6	3.60	Neg.	Neg.
	95†	17.7	2.23	81.7	10.29	302.5	38.12	85.8	10.81	25.3	3.19	Neg.	Neg.
70	32	26.3	3.31	70.7	8.9	257.4	32.43	95.7	12.06	66.0	8.32	Neg.	Neg.
	59	24.9	3.13	66.8	8.41	236.5	29.80	89.1	11.23	60.5	7.62	Neg.	Neg.
	95†	22.3	2.81	62.0	7.81	225.5	28.41	81.4	10.26	56.1	7.07	Neg.	Neg.
50	32	30.0	3.78	49.9	6.29	344.3	43.38	258.5	32.57	185.9	23.42	Neg.	Neg.
	59	28.6	3.60	53.6	6.75	328.9	41.44	246.4	31.05	177.1	22.31	Neg.	Neg.
	95†	26.1	3.28	49.9	6.29	299.2	37.70	224.4	28.27	161.7	20.37	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
Westinghouse, 1998.

Table 2-7. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas Westinghouse 501F (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Arsenic		Benzene		Beryllium		Cadmium		Chromium		Cobalt	
		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	32	3.83E-04	4.83E-05	4.02E-03	5.07E-04	2.30E-05	2.90E-06	2.11E-03	2.70E-04	2.68E-03	3.40E-04	1.61E-04	2.03E-05
	59	3.58E-04	4.51E-05	3.76E-03	4.74E-04	2.15E-05	2.71E-06	1.97E-03	2.50E-04	2.51E-03	3.20E-04	1.50E-04	1.90E-05
	95†	3.29E-04	4.15E-05	3.45E-03	4.35E-04	1.97E-05	2.50E-06	1.81E-03	2.30E-04	2.30E-03	2.90E-04	1.38E-04	1.74E-05

Unit Load (%)	Ambient Temp. (°F)	Dichlorobenzene		Formaldehyde		Lead		Manganese		Mercury		Naphthalene	
		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	32	2.30E-03	2.90E-04	1.44E-01	1.81E-02	9.57E-04	1.21E-04	7.27E-04	9.20E-05	4.98E-04	6.30E-05	1.17E-03	1.50E-04
	59	2.15E-03	2.71E-04	1.34E-01	1.70E-02	8.96E-04	1.13E-04	6.81E-04	8.60E-05	4.66E-04	5.90E-05	1.09E-03	1.40E-04
	95†	1.97E-03	2.50E-04	1.23E-01	1.60E-02	8.22E-04	1.04E-04	6.25E-04	7.90E-05	4.28E-04	5.40E-05	1.00E-03	1.30E-04

Unit Load (%)	Ambient Temp. (°F)	Nickel		Polycyclic Organic Matter		Selenium		Toluene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	32	4.02E-03	5.10E-04	1.69E-04	2.13E-05	4.59E-05	5.80E-06	6.51E-03	8.20E-04
	59	3.76E-03	4.74E-04	1.58E-04	2.00E-05	4.30E-05	5.42E-06	6.09E-03	7.70E-04
	95†	3.45E-03	4.35E-04	1.45E-04	1.83E-05	3.95E-05	5.00E-06	5.59E-03	7.04E-04

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2000.

Table 2-8. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil Westinghouse 501F (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Antimony		Arsenic		Beryllium		Cadmium		Chromium		Cobalt	
		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	32	3.89E-02	4.90E-03	8.67E-03	1.09E-03	5.84E-04	7.40E-05	7.43E-03	9.36E-04	8.31E-02	1.05E-02	1.61E-02	2.03E-03
	59	3.64E-02	4.60E-03	8.11E-03	1.02E-03	5.46E-04	6.90E-05	6.96E-03	8.77E-04	7.78E-02	9.80E-03	1.51E-02	1.90E-03
	95†	3.34E-02	4.20E-03	7.44E-03	9.37E-04	5.01E-04	6.31E-05	6.37E-03	8.03E-04	7.13E-02	8.98E-03	1.38E-02	1.74E-03

Unit Load (%)	Ambient Temp. (°F)	Lead		Manganese		Mercury		Nickel		Phosphorus		Selenium	
		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	32	1.03E-01	1.30E-02	6.01E-01	7.57E-02	1.61E-03	2.03E-04	2.12E+0	2.70E-01	5.31E-01	6.70E-02	9.38E-03	1.18E-03
	59	9.60E-02	1.21E-02	5.63E-01	7.10E-02	1.51E-03	1.90E-04	1.99E+0	2.51E-01	4.97E-01	6.30E-02	8.78E-03	1.11E-03
	95†	8.80E-02	1.11E-02	5.16E-01	6.50E-02	1.38E-03	1.74E-04	1.82E+0	2.30E-01	4.55E-01	5.73E-02	8.04E-03	1.01E-03

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2000.

Table 2-9. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas WH 501D5A (Per CT)

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	20	9.6	1.21	7.2	0.91	86.9	10.95	34.1	4.3	5.9	0.75	Neg.	Neg.
	59	8.8	1.10	6.7	0.84	80.6	10.16	31.8	4.0	5.4	0.68		
	95†	8.0	1.01	6.1	0.77	74.8	9.42	29.7	3.7	5.0	0.62	Neg.	Neg.
75	20	8.5	1.07	5.6	0.71	82.5	10.40	68.2	8.6	5.3	0.67	Neg.	Neg.
	59	7.7	0.97	5.3	0.67	77.4	9.75	61.9	7.8	4.8	0.61		
	95†	7.0	0.89	5.0	0.63	72.6	9.15	56.1	7.1	4.4	0.55	Neg.	Neg.
50	20	6.8	0.86	4.4	0.55	157.3	19.82	495.0	62.4	24.1	3.04	Neg.	Neg.
	59	6.4	0.81	4.1	0.52	148.7	18.74	463.0	58.3	23.1	2.91		
	95†	6.0	0.76	3.9	0.49	140.8	17.74	433.4	54.6	22.2	2.80	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
Westinghouse, 1998.

Table 2-10. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil WH 501D5A CT (Per CT)

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	20	35.9	4.52	72.4	9.13	260.7	32.85	104.5	13.2	22.0	2.77	Neg.	Neg.
	59	32.9	4.15	66.9	8.43	240.7	30.33	95.9	12.1	20.2	2.55	Neg.	Neg.
	95†	30.3	3.81	61.8	7.78	222.2	28.00	88.0	11.1	18.6	2.34	Neg.	Neg.
75	20	45.2	5.70	56.7	7.14	201.3	25.36	217.8	27.4	49.8	6.28	Neg.	Neg.
	59	41.2	5.19	53.1	6.69	188.7	23.78	198.4	25.0	47.0	5.93	Neg.	Neg.
	95†	37.5	4.72	49.7	6.27	177.1	22.31	180.4	22.7	44.4	5.60	Neg.	Neg.
50	20	54.1	6.81	38.8	4.88	235.4	29.66	2708.2	341.2	82.1	10.34	Neg.	Neg.
	59	50.0	6.30	38.8	4.88	222.8	28.07	2508.0	316.0	77.4	9.75	Neg.	Neg.
	95†	46.3	5.84	38.8	4.88	211.2	26.61	2323.2	292.7	73.0	9.20	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
Westinghouse, 1998.

Table 2-11. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas WH 501D5A CT (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Arsenic		Benzene		Beryllium		Cadmium		Chromium		Cobalt	
		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	32	2.78E-04	3.50E-05	2.92E-03	3.68E-04	1.67E-05	2.10E-06	1.53E-03	1.93E-04	1.94E-03	2.44E-04	1.17E-04	1.50E-05
	59	2.56E-04	3.23E-05	2.69E-03	3.00E-04	1.54E-05	1.94E-06	1.41E-03	2.00E-04	1.79E-03	2.00E-04	1.08E-04	1.36E-05
	95†	2.37E-04	2.99E-05	2.48E-03	3.13E-04	1.42E-05	1.79E-06	1.30E-03	1.64E-04	1.66E-03	2.10E-04	9.94E-05	1.30E-05

Unit Load (%)	Ambient Temp. (°F)	Dichlorobenzene		Formaldehyde		Lead		Manganese		Mercury		Naphthalene	
		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	32	1.67E-03	2.10E-04	1.04E-01	1.31E-02	9.64E-04	1.21E-04	5.28E-04	6.65E-05	3.61E-04	4.55E-05	8.47E-04	1.07E-05
	59	1.54E-03	2.00E-04	9.61E-02	1.21E-02	6.41E-04	1.00E-04	4.87E-04	6.14E-05	3.33E-04	4.20E-05	7.82E-04	9.85E-05
	95†	1.42E-03	1.79E-04	8.87E-02	1.12E-02	5.92E-04	7.46E-05	4.50E-04	5.70E-05	3.08E-04	3.88E-05	7.22E-04	9.10E-05

Unit Load (%)	Ambient Temp. (°F)	Nickel		Polycyclic Organic Matter		Selenium		Toluene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	32	2.92E-03	3.68E-04	1.22E-04	1.54E-05	3.33E-05	4.20E-06	4.72E-03	5.95E-04
	59	2.69E-03	3.39E-04	1.13E-04	1.42E-04	3.08E-05	3.88E-06	4.36E-03	5.49E-04
	95†	2.48E-03	3.13E-04	1.04E-04	1.31E-05	2.84E-05	3.60E-06	4.02E-03	5.07E-04

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2000.

Table 2-12. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil WH 501D5A CT (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Antimony		Arsenic		Beryllium		Cadmium		Chromium		Cobalt	
		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	32	2.94E-02	3.70E-03	6.55E-03	8.30E-04	4.41E-04	5.60E-05	5.61E-03	7.07E-04	6.28E-02	7.91E-03	1.22E-02	1.54E-03
	59	2.72E-02	3.43E-03	6.05E-03	7.62E-04	4.07E-04	5.13E-05	5.18E-03	6.53E-04	5.80E-02	7.31E-03	1.12E-02	1.41E-03
	95†	2.51E-02	3.16E-03	5.58E-03	7.03E-04	3.76E-04	4.74E-05	4.79E-03	6.04E-04	5.36E-02	6.75E-03	1.04-02	1.31E-03

Unit Load (%)	Ambient Temp. (°F)	Lead		Manganese		Mercury		Nickel		Phosphorus		Selenium	
		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	32	7.75E-02	9.77E-03	4.54E-01	5.72E-02	1.22E-03	1.54E-04	1.60E+0	2.02E-01	4.01E-01	5.05E-02	7.08E-03	8.92E-04
	59	7.16E-02	9.02E-03	4.20E-01	5.29E-02	1.12E-03	1.41E-04	1.48E+0	1.86E-01	3.70E-01	4.66E-02	6.54E-03	8.24E-04
	95†	6.61E-02	8.33E-03	3.87E-01	4.88E-02	1.04E-03	1.31E-04	1.37E+0	1.73E-01	3.42E-01	4.31E-02	6.04E-03	7.61E-04

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.

Table 2-13. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas ABB GT-24 CT (Per CT)

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	41.8	5.27	10.2	1.28	203.5	25.64	31.9	4.0	4.2	0.53	Neg.	Neg.
	60	24.2	3.05	9.2	1.16	183.7	23.15	23.1	2.9	2.9	0.36	Neg.	Neg.
	98†	23.1	2.91	8.5	1.07	172.7	21.76	20.9	2.6	2.6	0.33	Neg.	Neg.
75	0	37.4	4.71	8.1	1.03	162.8	20.51	75.9	9.6	3.6	0.46	Neg.	Neg.
	60	19.8	2.49	7.4	0.93	148.5	18.71	55.0	6.9	2.3	0.29	Neg.	Neg.
	98†	18.7	2.36	6.8	0.86	137.5	17.33	50.6	6.4	2.1	0.26	Neg.	Neg.
60	0	28.6	3.60	6.2	0.78	124.3	15.66	394.9	49.8	4.8	0.61	Neg.	Neg.
	60	17.6	2.22	6.4	0.80	122.2	15.40	149.6	18.8	1.9	0.24	Neg.	Neg.
	98†	16.5	2.08	5.9	0.74	113.1	14.25	138.6	17.5	1.8	0.22	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
ABB, 1998.

Table 2-14. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil ABB GT-24 CT (Per CT)

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	83.0	10.46	111.8	14.08	393.8	49.62	141.9	17.9	24.5	3.09	Neg.	Neg.
	60	46.2	5.82	97.5	12.28	342.5	43.15	126.6	16.0	22.7	2.86	Neg.	Neg.
	98†	22.9	2.88	84.3	10.63	314.6	39.64	113.6	14.3	20.1	2.53	Neg.	Neg.
75	0	78.0	9.83	86.7	10.93	305.8	38.53	56.1	7.1	19.0	2.40	Neg.	Neg.
	60	46.2	5.82	77.6	9.77	259.4	32.68	48.8	6.1	16.1	2.03	Neg.	Neg.
	98†	26.1	3.28	69.1	8.70	247.7	31.22	44.5	5.6	14.9	1.88	Neg.	Neg.
60	0	78.0	9.83	51.7	6.52	231.0	29.11	419.1	52.8	21.6	2.72	Neg.	Neg.
	60	37.4	4.71	58.1	7.32	196.8	24.79	380.5	47.9	19.6	2.46	Neg.	Neg.
	98†	11.7	1.47	51.7	6.52	165.4	20.84	346.7	43.7	17.9	2.25	Neg.	Neg.

*As measured by EPA Reference Method 5B or 17.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.
ABB, 1998.

Table 2-15. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Natural Gas ABB GT-24 CT (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Arsenic		Benzene		Beryllium		Cadmium		Chromium		Cobalt	
		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	3.93E-04	4.95E-05	4.13E-03	5.20E-04	2.36E-05	2.97E-06	2.16E-03	2.72E-04	2.75E-03	3.50E-04	1.65E-04	2.08E-05
	60	3.55E-04	4.47E-05	3.73E-03	4.70E-04	2.13E-05	2.68E-06	1.95E-03	2.50E-04	2.48E-03	3.13E-04	1.49E-04	1.88E-05
	98†	3.29E-04	4.15E-05	3.45E-03	4.35E-04	1.97E-05	2.50E-06	1.81E-03	2.28E-04	2.30E-03	2.90E-04	1.38E-04	1.74E-05

Unit Load (%)	Ambient Temp. (°F)	Dichlorobenzene		Formaldehyde		Lead		Manganese		Mercury		Naphthalene	
		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	2.36E-03	2.97E-04	1.47E-01	1.85E-02	9.83E-04	1.24E-04	7.47E-04	9.41E-05	5.11E-04	6.44E-05	1.20E-03	1.51E-04
	60	2.13E-03	2.68E-04	1.33E-01	1.68E-02	8.87E-04	1.12E-04	6.74E-04	8.49E-05	4.61E-04	5.81E-05	1.08E-03	1.36E-04
	98†	1.97E-03	2.48E-04	1.23E-01	1.60E-02	8.21E-04	1.03E-04	6.24E-04	7.86E-05	4.27E-04	5.38E-05	1.00E-03	1.26E-04

Unit Load (%)	Ambient Temp. (°F)	Nickel		Polycyclic Organic Matter		Selenium		Toluene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	0	4.13E-03	5.20E-04	1.73E-04	2.18E-05	4.72E-05	5.95E-06	6.68E-03	8.42E-04
	60	3.73E-03	4.70E-04	1.56E-04	1.97E-05	4.26E-05	5.37E-06	6.03E-03	7.60E-04
	98†	3.45E-03	4.35E-04	1.45E-04	1.83E-05	3.94E-05	4.96E-06	5.59E-03	7.04E-04

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2000.

Table 2-16. Maximum Hazardous Air Pollutant Emission Rates for Three Unit Loads and Three Temperatures—Distillate Fuel Oil ABB GT-24CT (Per CT)

Unit Load (%)	Ambient Temp. (°F)	Antimony		Arsenic		Beryllium		Cadmium		Chromium		Cobalt	
		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	4.57E-02	5.76E-03	1.02E-02	1.29E-03	6.86E-04	8.64E-05	8.73E-03	1.10E-03	9.76E-02	1.23E-02	1.89E-02	2.38E-03
	60	3.99E-02	5.03E-03	8.88E-03	1.12E-03	5.98E-04	7.53E-05	7.61E-03	9.59E-04	8.51E-02	1.07E-02	1.65E-02	2.08E-03
	98†	3.45E-02	4.35E-03	7.68E-03	9.68E-04	5.17E-04	6.51E-05	6.59E-03	8.30E-04	7.37E-02	9.29E-03	1.43E-02	1.80E-03

Unit Load (%)	Ambient Temp. (°F)	Lead		Manganese		Mercury		Nickel		Phosphorus		Selenium	
		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	1.20E-01	1.51E-02	7.06E-01	8.90E-02	1.89E-03	2.38E-04	2.49E+0	3.14E-01	6.23E-01	7.85E-02	1.10E-02	1.39E-03
	60	1.05E-01	1.32E-02	6.16E-01	7.76E-02	1.65E-03	2.08E-04	2.17E+0	2.73E-01	5.43E-01	6.84E-02	9.60E-03	1.21E-03
	98†	9.10E-02	1.15E-02	5.33E-01	6.72E-02	1.43E-03	1.80E-04	1.88E+0	2.37E-01	4.70E-01	5.92E-02	8.31E-03	1.05E-03

†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: ECT, 2000.

Table 2-17. Maximum H_2SO_4 Mist Pollutant Emission Rates for Three Loads and Three Ambient Temperatures

Unit Load (%)	Natural Gas H_2SO_4 mist		Distillate Fuel Oil H_2SO_4 mist	
	lb/hr	g/s	lb/hr	g/s
100	1.17	0.148	12.8	1.62
75	0.9	0.118	10.0	1.25
50	0.7	0.092	7.6	0.95

Sources: GPP, 1999.
ECT, 2000.

Table 2-18. Maximum Annualized Emission Rates (tpy)

Pollutant	Three Simple-Cycle CTGs	Natural Gas Heater	Fuel Oil Tank	Project Total
NO_x	945.7	4.4		950.1
CO	514.6	3.7		518.3
PM/PM_{10}*	125.4	0.1		125.5
SO_2	108.1	0.03		108.1
VOC	73.2	0.2	0.36	73.8
H_2SO_4 mist	14.0	Neg.		14.0
Arsenic	2.75E-03	Neg.		2.75E-03
Antimony	9.96E-03	Neg.		9.96E-03
Benzene	5.64E-03	Neg.		5.64E-03
Beryllium	1.81E-04	Neg.		1.81E-04
Cadmium	4.83E-03	Neg.		4.83E-03
Chromium	2.5E-02	Neg.		2.5E-02
Cobalt	4.35E-03	Neg.		4.35E-03
Dichlorobenzene	3.22E-03	Neg.		3.22E-03
Formaldehyde	2.02E-01	Neg.		2.02E-01
Lead	2.76E-02	Neg.		2.76E-02
Manganese	1.55E-01	Neg.		1.55E-01
Mercury	1.10E-03	Neg.		1.10E-03
Naphthalene	1.64E-03	Neg.		1.64E-03
Nickel	5.49E-01	Neg.		5.49E-01
Phosphorus	1.36E-01	Neg.		1.36E-01
Polycyclic Organic Matter	2.37E-04	Neg.		2.37E-04
Selenium	2.46E-03	Neg.		2.46E-03
Toluene	9.14E-03	Neg.		9.14E-03

*Excludes H_2SO_4 mist.

Sources: GPP, 1999.
ECT, 2000.

Table 2-19. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—GE 7241 FA CT (Per CT), Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	100	30.5	1,081	856	162.8	49.6	18.0	5.49
	59	100	30.5	1,117	876	155.7	47.5	18.0	5.49
	90	100	30.5	1,141	889	148.1	45.1	18.0	5.49
75	20	100	30.5	1,111	873	132.2	40.3	18.0	5.49
	59	100	30.5	1,139	888	129.0	39.3	18.0	5.49
	90	100	30.5	1,166	903	124.2	37.9	18.0	5.49
50	20	100	30.5	1,160	900	112.0	34.1	18.0	5.49
	59	100	30.5	1,184	913	109.9	33.5	18.0	5.49
	90	100	30.5	1,200	922	106.4	32.4	18.0	5.49

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

Sources: GPP, 1999.
ECT, 2000.

Table 2-20. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—GE 7241 FA CT (Per CT), Distillate Fuel Oil

Unit Load	Ambient Temperature	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
(%)	(°F)	ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	100	30.5	1,067	848	166.7	50.8	18.0	5.49
	59	100	30.5	1,098	865	160.4	48.9	18.0	5.49
	90	100	30.5	1,130	883	151.8	46.3	18.0	5.49
75	20	100	30.5	1,184	913	134.3	40.9	18.0	5.49
	59	100	30.5	1,195	919	130.8	39.9	18.0	5.49
	90	100	30.5	1,200	922	126.3	38.5	18.0	5.49
50	20	100	30.5	1,200	922	112.7	34.4	18.0	5.49
	59	100	30.5	1,200	922	111.3	33.9	18.0	5.49
	90	100	30.5	1,200	922	108.3	33.0	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

Table 2-21. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Westinghouse 501F, Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height m	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter M
100	32	100	30.5	1,085	858	164.5	50.2	18.0	5.49
	59	100	30.5	1,099	866	157.7	48.1	18.0	5.49
	95	100	30.5	1,123	879	148.3	45.2	18.0	5.49
70	32	100	30.5	1,026	825	120.6	36.8	18.0	5.49
	59	100	30.5	1,041	834	117.5	35.8	18.0	5.49
	95	100	30.5	1,064	846	114.8	35.0	18.0	5.49
50	32	100	30.5	1,165	903	126.1	38.4	18.0	5.49
	59	100	30.5	1,166	903	121.5	37.0	18.0	5.49
	95	100	30.5	1,200	922	118.1	36.0	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

Table 2-22. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Westinghouse 501F, Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	32	100	30.5	1,071	850	162.5	49.5	18.0	5.49
	59	100	30.5	1,080	855	155.5	47.4	18.0	5.49
	95	100	30.5	1,112	873	147.0	44.8	18.0	5.49
70	32	100	30.5	1,099	866	153.9	46.9	18.0	5.49
	59	100	30.5	1,097	865	146.5	44.6	18.0	5.49
	95	100	30.5	1,200	922	145.3	44.3	18.0	5.49
50	32	100	30.5	1,200	922	137.0	41.7	18.0	5.49
	59	100	30.5	1,200	922	131.5	40.1	18.0	5.49
	95	100	30.5	1,200	922	124.3	37.9	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

Table 2-23. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—WH 501D5A (Per CT), Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	100	30.5	972	795	131.6	40.1	18.0	5.49
	59	100	30.5	997	810	125.2	38.2	18.0	5.49
	95	100	30.5	1,021	823	119.0	36.3	18.0	5.49
75	20	100	30.5	884	746	109.0	33.2	18.0	5.49
	59	100	30.5	941	778	105.4	32.1	18.0	5.49
	95	100	30.5	993	807	101.4	30.9	18.0	5.49
50	20	100	30.5	905	758	88.9	27.1	18.0	5.49
	59	100	30.5	948	782	87.1	26.5	18.0	5.49
	95	100	30.5	987	804	85.2	26.0	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

Table 2-24. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—WH 501D5A CT (Per CT), Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	m	°F	K	ft/sec	m/sec	ft	m
100	20	100	30.5	975	797	132.1	40.3	18.0	5.49
	59	100	30.5	1,000	811	125.7	38.3	18.0	5.49
	95	100	30.5	1,023	824	119.4	36.4	18.0	5.49
75	20	100	30.5	831	717	112.5	34.3	18.0	5.49
	59	100	30.5	885	747	108.6	33.1	18.0	5.49
	95	100	30.5	935	775	104.2	31.8	18.0	5.49
50	20	100	30.5	841	723	90.9	27.7	18.0	5.49
	59	100	30.5	890	750	88.9	27.1	18.0	5.49
	95	100	30.5	939	775	86.6	26.4	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

Table 2-25. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—ABB GT-24 CT (Per CT), Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height m	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter m
100	0	100	30.5	1,000	811	138.5	42.2	18.0	5.49
	60	100	30.5	1,000	811	125.4	38.2	18.0	5.49
	98	100	30.5	1,000	811	117.9	35.9	18.0	5.49
75	0	100	30.5	1,000	811	112.2	34.2	18.0	5.49
	60	100	30.5	1,000	811	105.8	32.2	18.0	5.49
	98	100	30.5	1,000	811	101.7	31.0	18.0	5.49
60	0	100	30.5	1,000	811	91.7	27.9	18.0	5.49
	60	100	30.5	1,000	811	94.4	28.8	18.0	5.49
	98	100	30.5	1,000	811	90.8	27.7	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

Table 2-26. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—ABB GT-24 CT (Per CT), Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height m	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter m
100	0	100	30.5	1,000	811	140.4	42.8	18.0	5.49
	60	100	30.5	1,000	811	120.5	36.7	18.0	5.49
	98	100	30.5	1,000	811	105.8	32.3	18.0	5.49
75	0	100	30.5	1,000	811	113.9	34.7	18.0	5.49
	60	100	30.5	1,000	811	96.5	29.4	18.0	5.49
	98	100	30.5	1,000	811	83.6	25.5	18.0	5.49
60	0	100	30.5	1,000	811	92.4	28.2	18.0	5.49
	60	100	30.5	1,000	811	80.0	24.4	18.0	5.49
	98	100	30.5	1,000	811	71.1	21.7	18.0	5.49

Sources: GPP, 1999.
ECT, 2000.

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) 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 NAAQS 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 HCGF is located in Hardee County approximately 8 km west of Wauchula. Hardee 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. Hardee 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

The Project will be located in Hardee County. As noted above, Hardee County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the Project 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 [$\mu g/m^3$] 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

The proposed new simple-cycle CTGs will have potential emissions in excess of the significant emission rate thresholds. Therefore, the Project is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Comparisons of estimated potential annual emission rates for the Project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, CO, PM/PM_{10}, H_2SO_4, and SO_2 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. Appendix D provides detailed emission rate estimates for the Project.

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	950.1	40	Yes
CO	518.3	100	Yes
PM	125.5	25	Yes
PM_{10}	125.5	15	Yes
SO_2	108.1	40	Yes
Ozone/VOC	73.8	40	Yes
Lead	Negligible	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Not Present	3	No
H_2SO_4 mist	14.0	7	No
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 H 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 Project 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* (1987).

Rule 62-212.400(2)(e), F.A.C., provides an exemption from pre-construction monitoring requirements 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 Section 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 Project 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 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.

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.

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.

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.

The ambient impact analysis for the Project 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 the project under review. 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:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- 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 the project under review.

The additional impact analyses for the Project 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, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- 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 *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). Table 5-1 summarizes specific factors used in estimating capital and annual operating costs.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
<u>Direct Capital Costs</u>	
Sales tax	0.06 × control system cost
Freight	0.05 × control system cost
Instrumentation	0.10 × control system cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
<u>Indirect Capital Costs</u>	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
<u>Direct Annual Operating Costs</u>	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
<u>Indirect Annual Operating Costs</u>	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Source: EPA, 1996.

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

As indicated in Section 3.3, Table 3-2, projected annual emission rates of NO_x, CO, VOCs, PM/PM_{10}, SO_2, and H_2SO_4 mist for the HCGF 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 VOCs), and acid gases (NO_x, SO_2, and H_2SO_4 mist), respectively.

5.2 FEDERAL AND FLORIDA EMISSION STANDARDS

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 60), NESHAP (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.).

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 lower heating value (LHV) of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The HCGF 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 proposed CTGs have no applicable NESHAP/maximum achievable control technology (MACT) requirements.

FDEP emission standards for stationary sources are contained in Chapters 62-296, Stationary Sources—Emission Standards, F.A.C. Chapter 62-296, F.A.C., contains general emission standards for sources emitting VOCs and PM (Section 62-296.320, F.A.C.) which may be applicable to the HCGF. If deemed necessary by FDEP, vapor emission control devices must be employed during the handling of any VOC as required by Rule 62-296.320(1)(a), F.A.C. 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. Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment areas) and 62-296.700, F.A.C. (for PM nonattainment areas). Because the HCGF will be located in Hardee 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, is applicable to the HCGF CTGs. There are no applicable NESHAP requirements.

Tables 5-2 and 5-3 summarize applicable federal and state emission standards, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Appendix D. BACT emission limitations proposed for the HCGF are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM10

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 their low ash and sulfur contents, natural gas and distillate fuel oil combustion generate inherently low PM/PM_{10} emissions.

Table 5-2. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	$STD = 0.0075 \times (14.4/Y) + F$

where:
STD = allowable NOx emissions (percent by volume at 15-percent O_2 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 0.015	0
0.015 < N 0.1	$0.04 \times N$
0.1 < N 0.25	$0.004 + 0.0067 \times (N-0.1)$
N > 0.25	0.005

where:
N = nitrogen content of fuel; percent by weight.
SO_2 = 0.015 percent by volume at 15-percent O_2 and on a dry basis; or fuel sulfur content 0.8 weight percent.

Source: 40 CFR 60, Subpart 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
General VOCs or Organic Solvents Standard Rule 62-296.320(1)(a), F.A.C.	
• VOC	No person shall store, pump, handle, process, load, unload, or use in any process or installation VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

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

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 sized (greater than 10 microns) 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 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 postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from CTGs, none of the previously described control equipment have been applied to CTGs 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 HCGF CTGs will be fired with natural gas as the primary fuel and distillate fuel oil as the back-up fuel source. Combustion of natural gas and distillate fuel oil will generate low PM emissions in comparison to other fuels due to their low ash and sulfur contents. 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 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.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

BACT PM/PM_{10} limits obtained from the RBLC database for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-4 and 5-5, respectively. All determinations

Table 5-5. RBLC PM Summary for Distillate/Multiple Fuel Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0069	INTERNATIONAL PAPER CO. RIVERDALE MILL	SELMA	1/11/93	3/24/95	DIESEL	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	0.01 LB/MMBTU (GAS)	FUEL SPECIFICATION	BACT-PSD
AL-0126	MOBILE ENERGY LLC	MOBILE	1/5/99	4/9/99	DIESEL	TURBINE, GAS, COMBINED CYCLE	168 MW	0.009 LB/MMBTU	COMBUSTION OF CLEAN FUELS	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	DIESEL	TURBINE, OIL, 1 EACH	80 MW	0.025 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	0.025 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	60.6 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	60.6 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		58 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		58 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	0.026 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	0.026 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0057	FLORIDA POWER GENERATION	DEBARY	10/18/91	3/24/95	GAS/OIL	TURBINE, OIL, 6 EACH	92.9 MW	15 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	15 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	10 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	15 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	10 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	0.0472 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	0.0472 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0081	TECO POLK POWER STATION	BARTOW	34389	3/24/95	GAS/OIL	TURBINE, FUEL OIL	1765 MMBTU/H	0.009 LB/MMBTU	GOOD COMBUSTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1029 MMBTU/H	15 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1866 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSO
FL-0104	SEMINOLE HARDEE UNIT 3	FORT GREEN	1/1/96	5/31/96	GAS/OIL	COMBINED CYCLE COMBUSTION TURBINE	140 MW	7 LB/HR (NAT. GAS)	DRY LNB FUEL SPEC: LOW S OIL, GOOD COMBUSTION	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	0.012 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	0.012 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	0.0156 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	0.0156 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	55 LB/HR	CLEAN FUEL	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/98	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	55 LB/HR	CLEAN FUEL	BACT-PSD
HI-0013	MAUI ELECTRIC COMPANY, LTD.	MAALAEA	12/3/91	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	28 MW	0.045 GR/DSCF	FUEL SPEC: 0.4 % SULFUR	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	19.7 LB/HR	COMBUSTION DESIGN	BACT-PSD
HI-0015	MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	MAUI	7/28/92	3/24/95	GAS/OIL	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	19.7 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	BACT-OTHER
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	3/10/92	3/24/95	GAS/OIL	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1500 MM BTU/HR (EACH)	67 LB/HR (EACH)	COMBUSTION CONTROL	BACT-PSD.
KY-0057	EAST KENTUCKY POWER COOPERATIVE		3/24/93	3/24/95	GAS/OIL	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1492 MMBTU/H (EACH)	54 LBS/H (EACH)	PROPER COMBUSTION TECHNIOUES	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	GAS/OIL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	0.05 LB/MMBTU	FUEL SPECIFICATION: NO. 2 LIGHT OIL	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	GAS/OIL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	0.05 LB/MMBTU	FUEL SPECIFICATION: NO. 2 LIGHT OIL	BACT-OTHER
MA-0021	MILLENNIUM POWER PARTNER, LP	CHARLTON	2/2/98	4/19/99	GAS/OIL	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534 MMBTU/H	0.005 LB/MMBTU	DLN IN CONJUNCTION WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	GAS/OIL	TURBINE, COMBUSTION, ABB GT24	1792 MMBTU/H	17.4 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	GAS/OIL	ENGINE, DIESEL, FIRE PUMP	1.5 MMBTU/H	0.31 LB/MMBTU	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
ME-0016	GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	36133	4/19/99	GAS/OIL	TURBINE, COMBINED CYCLE	900 MW TOTAL	0.06 LB/MMBTU NAT GAS	.05 % SULFUR OIL #2 IS USED. EMISSION IS FROM EACH 300 MW SYSTEM.	BACT-PSD
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	GAS/OIL	DIESEL ENGINE-DRIVEN FIRE PUMP	2.7 MMBTU/HR	0.7 LB/HR	FUEL SELECTION, GOOD COMBUSTION.	BACT-PSD
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	GAS/OIL	COMBUSTION TURBINE/GENERATOR	1970 MMBTU/HR	10.7 LB/HR GAS	FUEL SELECTION, GOOD COMBUSTION	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	ENGINE, DIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	0.26 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1988 MMBTU/H (CTG)	0.0089 LB/MMBTU (NAT GAS)	COMBUSTING NATURAL GAS	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	ENGINE, DIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	0.26 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	36109	4/19/99	GAS/OIL	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1988 MMBTU/H (CTG)	0.0089 LB/MMBTU (NAT GAS)	NATURAL GAS COMBUSTION	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	163.5 TPY	NONE	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	24.5 TPY	NONE	BACT-PSD
MO-0017	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	2/28/95	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	88.77 MW	12.25 TPY	GOOD COMBUSTION CONTROL.	BACT-PSD
MO-0043	UNION ELECTRIC CO	WEST ALTON	5/6/79	10/6/97	GAS/OIL	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	622 MM BTU/HR	174 TPY		BACT-PSD
MS-0028	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	4/9/96	8/19/96	DIESEL	COMBUSTION TURBINE, COMBINED CYCLE	1299 MMBTU/HR NAT GAS	8.1 LB/HR, GAS	GOOD COMBUSTION CONTROLS	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	DIESEL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	9 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.8 MMBTU/HR	17 LB/HR	COMBUSTION CONTROL	BACT-PSD.
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1 MW EACH	3.44 LB/H		BACT-PSD
NV-0015	SAGUARO POWER COMPANY	HENDERSON	6/17/91	6/1/93	GAS/OIL	COMBUSTION TURBINE GENERATOR	34.5 MW	2.5 PPH	COMBUSTION SYSTEM	LAER
NV-0030	MUDDY RIVER L.P.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	17 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NV-0031	CSW NEVADA, INC.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	17 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	0.03 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0057	MEGAN-RACINE ASSOCIATES, INC	CANTON	8/5/89	3/30/95	GAS/OIL	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	0.028 LB/MMBTU, 12 LB/HR	NO CONTROLS	BACT-OTHER
NY-0061	ANITEC COGEN PLANT	BINGHAMTON	7/7/93	4/27/95	GAS/OIL	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	0.005 LB/MMBTU, 2.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.1% BY WEIGHT	BACT-OTHER
NY-0062	FULTON COGEN PLANT	FULTON	9/15/94	4/27/95	GAS/OIL	GE LM5000 GAS TURBINE	500 MMBTU/HR	0.024 LB/MMBTU, 12.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.3% BY WEIGHT	BACT-OTHER
NY-0063	TBG COGEN COGENERATION PLANT	BETHPAGE	8/5/90	4/27/95	GAS/OIL	GE LM2500 GAS TURBINE	214.9 MMBTU/HR	0.024 LB/MMBTU, 5.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.037% BY WEIGHT	BACT-OTHER
NY-0064	INDECK-OSWEGO ENERGY CENTER	OSWEGO	10/6/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	0.008 LB/MMBTU, 5.00 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.27% BY WEIGHT	BACT-OTHER
NY-0065	KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	11/18/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	491 BTU/HR	0.005 LB/MMBTU, 3.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEIGHT	BACT-OTHER
NY-0066	INDECK ENERGY COMPANY	SILVER SPRINGS	34101	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	0.006 LB/MMBTU, 2.5 LB/HR	NO CONTROLS	BACT-OTHER
NY-0068	KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	12/31/91	6/30/95	GAS/OIL	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	SEE NOTE #1	FUEL SPECIFICATION	BACT-OTHER
NY-0071	KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	9/10/92	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	0.005 LB/MMBTU, 3.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEIGHT	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	DIESEL GENERATOR (EP #00005)	22 MMBTU/HR	0.024 LB/MMBTU, 0.53 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	FIRE PUMP (EP #00007)	1.5 MMBTU/HR	0.2 LB/MMBTU, 0.29 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.15% BY WEIGHT	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	SIEMENS V64.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	0.008 LB/MMBTU, 5.8 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.15% BY WEIGHT	BACT-OTHER
NY-0073	LOCKPORT COGEN FACILITY	LOCKPORT	7/14/93	4/27/95	DIESEL	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	423.9 MMBTU/HR	0.006 LB/MMBTU, 2.5 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEIGHT	BACT-OTHER
NY-0075	PILGRIM ENERGY CENTER	ISLIP		4/27/95	DIESEL	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1400 MMBTU/HR	0.007 LB/MMBTU, 7.20 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.05% BY WEIGHT	BACT-OTHER
NY-0076	TRIGEN MITCHEL FIELD	HEMPSTEAD	4/16/93	3/31/95	DIESEL	GE FRAME 6 GAS TURBINE	424.7 MMBTU/HR	0.006 LB/MMBTU, 2.9 LB/HR	NO CONTROLS	BACT-OTHER
NY-0079	LEDERLE LABORATORIES	PEARL RIVER		4/27/95	DIESEL	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	SEE NOTE #2	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.30% BY WEIGHT	BACT-OTHER
NY-0081	LILCO SHOREHAM	HICKSVILLE	5/10/93	3/30/95	GAS/OIL	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	850 MMBTU/HR	0.012 LB/MMBTU, 10.2 LB/HR	NO CONTROLS	BACT-OTHER
OK-0027	OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	12/17/92	3/24/95	GAS/OIL	TURBINE, COMBUSTION	58 MW	0.0125 LB/MMBTU	FUEL SPEC: USE OF DISTILLATE FUEL	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	TURBINE (NATURAL GAS & OIL)	1150 MMBTU	0.1 LB/MMBTU*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	GENERATOR, STEAM	450 MMBTU	0.1 LB/MMBTU*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	72 LB/HR	SAME LIMITS APPLY TO PM10.	BACT-PSD
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	55 LB/HR	SAME LIMITS APPLY TO PM10.	BACT-PSD
SC-0021	CAROLINA POWER AND LIGHT CO.	DARLINGTON	9/23/91	3/24/95	GAS/OIL	TURBINE, I.C.	80 MW	15 LB/H		BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	5.9 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSO
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	22 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
SD-0001	NORTHERN STATES POWER COMPANY	NEAR SIOUX FALLS, SOUTH I	9/2/92	3/24/95	GAS/OIL	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	12 LB/H FOR GAS	FUEL SPEC: NATURAL GAS AS PRIMARY FUEL	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	0.0053 LB/MMBTU	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	0.036 LB/MMBTU	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	33907	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS (TOTAL)		74.6 TPY	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
WA-0280	EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	BELLINGHAM	9/26/91	4/16/99	GAS/OIL	TURBINES, COMBINED CYCLE COGEN, GE FRAME 6	123 MW	60 LB/D NG		BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	8/29/92	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)		12 LBS/HR	GOOD COMBUSTION	BACT-PSD

Source: RBLC 1999.

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

RBLC ID	Facility Name	City	Permit Dates Issuance	Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
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 COM- BUSTION TURBINE	BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL MS3002G 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
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)		0.01 LBS/MMBTU	CLEAN FUEL - NATURAL GAS/HYDROGEN	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW	0.012 LB/MMBTU	COMBUSTION OF NATURAL GAS ONLY	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION OF NATURAL GAS ONLY	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	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.012 LB/MMBTU	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 LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	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-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 REPOWERING S	33311	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	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-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-0068	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-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	4/7/93	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-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	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-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-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
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-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-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
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	35158	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	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
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1327 MMBTU/H	12.5 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	0.06 LB/MMBTU		BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	0.06 LB/MMBTU		BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	0.06 LB/MMBTU		BACT-OTHER
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	9 LB/H GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	0.06 LB/MMBTU		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
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 TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0023 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	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
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	SEE P2 DESC.	COMBUSTION AIR FILTERS	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATIC	HOBBS	35373	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM	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
NM-0039	TNP TECHN. LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375 MMBTU/H	7.8 LB/H PER TURBINE	GOOD COMBUSTION PRACTICES	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 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 LOW SULFUR OIL	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	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	33913	9/13/94	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSE	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	5/6/98	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	IMPLEMENT GOOD COMBUSTION PRACTICES	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	59 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES	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		BACT-PSD
TX 0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	52 TPY	INTERNAL COMBUSTION CONTROLS	BACT

Source: RBLC 1999.

are based on the use of clean fuels and good combustion practice. Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-6 and 5-7, respectively. All determinations are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for CTGs, the use of good combustion practices and clean fuels is considered to be BACT. The HCGF CTGs 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 completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTGs will be fired primarily with pipeline quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up fuel source. 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, visible emissions limits of 10-percent opacity (for natural gas-firing, all CTGs), 10-percent opacity (for oil-firing, GE 7F CTG), and 20-percent opacity (for oil-firing, Westinghouse and ABB CTGs are proposed as surrogate BACT limits for PM/PM_{10}). Table 5-8 summarizes PM/PM_{10} BACT emission limits proposed for the HCGF CTGs.

5.4 BACT ANALYSIS FOR CO AND VOC

CO and VOC emissions results 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/VOC emissions).

Table 5-6. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
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	7.0	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
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
11/25/98	FP&L Ft. Myers Plant Repowering	170	1,760	—	—	Combustion design and clean fuels
12/04/98	Santa Rosa Energy Center	167	1,780			Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-7. Florida BACT PM Emission Limitation Summary—Distillate Fuel Oil-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	Florida Power Corp. Intercession City	93	1,144	15.0	(0.0131)	Combustion design and clean fuels
		186	2,032	17.0	(0.0084)	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,170	36.8	0.0472	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	371	10.0	0.0323	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	928	15.0	0.0162	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,850	17.0	(0.0092)	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,765	17.0	0.009	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	406	20.0	0.026	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	991	15.0	(0.0151)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		—	—	Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,660	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,236	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,846	44.8	(0.0243)	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-8. Proposed PM/PM_{10} BACT Emission Limit

Emission Source	Proposed PM/PM_{10} BACT Emission Limit * (% Opacity) Natural Gas	Oil
GE PG7241 (FA) CTGs (per CT)	10	10
Westinghouse 501F CTGs (per CT)	10	20
Westinghouse 501D5A CTGs (per CT)	10	20
ABB GT-24 CTGs (per CT)	10	20

*Maximum rate for all operating scenarios.

Source: ECT, 2000.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOC from gas turbines: combustion process design and 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 VOC 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 both CO and VOC 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 900oF are needed to oxidize VOC. 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. Oxidation catalyst control systems typically achieve 80 to 90 percent oxidation of 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 oxidation catalyst is 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. 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 HCGF CTGs. 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 an appreciable amount of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs fired with natural gas and distillate fuel oil. Because CO and VOC emission rates from CTGs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements, e.g., well below the defined PSD significant impact levels for CO. The location of the HCGF (Hardee 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 the HCGF indicate 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 HCGF CTGs is projected to have a pressure drop across the catalyst bed of approximately 1.5 inch of water (H_2O). This pressure drop will result in a 0.3-percent energy penalty due to reduced turbine output power. For the Westinghouse 501F CTGs, the reduction in turbine output power (lost power generation) will result in an energy penalty of 2,295,000 kilowatt-hours (kwh) (7,831 million British thermal units [MMBtu]) per year at baseload (170 MW) operation and 3,000 hr/yr operation per CT. This energy penalty is equivalent to the use of 22.4 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 all three CTGs. The lost power generation energy penalty, based on a power cost of $0.060/kwh, is $481,951 per year for all three CTGs. The magnitude of the energy penalty will be comparable for the GE 7FA and ABB GT-24 CTGs and somewhat lower for the Westinghouse 501D5A 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 5-9. Tables 5-10 and 5-11 summarize specific capital and annual operating costs for the oxidation catalyst control system. The economic analysis was conducted for the Westinghouse 501D5A CTGs because these units are estimated to have the highest annual HCGF CO emission rate and, therefore, expected to have the lowest control system cost effectiveness. Cost effectiveness of oxidation catalyst control technology for the remaining CTGs under consideration will be comparable to that determined for the Westinghouse 501D5A CTGs.

Table 5-9. Economic Cost Factors

Factor	Units	Value
Interest rate	%	10.0
Control system life	Years	10
Catalyst life	Years	
Oxidation		6*
SCR		6*
Electricity cost	$/kwh	0.060
Aqueous NH_3 cost	$/ton	105
Labor costs (base rates)	$/hour	
Operator		27.00
Maintenance		30.00

*Control system vendor guarantee is 3 years; 6 years estimated due to low capacity factor.

Sources: GPP, 1999.
ECT, 2000.

Table 5-10. Capital Costs for Oxidation Catalyst System—Three CTGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	2,997,327	A
Sales tax	179,840	0.06 × A
Instrumentation	299,733	0.10 × A
Freight	149,866	0.05 × A
Subtotal Purchased Equipment	**$3,626,765**	**B**
Installation		
Foundations and supports	290,141	0.08 × B
Handling and erection	507,747	0.14 × B
Electrical	145,071	0.04 × B
Piping	72,535	0.02 × B
Insulation for ductwork	36,268	0.01 × B
Painting	36,268	0.01 × B
Subtotal Installation Cost	**$1,088,030**	
Subtotal Direct Costs	**$4,714,795**	
Indirect Costs		
Engineering	362,677	0.10 × B
Construction and field expenses	181,338	0.05 × B
Contractor fees	362,677	0.10 × B
Start-up	72,535	0.02 × B
Performance test	36,268	0.01 × B
Contingency	108,803	0.03 × B
Subtotal Indirect Costs	**$1,124,247**	
TOTAL CAPITAL INVESTMENT	**$5,839,092** (TCI)	

Sources: Engelhard, 1999
ECT, 2000

Table 5-11. Annual Operating Costs for Oxidation Catalyst System—Three CTGs

Item	Dollars		OAQPS Factor
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	2,486,549		
Credit for used catalyst	(335,631)		
Subtotal Catalyst Costs	**$2,150,918**		
Annualized Catalyst Costs	**$493,867**		
Energy penalties			
Turbine backpressure	272,160		
Subtotal Direct Costs	**$766,027**	(TDC)	
Indirect Costs			
Administrative charges	116,782		0.02 × TCI
Property taxes	58,391		0.01 × TCI
Insurance	58,391		0.01 × TCI
Capital recovery	545,611		
Emission Fee Credit	(11,578)		
Subtotal Indirect Costs	**$767,597**		
TOTAL ANNUAL COST	**$1,533,623**		

Sources: Engelhard, 1999
GPP, 1999.
ECT, 2000.

Base case CT exhaust CO concentrations for natural gas and fuel oil firing are 10 and 27 ppmvd, respectively. Control efficiency for the CO oxidation catalyst system, consistent with efficiencies typically required for oxidation catalyst systems located in nonattainment areas, is assumed to be 90 percent. Base case and controlled CO emission rates are summarized in Table 5-12.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $3,312 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered economically feasible. Table 5-12 summarizes results of the oxidation catalyst economic analysis.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

BACT CO limits obtained from the RBLC database for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-13 and 5-14, respectively. Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-15 and 5-16, respectively.

The use of oxidation catalyst to control CO from CTGs is typically required only for facilities located in CO nonattainment areas. GPP is not aware of any CO catalyst systems that have been installed in CO attainment areas. FDEP gas turbine CO BACT determinations for natural, gas-fired CTGs 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 natural gas-fired CTGs, 13 determinations established a limit of 20 ppmvd or higher.

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 fired with natural gas. Because CO and VOC emission rates from CTGs 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).

Table 5-12. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
	Emission Rates		Emission Reduction	Installed Capital Cost	Total Annualized Cost	Cost Effectiveness Over Baseline	Increase Over Baseline	Toxic Impact	Adverse Envir. Impact
Control Option	lb/hr	tpy	(tpy)	($)	($/yr)	($/ton)	(MMBtu/yr)	(Y/N)	(Y/N)
Oxidation catalyst	34.3	51.5	463.1	5,839,092	1,533,623	3,312	5,528	Y	Y
Baseline	343.1	514.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Three Westinghouse 501D5A CTGs, 100-percent load for 2,000 hr/yr gas-firing, 50-percent load for 500 hr/hr gas-firing, and 100-percent load for 500 hr/yr oil-firing.

Sources: Westinghouse, 1998.
Engelhard, 1999.
GRU, 1999.
ECT, 2000.

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Table 5-13. RBLC CO Summary for Natural Gas Fired CTs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	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 CON	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
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)				BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW			BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.165 LB/MMBTU	EFFICIENT COMBUSTION	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 @ 15% 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	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	BACT-PSD
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		10 PPM @ 15% O2	OXIDATION CATALYST	BACT-OTHER
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	4/19/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25 MW	669.19 LB/D	OXIDATION CATALYST	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	4/19/99	TURBINE, GE, COGENERATION, 48 MW	48 MW	252.6 LB/D	OXIDATION CATALYST	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
CT-0130	BRIDGEPORT ENERGY, LLC	BRIDGEPORT	6/29/98	1/21/99	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260 MW/HRSG PER TURBINE	10 PPM GAS & OIL	PRE-MIX FUEL FAIR TO OPTIMIZE EFFICIENCY ACTUAL E	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	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	33394	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-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 REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	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-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-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-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	4/7/93	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-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	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-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-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 IF	BACT-PSD
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	34970	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION	BACT-PSD
FL-0116	SANTA ROSA ENERGY LLC	NORTHBROOK	12/4/98	4/16/99	TURBINE, COMBUSTION, NATURAL GAS	241 MW			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-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-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
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 AND EMISSIONS NOT TO EXCEED	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 AND EMISSIONS NOT TO EXCEED	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 OPERATIO	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	32842	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-OTHER
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
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	ENGINES, CHILLER, NATURAL GAS-FIRED, TWO	23.4 MMBTU/H	0.4 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1327 MMBTU/H	5.97 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR	BACT-PSD
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
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
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	15 PPM @15% O2	USING 15 % EXCESS AIR.	BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	9 PPMVD @15% O2 GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	35989	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	20 PPM @ 15% O2	15% EXCESS AIR	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
MI-0244	WYANDOTTE ENERGY	WYANDOTTE	2/8/99	4/19/99	TURBINE, COMBINED CYCLE, POWER PLANT	500 MW	3 PPM	CATALYTIC OXIDIZER	LAER
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
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	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	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
NJ-0031	UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NEWARK	6/26/97	2/17/99	COMBUSTION TURBINE COGENERATION UNITS, 3	56 MMBTU/H	75 PPMVD NAT. GAS		RACT
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	2.5 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.	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 BY MAINTAINING PROPEF	BACT-PSD
NM-0039	TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375 MMBTU/H	18 PPM	GOOD COMBUSTION PRACTICES	BACT-PSD

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Table 5-13. RBLC CO Summary for Natural Gas Fired CTs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
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-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	6/18/92	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-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GENERATOR, EMERGENCY (NATURAL GAS)	1.5 MMBTU/HR	6.5 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	33932	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 HOUSI	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	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	7/7/94	1/27/99	TURBINES, NATURAL GAS (2)	1696 MMBTU/H	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	OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	3.1 PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRIN	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	7/31/91	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	BACT-PSD
WY-0032	QUESTAR PIPELINE CORP. - RK SPRINGS COMPRESSOR COM	ROCK SPRINGS	9/25/97	2/1/99	TURBINE COMPRESSOR ENGINE, NATURAL GAS FIRED, 2EA	1001 HP	3.5 G/B-HP-H		BACT-PSD
WY-0039	TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	15 MILES SE OF WRIGHT	2/27/98	3/31/99	TURBINE, STATIONARY	33.3 MW	25 PPM @ 15% O2		OTHER

Source: RBLC 1999.

Table 5-14. RBLC CO Summary for Distillate/Multiple Fuel Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0069	INTERNATIONAL PAPER CO. - RIVERDALE MILL	SELMA	1/11/93	3/24/95	GAS/OIL	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	22.1 LB/HR	DESIGN	BACT-PSD
AL-0126	MOBILE ENERGY LLC	MOBILE	1/5/99	4/9/99	GAS/OIL	TURBINE, GAS, COMBINED CYCLE	168 MW	0.04 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 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	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	78 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	78 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0057	FLORIDA POWER GENERATION	DEBARY	10/18/91	3/24/95	GAS/OIL	TURBINE, OIL, 6 EACH	92.9 MW	54 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	98.4 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	98.4 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	65 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	76 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	65 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	76 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	33952	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0081	TECO POLK POWER STATION	BARTOW	2/24/94	3/24/95	GAS/OIL	TURBINE, FUEL OIL	1765 MMBTU/H	40 PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	30 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	30 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1029 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1866 MMBTU/H	79 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0104	SEMINOLE HARDEE UNIT 3	FORT GREEN	1/1/96	5/31/96	GAS/OIL	COMBINED CYCLE COMBUSTION TURBINE	140 MW	20 PPM (NAT. GAS)	DRY LNB GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0115	CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	7/10/98	4/16/99	GAS/OIL	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO	2174 MMBTU/H	25 PPM	GOOD COMBUSTION WITH DLN	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	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	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 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	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	30 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	30 PPMVD	COMPLETE COMBUSTION	BACT-PSD
HI-0013	MAUI ELECTRIC COMPANY, LTD.	MAALAEA	12/3/91	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	28 MW	SEE NOTES	GOOD COMBUSTION PRACTICES	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	26.8 LB/HR @ 100% PEAKLD	COMBUSTION DESIGN	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	56.4 LB/H @ 75 < 100% PKLD	COMBUSTION DESIGN	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	181 LB/H @ 50 < 75% PKLD	COMBUSTION DESIGN	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	475.6 LB/H @ 25 < 50% PKLD	COMBUSTION DESIGN	BACT-PSD
HI-0015	MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	MAUI	7/28/92	3/24/95	GAS/OIL	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	26.9 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	BACT-OTHER
IN-0053	PSI ENERGY, INC. WABASH RIVER STATION	WEST TERRE HAUTE	5/27/93	7/20/94	GAS/OIL	COMBINED CYCLE SYNGAS TURBINE	1775 MMBTU/HR	15 LESS THAN PPM	OPERATION PRAC. AND GOOD COMB. SYNGAS TURBINE	BACT-PSD
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	33673	3/24/95	GAS/OIL	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1500 MM BTU/HR (EACH)	75 LB/HR (EACH)	COMBUSTION CONTROL	BACT-PSD
KY-0057	EAST KENTUCKY POWER COOPERATIVE		3/24/93	3/24/95	GAS/OIL	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1492 MMBTU/H (EACH)	75 LBS/H (EACH)	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
MA-0021	MILLENNIUM POWER PARTNER, LP	CHARLTON	2/2/98	4/19/99	GAS/OIL	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534 MMBTU/H	0.07 LB/MMBTU	DLN IN CONJ. WITH SCR ADD-ON NOX CONTROL	BACT-PSD
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	GAS/OIL	TURBINE, COMBUSTION, ABB GT24	1792 MMBTU/H	14.3 LB/H	DLN WITH SCR ADD-ON NOX CONTROL	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	DIESEL	ENGINE, DIESEL, FIRE PUMP	1.5 MMBTU/H	0.95 LB/MMBTU	DLN WITH SCR ADD-ON NOX CONTROL	BACT-PSD
ME-0016	GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	12/4/98	4/19/99	GAS/OIL	TURBINE, COMBINED CYCLE	900 MW TOTAL	5 PPM @ 15% O2 (NAT G)	0.05% S #2 IS USED. EACH 300 MW SYSTEM	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	34471	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	1290 TPY	NONE	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	120 TPY	NONE	BACT-PSD
MO-0017	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	2/28/95	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	88.77 MW	427.5 TPY	GOOD COMBUSTION CONTROL	BACT-PSD
MO-0043	UNION ELECTRIC CO	WEST ALTON	5/6/79	10/6/97	GAS/OIL	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	622 MM BTU/HR	463 TPY		BACT-PSD
MS-0028	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	4/9/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, COMBINED CYCLE	1299 MMBTU/HR NAT GAS	26.3 PPM @ 15% O2, GAS	GOOD COMBUSTION CONTROLS	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	60 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	60 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	80 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	81 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	GAS/OIL	TURBINE, KEROSENE FIRED	585 MMBTU/HR	0.063 LB/MMBTU	CATALYTIC OXIDATION	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.06 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.06 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1 MM EACH	15.2 LB/H		BACT
NV-0015	SAGUARD POWER COMPANY	HENDERSON	6/17/91	6/1/93	GAS/OIL	COMBUSTION TURBINE GENERATOR	34.5 MW	9 PPH	CONVERTER (CATALYTIC)	BACT-PSD
NV-0030	MUDDY RIVER L.P.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	77 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NV-0031	CSW NEVADA, INC	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	83 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240 MW	5 PPM @ 15% O2		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000 KW	0.25 LB/MMBTU		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240 MW	5 PPM @ 15% O2		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000 KW	0.25 LB/MMBTU		LAER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	DIESEL	FIRE PUMP (DIESEL)	1.3 MMBTU/HR	0.71 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	8.5 PPM	COMBUSTION CONTROL	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	33917	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9.5 PPM	COMBUSTION CONTROLS	BACT-OTHER
NY-0057	MEGAN-RACINE ASSOCIATES, INC	CANTON	8/5/89	3/30/95	GAS/OIL	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	0.026 LB/MMBTU, 11 LB/HR	NO CONTROLS	BACT-OTHER
NY-0061	ANITEC COGEN PLANT	BINGHAMTON	7/7/93	4/27/95	GAS/OIL	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	36 PPM, 33 LB/HR	BAFFLE CHAMBER	SEE NOTE #4
NY-0062	FULTON COGEN PLANT	FULTON	9/15/94	4/27/95	GAS/OIL	GE LM5000 GAS TURBINE	500 MMBTU/HR	107 PPM, 120 LB/HR	NO CONTROLS	BACT-OTHER
NY-0063	TBG COGEN COGENERATION PLANT	BETHPAGE	8/5/90	4/27/95	GAS/OIL	GE LM2500 GAS TURBINE	214.9 MMBTU/HR	0.181 LB/MMBTU	CATALYTIC OXIDIZER	BACT
NY-0064	INDECK-OSWEGO ENERGY CENTER	OSWEGO	10/6/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	10 PPM, 10.00 LB/HR	NO CONTROLS	BACT-OTHER
NY-0065	KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	1/18/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	491 BTU/HR	10 PPM, 11.0 LB/HR	NO CONTROLS	BACT-OTHER
NY-0066	INDECK ENERGY COMPANY	SILVER SPRINGS	5/12/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	40 PPM	NO CONTROLS	BACT-OTHER
NY-0068	KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	12/31/91	6/30/95	GAS/OIL	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	0.02 LB/MMBTU, 10 LB/HR	NO CONTROLS	BACT-OTHER
NY-0071	KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	9/10/92	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	9 PPM, 11.0 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	DIESEL GENERATOR (EP #00005)	22 MMBTU/HR	0.371 LB/MMBTU, 8.27 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	FIRE PUMP (EP #00007)	1.5 MMBTU/HR	2.88 LB/MMBTU, 4.23 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	SIEMENS V64.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	9.5 PPM	NO CONTROLS	BACT-OTHER
NY-0073	LOCKPORT COGEN FACILITY	LOCKPORT	7/14/93	4/27/95	GAS/OIL	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	423.9 MMBTU/HR	10 PPM	NO CONTROLS	BACT-OTHER
NY-0075	PILGRIM ENERGY CENTER	ISLIP		4/27/95	GAS/OIL	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1400 MMBTU/HR	10 PPM, 29.0 LB/HR		BACT-OTHER
NY-0076	TRIGEN MITCHEL FIELD	HEMPSTEAD	4/16/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE	424.7 MMBTU/HR	10 PPM, 10.0 LB/HR	NO CONTROLS	BACT-OTHER

Table 5-14. RBLC CO Summary for Distillate/Multiple Fuel Fired CTGs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
NY-0077	INDECK-YERKES ENERGY SERVICES	TONAWANDA	6/24/92	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE (EP #00001)	432.2 MMBTU/HR	10 PPM, 10 LB/HR	NO CONTROLS	BACT-OTHER
NY-0079	LEDERLE LABORATORIES	PEARL RIVER		4/27/95	GAS/OIL	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	48 PPM, 12.6 LB/HR		BACT-OTHER
NY-0081	LILCO SHOREHAM	HICKSVILLE	5/10/93	3/30/95	DIESEL	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	850 MMBTU/HR	10 PPM, 19.7 LB/HR	NO CONTROLS	BACT-OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	DIESEL	GENERATORS, DIESEL, 2	1135 KW EACH	7.9 LB/H EACH		OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	TURBINE (NATURAL GAS & OIL)	1150 MMBTU	0.0055 LB/MMBTU (GAS)*	COMBUSTION	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	GENERATOR, STEAM	450 MMBTU	0.0055 LB/MMBTU (NAT GAS)*	COMBUSTION	BACT-OTHER
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	34911	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	20 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES.	BACT-PSD
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	104 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES.	BACT-PSD
SC-0021	CAROLINA POWER AND LIGHT CO.	DARLINGTON	9/23/91	3/24/95	GAS/OIL	TURBINE, I.C.	80 MW	60 LB/H		BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	702 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	414 LB/H	PROPER OPERATION TO ACHIEVE GOOD CDMBUSTION	BACT-PSD
SC-0038	GENERAL ELECTRIC GAS TURBINES	GREENVILLE	4/19/96	8/19/96	GAS/OIL	I.C. TURBINE	2700 MMBTU/HR	27169 LB/HR	GOOD COMBUSTION PRACTICES TO MIN. EMISSIONS	BACT-PSD
SD-0001	NORTHERN STATES POWER COMPANY	NEAR SIOUX FALLS, SOUTH I	9/2/92	3/24/95	GAS/OIL	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	50 PPM FOR GAS	GOOD COMBUSTION TECHNIQUES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	1331.13 X10(7) SCF/Y NAT GAS	249.9 TOTAL TPY	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	7.44 X10(7) GPY FUEL OIL	249.9 TOTAL TPY	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) (EACH WITH A SF)	1.51 X10(9) BTU/HR N GAS	57 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) (EACH WITH A SF)	1.36 X10(9) BTU/H #2 OIL	68 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	11 LBS/HR	GOOD COMBUSTION	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	11 LBS/HR	GOOD COMBUSTION	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS (TOTAL)		48.2 TPY	GOOD COMBUSTION	BACT-PSD
VA-0206	PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	9/15/93	5/7/97	GAS/OIL	TURBINE, CCMBUSTION, SIEMENS MODEL V84.2, 3	10.2 X109 SCF/YR NAT GAS	26 LB/HR	GOOD COMBUSTION OPERATING PRACTICES	BACT-PSD
WA-0280	EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	BELLINGHAM	9/26/91	4/16/99	GAS/OIL	TURBINES; COMBINED CYCLE COGEN, GE FRAME 6	123 MW	10 PPMDV @ 15% D2		BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	8/29/92	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)		25 LBS/HR (SEE NOTES)		BACT-PSD

Source: RBLC 1999.

Table 5-22. RBLC NO_x Summary for Natural Gas Fired CTs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12600 BHP	0.58 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DLN COMBUSTION	BACT-PSD
AL-0089	SOUTHERN NATURAL GAS COMPANY-SELMA COMPRESS(	SELMA	12/4/96	12/18/96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE		53 LB/HR		BACT-PSD
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	25 PPMVD@ 15% O2 (GAS)		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	53 LB/HR		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	53 LB/HR		BACT-PSD
AL-0115	ALABAMA POWER COMPANY	MCINTOSH	12/17/97	4/24/98	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100 MW	15 PPM	DRY LOW NOX BURNERS	BACT-PSD
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)		0.07 LBS/MMBTU COMBINED	DLN ON TURBINE AND LOW NOX BURNER ON DB	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATIOI	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW	0.013 LB/MMBTU	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATIOI	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.053 LB/MMBTU	LNB AND FLUE GAS RECIRCULATION	BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	84.9 PPM @ 15% O2	LEAN BURN	NSPS
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	85.1 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	NSPS
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	225 PPM @ 15% O2	LEAN BURN	BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
CA-0418	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	8/4/93	TURBINE, GAS-FIRED	47.64 MMBTU/H	8 PPMVD @ 15% O2	HIGH TEMPERATURE SCR	BACT-PSD
CA-0437	KINGSBURG ENERGY SYSTEMS		9/28/89	8/3/93	TURBINE, NATURAL GAS FIRED, DUCT BURNER	34.5 MW	6 PPM @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
CA-0441	GRANITE ROAD LIMITED		5/6/91	8/3/93	TURBINE, GAS, ELECTRIC GENERATION	460.9 MMBTU/H*	3.5 PPMVD @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
CA-0463	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	5/31/92	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	8 PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	BACT-PSD
CA-0544	GOAL LINE, LP ICEFLOE	ESCONDIDO	33911	8/4/94	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386 MMBTU/HR	5 PPMVD @ 15% OXYGEN	H2O INJECT. & SCR W/ AUTOMATIC NH3 INJECT.	BACT-OTHER
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		9 PPM @ 15% O2	SCR, WATER INJECTN	BACT-OTHER
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX BURNERS	LAER
CA-0774	SOUTHERN CALIFORNIA GAS COMPANY	WHEELER RIDGE	5/14/97	3/16/98	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50.1 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.109 LB/MMBTU	LOW-NOX COMBUSTOR	LAER
CA-0794	CALRESOURCES LLC		1/10/97	3/16/98	SOLAR MODEL 1100 SATURN GAS TURBINE	13.6 MMBTU/HR	69 PPMVD @15% O2	NO CONTROL	LAER
CA-0845	SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	8/19/94	4/13/99	TURBINE, GAS , COMBINED CYCLE, SIEMENS V84.2	1257 MMBTU/H	3 PPMVD @ 15% O2	SCR AND DRY LOW NOX CO MBUSTION	BACT
CA-0846	CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING	ELK GROVE	7/23/93	4/13/99	TURBINE, GAS, COMBINED CYCLE, GE LM6000	450 MMBTU/H	5 PPMVD @ 15% O2	SCR AND WATER INJECTION	BACT
CA-0846	CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING	ELK GROVE	7/23/93	4/13/99	TURBINE, GAS, SIMPLE CYCLE, GE LM6000	450 MMBTU/H	5 PPMVD @ 15% O2	SCR AND WATER INJECTION	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	4/19/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25 MW	96.96 LB/D	WATER INJECTION AND SCR	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	4/19/99	TURBINE, GE, COGENERATION, 48 MW	48 MW	3.6 PPMVD @ 15% O2	STEAM INJECTION AND SCR	BACT-OTHER
CA-0863	SUNLAW COGEN. (FEDERAL COLD STORAGE COGENERATI	VERNON	1/15/94	4/19/99	TURBINE, NATURAL GAS FIRED, COMBINED CYCLE AND COG	28 MW	186817 LB/YR	WATER INJECTION AND SCONOX (MOD 2)	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	DRY LOW NOX TECH.	BACT-PSD
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX BURNER	BACT-PSD
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TU	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #1, GE FRAME 6	33 MW	25 PPM @ 15% O2	WATER INJECTION	OTHER
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #2, GE FRAME 6	33 MW	9 PPM @ 15% O2	SCR	OTHER
CO-0021	NORTHWEST PIPELINE CORPORATION	LA PLATA B" STATION"	5/29/92	7/20/94	TURBINE, SOLAR TAURUS	45 MMBTU/HR	95 PPMVD (UNTIL 11/98)	DRY LOW NOX COMBUSTOR (BY 11/01/98)	BACT-PSD
CO-0023	PHOENIX POWER PARTNERS	GREELEY	5/11/93	3/24/95	TURBINE (NATURAL GAS)	311 MMBTU/HR	22 PPM @ 15% O2	DRY LOW NOX COMBUSTION	BACT-OTHER
CO-0037	COLORADO SPRINGS UTILITIES	FOUNTAIN	1/4/99	4/19/99	TURBINE, COMBINE, NATURAL GAS FIRED	30 MW EACH	15 PPMVD ABOVE 70% LOAD	POLLUTION PREVENTION BUILT INTO EQUIPMENT	BACT-PSD
CT-0130	BRIDGEPORT ENERGY, LLC	BRIDGEPORT	6/29/98	1/21/99	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260 MW/HRSG PER TUR	6 PPM NAT. GAS	DRY LOW NOX BURNER WITH SCR	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	33444	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	25 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	25 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	42 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	25 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	25 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	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0059	SEMINOLE FERTILIZER CORPORATION	BARTOW	3/17/91	5/14/93	TURBINE, GAS	26 MW	9 PPM @ 15% O2	SCR	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX.COMBUSTOR	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0074	FLORIDA GAS TRANSMISSION	PERRY	9/27/93	4/11/94	TURBINE, GAS	131.59 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	34800	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	15 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT	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	15 PPM AT 15% OXYGEN	DLN	BACT-PSD
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	15 PPM @ 15% O2	DRY LOW NOX BURNER	BACT-PSD
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	9/28/95	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	75 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0116	SANTA ROSA ENERGY LLC	NORTHBROOK	12/4/98	4/16/99	TURBINE, COMBUSTION, NATURAL GAS	241 MW	9.8 PPM@15%O2 DB ON	DRY LOW NOX BURNER	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GA:	25 PPM @ 15% O2	MAX WATER INJECTION	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GA:	25 PPM @ 15% O2	MAX WATER INJECTION	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 PPM @ 15% O2	MAXIMUM WATER INJECTION	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 PPM @ 15% O2	MAXIMUM WATER INJECTION	BACT-PSD
GA-0056	GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	ROBINS AIR FORCE BASE	5/13/94	3/24/95	TURBINE, COMBUSTION, NATURAL GAS	80 MW	25 PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR	BACT-PSD

Table 5-22. RBLC NO_x Summary for Natural Gas Fired CTs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
LA-0079	ENRON LOUISIANA ENERGY COMPANY	EUNICE	8/5/91	10/30/91	TURBINE, GAS, 2	39.1 MMBTU/H	40 PPM @ 15% O2	H2O INJECT 0.67 LB/LB	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBIN	25 PPMV 15% O2 TURBINE	DLN/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	9 PPMV	DLN DESIGN AND CONTROL	LAER
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	25 PPMV CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION	BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLAN	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DLN DESIGN AND CONSTRUCTION.	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	25 PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	ENGINES, CHILLER, NATURAL GAS-FIRED, TWO	23.4 MMBTU/H	0.7 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1327 MMBTU/H	17.12 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	33049	7/20/94	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	77 PPM @ 15% O2	DRY PREMIX AND WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	77 PPM @ 15% O2	DRY PREMIX AND WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	2.5 PPM @15% O2	SCR AND DRY LOW NOX BUR- NERS.	LAER
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	9 PPMVD @15% O2 GAS	DLN	BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	3.5 PPM @15% O2	SELECTIVE CATALYTIC REDUCTION	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	15 PPMV	DRY LOW NOX TURBINES	BACT-PSD
MI-0244	WYANDOTTE ENERGY	WYANDOTTE	2/8/99	4/19/99	TURBINE, COMBINED CYCLE, POWER PLANT	500 MW	4.5 PPM	SCR	BACT
MS-0030	SOUTHERN NATURAL GAS COMPANY	BAY SPRINGS	12/17/96	3/24/97	TURBINE, NATURAL GAS-FIRED	9160 HORSEPOWER	110 PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	119 LB/HR	MAXIMUM WATER INJECTION	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	119 LB/HR	MAXIMUM WATER INJECTION	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.033 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NJ-0010	PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	OLDMANS TOWNSHIP	2/23/90	4/30/93	TURBINE, NATURAL GAS FIRED	1000 MMBTU/HR	0.044 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NJ-0011	LINDEN COGENERATION TECHNOLOGY	LINDEN	1/21/92	4/30/93	TURBINE, NATURAL GAS FIRED	50 X E12 BTU/YR	33.8 LB/HR	STEAM INJECTION AND SCR	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.033 LB/MMBTU	SCR, DRY LOW NOX BURNER	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.033 LB/MMBTU	SCR, DRY LOW NOX BURNER	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)	8.3 PPMDV	SCR	BACT-PSD
NJ-0030	HOFFMAN-LA ROCHE, NUTLEY COGEN FACILITY	NUTLEY	5/8/95	2/2/99	TURBINE, GM LM500	86.6 MMBTU/H	0.34 LB/MMBTU		RACT
NJ-0031	UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NEWARK	6/26/97	2/17/99	COMBUSTION TURBINE COGENERATION UNITS, 3	56 MMBTU/H	0.167 LB/MMBTU NAT.GAS		RACT
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11257 HP	42 PPM @ 15% O2	SOLONOX COMBUSTOR, DLN	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	ENGINE, GAS-FIRED, RECIPROCATING	1000 HP	1.4 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	7.4 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DLN	BACT-PSD
NM-0024	MILAGRO; WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	9 PPM @ 15% O2	DLN (GENERAL ELECTRIC MODEL PG6541B)	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STAT	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	15 PPM (SEE FAC. NOTES)	DRY LOW NOX COMBUSTION	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE FACILITY NOTES	DRY LOW NOX COMBUSTION	BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	74.4 LBS/HR	DLN	BACT-PSD
NM-0039	TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375 MMBTU/H	15 PPM	WATER INJECTION FOLLOWED BY SCR	BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLAN	LAS VEGAS	9/16/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EA	88.6 TPY (EACH TURBINE)	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	3.5 PPM @ 15% O2	SCR	LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240 MW	3.5 PPM @ 15% O2	SCR	LAER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	9 PPM GAS	STEAM INJECTION AND SCR	BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	25 PPM GAS	STEAM INJECTION	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	9 PPM	SCR	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GENERATOR, EMERGENCY (NATURAL GAS)	1.5 MMBTU/HR	1.3 LB/MMBTU	LEAN BURN ENGINE	BACT-OTHER
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	11/5/92	9/13/94	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR	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)	4.5 PPM	SCR AND DRY LOW NOX	BACT-OTHER
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	25 PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	BACT
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	1.6 G/HP-HR*	LOW NOX COMBUSTION	BACT-OTHER
OR-0007	PACIFIC GAS TRANSMITION	MADRAS	11/3/89	7/20/94	TURBINE, NAT. GAS	14600 HP	42 PPM @ 15% O2	LOW NOX BURNERS	BACT-PSD
OR-0009	PACIFIC GAS TRANSMISSION COMPANY	MADRAS	6/19/90	7/20/94	TURBINE GAS, COMPRESSOR STATION	110 MMBTU/HR	199 PPM @ 15% O2	LOW NOX BURNER DESIGN	NSPS
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1720 MMBTU	4.5 PPM @ 15% O2	SCR	BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	34522	1/27/99	TURBINES, NATURAL GAS (2)	1696 MMBTU/H	4.5 PPM @ 15% O2	SCR	BACT-PSD
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	25 PPM @ 15% O2	STEAM INJECTION/ + SCR IN 1997	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	21 LB/HR	SCR WITH LOW NOX COMBUSTORS	BACT-OTHER
PA-0130	PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	MEHOOPANY	5/31/95	11/27/95	TURBINE, NATURAL GAS	580 MMBTU/HR	55 PPM @ 15% O2	STEAM INJECTION	RACT
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	4 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION FOR OIL	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	SOLONOX BURNER: LOW NOX BURNER	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	60 LB/HR	STEAM/WATER INJECTION AND SCR	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	73 LB/HR	STEAM/WATER INJECTION AND SCR.	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	9 PPM @ 15% O2, GAS	SCR	BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	7/31/91	5/31/92	TURBINE, GAS, 2	49 MMBTU/H	100 PPM @ 15% O2	LOW NOX COMBUSTION	BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	308 LBS/HR	WATER INJECTION	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER	200 TPY	INTERNAL COMBUSTION CONTROLS	BACT-PSD
WA-0027	SUMAS ENERGY INC.	SUMAS	6/25/91	8/1/91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	SCR	BACT-PSD
WA-0274	NORTHWEST PIPELINE COMPANY	SUMAS	8/13/92	4/5/95	TURBINE, GAS-FIRED	12100 HP	196 PPM @ 15% O2	ADVANCED DLN (BY 07/01/95)	BACT-PSD
WY-0032	QUESTAR PIPELINE CORP. - RK SPRINGS COMPRESSOR CO	ROCK SPRINGS	9/25/97	2/1/99	TURBINE COMPRESSOR ENGINE, NATURAL GAS FIRED, 2EA	1001 HP	2.8 G/B-HP-H		BACT-PSD
WY-0039	TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	15 MILES SE OF WRIGHT	2/27/98	3/31/99	TURBINE, STATIONARY	33.3 MW	25 PPM @ 15% O2	DRY LOW NOX BURNERS	BACT-PSD

Source: RBLC 1999.

Table 5-23. RBLC NO_x Summary for Distillate/Multiple Fuel Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0069	INTERNATIONAL PAPER CO. RIVERDALE MILL	SELMA	1/11/93	3/24/95	GAS/OIL	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT I	40 MW	0.08 LB/MMBTU (GAS)	STEAM INJECTI ON INTO THE TURBINE	BACT-PSD
AL-0126	MOBILE ENERGY LLC	MOBILE	1/5/99	4/9/99	GAS/OIL	TURBINE, GAS, COMBINED CYCLE	168 MW	0.019 LB/MMBTU	SCR & DLN COMBUSTORS DURING GAS FIRING. STI	BACT-PSD
CA-0611	BANK OF AMERICA LOS ANGELES DATA CENTER		6/24/93	3/24/95	DIESEL	TURBINE, DIESEL & GENERATOR (SEE NOTES)		163 PPM @ 15% O2	FUEL SPEC: LOW NOX DIESEL FUEL (SEE NOTES)	BACT-OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	65 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	65 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S'	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		65 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S'	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		65 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	65 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	65 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0057	FLORIDA POWER GENERATION	DEBARY	10/18/91	3/24/95	GAS/OIL	TURBINE, OIL, 6 EACH	92.9 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	42 PPMVD @ 15 % O2	STEAM INJECTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	42 PPMVD @ 15 % O2	STEAM INJECTION	BACT-PSD
FL-0081	TECO POLK POWER STATION	BARTOW	2/24/94	3/24/95	GAS/OIL	TURBINE, FUEL OIL	1765 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	42 PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	42 PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1029 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1866 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	GAS/OIL	OIL FIRED COMBUSTION TURBINE	74 MW	42 PPM AT 15% OXYGEN	WATER INJECTION	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	GAS/OIL	OIL FIRED COMBUSTION TURBINE	74 MW	42 PPM AT 15% OXYGEN	WATER INJECTION	BACT-PSD
FL-0104	SEMINOLE HARDEE UNIT 3	FORT GREEN	1/1/96	5/31/96	GAS/OIL	COMBINED CYCLE COMBUSTION TURBINE	140 MW	15 PPM @ 15% O2	DRY LNB STAGED COMBUSTION	BACT-PSD
FL-0115	CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	7/10/98	4/16/99	GAS/OIL	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL,	2174 MMBTU/H	25 PPM @ 15% O2	DLN FOR SIMPLE CYCLE, SCR WHEN COMBINED CY	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	SEE NOTES	MAX WATER INJECTION	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	SEE NOTES	MAX WATER INJECTION	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD, FUEL N AFLOW	MAXIMUM WATER INJECTION	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD, FUEL N AFLOW	MAXIMUM WATER INJECTION	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	20 PPMVD	WATER INJECTION WITH SCR	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	20 PPMVD	WATER INJECTION WITH SCR	BACT-PSD
HI-0013	MAUI ELECTRIC COMPANY, LTD.	MAALAEA	12/3/91	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	28 MW	42 PPM	WATER INJECTION	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	42.3 LB/HR	COMBUSTOR WATER INJECTOR, WATER INJECTION	BACT-PSD
HI-0015	MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING	MAUI	7/28/92	3/24/95	GAS/OIL	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	42.3 LB/HR	WATER INJECTION	BACT-OTHER
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	3/10/92	3/24/95	GAS/OIL	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1500 MM BTU/HR (EACH)	42 PPM @ 15% O2, N. GAS	WATER INJECTION	BACT-PSD
KY-0057	EAST KENTUCKY POWER COOPERATIVE		34052	3/24/95	GAS/OIL	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1492 MMBTU/H (EACH)	42 PPM @ 15% O2 (OIL)	WATER INJECTION	SEE NOTES
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	DIESEL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	40 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	DIESEL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	40 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0021	MILLENNIUM POWER PARTNER, LP	CHARLTON	2/2/98	4/19/99	GAS/OIL	TURBINE, COMBUSTION, WESTINGHOUSE MODEL	2534 MMBTU/H	0.013 LB/MMBTU	DLN IN CONJUNCTION WITH SCR ADD-ON NOX CON	BACT-PSD
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	GAS/OIL	TURBINE, COMBUSTION, ABB GT24	1792 MMBTU/H	20.3 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	DIESEL	ENGINE, DIESEL, FIRE PUMP	1.5 MMBTU/H	4.41 LB/MMBTU	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	32782	3/24/95	DIESEL	TURBINE, OIL FIRED ELECTRIC	90 MW	400 LB/HR	WATER INJECTION	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	DIESEL	TURBINE, OIL FIRED ELECTRIC	90 MW	400 LB/HR	WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 105 MW OIL FIRED ELECTRIC	105 MW	25 PPM @ 15% O2	DRY PREMIX BURNER	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 84 MW OIL FIRED ELECTRIC	84 MW	58 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 105 MW OIL FIRED ELECTRIC	105 MW	25 PPM @ 15% O2	DRY PREMIX BURNER	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 84 MW OIL FIRED ELECTRIC	84 MW	58 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	DIESEL	TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	65 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	DIESEL	TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	65 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	DIESEL	TURBINE, 124 MW OIL FIRED	125 MW	77 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	DIESEL	TURBINE, 124 MW OIL FIRED	125 MW	77 PPM @ 15% O2	WATER INJECTION	BACT-PSD
ME-0016	GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	12/4/98	4/19/99	GAS/OIL	TURBINE, COMBINED CYCLE	900 MW TOTAL	2.5 PPM @ 15% O2 (NAT G)	SCR. EMISSION IS FROM EACH 300 MW SYSTEM.	LAER
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	DIESEL	DIESEL ENGINE-DRIVEN FIRE PUMP	2.7 MMBTU/HR	5 LB/HR	RETARDATION OF ENGINE TIMING, TURBOCHARGE	BACT-PSD
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	GAS/OIL	COMBUSTION TURBINE/GENERATOR	1970 MMBTU/HR	4.5 PPM @ 15% O2 GAS	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	DIESEL	ENGINE, DIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	1.85 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	GENERATOR, COMBUSTION TURBINE & DUCT BUF	1988 MMBTU/H (CTG)	4.5 PPMDV @15%O2 (NG)	SCR WITH A NOX CEM AND A NOX PEM.	BACT-PSD
MO-0013	HIGGINSVILLE MUNICIPAL POWER FACILITY	HIGGENSVILLE	7/27/95	10/6/97	GAS/OIL	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49.1 MW	75 PPM BY VOL 1 HR AVG	CONTROLS FOR FUEL CONSUMPTION AND WATER	BACT-PSD
MO-0013	HIGGINSVILLE MUNICIPAL POWER FACILITY	HIGGENSVILLE	7/27/95	10/6/97	GAS/OIL	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49.1 MW	42 PPM BY VOL 1 HR AVG	CONTROLS FOR FUEL CONSUMPTION AND WATER	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	1135 TPY	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	25 PPM BY VOL 1 HR AVG	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
MO-0017	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	2/28/95	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	88.77 MW	360 TPY	WATER INJECTION.	BACT-PSD
MO-0043	UNION ELECTRIC CO	WEST ALTON	5/6/79	10/6/97	GAS/OIL	CONSTRUCTION OF A NEW OIL FIRED COMBUSTIC	622 MM BTU/HR	5242 TPY	WATER INJECTION FOR NOX EMISSIONS	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	12/20/91	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	287 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER IN.	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	33592	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	287 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER IN.	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	158 LB/HR	WATER INJECTION	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	512.3 LB/HR	WATER INJECTION, FUEL SPEC: 0.04% N FUEL OIL	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	GAS/OIL	TURBINE, KEROSENE FIRED	585 MMBTU/HR	0.063 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.082 LB/MMBTU	SCR AND WATER INJECTION	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.082 LB/MMBTU	SCR AND WATER INJECTION	BACT-OTHER

Table 5-23. RBLC NO_x Summary for Distillate/Multiple Fuel Fired CTGs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Throput Rate		Emission Limit	Control System Description	Basis
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1	MW EACH	NOT APPLICABLE	GOOD COMBUSTION PRACTICE	RACT
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1	MW EACH	43.38 LB/H		BACT
NV-0015	SAGUARO POWER COMPANY	HENDERSON	6/17/91	6/1/93	GAS/OIL	COMBUSTION TURBINE GENERATOR	34.5	MW	16.9 PPH (WINTER)	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
NV-0030	MUDDY RIVER L.P.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140	MEGAWATT	303 LB/HR	LOW NOX BURNER	BACT-PSD
NV-0031	CSW NEVADA, INC.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140	MEGAWATT	273 LB/HR	DRY LOW NOX COMBUSTOR	BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240	MW	10 PPM @ 15% O2	SCR	LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000	KW	2.6 LB/MMBTU		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240	MW	10 PPM @ 15% O2	SCR	LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000	KW	2.6 LB/MMBTU		LAER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	DIESEL	FIRE PUMP (DIESEL)	1.3	MMBTU/HR	1.3 LB/MMBTU	LEAN BURN ENGINE	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION GAS (150 MW)	1146	MMBTU/HR (GAS)*	9 PPM	DRY LOW NOX	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION GAS (150 MW)	1146	MMBTU/HR (GAS)*	42 PPM	WATER INJECTOR	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILI	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (7	650	MMBTU/HR	9 PPM	DRY LOW NOX OR SCR	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILI	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (7	650	MMBTU/HR	55 PPM	DRY LOW NOX OR SCR	BACT-OTHER
NY-0057	MEGAN-RACINE ASSOCIATES, INC	CANTON	8/5/89	3/30/95	GAS/OIL	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	LB/MMBTU	42 PPMDV @ 15% O2	WATER INJECTION	BACT
NY-0061	ANITEC COGEN PLANT	BINGHAMTON	7/7/93	4/27/95	GAS/OIL	GE LM5000 COMBINED CYCLE GAS TURBINE EP #	451	MMBTU/HR	25 PPM, 41 LB/HR	NO CONTROLS	BACT-OTHER
NY-0062	FULTON COGEN PLANT	FULTON	34592	4/27/95	GAS/OIL	GE LM5000 GAS TURBINE	500	MMBTU/HR	36 PPM, 65 LB/HR	WATER INJECTION	BACT
NY-0063	TBG COGEN COGENERATION PLANT	BETHPAGE	8/5/90	4/27/95	GAS/OIL	GE LM2500 GAS TURBINE	214.9	MMBTU/HR	75 PPM + FBN CORRECTION	WATER INJECTION	BACT
NY-0064	INDECK-OSWEGO ENERGY CENTER	OSWEGO	10/6/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	533	LB/MMBTU	42 PPM, 75.00 LB/HR	STEAM INJECTION	BACT
NY-0065	KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	1/18/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	491	BTU/HR	42 PPM, 76.6 LB/HR	STEAM INJECTION	BACT
NY-0066	INDECK ENERGY COMPANY	SILVER SPRINGS	5/12/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE EP #00001	491	MMBTU/HR	32 PPM	STEAM INJECTION	BACT
NY-0068	KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	12/31/91	6/30/95	GAS/OIL	GE FRAME 6 GAS TURBINE	500	MMBTU/HR	42 PPM, 80.1 LB/HR	STEAM INJECTION	BACT
NY-0071	KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	9/10/92	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	498	MMBTU/HR	42 PPM, 76.6 LB/HR	WATER INJECTION	BACT
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	DIESEL GENERATOR (EP #00005)	22	MMBTU/HR	1.166 LB/MMBTU, 26.0 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	FIRE PUMP (EP #00007)	1.5	MMBTU/HR	4.25 LB/MMBTU, 6.25 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	SIEMENS V64.3 GAS TURBINE (EP #00C01)	650	MMBTU/HR	25 PPM	WATER INJECTION	BACT
NY-0073	LOCKPORT COGEN FACILITY	LOCKPORT	7/14/93	4/27/95	GAS/OIL	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	423.9	MMBTU/HR	42 PPM	STEAM INJECTION	BACT
NY-0075	PILGRIM ENERGY CENTER	ISLIP		4/27/95	GAS/OIL	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 0C	1400	MMBTU/HR	4.5 PPM, 23.6 LB/HR	STEAM INJECTION FOLLOWED BY SCR	BACT
NY-0076	TRIGEN MITCHEL FIELD	HEMPSTEAD	4/16/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE	424.7	MMBTU/HR	60 PPM, 90 LB/HR	STEAM INJECTION	BACT
NY-0077	INDECK-YERKES ENERGY SERVICES	TONAWANDA	6/24/92	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE (EP #00001)	432.2	MMBTU/HR	42 PPM, 74 LB/HR	STEAM INJECTION	BACT
NY-0079	LEDERLE LABORATORIES	PEARL RIVER		4/27/95	GAS/OIL	(2) GAS TURBINES (EP #S 00101&102)	110	MMBTU/HR	42 PPM, 18 LB/HR	STEAM INJECTION	BACT-PSD
NY-0081	LILCO SHOREHAM	HICKSVILLE	5/10/93	3/30/95	DIESEL	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	850	MMBTU/HR	55 PPM + FBN & HEAT RATE	WATER INJECTION	BACT
OK-0027	OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	12/17/92	3/24/95	GAS/OIL	TURBINE, COMBUSTION	58	MW	25 PPM @ 15% O2	COMBUSTION CONTROLS	BACT-OTHER
OK-0027	OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	12/17/92	3/24/95	GAS/OIL	TURBINE, COMBUSTION	58	MW	65 PPM @ 15% O2	COMBUSTION CONTROLS	BACT-OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	DIESEL	GENERATORS, DIESEL, 2	1135	KW EACH	36 LB/H EACH		OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	TURBINE (NATURAL GAS & OIL)	1150	MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	GENERATOR, STEAM	450	MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCL	248	MW	35 LB/HR AS NO2	STEAM INJECTION PLUS SCR. N2 NOT TO EXCEED (	BACT-PSD
SC-0021	CAROLINA POWER AND LIGHT CO.	DARLINGTON	9/23/91	3/24/95	GAS/OIL	TURBINE, I.C.	80	MW	292 LB/H	WATER INJECTION	BACT-PSO
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520	MMBTU/H	25 PPMDV @ 15% O2	WATER INJECTION	BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520	MMBTU/H	62 PPMDV @ 15% O2	WATER INJECTION	BACT-PSD
SC-0038	GENERAL ELECTRIC GAS TURBINES	GREENVILLE	4/19/96	8/19/96	GAS/OIL	I.C. TURBINE	2700	MMBTU/HR	885.3 LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMIS	BACT-PSD
SD-0001	NORTHERN STATES POWER COMPANY	NEAR SIOUX FALLS, SOUTH C	9/2/92	3/24/95	GAS/OIL	TURBINE, SIMPLE CYCLE, 4 EACH	129	MW	24 PPM @ 15% O2 GAS	WATER INJECTION FOR GAS & DISTILLATION	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	1331.13	X10(7) SCF/Y NAT (	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR) W/ WATE	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	7.44	X10(7) GPY FUEL O	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) (EACH WITH A SF)	1.51	X10(9) BTU/HR N.G.	9 PPMDV/UNIT @ 15% O2	SCR WITH WATER INJECTION	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) (EACH WITH A SF)	1.36	X10(9) BTU/H #2 OI	66 LBS/HR/UNIT	WATER INJECTION AND SCR	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	474	X10(6) BTU/HR N. C	9 PPM	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	468	X10(6) BTU/HR #2 (	15 PPM	SCR	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS (TOTAL)			69.7 TPY	SCR	BACT-PSD
VA-0206	PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	9/15/93	5/7/97	GAS/OIL	TURBINE, COMBUSTION, SIEMENS MODEL V84.2,	10.2	X109 SCF/YR NAT	131 LB/HR(GAS), 339 OIL	DRY LOW NOX COMBUSTOR, DESIGN, WATER INJE	BACT-PSD
WA-0280	EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PR(	BELLINGHAM	9/26/91	4/16/99	GAS/OIL	TURBINES, COMBINED CYCLE COGEN, GE FRAME	123	MW	7 PPMDV@15%O2 NG	STEAM INJECTION AND SCR	BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	33845	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)			25 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	8/29/92	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)			65 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD

Source: RBLC 1999.

Table 5-15. 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
09/28/98	Florida Power Corp. 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 Center	167	9	Good combustion
			24 (with duct burner)	Good combustion

Source: FDEP, 1998.

Table 5-16. Florida BACT CO Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	63	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	30	Good combustion
02/21/94	Polk Power Partners	84	35	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	40	Good combustion
07/20/94	Pasco Cogen, Limited	42	18	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	25	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	90	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	90	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	30	Good combustion

Source: FDEP, 1998.

The application of DLN combustors for the HCGF CTGs results in a trade-off between NO_x and CO emission rates. Because ambient CO concentrations in the vicinity of the HCGF would be expected to be well below ambient standards, the reduction in NO_x emissions is considered to have a greater environmental benefit and would more than compensate for the higher CO emission rates associated with DLN technology.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOC. These control techniques have been considered by FDEP to represent BACT for CO and VOC for all simple-cycle CTG projects. Tables 5-17 and 5-18 summarize the CO and VOC BACT emission limits proposed for the HCGF, respectively.

5.5 BACT ANALYSIS FOR NO_X

NO_x emissions from combustion sources consist of two components: oxidation of combustion air atmospheric nitrogen (thermal NO_x and prompt NO_x) and conversion of chemically bound fuel nitrogen (fuel NO_x). Essentially all CT NO_x emissions originate as nitric oxide (NO). NO generated by the CT combustion process is subsequently further oxidized in the CT exhaust system or in the atmosphere to the more stable NO_2 molecule.

Thermal NO_x results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism. Prompt NO_x is formed near the combustion flame front from the oxidation of intermediate combustion products such as hydrogen cyanide (HCN), nitrogen (N), and NH. Prompt NO_x comprises a small portion of total NO_x in conventional near-stoichiometric CTG combustors but increases under fuel-lean conditions. Prompt NO_x, therefore, is an important consideration with respect to DLN combustors that use lean fuel mixtures. Fuel NO_x arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound nitrogen content

Table 5-17. Proposed CO BACT Emission Limits

Emission Source	lb/hr*	ppmvd†
GE PG7241 (FA) CTGs		
(Natural Gas-Fired, Per CTG)	52.8	12
(Distillate Fuel Oil-Fired, Per CTG)	116.6	23
Westinghouse 501F CTGs		
(Natural Gas-Fired, Per CTG)	75.9	16
(Distillate Fuel Oil-Fired, Per CTG)	95.7	20
Westinghouse 501D5A CTGs		
(Natural Gas-Fired, Per CTG)	31.8	10
(Distillate Fuel Oil-Fired, Per CTG)	95.9	28
ABB GT-24 CTGs		
(Natural Gas-Fired, Per CTG)	23.1	6
(Distillate Fuel Oil-Fired, Per CTG)	126.6	25

*At ISO conditions.
†Maximum at base load conditions.

Sources: GE, 1998.
Westinghouse, 1998.
ABB, 1998.
ECT, 2000.

Table 5-18. Proposed VOC BACT Emission Limits

Emission Source	lb/hr*	ppmvd†
GE PG7241 (FA) CTGs		
(Natural Gas-Fired, Per CTG)	3.1	1.2
(Distillate Fuel Oil-Fired, Per CTG)	7.7	2.8
Westinghouse 501F CTGs		
(Natural Gas-Fired, Per CTG)	8.8	3.0
(Distillate Fuel Oil-Fired, Per CTG)	28.6	10.0
Westinghouse 501D5A CTGs		
(Natural Gas-Fired, Per CTG)	5.4	3.0
(Distillate Fuel Oil-Fired, Per CTG)	20.2	10.0
ABB GT-24 CTGs		
(Natural Gas-Fired, Per CTG)	2.9	1.5
(Distillate Fuel Oil-Fired, Per CTG)	22.7	7.5

*At ISO conditions.
†Maximum at base load conditions.

Sources: GE, 1998.
Westinghouse, 1998.
ABB, 1998.
ECT, 2000.

of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN (see Table 5-2). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however, the N_2 found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies for controlling NO_x emissions from CTGs include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications:

- Water or steam injection and standard combustor design.
- Water or steam injection and advanced combustor design.
- DLN combustor design.

Postcombustion Exhaust Gas Treatment Systems:

- Selective non-catalytic reduction (SNCR).
- Non-selective catalytic reduction (NSCR).
- SCR.
- SCONOx™

A description of each of the listed control technologies is provided in the following sections.

Water or Steam Injection and Standard Combustor Design

Injection of water or steam into the primary combustion zone of a CTG reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel. Water or steam injection will not reduce the formation of fuel NO_x.

The maximum amount of steam or water that can be injected depends on the CTG combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam or water injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely effect safe, efficient, and reliable operation of the turbine.

The use of water or steam injection and standard turbine combustor design can generally achieve NO_x exhaust concentrations of 42 and 65 ppmvd for gas and oil firing, respectively.

Water or Steam Injection and Advanced Combustor Design

Water or steam injection functions in the same manner for advanced combustor designs as described previously for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO_x and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd for gas and oil firing, respectively.

Dry Low-NO_x Combustor Design

A number of turbine vendors have recently developed DLN combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperature are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 40 percent of baseline due to flame stability considerations. During oil firing, wet injection is employed to control NO_x emissions.

In addition to lean premixed combustion, CTG DLN combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All CTGs cool the high-temperature CTG exhaust gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the CTG turbine. By adding additional dilution air, the hot CTG exhaust gases are rapidly cooled to temperatures below those needed for NO_x formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO_x is reduced because the CTG combustion gases are at a higher temperature for a shorter period of time.

Current DLN combustor technology can typically achieve a NO_x exhaust concentration of 9 to 25 ppmvd or less using natural gas fuel.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor.

Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Non-Selective Catalytic Reduction

The NSCR process utilizes a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3 percent O_2) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting NH_3 with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. NH_3 is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), NH_3/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions.

As was the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in

NO_x emissions. Specially formulated high temperature zeolite catalysts have been recently developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. The exhaust temperature range for a typical simple cycle unit is 1,067 to 1,200°F. Accordingly, the CTG exhaust temperature would need to be reduced to an acceptable level prior to treatment by a hot SCR control system. NO_x removal efficiencies for SCR systems typically range from 50 to 90 percent.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CTGs has been primarily limited to natural gas-fired units.

<u>SCONO$_x$™</u>

SCONO$_x$™ is a NO_x and CO catalytic absorption control system exclusively offered by Goal Line Environmental Technologies (GLET).

The SCONO$_x$™ system operates at a temperature range of 300 to 700°F and, therefore, is not applicable to simple-cycle CTGs.

<u>Technical Feasibility</u>

All of the combustion process modification technologies mentioned (water or steam injection and standard combustor design, water or steam injection and advanced combustor, and DLN combustor design) would be feasible for the HCGF CTGs. Of the postcombustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CT exhaust gas streams (approximately 1,100°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent O_2) environment. Due to high excess air rates, the O_2 content of combustion turbine exhaust gases is typically 13 percent. The SCONO$_x$™ control technology is not technically feasible because the temperature required for this technology (between 300 to 700°F) is well below the 1,100°F typically occurring for simple-cycle CTG exhaust gas streams.

For natural gas firing, use of advanced DLN combustor technology will achieve NO_x emission rates comparable to or less than wet injection based on CTG vendor data. Accordingly, the BACT analysis for NO_x for the HCGF CTGs was confined to advanced DLN combustors (natural gas firing), water injection (distillate fuel oil firing), and the application of postcombustion hot SCR control technologies. Hot SCR is considered potentially feasible with the addition of CTG exhaust stream cooling. However, there are currently no such installations on large, simple-cycle CTGs. The following sections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.5.2 ENERGY AND ENVIRONMENTAL IMPACTS

The use of advanced DLN combustor technology will not have a significant adverse impact on CTG heat rate.

The installation of hot SCR technology would cause an increase in back pressure on the CTGs due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. For the Westinghouse 501F CTGs, the reduction in turbine output power (lost power generation) will result in an energy penalty of 3,060,000 kilowatt-hours (kwh) (10,441 million British thermal units [MMBtu]) per year at baseload (170 MW) operation and 3,000 hr/yr operation per CT. This energy penalty is equivalent to the use of 29.8 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 all three CTGs. The lost power generation energy penalty, based on a power cost of $0.060/kwh, is $481,951 per year for all three CTGs. The magnitude of the energy penalty will be comparable for the GE 7FA and ABB GT-24 CTGs and somewhat lower for the Westinghouse 501D5A CTGs.

There are no significant adverse environmental effects due to the use of advanced DLN combustor technology. In contrast, application of hot SCR technology would result in the following adverse environmental impacts:

- NH_3 emissions due to *ammonia slip*; NH_3 emissions are estimated to total 134 tpy (at baseload and 59°F ambient temperature) for a SCR design NH_3 slippage rate of 5 ppmvd for three CTGs. However, ammonia slip can increase significantly during start-ups, upsets or failures of the NH_3 injection system, or due to catalyst degradation. In instances where such events have occurred, NH_3 exhaust concentrations of 50 ppmv or greater have been measured. Since the odor threshold of NH_3 is 20 ppmv, releases of NH_3 during upsets or malfunctions have the potential to cause ambient odor problems. NH_3 also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, NH_3 can cause eye, skin, and mucous membrane irritation. These effects can vary from minor irritation to severe damage. Contact of the skin or mucosa with liquid NH_3 or a high vapor concentration can result in burns or obstructed breathing.
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases; total PM emissions would increase by approximately 50 percent.

5.5.3 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced DLN combustor technology and baseline technology with the addition of SCR controls. The economic analysis was conducted for the ABB GT-24 CTGs because these units are estimated to have the highest annual HCGF NO_x emission rate and, therefore, expected to have the lowest control system cost effectiveness. Cost effectiveness of SCR control technology for the remaining CTGs under consideration will be comparable to that determined for the ABB GT-24 CTGs. Baseline technology is expected to achieve NO_x exhaust concentrations of 25 and 42 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing, respectively. SCR technology was premised to achieve NO_x concentrations of 3.5 and 10.0 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing, respectively. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired CTGs equipped with DLN combustor technology and SCR controls.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-9. Emission reductions were calculated assuming baseload operation for 2,500 and 500 hr/yr (for natural gas and distillate fuel oil firing, respectively) at an annual average ambient temperature of 59°F. Tables 5-19 and 5-20 summarize specific capital and annual operating costs for the SCR control system, respectively.

Cost effectiveness for the application of SCR technology to the HCGF CTGs was determined to be \$9,394 per ton of NO_x removed. This control cost is considered economically unreasonable. Table 5-21 summarizes results of the NO_x BACT analysis.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

BACT NO_x limits obtained from the RBLC database for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-22 and 5-23, respectively. Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are shown in Tables 5-24 and 5-25.

FDEP natural gas-fired CTG NO_x BACT determinations for the past 5 years range from 12 to 25 ppmvd at 15-percent oxygen with an average NO_x limit of 15 ppmvd at 15-percent oxygen. Of the ten most recent FDEP NO_x BACT determinations for CTGs, seven determinations established a limit of 15 ppmvd or higher.

Table 5-26 summarizes the NO_x BACT emission limits proposed for the HCGF. NO_x emission rates proposed as BACT for the HCGF CTGs are consistent with prior FDEP BACT determinations.

Table 5-19. Capital Costs for SCR System – Three CTGs

Item	Dollars		OAQPS Factor
Direct Costs			
Purchased equipment	14,549,733	(A)	
Sales tax	872,984		0.06 × A
Freight	727,487		0.05 × A
Instrumentation	1,454,973		0.10 × A
Subtotal Purchase Equipment	**$17,605,177**		B
Installation			
Foundations and supports	1,408,414		0.08 × B
Handling and erection	2,464,725		0.14 × B
Electrical	704,207		0.04 × B
Piping	352,104		0.02 × B
Insulation for ductwork	176,052		0.01 × B
Painting	176,052		0.01 × B
Subtotal Installation Cost	**$5,281,553**		
Subtotal Direct Costs	**$22,886,730**		
Indirect Costs			
Engineering	1,760,518		0.10 × B
Construction and field expenses	880,259		0.05 × B
Contractor fees	1,760,518		0.10 × B
Start-up	352,104		0.02 × B
Performance test	176,052		0.01 × B
Contingency	528,155		0.15 × B
Subtotal Indirect Costs	**$5,457,605**		
TOTAL CAPITAL INVESTMENT	**$28,344,335**	(TCI)	

Sources: Engelhard, 1999.
ECT, 2000.

Table 5-20. Annual Operating Costs for SCR System

Item	Dollars		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	5,063	(A)	
Supervisor	759		0.15 × A
Maintenance			
Labor	5,625	(B)	
Materials	5,625		1.00 × B
Subtotal Labor, Material, and Maintenance Costs	**$17,072**	**(C)**	
Catalyst costs			
Replacement (materials and labor)	$7,639,804		
Annualized Catalyst Costs	**$1,754,155**		
Raw materials and utilities			
Electricity	308,094		
Aqueous NH_3	159,052		
Subtotal Raw Materials and Utilities	**$467,146**		
Energy penalties			
Turbine backpressure	583,200		
Subtotal Direct Costs	**$2,821,573**	(TDC)	
Indirect Costs			
Overhead	10,243		0.60 × C
Administrative charges	566,887		0.02 × TCI
Property taxes	283,443		0.01 × TCI
Insurance	283,443		0.01 × TCI
Capital recovery	3,445,641		
Emission Fee Credit	(6,570)		
Subtotal Indirect Costs	**$4,583,087**		
TOTAL ANNUAL COST	**$7,404,660**		

Sources: Engelhard, 1999.
ECT, 2000.

Table 5-21. Summary of NO_x BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
Oxidation catalyst	105.1	157.6	788.2	28,344,335	7,404,660	9,394	33,166	Y	Y
Baseline	430.5	945.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Three ABB GT-24 CTGs, 100-percent load for 2,500 hr/yr gas-firing and 500 hr/yr oil-firing.

Sources: Westinghouse, 1998.
Engelhard, 1999.
GPP, 1999.
ECT, 2000.

Table 5-24. Florida BACT NO_X Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_X Emission Limit (ppmvd)	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	15	DLN combustors
08/17/92	Florida Power Corp. University of Florida	43	25	Steam injection
12/17/92	Auburndale Power Partners	104	25	Steam injection
			15	Steam injection
04/09/93	Kissimmee Utility Authority	40	25	Water injection
			15	DLN combustors
04/09/93	Kissimmee Utility Authority	80	25	Water injection
			15	DLN combustors
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	25	DLN combustors
		184	15	DLN combustors
02/21/94	Polk Power Partners	84	25	DLN combustors
			15	DLN combustors
02/24/94	Tampa Electric Company Polk Power Station	260	25	Nitrogen diluent injection
07/20/94	Pasco Cogen, Limited	42	25	Wet injection
03/07/95	Orange Cogeneration, L.P.	39	15	DLN combustors
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	15	DLN combustors
06/01/95	Panda-Kathleen	75	15	DLN combustors
09/28/95	City of Key West (relocated unit)	23	75	Water injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	15	DLN combustors
05/98	City of Tallahassee Purdom Unit 8	160	12	DLN combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	25	DLN combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	9	DLN combustors or SCR (effective 05/01/2002)
09/28/98	Florida Power Corp. Hines Energy Complex	165	12	DLN combustors and/or SCR
12/04/98	Santa Rosa Energy Center	167	9	DLN combustors

Source: FDEP, 1998.

Table 5-25. Florida BACT NO_X Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_X Emission Limit (ppmvd)	Control Technology
08/17/92	Florida Power Corp. University of Florida	43	42	Steam injection
08/17/92	Florida Power Corp. Intercession City	93	42	Wet injection
08/17/92	Florida Power Corp. Intercession City	186	42	Steam injection
12/17/92	Auburndale Power Partners	104	42	Steam injection
04/09/93	Kissimmee Utility Authority	40	42	Water injection
04/09/93	Kissimmee Utility Authority	80	42	Water injection
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	42	Wet injection
02/21/94	Polk Power Partners	84	42	Wet injection
02/24/94	Tampa Electric Company Polk Power Station	260	42	Wet injection
07/20/94	Pasco Cogen, Limited	42	42	Wet injection
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	42	Wet injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	—	—
05/98	City of Tallahassee Purdom Unit 8	160	42	Water or steam injection
07/10/98	City of Lakeland McIntosh Unit 5	250	42	Water injection
09/28/98	Florida Power Corp. Hines Energy Complex	165	42	Water injection

Source: FDEP, 1998.

Table 5-26. Proposed NO_x BACT Emission Limits

Emission Source	lb/hr*	ppmvd†
GE PG7241 (FA) CTGs		
(Natural Gas-Fired, Per CTG)	75.7	10.5
(Distillate Fuel Oil-Fired, Per CTG)	350.9	42
Westinghouse 501F CTGs		
(Natural Gas-Fired, Per CTG)	116.9	15
(Distillate Fuel Oil-Fired, Per CTG)	328.9	42
Westinghouse 501D5A CTGs		
(Natural Gas-Fired, Per CTG)	80.6	15
(Distillate Fuel Oil-Fired, Per CTG)	240.7	42
ABB GT-24 CTGs		
(Natural Gas-Fired, Per CTG)	183.7	25
(Distillate Fuel Oil-Fired, Per CTG)	342.5	42

*At ISO conditions.
† Corrected to 15-percent O_2, maximum at base load conditions.

Sources: GE, 1998.
Westinghouse, 1998.
ABB, 1998.
ECT, 2000.

5.6 BACT ANALYSIS FOR SO2 AND H2SO4 MIST

5.6.1 POTENTIAL CONTROL TECHNOLOGIES

Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and postcombustion 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 and fuel oils containing sulfur compounds (e.g., H_2S), a variety of technologies are available to remove these sulfur compounds to acceptable levels. Desulfurization of natural gas and fuel oils are performed by the fuel supplier prior to distribution by pipeline.

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be 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 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

Treatment of natural gas and fuel oils to remove sulfur compounds is conducted by the fuel supplier, when necessary, prior to distribution. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas and distillate fuel oil sulfur contents have already been reduced to very low levels.

There have been no applications of FGD technology to CTGs because low sulfur fuels are typically used. The HCGF CTGs will be fired with natural gas and distillate fuel oil. The sulfur content of natural gas, the primary fuel source, is more than 100 times lower than the fuels (e.g., coal) employed in boilers using FGD systems. In addition, CTGs operate with a significant amount of excess air that generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of an FGD system to a CTG 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 because removal efficiencies would be unreasonably low.

5.6.2 PROPOSED BACT EMISSION LIMITATIONS

Because postcombustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the HCGF CTGs. Natural gas used at the HCGF will contain no more than 2.0 gr S/100 scf. Distillate fuel oil used for the new CTGs as a back-up fuel source will contain no more than 0.05 wt%S. The proposed BACT limits are based on the use of natural gas containing no more than 2.0 gr S/100 scf and distillate fuel oil containing no more than 0.05 wt%S. Table 5-27 summarizes the SO_2 and H_2SO_4 mist BACT emission limits proposed for the HCGF.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-28 summarizes control technologies proposed by the applicant as BACT for each pollutant subject. Table 5-29 summarizes specific applicant proposed BACT emission limits for each pollutant.

Table 5-27. Proposed SO_2 and H_2SO_4 Mist BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits* Fuel Sulfur Content (wt%S)
Natural Gas firing, All CTGs		
	SO_2	Pipeline Quality Natural Gas
	H_2SO_4 mist	Pipeline Quality Natural Gas
Distillate Fuel Oil firing, All CTGs		
	SO_2	≤0.05
	H_2SO_4 mist	≤0.05

*Maximum rates for all operating scenarios.

Sources: GPP, 1999.
ECT, 1999.

Table 5-28. Summary of BACT Control Technologies

Pollutant	Control Technology
PM/PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil. • Efficient and complete combustion.
CO/VOC	• Efficient and complete combustion.
NO_x	• Use of advanced DLN burners (natural gas firing). • Use of wet injection (distillate fuel oil firing).
SO_2/H_2SO_4 mist	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil.

Source: ECT, 2000.

Table 5-29. Summary of Proposed BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits ppmvd	lb/hr
All CTGs			
Natural Gas firing, Per CTG			
	PM/PM_{10}	10-percent opacity	
	SO_2	Pipeline Quality Natural Gas	
	H_2SO_4 mist	Pipeline Quality Natural Gas	
Distillate Fuel Firing, Per CTG			
	PM/PM_{10}	10-percent opacity (GE PG7241 [FA] CTG)	
	PM/PM_{10}	20-percent opacity	
	SO_2	Fuel Oil ≤0.05 wt % S	
	H_2SO_4 mist	Fuel Oil ≤0.05 wt % S	
GE PG7241 (FA) CTGs			
Natural Gas firing, Per CTG			
	CO	12*	52.8†
	NO_x	10.5*	75.7†
	VOC	1.2*	3.1†
Distillate Fuel Firing, Per CTG			
	CO	23*	116.6†
	NO_x	42*	350.9†
	VOC	2.8*	7.7†
WESTINGHOUSE 501F CTGs			
Natural Gas firing, Per CTG			
	CO	16*	75.9†
	NO_x	15*	116.9†
	VOC	3.0*	8.8†
Distillate Fuel Firing, Per CTG			
	CO	20*	95.7†
	NO_x	42*	328.9†
	VOC	10.0*	28.6†

Table 5-29. Summary of Proposed BACT Emission Limits (Page 2 of 2)

Emission Source	Pollutant	Proposed BACT Emission Limits ppmvd	lb/hr
WESTINGHOUSE 501D5A CTGs			
Natural Gas firing, Per CTG			
	CO	10*	31.8†
	NO_x	15*	80.6†
	VOC	3.0*	5.4†
Distillate Fuel Firing, Per CTG			
	CO	28*	95.9†
	NO_x	42*	240.7†
	VOC	10.0*	20.2†
ABB GT-24 CTGs			
Natural Gas firing, Per CTG			
	CO	6*	23.1†
	NO_x	25*	183.7†
	VOC	1.5*	2.9†
Distillate Fuel Firing, Per CTG			
	CO	25*	126.6†
	NO_x	42*	342.5†
	VOC	7.5*	22.7†

* Corrected to 15 percent O_2, at base load conditions.
† ISO conditions.

Sources: GE, 1998.
Westinghouse, 1998.
ABB, 1998.
ECT, 2000.

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 practice. Guidance contained in EPA manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the Project will have the potential to emit 950.1 tpy NO_x, 518.3 tpy of CO, 125.5 tpy of PM/PM_{10}, 108.1 tpy of SO_2, 73.8 tpy of VOCs, and 14.0 tpy of H_2SO_4 mist. Table 3-2 previously provided a comparison of estimated potential annual emission rates for the Project and the PSD significant emission rate thresholds. As shown in that table, potential emissions of NO_x, CO, PM/PM_{10}, H_2SO_4, and SO_2 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.

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 simple-cycle CTGs. 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, fuel type, 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 predefined, worst-case meteorological conditions. SCREEN3 is appropriate for use in assessing building wake downwash. SCREEN3 also includes algorithms for analyzing concentrations on simple and complex terrain. Both simple terrain and the rural designation were selected for all SCREEN3 analyses.

The proposed CTGs may operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and fuel type (i.e., natural gas or distillate fuel oil). Plume dispersion and, therefore, ground-level impacts will be affected by these different operating scenarios since 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 that caused the highest impact. These worst-case operating scenarios were then subsequently evaluated using the refined Industrial Source Complex (ISC3) dispersion model. 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, Tables 7-1 through 7-4. 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 ISC3 models (EPA, 1999) 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 99155) 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 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.

6.3.3 NO_2 AMBIENT IMPACT ANALYSIS

For annual NO_2 impacts, the tiered screening approach described in the GAQM, Section 6.2.3 was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO_2. Tier 2 applies an empirically derived NO_2/NO_x ratio of 0.75 to the Tier 1 results.

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 uses 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 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 HCGF (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as 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 CTGs stack bases for modeling purposes).

6.6 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

According to EPA 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 the GEP stack height regulations require that stack heights used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack heights, 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 simple-cycle CTGs (100 feet [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 that 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 the previous two items are satisfied (i.e., 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.

Table 6-1 provides dimensions of the building/structures evaluated for wake effects; the locations of these buildings/structures were previously provided on Figure 2-2. As shown in Table 6-1, there are no structures which would cause downwash of the CTG stacks.

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
Maintenance building	9.0	15.2	12.0
Control building	30.5	48.6	12.0
CT air inlet filter	12.2	12.2	12.2

Sources: GPP, 1999.
ECT, 1999.

6.7 RECEPTOR GRIDS

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." Section 2.0 provided a plot plan showing the site fence lines (see Figure 2-2). As shown in Figure 2-2, the entire perimeter of the plant site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

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

- Fence line Cartesian receptors—Discrete receptors placed on the site fence line at approximately 50-meter intervals.
- Near-field Cartesian receptors—Discrete receptors placed at 50-meter intervals from the site fence line to the first polar receptor ring.
- Near-field polar receptors—Polar receptors consisting of 11 rings of 36 receptors each (36 radials at 10° radial spacings) at 50-meter intervals beginning 500 meters from the receptor grid origin (CT2) to a distance of 1,000 meters.
- Mid-field polar receptors—Polar receptors consisting of 10 rings of 36 receptors each (36 radials at 10° radial spacings) at 100-meter intervals beginning 1,100 meters from the receptor grid origin to a distance of 2,000 meters.
- Far-field Polar receptors—Polar receptors consisting of 28 rings of 36 receptors each (36 radials at 10° radial spacings) at 1,000-meter intervals beginning 3,000 meters from the receptor grid origin to a distance of 30,000 meters.

To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°. Figure 6-1 illustrates a graphical representation of the receptor grids (out to a distance of 500 meters). A depiction of the receptor grids (from 500 meters to 30 km) is shown in Figure 6-2.

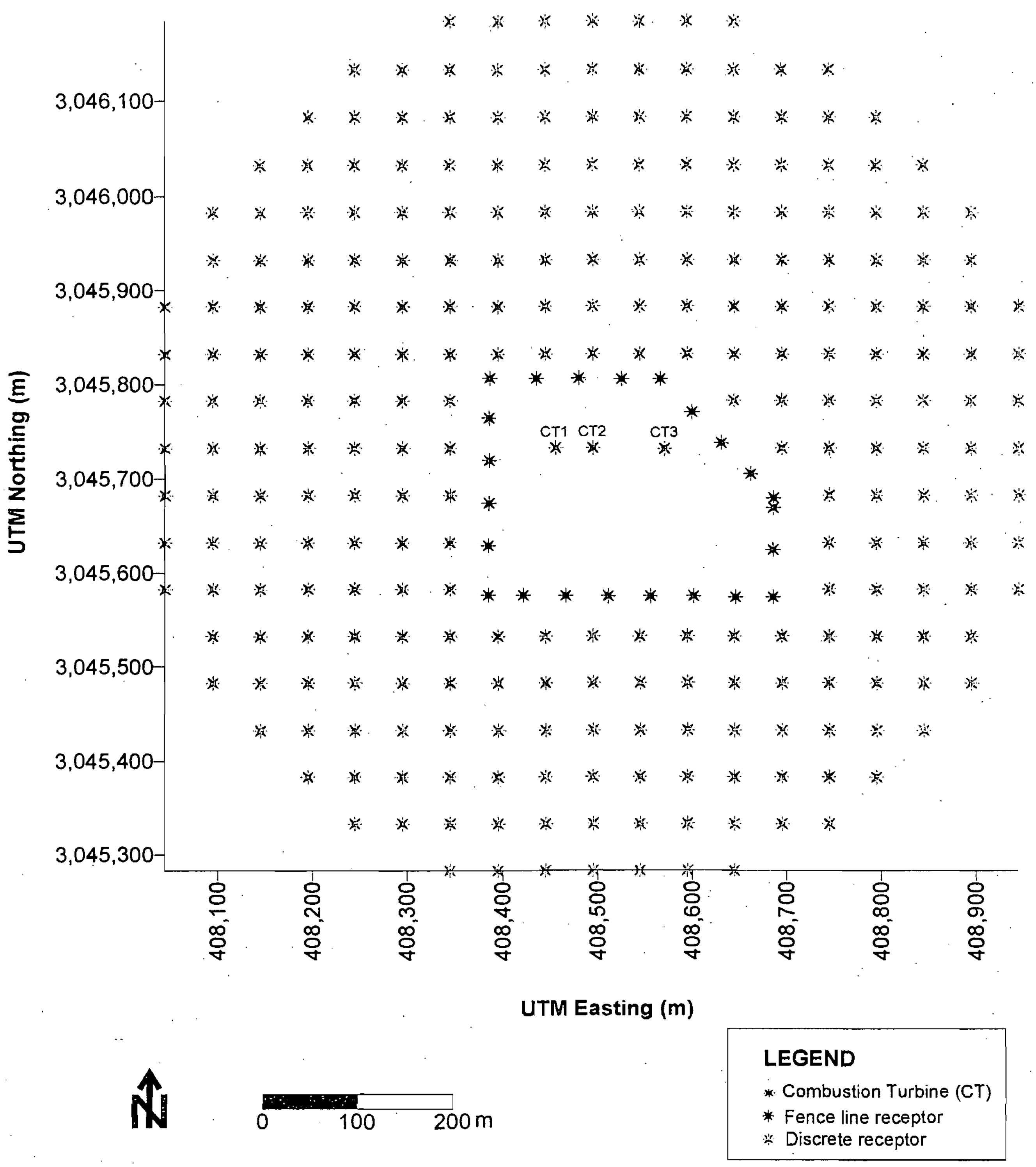

FIGURE 6-1.

RECEPTOR LOCATIONS (WITHIN 500 m)

Environmental Consulting & Technology, Inc.

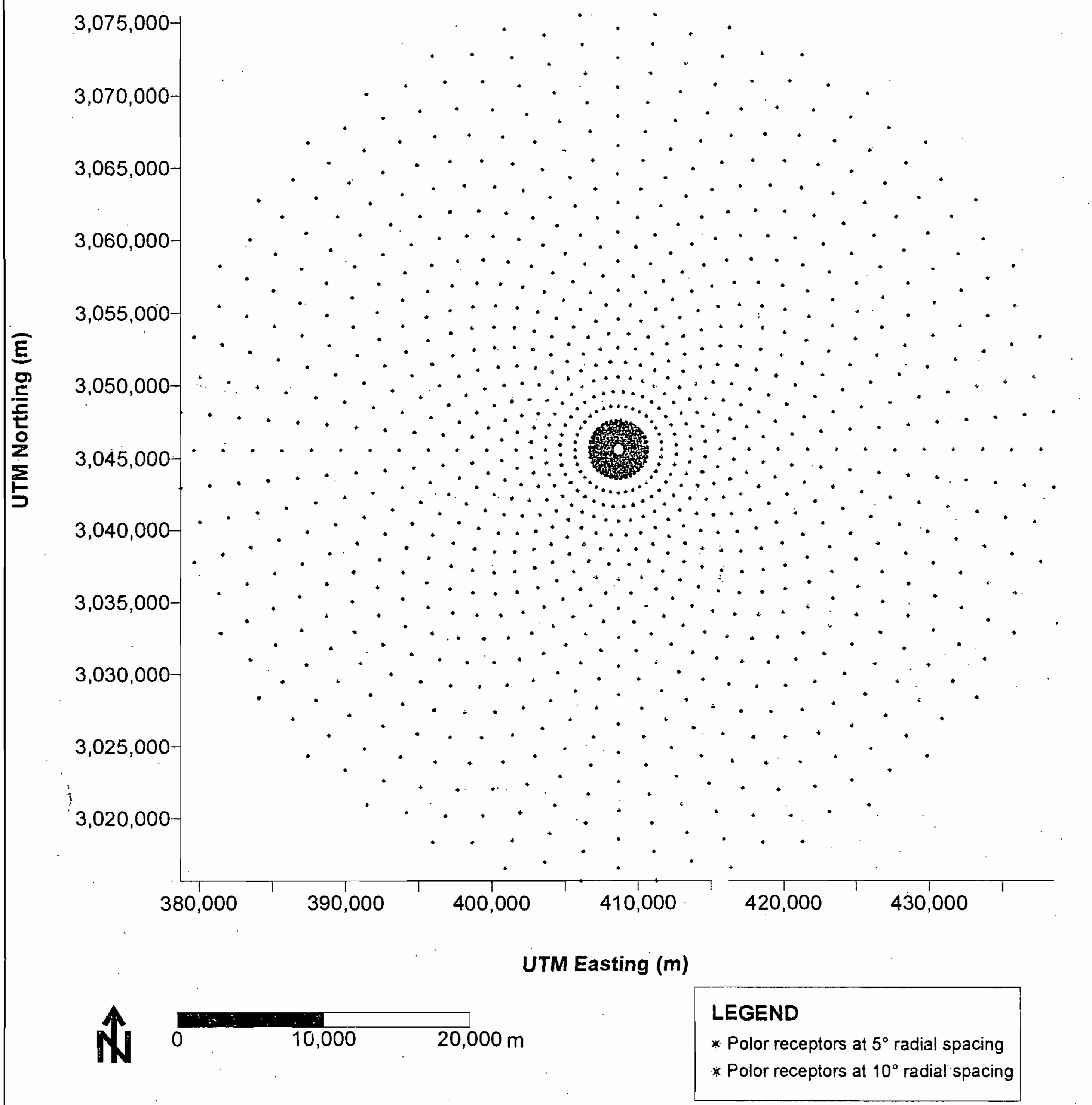

FIGURE 6-2.
RECEPTOR LOCATIONS (From 500m to 30 km)

Environmental Consulting & Technology, Inc.

6.8 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC3 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).

Consistent with the GAQM and FDEP guidance, modeling should be conducted using the most recent, readily available, 5 years of meteorological data collected at a nearby observation station. In accordance with this guidance, the selected meteorological dataset consisted of St. Petersburg/Clearwater International Airport (SPG), Station ID 72211, surface data and Ruskin (RUS), Station ID 12842, upper air data. These data were obtained from the National Climatic Data Center (NCDC) for the 1992 through 1996 5-year period.

The surface and mixing height data for each of the 5 years were processed using EPA's PCRAMMET meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model.

6.9 MODELED EMISSION INVENTORY

The modeled on-property emission source consisted of the new, proposed simple-cycle CTGs. As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the new CTG resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods. Accordingly, additional, multisource interactive dispersion modeling was not required.

Emission rates and stack parameters for the new, simple-cycle CTGs were previously presented in Tables 2-1 through 2-8.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The SCREEN3 dispersion model was used to assess each of the nine CTG operating cases (i.e., a matrix of three CTG loads [100-, 75-, and 50-percent]; three ambient temperatures [0°F, 59°F, and 95°F]; and one fuel type [fuel oil] for each pollutant subject to PSD review [NO_2, SO_2, PM_{10}, and CO]). The worst-case operating modes identified by the SCREEN3 model for each pollutant were 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 10.0 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 the three simple-cycle CTGs. SCREEN3 model options used include rural dispersion, full meteorology, and automated receptors extending from 48 to 10,000 meters.

Tables 7-1 through 7-4 provide SCREEN3 model maximum 1-hour impacts for NO_2, SO_2, CO, and PM_{10}, respectively. These tables indicate, for each operating case, the maximum emission rate for three CTGs, SCREEN3 model results based on a nominal 10.0-g/s emission rate, emission rate scaling factor, scaled SCREEN3 model result, and location of maximum impact.

As shown in the SCREEN3 summary tables, the maximum 1-hour impact for NO_2 and CO occurred under Case 9 operating conditions (i.e., 50-percent load, fuel oil firing, and 95°F ambient temperature). For SO_2, the maximum 1-hour SCREEN3 impact occurred under Case 7 conditions (i.e., 100-percent load, fuel oil firing, and 95°F ambient temperature). For PM_{10}, the maximum 1-hour SCREEN3 impact occurred under Case 3 conditions (i.e., 50-percent load, fuel oil firing, and 0°F ambient temperature). These worst-case operating cases were then further analyzed using the refined ISCST3 dispersion model.

Table 7-1. SCREEN3 Model Results - NO_2 Impacts; Three CTGs

Operating Scenarios					One-Hour Impacts (μg/m^3)			
Case No.	Load (%)	Ambient Temperature (°F)	CT Fuel Type	Emission Rate (g/s)	SCREEN3 Unadjusted Results*	Emission Rate Factor**	SCREEN3 Adjusted Results***	Downwind Distance (m)
1	100	0	Fuel Oil	148.85	2.69	14.89	40.1	1,448
2	75	0	Fuel Oil	115.59	3.28	11.56	38.0	1,363
3	50	0	Fuel Oil	130.14	3.76	13.01	48.9	1,311
4	100	59	Fuel Oil	132.64	3.08	13.26	40.8	1,390
5	75	59	Fuel Oil	106.86	3.76	10.69	40.1	1,311
6	50	59	Fuel Oil	124.32	4.13	12.43	51.4	1,330
7	100	95	Fuel Oil	120.58	3.60	12.06	43.4	1,326
8	75	95	Fuel Oil	97.71	4.05	9.77	39.6	1,338
9	**50**	**95**	**Fuel Oil**	**113.10**	**4.70**	**11.31**	**53.2**	**1,279**
						Maximum	**53.2**	

*Based on 10.0 - g/s emission rate

** Emission rate in (g/s) divided by 10.0 g/s.

***SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 2000.

Table 7-2. SCREEN3 Model Results - SO_2 Impacts; Three CTGs

Operating Scenarios					One-Hour Impacts ($\mu g/m^3$)			
Case No.	Load (%)	Ambient Temperature (°F)	CT Fuel Type	Emission Rate (g/s)	SCREEN3 Unadjusted Results*	Emission Rate Factor**	SCREEN3 Adjusted Results***	Downwind Distance (m)
1	100	0	Fuel Oil	42.26	2.69	4.23	11.4	1,448
2	75	0	Fuel Oil	32.77	3.28	3.28	10.8	1,363
3	50	0	Fuel Oil	24.91	3.76	2.49	9.4	1,311
4	100	59	Fuel Oil	37.08	3.08	3.71	11.4	1,390
5	75	59	Fuel Oil	30.13	3.76	3.01	11.3	1,311
6	50	59	Fuel Oil	23.70	4.13	2.37	9.8	1,330
7	**100**	**95**	**Fuel Oil**	**33.72**	**3.60**	**3.37**	**12.1**	**1,326**
8	75	95	Fuel Oil	27.63	4.05	2.76	11.2	1,338
9	50	95	Fuel Oil	21.85	4.70	2.19	10.3	1,279
						Maximum	**12.1**	

*Based on 10.0 - g/s emission rate
** Emission rate in (g/s) divided by 10.0 g/s.
***SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 2000.

GDP-99/LSPWR/7HTB.XLS--010700

Table 7-3. SCREEN3 Model Results - PM_{10} Impacts; Three CTGs

Operating Scenarios					One-Hour Impacts (μg/m^3)			
Case No.	Load (%)	Ambient Temperature (°F)	CT Fuel Type	Emission Rate (g/s)	SCREEN3 Unadjusted Results*	Emission Rate Factor**	SCREEN3 Adjusted Results***	Downwind Distance (m)
1	100	0	Fuel Oil	31.37	2.69	3.14	8.4	1,448
2	75	0	Fuel Oil	29.48	3.28	2.95	9.7	1,363
3	**50**	**0**	**Fuel Oil**	**29.48**	**3.76**	**2.95**	**11.1**	**1,311**
4	100	59	Fuel Oil	17.46	3.08	1.75	5.4	1,390
5	75	59	Fuel Oil	17.46	3.76	1.75	6.6	1,311
6	50	59	Fuel Oil	18.90	4.13	1.89	7.8	1,330
7	100	95	Fuel Oil	11.45	3.60	1.15	4.1	1,326
8	75	95	Fuel Oil	14.17	4.05	1.42	5.7	1,338
9	50	95	Fuel Oil	17.50	4.70	1.75	8.2	1,279
						Maximum	**11.1**	

*Based on 10.0 - g/s emission rate
** Emission rate in (g/s) divided by 10.0 g/s.
***SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 2000.

Table 7-4. SCREEN3 Model Results - CO Impacts; Three CTGs

Operating Scenarios					One-Hour Impacts ($\mu g/m^3$)			
Case No.	Load (%)	Ambient Temperature (°F)	CT Fuel Type	Emission Rate (g/s)	SCREEN3 Unadjusted Results*	Emission Rate Factor**	SCREEN3 Adjusted Results***	Downwind Distance (m)
1	100	0	Fuel Oil	53.64	2.69	5.36	14.4	1,448
2	75	0	Fuel Oil	82.33	3.28	8.23	27.0	1,363
3	50	0	Fuel Oil	1023.68	3.76	102.37	384.9	1,311
4	100	59	Fuel Oil	47.85	3.08	4.79	14.7	1,390
5	75	59	Fuel Oil	74.99	3.76	7.50	28.2	1,311
6	50	59	Fuel Oil	948.00	4.13	94.80	391.8	1,330
7	100	95	Fuel Oil	42.94	3.60	4.29	15.4	1,326
8	75	95	Fuel Oil	68.19	4.05	6.82	27.6	1,338
9	**50**	**95**	**Fuel Oil**	**878.15**	**4.70**	**87.82**	**413.0**	**1,279**
						Maximum	**413.0**	

*Based on 10.0 - g/s emission rate
** Emission rate in (g/s) divided by 10.0 g/s.
***SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 2000.

GDP-99/LSPWR/7HTB.XLS--010700

7.2 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The refined ISCST3 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 (1992 to 1996) are summarized on Table 7-5 (annual NO_2 impacts), Table 7-6 (annual SO_2 impacts), Table 7-7 (3-hour SO_2 impacts), Table 7-8 (24-hour SO_2 impacts), Table 7-9 (annual PM_{10} impacts), Table 7-10 (24-hour PM_{10} impacts), Table 7-11 (1-hour CO impacts), and Table 7-12 (8-hour CO impacts).

Tables 7-5 through 7-12 demonstrate that Project impacts, for all pollutants and all averaging times, are below the PSD significant impact levels previously shown in Table 4-2. Table 7-13 provides a summary of maximum Project impacts and PSD significant impact levels.

7.3 PSD CLASS I IMPACTS

Maximum impacts at the Chassahowitzka NWR were conservatively estimated using the ISCST3 dispersion model. Table 7-14 provides a summary of maximum Project Class I area impacts and the EPA PSD Class I area significant impact levels.

The Chassahowitzka NWR is located approximately 138 km northwest of the HCGF. Accordingly, use of the ISCST3 dispersion model to predict impacts at this Class I area will yield conservative results (i.e., over-estimate actual impacts). Short-term impacts were developed assuming natural gas firing operating conditions. As stated previously, the new simple cycle CTGs will operate with a fuel oil annual capacity factor of 5.7 percent (i.e., no more 500 hr/yr at base load).

7.4 H_2SO_4 MIST ASSESSMENT

The maximum 1-hour average SCREEN3 model impact was 12.1 micrograms per cubic meter ($\mu g/m^3$) for SO_2 (oil firing). Because H_2SO_4 mist emissions are proportional to SO_2 emissions (by a factor of 0.115), and because ambient air quality modeled impacts are directly proportional to emission rates (all other variables remaining the same), the

Table 7-5. ISCST3 Model Results - Annual Average NO_2 Impacts, HCGF

Maximum Annual Impacts	1992	1993	**1994**	1995	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.0602	0.0666	**0.0739**	0.0674	0.0677
Emission Rate Scaling Factor†	4.962	4.962	**4.962**	4.962	4.962
Tier 1 Impact ($\mu g/m^3$)**	0.299	0.330	**0.367**	0.334	0.336
Tier 2 Impact ($\mu g/m^3$)‡	0.224	0.248	**0.275**	0.251	0.252
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 (%)	22.4	24.8	**27.5**	25.1	25.2
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	14.0	**14.0**	14.0	14.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	**N**	N	N
Percent of PSD *de minimis* Ambient Impact (%)	1.6	1.8	**2.0**	1.8	1.8
Receptor UTM Easting (m)	418,020.3	415,564.7	**398,532.1**	400,699.8	400,036.8
Receptor UTM Northing (m)	3,040,232.5	3,037,306.0	**3,046,604.0**	3,041,232.5	3,042,654.3
Distance From Grid Origin (m)	11,000	11,000	**10,000**	9,000	9,000
Direction From Grid Origin (Vector °)	120	140	**275**	240	250

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

‡ Tier 1 impact times EPA national default NO_2/NO_x ratio of 0.75.

Source: ECT, 2000.

Table 7-6. ISCST3 Model Results - Annual Average SO_2 Impacts, HCGF

Maximum Annual Impacts	1992	1993	**1994**	1995	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.0348	0.0377	**0.0417**	0.0371	0.0365
Emission Rate Scaling Factor†	1.409	1.409	**1.409**	1.409	1.409
Adjusted Impact ($\mu g/m^3$)**	0.049	0.053	**0.059**	0.052	0.051
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 (%)	4.9	5.3	**5.9**	5.2	5.1
Receptor UTM Easting (m)	419,962.1	418,135.8	**394,547.3**	398,967.7	398,157.4
Receptor UTM Northing (m)	3,037,702.5	3,034,241.8	**3,046,952.8**	3,040,232.5	3,041,970.3
Distance From Grid Origin (m)	14,000	15,000	**14,000**	11,000	11,000
Direction From Grid Origin (Vector °)	125	140	**275**	240	250

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

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

Maximum 3-Hour Impacts	1992	1993	1994	**1995**	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	2.733	2.993	2.956	**3.358**	3.065
Emission Rate Scaling Factor†	1.409	1.409	1.409	**1.409**	1.409
Adjusted Impact ($\mu g/m^3$)**	3.85	4.22	4.16	**4.73**	4.32
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 (%)	15.4	16.9	16.7	**18.9**	17.3
Receptor UTM Easting (m)	419,965.5	405,194.7	398,994.0	**410,237.1**	394,351.9
Receptor UTM Northing (m)	3,029,349.5	3,064,443.8	3,062,187.0	**3,025,808.5**	3,059,874.8
Distance From Grid Origin (m)	20,000	19,000	19,000	**20,000**	20,000
Direction From Grid Origin (Vector °)	145	350	330	**175**	315
Date of Maximum Impact	12/21/92	7/13/93	8/23/94	**11/19/95**	9/10/96
Julian Date of Maximum Impact	356	194	235	**323**	254
Ending Hour of Maximum Impact	2100	0300	0600	**2100**	0600

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-8. ISCST3 Model Results - Maximum 24-Hour Average SO_2 Impacts; HCGF

Maximum 24-Hour Impacts	1992	1993	1994	1995	1996
Unadjusted ISCST3 Impact (µg/m^3)*	0.586	0.631	0.647	0.620	0.649
Emission Rate Scaling Factor†	1.409	1.409	1.409	1.409	1.409
Adjusted Impact (µg/m^3)**	0.82	0.89	0.91	0.87	0.91
PSD Significant Impact (µg/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 (%)	16.5	17.8	18.2	17.5	18.3
PSD *de minimis* Ambient Impact Threshold (µg/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 (%)	6.3	6.8	7.0	6.7	7.0
Receptor UTM Easting (m)	408,494.0	427,205.3	424,948.5	392,039.5	388,760.5
Receptor UTM Northing (m)	3,064,732.5	3,042,433.3	3,036,232.5	3,055,232.5	3,038,550.0
Distance From Grid Origin (m)	19,000	19,000	19,000	19,000	21,000
Direction From Grid Origin (Vector °)	360	100	120	300	250
Date of Maximum Impact	10/9/92	3/28/93	12/25/94	11/27/95	12/28/96
Julian Date of Maximum Impact	283	87	359	331	363

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-9. ISCST3 Model Results - Annual Average PM_{10} Impacts, HCGF

Maximum Annual Impacts	1992	1993	**1994**	1995	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.0461	0.0510	**0.0563**	0.0510	0.0524
Emission Rate Scaling Factor†	1.046	1.046	**1.046**	1.046	1.046
Adjusted Impact ($\mu g/m^3$)**	0.048	0.053	**0.059**	0.053	0.055
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 (%)	4.8	5.3	**5.9**	5.3	5.5
Receptor UTM Easting (m)	419,752.3	416,850.3	**398,532.1**	398,967.7	398,157.4
Receptor UTM Northing (m)	3,039,232.5	3,035,774.0	**3,046,604.0**	3,040,232.5	3,041,970.3
Distance From Grid Origin (m)	13,000	13,000	**10,000**	11,000	11,000
Direction From Grid Origin (Vector °)	120	140	**275**	240	250

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-10. ISCST3 Model Results - Maximum 24-Hour Average PM_{10} Impacts; HCGF

Maximum 24-Hour Impacts	1992	**1993**	1994	1995	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.715	**0.834**	0.798	0.769	0.799
Emission Rate Scaling Factor†	1.046	**1.046**	1.046	1.046	1.046
Adjusted Impact ($\mu g/m^3$)**	0.75	**0.87**	0.83	0.80	0.84
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 (%)	14.9	**17.4**	16.7	16.1	16.7
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	10.0	**10.0**	10.0	10.0	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	**N**	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	7.5	**8.7**	8.3	8.0	8.4
Receptor UTM Easting (m)	393,494.0	**415,564.7**	423,216.4	414,279.1	390,639.8
Receptor UTM Northing (m)	3,045,732.5	**3,037,306.0**	3,037,232.5	3,038,838.0	3,039,234.0
Distance From Grid Origin (m)	15,000	**11,000**	17,000	9,000	19,000
Direction From Grid Origin (Vector °)	270	**140**	120	140	250
Date of Maximum Impact	11/10/92	**3/14/93**	12/25/94	8/14/95	12/28/96
Julian Date of Maximum Impact	315	**73**	359	226	363

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-11. ISCST3 Model Results - Maximum 1-Hour Average CO Impacts; HCGF

Maximum 1-Hour Impacts	1992	1993	**1994**	1995	1996
Unadjusted ISCST3 Impact (µg/m^3)*	6.407	7.918	**8.172**	7.728	6.802
Emission Rate Scaling Factor†	34.123	34.123	**34.123**	34.123	34.123
Adjusted Impact (µg/m^3)**	218.63	270.19	**278.87**	263.72	232.09
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 (%)	10.9	13.5	**13.9**	13.2	11.6
Receptor UTM Easting (m)	414,289.6	408,668.3	**407,346.8**	405,895.9	412,824.1
Receptor UTM Northing (m)	3,044,179.5	3,047,725.0	**3,047,370.8**	3,044,232.5	3,043,232.5
Distance From Grid Origin (m)	6,000	2,000	**2,000**	3,000	5,000
Direction From Grid Origin (Vector °)	105	5	**325**	240	120
Date of Maximum Impact	4/25/92	12/1/93	**8/1/94**	9/6/95	7/2/96
Julian Date of Maximum Impact	116	335	**213**	249	184
Ending Hour of Maximum Impact	1200	1500	**1900**	1200	1000

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

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

** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

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Table 7-12. ISCST3 Model Results - Maximum 8-Hour Average CO Impacts; HCGF

Maximum 8-Hour Impacts	1992	**1993**	1994	1995	1996
Unadjusted ISCST3 Impact (μg/m^3)*	2.153	**3.284**	2.133	2.959	2.633
Emission Rate Scaling Factor†	34.123	**34.123**	34.123	34.123	34.123
Adjusted Impact (μg/m^3)**	73.47	**112.05**	72.78	100.97	89.83
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 (%)	14.7	**22.4**	14.6	20.2	18.0
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 (%)	12.8	**19.5**	12.7	17.6	15.6
Receptor UTM Easting (m)	408,494.0	**425,235.7**	395,766.1	393,771.6	395,471.3
Receptor UTM Northing (m)	3,062,732.5	**3,042,780.5**	3,058,460.5	3,054,232.5	3,056,660.0
Distance From Grid Origin (m)	17,000	**17,000**	18,000	17,000	17,000
Direction From Grid Origin (Vector °)	360	**100**	315	300	310
Date of Maximum Impact	10/9/92	**3/28/93**	5/1/94	11/27/95	9/9/96
Julian Date of Maximum Impact	283	**87**	121	331	253
Ending Hour of Maximum Impact	0800	**0800**	0800	0800	0800

* Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.
† Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0 g/s emission rate.
** Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-13. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.275	1.0
CO	8-hour	112.1	500
	1-hour	278.9	2,000
PM	Annual	0.059	1.0
	24-hour	0.87	5.0
SO_2	Annual	0.059	1.0
	24-hour	0.91	5.0
	3-hour	4.73	25.0

Source: ECT, 2000.

Table 7-14. ISCST3 Model Results—Maximum Class I Area Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	EPA Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.027	0.1
PM	Annual	0.005	0.2
	24-hour	0.095	0.3
SO_2	Annual	0.001	0.1
	24-hour	0.021	0.2
	3-hour	0.135	1.0

Source: ECT, 2000.

maximum 1-hour SCREEN3 model impact for H_2SO_4 mist is 1.39 μg/m^3. 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 0.97 and 0.56 μg/m^3, respectively. These impacts are well below the FDEP ambient reference concentrations (ARCs) for H_2SO_4 mist of 10.0 and 2.4 μg/m^3 for 8- and 24-hour average periods, respectively. Table 7-15 provides a summary of Project H_2SO_4 mist impacts and the FDEP ARC levels.

7.5 CONCLUSIONS

Comprehensive dispersion modeling using the SCREEN3 and refined ISCST3 models demonstrates that the Project will result in ambient air quality impacts that are:

- Below PSD significant impact levels for all pollutants and all averaging periods.
- Below PSD *de minimis* ambient impact levels for all pollutants and all averaging periods.
- Below the FDEP ARCs for H_2SO_4 mist.

Table 7-15. Summary of Worst-Case Estimates of H_2SO_4 Mist Impacts Compared to FDEP ARCs

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	ARCs ($\mu g/m^3$)
H_2SO_4 mist	8-hour	0.97	10
	24-hour	0.56	2.4

Source: ECT, 2000.

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 Nichols, Polk County, approximately 37 km north of the project site. The FDEP monitoring station at Nichols monitors PM_{10} and SO_2. The nearest FDEP station that monitors ozone is located in Lakeland, Polk County, approximately 45 km north of the project site. The closest FDEP monitoring stations that monitor PM_{10} and SO_2 are situated in Nichols and Mulberry, Polk County, which are respectively located approximately 37 and 38 km north of the project site. The nearest FDEP stations that monitor NO_x and CO are located in Tampa, Hillsborough County, approximately 74 km northwest of the project site. The nearest FDEP station monitoring for lead is situated in Ruskin, Hillsborough County, approximately 53 km northwest of the project site. A summary of 1996 and 1997 ambient air quality data for these FDEP stations is provided in Tables 8-1 and 8-2.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

FDEP Rule 62-212.400(2)(e), F.A.C., provides an exemption from 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 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 0.87 $\mu g/m^3$. This concentration is below the 10 $\mu g/m^3$ *de minimis* level ambient impact level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate for the proposed facility.

Table 8-1. Summary of 1996 FDEP Ambient Air Quality Data

Pollutant	Site Location		Site No.	Averaging	Sampling	No. of	Ambient Concentration (ug/m³)				
	County	City		Period	Period	Observations	1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Polk	Auburndale	0120 001 F01	24-Hr	Jan-May	18	34	34	34		150[1]
				Annual						20	50[2]
		Lakeland	2160 007 F01	24-Hr	Jan-May	21	32	26	32		
				Annual						17	
		Mulberry	2860 006 F02	24-Hr	Jan-May	21	36	28	36		
				Annual						21	
		Nichols	3680 010 F02	24-Hr	Jan-Dec	61	75	45	75		
				Annual						22	
SO_2	Polk	Mulberry	2860 006 F02	1-Hr	Feb-Dec	7,272	204	165			
				3-Hr			150	124			1,300[3]
				24-Hr			57	43			260[3]
				Annual						11	60[2]
		Nichols	3680 010 F02	1-Hr	Jan-Dec	8,610	1258	354			
				3-Hr			432	257			1,300[3]
				24-Hr			86	80			260[3]
				Annual						15	60[2]
NO_2	Hillsborough	Tampa	4360 065 G01	1-Hr	Jan-Dec	8,637	130	100			
				Annual						18	100[2]
CO	Hillsborough	Tampa	4360 045 G01	1-Hr	Jan-Dec	8,669	9,200	6,900			40,000[3]
				8-Hr		-	4,600	4,600			10,000[3]
O_3	Polk	Lakeland	2160 005 F01	1-Hr	Jan-Dec	8,689	187	167			235[4]
			2160 006 F01	1-Hr	Jan-Dec	8,718	194	181			235[4]
Lead	Hillsborough	Ruskin	1800 003 G03	24-Hr							
					Jan-Mar	8				0.0	1.5[2]
					Apr-Jun	7				0.0	
					Jul-Sep	8				0.0	
					Oct-Dec	8				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

Source: FDEP, 1998.

Table 8-2. Summary of 1997 FDEP Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site No.	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Polk	Nichols	3680 010 F02	24-Hr	Jan-Dec	31	41	36	41		150[1]
				Annual						20	50[2]
SO_2	Polk	Mulberry	2860 006 F02	1-Hr	Jan-Dec	8,647	254	173			
				3-Hr			168	134			1,300[3]
				24-Hr			49	38			260[3]
				Annual						11	60[2]
		Nichols	3680 010 F02	1-Hr	Jan-Dec	8,680	246	199			
				3-Hr			176	148			1,300[3]
				24-Hr			53	48			260[3]
				Annual						17	60[2]
NO_2	Hillsborough	Tampa	4360 065 G01	1-Hr	Jan-Dec	8,087	111	111			
				Annual						18	100[2]
CO	Hillsborough	Tampa	4360 045 G01	1-Hr	Jan-Dec	8,527	5,750	5,750			40,000[3]
				8-Hr		-	3,450	3,450			10,000[3]
O_3	Polk	Lakeland	2160 005 F01	1-Hr	Jan-Dec	8,601	204	200			235[4]
			2160 006 F01		Jan-Dec	8,686	216	196			
Lead	Hillsborough	Tampa	180 003 G03	24-Hr							
					Jan-Mar	7				0.0	1.5[2]
					Apr-Jun	8				0.0	
					Jul-Sep	7				0.0	
					Oct-Dec	8				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

Source: FDEP, 1998.

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8.2.2 CO

The maximum 8-hour CO impact was predicted to be 112.1 μg/m^3. This concentration is below the 575-μg/m^3 *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption for CO is appropriate for the proposed facility.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.28 μg/m^3. This concentration is below the 14-μg/m^3 *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for the proposed facility.

8.2.4 SO_2

The maximum 24-hour SO_2 impact was predicted to be 0.9 μg/m^3. This concentration is below the 13-μg/m^3 *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for the proposed facility.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and 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 assess air quality impacts that would result from that growth.

Impacts associated with construction of the HCGF simple-cycle CTGs 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 new, simple-cycle CTGs are being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the Project are anticipated. When operational, the simple-cycle CTGs are projected to generate approximately 5 to 10 new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate fuel oil demand due to operation of the new simple-cycle CTGs 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

Maximum air quality impacts in the vicinity of the HCGF due to operation of the proposed simple-cycle CTGs are well below applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the HCGF are anticipated. The following sections discuss potential impacts on the nearest Class I area; the Chassahowitzka NWR.

9.2.1 IMPACTS ON SOILS

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

Typically, SO_2 represents the greatest threat to soil since this pollutant causes increased sulfur content and decreased pH. However, for this project, given the extremely low levels of SO_2 emitted, the distance from the source, the naturally high sulfur content of the Class I area soils, and the pH variability caused by tidal influences, no impacts to soils are expected.

9.2.2 IMPACTS ON VEGETATION

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

The literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of

HCGF due to operation of the simple-cycle CTGs would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka NWR due to emissions from the HCGF simple-cycle CTGs will be far less, as presented previously. The potential for damage at the Chassahowitzka NWR could be negligible given the absence of any plant species at Chassahowitzka NWR that would be especially sensitive to the very low predicted pollutant concentrations.

9.2.3 IMPACTS ON WILDLIFE

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

Air pollution impacts to wildlife have been reported in the literature, although many of the incidents involved acute exposures to pollutants usually caused by unusual or highly concentrated releases or unique weather conditions.

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the low concentrations of pollutants resulting from the Project will cause any injury to wildlife.

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

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

In conclusion, it is unlikely the projected air emission levels from the HCGF simple-cycle CTGs will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka NWR.

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 simple-cycle CTG. Opacity of the simple-cycle CTG exhaust will be 10 percent when firing natural gas, 20 percent when firing oil, or less, excluding water. Emissions of primary particulates and sulfur oxides from the CTG will be low due to the primary use of pipeline quality natural gas and low sulfur, low ash distillate fuel oil as the back-up fuel source. The simple-cycle CTG will comply with all applicable FDEP requirements pertaining to visible emissions.

A Level 1 visibility screening analysis was conducted using the VISCREEN program, consistent with EPA (1988) guidance. Emissions input to the VISCREEN program were the maximum short-term (g/s) emission rates for primary PM, NO_x, and H_2SO_4 mist from the three proposed simple-cycle CTGs. These rates were 31.37 g/s of PM, 148.85 g/s of

NO_x, and 4.84 g/s of H_2SO_4 mist. Table 9-1 summarizes the results of the Level 1 analysis, which, even with the conservative assumptions inherent to such an analysis, resulted in impact values well below the screening thresholds. Therefore, it could be concluded that HCGF simple-cycle CTGs emissions will not cause impairment of visibility in the Chassahowitzka NWR Class I area.

Table 9-1. Visual Effects Screening Analysis

Visual Effects Screening Analysis for
Source: Hardee County Generation
Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	31.37	G	/S
NOx (as NO2)	148.85	G	/S
Primary NO2	.00	G	/S
Soot	.00	G	/S
Primary SO4	4.84	G	/S

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	138.00 km
Min. Source-Class I Distance:	138.00 km
Max. Source-Class I Distance:	145.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability: 6	
Wind Speed: 1.00 m/s	

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	138.0	84.	2.00	.939	.05	.005
SKY	140.	84.	138.0	84.	2.00	.319	.05	-.012
TERRAIN	10.	84.	138.0	84.	2.00	.310	.05	.004
TERRAIN	140.	84.	138.0	84.	2.00	.081	.05	.003

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	65.	128.8	104.	2.00	.988	.05	.005
SKY	140.	65.	128.8	104.	2.00	.331	.05	-.013
TERRAIN	10.	55.	123.5	114.	2.00	.398	.05	.005
TERRAIN	140.	55.	123.5	114.	2.00	.108	.05	.004

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APPENDIX 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: **Granite Power Partners II, LP (LS Power, LLC – General Partner)**	
2. Site Name: **Hardee County Generating Facility**	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: **5 Miles West of Wachula** Street Address or Other Locator: **Fort Green Ona Road** City: **Wachula** County: **Hardee** Zip Code: **33834**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [ ] Yes [✔] No

Application Contact

1. Name and Title of Application Contact: **Michael F. Vogt** **Project Manager**
2. Application Contact Mailing Address: Organization/Firm: **Granite Power Partners II, LP** **(LS Power, LLC – General Partner)** Street Address: **655 Craig Road, Suite 336** City: **St. Louis** State: **MO** Zip Code: **63025**
3. Application Contact Telephone Numbers: Telephone: **(314)993-2700** Fax: **(314) 993-2790**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	January 18, 2000
2. Permit Number:	0490044-001-AC
3. PSD Number (if applicable):	PSD-FL-281
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:
   Michael F. Vogt, Project Manager

2. Application Contact Mailing Address:
   Organization/Firm: **Granite Power Partners II, LP**
   (LS Power, LLC – General Partner)
   Street Address: **655 Craig Road, Suite 336**
   City: **St. Louis** State: **MO** Zip Code: **63025**

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: **(314) 993-2700** Fax: **(314) 993-2790**

4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative(check here [ ], if so) or the responsible official (check here [✓], if so) 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 unit.*

   Michael F. Vogt 1/13/00

   Signature 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 — Signature

1/12/00 — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	Combustion Turbine Generator Unit No. 1	AC1A	$7,500
002	Combustion Turbine Generator Unit No. 2	AC1A	*
003	Combustion Turbine Generator Unit No. 3	AC1A	*

Application Processing Fee

Check one: [✔] Attached - Amount: $7,500 [ ] Not Applicable

*** - Similar Emissions Unit Fee provided per Rule 62.4050(4)(a)4., F.A.C.**

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Project consists of the installation of three simple cycle combustion turbine generators (CTGs). The CTGS will be either nominal 170-MW GE 7FA units, nominal 170-MW Siemens Westinghouse 501F units, nominal 120-MW Siemens Westinghouse 501D5A units, or nominal 180-MW ABB Power Generation GT-24 units. The CTGs will be fired primarily using pipeline quality natural gas with low-sulfur, distillate fuel oil serving as a backup fuel. The new simple-cycle CTGs will operate at for a total of 3,000 hours per year. Of the 3,000 hours per year total, oil-firing may occur for up to 500 hours per year.**
2. Projected or Actual Date of Commencement of Construction: **4th Q 2000**
3. Projected Date of Completion of Construction: **3rd Q 2001**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **408.49**	North (km): **3,045.73**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact **(Not Available – To Be Provided at a Later Date)**

1. Name and Title of Facility Contact: **Not Available**		
2. Facility Contact Mailing Address: Organization/Firm: **Granite Power Partners II, LP** Street Address: **Not Available** City: **Not Available**	State: **FL**	Zip Code: **33834**
3. Facility Contact Telephone Numbers: Telephone: **Not Available**	Fax: **Not Available**	

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**	**N/A**	**N/A**	
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**	
VOC	**A**	**N/A**	**N/A**	**N/A**	
SAM	**B**	**N/A**	**N/A**	**N/A**	

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [✓] Attached, Document ID: **Fig. 2-1** [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [✓] Attached, Document ID: **Fig. 2-2** [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [✓] Attached, Document ID: **Fig. 2-3** [ ] 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:	

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	

GENERAL ELECTRIC 7241FA

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 three, identical General Electric (GE) 7241 FA simple-cycle combustion turbine generators (CTGs) each having a nominal rating of 170 megawatts (MW). The CTGs will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a back-up fuel.

4. Emissions Unit Identification Number:
ID: **001, 002, 003 (CTG Nos. 1, 2, and 3)**
[ ] No ID
[ ] 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 (Per CTG)

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **NO_x Controls** **Dry low-NO_x combustors (natural gas-firing)** **Water injection (distillate fuel-oil firing)**
2. Control Device or Method Code(s): **25 (dry low-NO_x), 28 (water injection)**

Emissions Unit Details (Per CTG)

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 (Per CTG)

1. Maximum Heat Input Rate:	**1,905 (LHV)** mmBtu/hr		
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**3,000**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is lower heating value (LHV) at 100 percent load, 20°F, fuel oil-firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.**			

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 (Per CTG)

1. Identification of Point on Plot Plan or Flow Diagram? **CT1, CT2, CT3**	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: **100** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,117** °F	9. Actual Volumetric Flow Rate: **2,377,044** 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, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.

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

Segment Description and Rate: Segment 1 of 2 **(Per CTG)**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.848**	5. Maximum Annual Rate: **5,544.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **923**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV). Maximum hourly rate (Field 12) based on 20°F ambient temperature.**		

Segment Description and Rate: Segment 2 of 2 **(Per CTG)**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with distillate fuel oil.**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **14.243**	5. Maximum Annual Rate: **7,121.5**	6. Estimated Annual Activity Factor:
6. Maximum % Sulfur: **0.05**	7. Maximum % Ash: **0.01**	8. Million Btu per SCC Unit: **134**
9. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV). Maximum hourly rate (Field 12) based on 20°F ambient temperature.**		

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			EL
4 – PM10			EL
5 – SO2			EL
6 – SAM			EL
7 – VOC			EL

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **371.8** lb/hour **182.4** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **371.8 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, 20°F, fuel oil-firing case. Annual emissions based on 75.7 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 350.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10.5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **75.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **350.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Field 4 limit applicable for fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **124.3** lb/hour **95.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **124.3 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, 20°F, fuel oil-firing case. Annual emissions based on 52.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 116.6 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **52.8** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **25.2 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**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 18.7 lb/hour 17.1 tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **18.7 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, 20°F, fuel oil-firing case. Annual emissions based on 9.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 18.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

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: 9.9 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

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: **18.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **18.7** lb/hour **17.1** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **18.7 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, 20°F, fuel oil-firing case. Annual emissions based on 9.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 18.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 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: **9.9** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 9

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

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

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: **18.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **104.1** lb/hour **36.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **104.1 lb/hr** Reference: **GE data**	7. Emissions Method Code: **2**

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

(0.05 lb S/100 lb oil) x (104,120 lb oil/hr) x (2 lb SO_2/lb S) = 104.1 lb/hr SO_2

Annual emissions based on 9.2 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 98.1 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 2 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **9.2** 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):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **98.1** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions..**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **12.0** lb/hour	**4.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **12.0 lb/hr** Reference: **GE data**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **(104.1 lb/hr SO_2) x (7.5/100) x (98 lb H_2SO_4/64 lb SO_2 = 12.0 lb/hr H_2SO_4** **Annual emissions based on 1.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 11.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions 1 of 2 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **1.1** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **11.3** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.3** lb/hour **5.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **8.3 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, 20°F, fuel oil-firing case. Annual emissions based on 3.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 7.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.3 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **3.1** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 18 or 25

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

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **7.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).** **Field 4 limit applicable for distillate fuel oil-firing at ISO Conditions.**	

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).** **Limit applicable for natural gas or fuel oil firing.**	

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**	
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.** **Limit applicable for natural gas or fuel oil firing.**	

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:
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Specific CEMS information will be provided to FDEP when available.**	

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

1. Parameter Code: $\mathbf{O_2}$	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).** **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. 2-3** [ ] 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:________ [ ] 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

WESTINGHOUSE 501F

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 three, identical Westinghouse 501F simple-cycle combustion turbine generators (CTGs) each having a nominal rating of 170 megawatts (MW). The CTGs will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a back-up fuel.

4. Emissions Unit Identification Number: [ ] No ID
ID: **001, 002, 003 (CTG Nos. 1, 2, and 3)** [ ] 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 (Per CTG)

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): NO_x Controls **Dry low-NO_x combustors (natural gas-firing)** **Water injection (distillate fuel-oil firing)**
2.	Control Device or Method Code(s): **25 (dry low-NO_x), 28 (water injection)**

Emissions Unit Details (Per CTG)

1.	Package Unit: Manufacturer: **Westinghouse**	Model Number: **501F**
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 (Per CTG)

1. Maximum Heat Input Rate:	**1,769 (LHV)** mmBtu/hr		
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**3,000**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is lower heating value (LHV) at 100 percent load, 32°F, fuel oil-firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.**			

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 (Per CTG)

1. Identification of Point on Plot Plan or Flow Diagram? **CT1, CT2, CT3**	9. Emission Point Type Code: **1**

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

N/A

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

N/A

12. Discharge Type Code: **V**	6. Stack Height: **100** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,099** °F	9. Actual Volumetric Flow Rate: **2,407,886** 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, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.

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

Segment Description and Rate: Segment 1 of 2 (Per CTG)

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Combustion turbine fired with pipeline quality natural gas.

2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.914**	5. Maximum Annual Rate: **5,742.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **923**

10. Segment Comment (limit to 200 characters):

Fuel heat content (Field 9) represents lower heating value (LHV).
Maximum hourly rate (Field 12) based on 32°F ambient temperature.

Segment Description and Rate: Segment 2 of 2 (Per CTG)

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Combustion turbine fired with distillate fuel oil.

2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **13.020**	5. Maximum Annual Rate: **6,510.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **134**

10. Segment Comment (limit to 200 characters):

Fuel heat content (Field 9) represents lower heating value (LHV).
Maximum hourly rate (Field 12) based on 32°F ambient temperature.

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			**EL**
4 – PM10			**EL**
5 – SO2			**EL**
6 – SAM			**EL**
7 – VOC			**EL**

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **352.0** lb/hour	**228.4** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: **352.0 lb/hr** Reference: **Westinghouse data**		7. Emissions Method Code: **5**

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

Hourly emission rate based on Westinghouse data for 100 percent load, 32°F, fuel oil-firing case. Annual emissions based on 116.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 328.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **116.9** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 20 (initial), NO_x CEMS

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

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **328.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Field 4 limit applicable for fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **245.3** lb/hour **158.4** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **245.3 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 50 percent load, 32°F, natural gas-firing case. Annual emissions based on 75.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 234.3 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr and 95.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **16 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **75.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, natural gas-firing.** **Field 4 limit applicable for 100% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 4 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **83 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: 234.3 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 50% load, natural gas-firing.** **Field 4 limit applicable for 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 4 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: 95.7 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, fuel oil-firing.** **Field 4 limit applicable for 100% load, fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 4 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **26 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **89.1** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 70% load, fuel oil-firing.** **Field 4 limit applicable for 70% load, fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 26.3 lb/hour 16.7 tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **26.3 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 70 percent load, 32°F, fuel oil-firing case. Annual emissions based on 9.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 9.5 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr and 19.8 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2 **(Per CTG)**

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: **9.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 % opacity**	4. Equivalent Allowable Emissions: **26.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for 70% load, distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.3** lb/hour **16.7** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **26.3 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 70 percent load, 32°F, fuel oil-firing case. Annual emissions based on 9.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 9.5 lb/hr (50 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr and 19.8 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 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: **9.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 % opacity**	4. Equivalent Allowable Emissions: **26.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT) Field 4 limit applicable for 70% load, distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **95.2** lb/hour **33.9** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **95.2 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **2**

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

(0.05 lb S/100 lb oil) x (95,200 lb oil/hr) x (2 lb SO_2/lb S) = 95.2 lb/hr SO_2

Annual emissions based on 9.3 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 89.1 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions __1__ of __2__ (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **9.3** 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):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **89.1** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10.9** lb/hour **3.9** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10.9 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **2**

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

$(95.2\ lb/hr\ SO_2) \times (7.5/100) \times (98\ lb\ H_2SO_4/64\ lb\ SO_2) = 10.9\ lb/hr\ H_2SO_4$

Annual emissions based on 1.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 10.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **1.1** 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):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **10.2** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 66.0 lb/hour 24.2 tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **66.0 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 70 percent load, 32°F, oil-firing case. Annual emissions based on 8.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 33.0 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr and 28.6 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 4 (Per CTG)

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: 8.8 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, natural gas-firing.** **Field 4 limit applicable for 100% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **33.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 50% load, natural gas-firing.** **Field 4 limit applicable for 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **28.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, fuel oil-firing.** **Field 4 limit applicable for 100% load, fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 4 of 4 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **31 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: 60.5 lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 70% load, fuel oil-firing.** **Field 4 limit applicable for 70% load, fuel oil-firing at ISO conditions.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

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).** **Limit applicable for natural gas firing.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % 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).** **Limit applicable for fuel oil firing.**	

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE10**	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**	
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. Limit applicable for natural gas or fuel oil firing.**	

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:
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **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:
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **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. 2-3** [ ] 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:________ [ ] 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

WESTINGHOUSE 501D5A

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 three, identical Westinghouse 501D5A simple-cycle combustion turbine generators (CTGs) each having a nominal rating of 120 megawatts (MW). The CTGs will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a back-up fuel.

4. Emissions Unit Identification Number: [ ] No ID
ID: **001, 002, 003 (CTG Nos. 1, 2, and 3)** [ ] 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 (Per CTG)

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **NO_x Controls** **Dry low-NO_x combustors (natural gas-firing)** **Water injection (distillate fuel-oil firing)**
2.	Control Device or Method Code(s): **25 (dry low-NO_x), 28 (water injection)**

Emissions Unit Details (Per CTG)

1.	Package Unit: Manufacturer: **Westinghouse**	Model Number: **501D5A**
2.	Generator Nameplate Rating: **120** 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 (Per CTG)

1. Maximum Heat Input Rate:	1,337 (LHV) mmBtu/hr		
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	3,000	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Maximum heat input is lower heating value (LHV) at 100 percent load, 20°F, fuel oil-firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.

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 (Per CTG)

1. Identification of Point on Plot Plan or Flow Diagram? **CT1, CT2, CT3**	16. Emission Point Type Code: **1**

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

N/A

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

N/A

19. Discharge Type Code: **V**	6. Stack Height: **100** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **997** °F	9. Actual Volumetric Flow Rate: **1,912,234** 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, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.

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

Segment Description and Rate: Segment 1 of 2 (Per CTG)

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.388**	5. Maximum Annual Rate: **4,164.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **923**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV).** **Maximum hourly rate (Field 12) based on 20°F ambient temperature.**		

Segment Description and Rate: Segment 2 of 2 (Per CTG)

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with distillate fuel oil.**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **9.909**	5. Maximum Annual Rate: **4,954.5**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **134**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV).** **Maximum hourly rate (Field 12) based on 20°F ambient temperature.**		

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			EL
4 – PM10			EL
5 – SO2			EL
6 – SAM			EL
7 – VOC			EL

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **260.7** lb/hour	**178.0** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: **260.7 lb/hr** Reference: **Westinghouse data**		7. Emissions Method Code: **5**

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

Hourly emission rate based on Westinghouse data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 80.6 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 148.7 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr, and 240.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 3 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **80.6** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 20 (initial), NO_x CEMS

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

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).
Field 4 limit applicable 100% load, natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **45 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **148.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Field 4 limit applicable 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **240.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Field 4 limit applicable for fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **495.0** lb/hour **171.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **495.0 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 50 percent load, 20°F, natural gas-firing case. Annual emissions based on 31.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 463.0 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr and 95.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **31.8** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, natural gas-firing.** **Field 4 limit applicable for 100% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 4 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **232 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **463.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 50% load, natural gas-firing.** **Field 4 limit applicable for 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 4 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **28 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: 95.9 lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, fuel oil-firing.** **Field 4 limit applicable for 100% load, fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 4 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **75 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: 198.4 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 75% load, fuel oil-firing.** **Field 4 limit applicable for 75% load, fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **45.2** lb/hour **19.2** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **45.2 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 75 percent load, 20°F, fuel oil-firing case. Annual emissions based on 8.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 32.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2 **(Per CTG)**

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: **8.8** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 % opacity**	4. Equivalent Allowable Emissions: **41.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for 75% load, distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **45.2** lb/hour **19.2** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **45.2 lb/hr** Reference: **Westinghouse data**		7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 75 percent load, 20°F, fuel oil-firing case. Annual emissions based on 8.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 32.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 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: **8.8** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 % opacity**	4. Equivalent Allowable Emissions: **41.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for 75% load, distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: **72.4** lb/hour **25.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **72.4 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **(0.05 lb S/100 lb oil) x (72,400 lb oil/hr) x (2 lb SO_2/lb S) = 72.4 lb/hr SO_2** **Annual emissions based on 6.7 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 66.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__ (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **6.7** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: 66.9 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.3** lb/hour **2.9** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **8.3 lb/hr** Reference: **Westinghouse data**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **(72.4 lb/hr SO_2) x (7.5/100) x (98 lb H_2SO_4/64 lb SO_2) = 8.3 lb/hr H_2SO_4** **Annual emissions based on 0.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 7.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__ (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **0.8** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **7.7** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 49.8 lb/hour 16.2 tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **49.8 lb/hr** Reference: **Westinghouse data**		7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Westinghouse data for 75 percent load, 20°F, distillate fuel oil-firing case. Annual emissions based on 5.4 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 23.1 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr and 20.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions 1 of 4 (Per CTG)

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: 5.4 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, natural gas-firing.** **Field 4 limit applicable for 100% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **23.1** lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 50% load, natural gas-firing.** **Field 4 limit applicable for 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 4 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **20.2** lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, fuel oil-firing.** **Field 4 limit applicable for 100% load, fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 4 of 4 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **30 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **47.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 75% load, fuel oil-firing.** **Field 4 limit applicable for 75% load, fuel oil-firing at ISO conditions.**	

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

<u>**Visible Emissions Limitation:**</u> Visible Emissions Limitation 1 of 3

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). Limit applicable for natural gas firing.**	

<u>**Visible Emissions Limitation:**</u> Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % 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). Limit applicable for fuel oil firing.**	

Visible Emissions Limitation: Visible Emissions Limitation —3— of —3—

1. Visible Emissions Subtype: VE10	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**	
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. Limit applicable for natural gas or fuel oil firing.**	

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).** **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).** **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. 2-3** [ ] 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:________ [ ] 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

ABB GT-24

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 three, identical ABB GT-24 simple-cycle combustion turbine generators (CTGs) each having a nominal rating of 180 megawatts (MW). The CTGs will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a back-up fuel.

4. Emissions Unit Identification Number: [ ] No ID
ID: **001, 002, 003 (CTG Nos. 1, 2, and 3)** [ ] 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 (Per CTG)

1. Control Equipment/Method Description (Limit to 200 characters per device or method): NO_x Controls **Dry low-NO_x combustors (natural gas-firing)** **Water injection (distillate fuel-oil firing)**	
2. Control Device or Method Code(s): **25 (dry low-NO_x), 28 (water injection)**	

Emissions Unit Details **(Per CTG)**

1. Package Unit: Manufacturer: **ABB Power Generation**	Model Number: **GT-24**
2. Generator Nameplate Rating: **180** 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 (Per CTG)

1. Maximum Heat Input Rate:	**2,078 (LHV)** mmBtu/hr			
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
		hours/day		days/week
		weeks/year	**3,000**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is lower heating value (LHV) at 100 percent load, 0°F, fuel oil-firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.**				

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 (Per CTG)

1. Identification of Point on Plot Plan or Flow Diagram? **CT1, CT2, CT3**	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: **100** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,000 °F**	9. Actual Volumetric Flow Rate: **1,914,688** 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, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.

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

Segment Description and Rate: Segment 1 of 2 (Per CTG)

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): 20100201	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: 1.965	5. Maximum Annual Rate: 11,583.7	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 923
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV).** **Maximum hourly rate (Field 12) based on 0°F ambient temperature.**		

Segment Description and Rate: Segment 2 of 2 (Per CTG)

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with distillate fuel oil.**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: 15.291	5. Maximum Annual Rate: 7,645.5	6. Estimated Annual Activity Factor:
6. Maximum % Sulfur: 0.05	7. Maximum % Ash: 0.01	8. Million Btu per SCC Unit: 134
9. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents lower heating value (LHV).** **Maximum hourly rate (Field 12) based on 0°F ambient temperature.**		

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			EL
4 – PM10			EL
5 – SO2			EL
6 – SAM			EL
7 – VOC			EL

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **398.3** lb/hour **315.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **398.3 lb/hr** Reference: **ABB data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on ABB data for 100 percent load, 0°F, fuel oil-firing case. Annual emissions based on 183.7 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr, and 342.5 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **25 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **183.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **342.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).** **Field 4 limit applicable for fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions ____ of ____ **(Per CTG)**

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 (Per CTG)

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **394.9** lb/hour **92.2** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **394.9 lb/hr** Reference: **ABB data**		7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on ABB data for 50 percent load, 0°F, natural gas-firing case. Annual emissions based on 23.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,000 hrs/yr, 149.6 lb/hr (50 percent load, 59°F, natural gas-firing case) for 500 hrs/yr and 126.6 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions 1 of 3 (Per CTG)

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: **23.1** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, natural gas-firing.** **Field 4 limit applicable for 100% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
11. Requested Allowable Emissions and Units: **132 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **149.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 50% load, natural gas-firing.** **Field 4 limit applicable for 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
7. Requested Allowable Emissions and Units: **28 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **126.6** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, fuel oil-firing.** **Field 4 limit applicable for 100% load, fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions ____ of ____ **(Per CTG)**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
12. 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)

<u>Potential/Fugitive Emissions</u> (Per CTG)

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 83.0 lb/hour 41.8 tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **83.0 lb/hr** Reference: **ABB data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on ABB data for 100 percent load, 0°F, fuel oil-firing case. Annual emissions based on 24.2 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 46.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

<u>**Allowable Emissions**</u> Allowable Emissions __1__ of __2__ **(Per CTG)**

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
19. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **24.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
20. Requested Allowable Emissions and Units: **20 % opacity**	4. Equivalent Allowable Emissions: **46.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for 100% load, distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **83.0** lb/hour **41.8** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **83.0 lb/hr** Reference: **ABB data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on ABB data for 100 percent load, 0°F, fuel oil-firing case. Annual emissions based on 24.2 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 46.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 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:
21. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **24.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
22. Requested Allowable Emissions and Units: **20 % opacity**	4. Equivalent Allowable Emissions: **46.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for 100% load, distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **111.8** lb/hour **35.9** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **111.8 lb/hr** Reference: **ABB data**	7. Emissions Method Code: **2**

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

(0.05 lb S/100 lb oil) x (111,800 lb oil/hr) x (2 lb SO_2/lb S) = 111.8 lb/hr SO_2

Annual emissions based on 9.2 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 97.5 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
23. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **9.2** 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):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
24. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **97.5** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.8** lb/hour **4.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **12.8 lb/hr** Reference: **ABB data**	7. Emissions Method Code: **2**

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

(111.8 lb/hr SO_2) x (7.5/100) x (98 lb H_2SO_4/64 lb SO_2) = 12.8 lb/hr H_2SO_4

Annual emissions based on 1.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 11.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
25. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **1.1** 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):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)
Field 4 limit applicable for natural gas-firing at ISO conditions.

Allowable Emissions Allowable Emissions 2 of 2 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
26. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **11.2** 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): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 4 limit applicable for distillate fuel oil-firing at ISO conditions.**	

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

Potential/Fugitive Emissions (Per CTG)

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **24.5** lb/hour **9.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **24.5 lb/hr** Reference: **ABB data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on ABB data for 100 percent load, 0°F, distillate fuel oil-firing case. Annual emissions based on 2.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,500 hrs/yr and 22.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 500 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **2.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, natural gas-firing.** **Field 4 limit applicable for 100% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **1.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 50% load, natural gas-firing.** **Field 4 limit applicable for 50% load, natural gas-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions 3 of 3 (Per CTG)

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **7.5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **22.7** lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Field 3 limit applicable for 100% load, fuel oil-firing.** **Field 4 limit applicable for 100% load, fuel oil-firing at ISO conditions.**	

Allowable Emissions Allowable Emissions ____ of ____ **(Per CTG)**

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 1 of 3

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). Limit applicable for natural gas firing.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [✓] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % 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). Limit applicable for fuel oil firing.**	

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: VE10	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**
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.** **Limit applicable for natural gas or fuel oil firing.**

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).** **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).** **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. 2-3** [ ] 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:________ [ ] 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

APPENDIX A1

REGULATORY APPLICABILITY ANALYSES

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

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(b) - (h)		CTs 1-3	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CTs 1-3	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CTs 1-3	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CTs 1-3	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		CTs 1-3	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CTs 1-3	General procedures regarding reporting deadlines.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	§60.332(a)(1) and (b), (f), and (i)		CTs 1-3	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		CTs 1-3	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.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines (continued)				
Monitoring Requirements	§60.334(a)		CTs 1-3	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 to CTGs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CTs 1-3	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CTs 1-3	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Ca, Cb, Cc, Cd, Ce, D, Da, 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, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to HCGF CTs 1-3.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements which are applicable to HCGF CTs 1-3.
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, 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 HCGF CTs 1-3.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
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)		CTs 1-3	General Acid Rain Program requirements. SO_2 allowance program requirements start January 1, 2000 **(future requirement)**.
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		CTs 1-3	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CTs 1-3	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)**.
Permit Application Shield	§72.32		CTs 1-3	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CTs 1-3	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to HCGF CTs 1-3.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CTs 1-3	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				
Fast-Track Modifications	§72.82(a) and (c)		CTs 1-3	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CTs 1-3	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CTs 1-3	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CTs 1-3	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CTs 1-3	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CTs 1-3	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)		CTs 1-3	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CTs 1-3	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CTs 1-3	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CTs 1-3	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CTs 1-3	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CTs 1-3	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CTs 1-3	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)		CTs 1-3	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CTs 1-3	Monitor data availability procedure requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Standard Missing Data Procedures	§75.33(a) and (c)		CTs 1-3	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CTs 1-3	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CTs 1-3	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CTs 1-3	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CTs 1-3	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CTs 1-3	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CTs 1-3	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CTs 1-3	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CTs 1-3	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.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CTs 1-3	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)		CTs 1-3	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				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CTs 1-3	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)		CTs 1-3	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		CTs 1-3	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		HCGF CTs 1-3 will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B		Vehicle Fleet Maintenance	Servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner will be performed by contractors who comply with Subpart B requirements.
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		The HCGF will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		HCGF CTs 1-3 will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Contractors maintain, service, repair, or dispose of any appliances in compliance with §82.154 prohibitions. Appliances are 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.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors 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 9 of 10)

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	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Contractors' technicians meet the certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		Contractors 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.
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.

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
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, 67, 68, 69, 71, 74, 76, 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 HCGF CTs 1-3.

Source: ECT, 2000.

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 HCGF CTs 1-3.
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		X			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) 39., (c), (d), and (e), F.A.C.[1]**			CTs 1-3	NSPS Subpart 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.			CTs 1-3	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 HCGF CTs 1-3.
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 HCGF CTs 1-3.
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.			CTs 1-3	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	62-210.700(2) and (3), F.A.C.	X			Not applicable to HCGF CTs 1-3.
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.

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(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 HCGF CTs 1-3.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			HCGF CTs 1-3 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 HCGF CTs 1-3.
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

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
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 implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CTs 1-3	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.
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.

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 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		HCGF CTs 1-3 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.			CTs 1-3	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.
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CTs 1-3	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.			CTs 1-3	The designated representative must certify all Acid Rain submissions. **(future requirement)**.

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
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.			CTs 1-3	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.			CTs 1-3	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 HCGF CTs 1-3.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to HCGF CTs 1-3.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to HCGF CTs 1-3.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
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

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
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 HCGF CTs 1-3.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281.300, .400, .500, and .900, F.A.C.	X			Servicing of motor vehicle air conditioners and vehicle maintenance that may release refrigerants. Not applicable to HCGF CTs 1-3.
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.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			HCGF CTs 1-3 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.

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
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 HCGF CTs 1-3.
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			HCGF CTs 1-3 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			HCGF CTs 1-3 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			HCGF CTs 1-3 is not located in a lead nonattainment 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			HCGF CTs 1-3 is not located in a PM nonattainment area or a PM air quality maintenance area.

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
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.			CTs 1-3	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 HCGF CTs 1-3.
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, 2000.

APPENDIX A2

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 Hardee County Generating Facility operations include:

- Vehicular traffic on paved and unpaved roads.

- 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

APPENDIX A3

III.L.2–FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.0571
Propane	0.7101
I-butane	0.1479
N-butane	0.1558
I-Pentane	0.0476
N-Pentane	0.0308
Nitrogen	0.3750
Methane	94.7805
CO_2	0.5244
Ethane	3.1708
Other Characteristics	
Heat content (HHV)	1,051.9 Btu/ft^3 at 60°F, 14.73 psia, dry
Real specific gravity	0.5913
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: ECT, 2000.

1C010800

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Minimum gross heating value, Btu/gal HHV	137,000
Ash, percent by weight (maximum)	0.05
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015

Note: Btu/gal = British thermal units per gallon.
HHV = higher heating value.

Source: ECT, 2000.

APPENDIX B

CTG VENDOR EMISSIONS DATA

GENERAL ELECTRIC 7241FA

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,886	20,886	20,886
Fuel Temperature	Deg F	80	80	80
Output	kW	183,400.	137,500.	91,700.
Heat Rate (LHV)	Btu/kWh	9,300.	9,950.	11,910.
Heat Cons. (LHV) X 10^6	Btu/h	1,705.6	1,368.1	1,092.1
Exhaust Flow X 10^3	lb/h	3776.	3010.	2473.
Exhaust Temp.	Deg F.	1081.	1111.	1160.
Exhaust Heat (LHV) X 10^6	Btu/h	1017.8	848.9	738.3

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	63.	50.	39.
CO	ppmvd	15.	15.	15.
CO	lb/h	51.	41.	34.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.91	0.90
Nitrogen	75.06	75.07	75.18
Oxygen	12.56	12.59	12.90
Carbon Dioxide	3.87	3.85	3.71
Water	7.61	7.59	7.31

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	30
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(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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TECO - Polk station
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,886	20,886	20,886
Fuel Temperature	Deg F	80	80	80
Output	kW	170,300.	127,700.	85,100.
Heat Rate (LHV)	Btu/kWh	9,370.	10,130.	12,200.
Heat Cons. (LHV) X 10^6	Btu/h	1,595.7	1,293.6	1,038.2
Exhaust Flow X 10^3	lb/h	3518.	2874.	2384.
Exhaust Temp.	Deg F.	1117.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	956.6	810.4	708.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
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	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.88	0.89
Nitrogen	74.38	74.43	74.54
Oxygen	12.38	12.52	12.85
Carbon Dioxide	3.87	3.80	3.65
Water	8.49	8.37	8.07

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
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(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	90.	90.	90.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,886	20,886	20,886
Fuel Temperature	Deg F	80	80	80
Output	kW	151,100.	113,300.	75,500.
Heat Rate (LHV)	Btu/kWh	9,720.	10,620.	12,860.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.7	1,203.2	970.9
Exhaust Flow X 10^3	lb/h	3263.	2695.	2262.
Exhaust Temp.	Deg F.	1141.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	899.5	772.2	676.3

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	54.	44.	35.
CO	ppmvd	15.	15.	15.
CO	lb/h	43.	36.	30.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.87	0.86
Nitrogen	72.32	72.37	72.50
Oxygen	11.96	12.10	12.48
Carbon Dioxide	3.80	3.73	3.56
Water	11.06	10.93	10.60

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	80
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(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

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ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	20.	20.	20.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	59	59	59
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	189,400.	142,100.	94,700.
Heat Rate (LHV)	Btu/kWh	10,060.	10,880.	12,730.
Heat Cons. (LHV) X 10^6	Btu/h	1,905.4	1,546.	1,205.5
Exhaust Flow X 10^3	lb/h	3894.	2911.	2430.
Exhaust Temp.	Deg F.	1067.	1184.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	1056.0	900.4	766.3
Water Flow	lb/h	132,150.	102,410.	69,710.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	338.	272.	210.
CO	ppmvd	33.	33.	33.
CO	lb/h	113.	84.	71.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	11.	10.
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.85	0.87
Nitrogen	71.82	71.53	72.47
Oxygen	11.17	10.49	11.37
Carbon Dioxide	5.61	6.02	5.60
Water	10.54	11.11	9.70

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	30
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(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	59	59	59
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	178,800.	134,100.	89,400.
Heat Rate (LHV)	Btu/kWh	10,040.	10,880.	12,840.
Heat Cons. (LHV) X 10^6	Btu/h	1,795.2	1,459.	1,147.9
Exhaust Flow X 10^3	lb/h	3662.	2812.	2395.
Exhaust Temp.	Deg F.	1098.	1195.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	996.1	854.1	735.2
Water Flow	lb/h	120,430.	91,300.	62,380.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	257.	200.
CO	ppmvd	33.	33.	33.
CO	lb/h	106.	81.	70.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.86	0.87
Nitrogen	71.31	71.26	72.21
Oxygen	11.04	10.63	11.59
Carbon Dioxide	5.61	5.88	5.40
Water	11.19	11.37	9.94

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
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(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	90.	90.	90.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	59	59	59
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	159,900.	119,900.	79,900.
Heat Rate (LHV)	Btu/kWh	10,210.	11,150.	13,240.
Heat Cons. (LHV) X 10^6	Btu/h	1,632.6	1,336.9	1,057.9
Exhaust Flow X 10^3	lb/h	3375.	2693.	2316.
Exhaust Temp.	Deg F.	1130.	1200.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	931.9	808.1	698.3
Water Flow	lb/h	91,870.	67,650.	44,800.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	290.	235.	184.
CO	ppmvd	33.	33.	33.
CO	lb/h	97.	77.	67.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.85
Nitrogen	70.02	70.24	71.08
Oxygen	10.85	10.77	11.69
Carbon Dioxide	5.50	5.59	5.12
Water	12.79	12.56	11.27

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	80
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(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

GE International
Power Systems

Paul L. Moyer
Project Manager

Global Power Plant Systems Department
General Electric International, Inc.
1 River Road, Bldg. 2 - 341
Schenectady, NY 12345
Tele: (518) 385-1563
Fax: (518) 385-1709

March 29, 1999

Mr. James Badgerow
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111
6944 U. S. Highway 41N
Apollo Beach, Florida 33572

Subject: **Polk Power Station No. 2**
Emission Guarantees

GE Ref: **GEII/TECO-016/99**

Dear Jim:

As requested, the following are Polk Power Station No. 2 emission guarantees:

EMISSIONS GUARANTEES FOR IPS80571 TECO 7FA							
Fuel	Operation	Diluent	Nox - ppmvd	CO ppmvd	UHC ppmvw	VOC ppmvw	Particulates (TSP/PM10 - FRONT HALF ONLY) lbm/hr
natural gas	base & part(1)	dry	9	15	7	1.4	9
Distillate	base & part(1)	water	42	33	7	3.5	17

If you have any questions, please advise.

Best Regards,

P. Moyer

Paul L. Moyer
Project Manager

PLM-3899
PLM/pva

cc: M. Broder
J. Chalfin

A Subsidiary of General Electric Company, USA

WESTINGHOUSE 501F

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Attachment I

SIEMENS Westinghouse

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
2-95x200 Air Cooled Generator (0.85 PF)

CTT-1741 rev6
10/21/98

SITE CONDITIONS:	Base Load Cases		
FUEL TYPE	GAS	GAS	GAS
LOAD LEVEL	BASE	BASE	BASE
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,968	20,968	20,968
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,196	23,196	23,196
AMBIENT TEMPERATURE, °F	95.0	59.0	32.0
AMBIENT RELATIVE HUMIDITY, %	80%	60%	30%
COMPRESSOR INLET TEMPERATURE, °F	95.0	59.0	32.0
BAROMETRIC PRESSURE, psia	14.630	14.630	14.630
COMBUSTION TURBINE PERFORMANCE:			
GROSS POWER OUTPUT, kW	160,720	181,440	197,690
GROSS HEAT RATE, Btu/kWh (LHV)	9,480	9,150	8,970
GROSS HEAT RATE, Btu/kWh (HHV)	10,490	10,120	9,925
FUEL FLOW, lbm/hr	72,683	79,159	84,587
INJECTION RATE, lbm/hr	-	-	-
EXHAUST FLOW, lbm/hr	3,285,274	3,598,206	3,800,538
EXHAUST FLOW, ACFM	948,472	1,018,843	1,071,270
STACK EXIT VELOCITY (ft/sec)	62.0	66.7	70.2
STACK EXHAUST TEMPERATURE (F)	201.0	198.0	197.0
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	11.84	12.48	12.53
CARBON DIOXIDE	3.87	3.90	3.96
WATER	11.51	8.25	7.55
NITROGEN	71.86	74.42	75.01
ARGON	0.90	0.93	0.94
MOLECULAR WEIGHT	28.06	28.42	28.50
NET EMISSIONS: Based on Westinghouse 21T5620 test methods			
NOx, ppmvd @ 15% O2	6	6	6
NOx, lbm/hr as NO2 (6 ppm case)	39	42	45
NOx, ppmvd @ 15% O2	9	9	9
NOx, lbm/hr as NO2 (9 ppm case)	58	63	68
NOx, ppmvd @ 15% O2	12	12	12
NOx, lbm/hr as NO2 (12 ppm case)	78	85	91
CO, ppmvd	20	20	20
CO, ppmvd @ 15% O2	16	16	16
CO, lbm/hr	62	69	73
SO2, ppmvd	1	1	1
SO2, ppmvd @ 15% O2	1	1	1
SO2, lbm/hr	2	2	2
VOC, ppmvd as CH4	4	4	4
VOC, ppmvd @ 15% O2 as CH4	3	3	3
VOC, lbm/hr as CH4	7	8	8
PARTICULATES, lbm/hr	5.0	5.5	5.9

NOTES:

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- Gross power output is at the generator terminals.
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Gas fuel composition is 83.4% CH_4, 15.8% C_2H_6, 0.8% N_2, and 0.2 grains of sulfur per 100 SCF.
- Gas fuel must be in compliance with the latest revision of the Westinghouse Gas Fuel Spec (21T0306).
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Average temperature of the gas fuel is 280 °F. Sensible heat of the fuel is not included in the fuel heating values, heat input, or heat rate.
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per US EPA Method 5B (front half only) and do not include H2SO4 mist.
- Maximum gross power is 199 MW.

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Attachment I

SIEMENS Westinghouse

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
2-95x200 Air Cooled Generator (0.85 PF)

CTT-1741 rev6
10/21/98

SITE CONDITIONS:	70% Case			50% Case		
FUEL TYPE	GAS	GAS	GAS	GAS	GAS	GAS
LOAD LEVEL	70%	70%	70%	50%	50%	50%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,968	20,968	20,968	20,968	20,968	20,968
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,196	23,196	23,196	23,196	23,196	23,196
AMBIENT TEMPERATURE, °F	95.0	59.0	32.0	95.0	59.0	32.0
AMBIENT RELATIVE HUMIDITY, %	80%	60%	30%	80%	60%	30%
COMPRESSOR INLET TEMPERATURE, °F	95.0	59.0	32.0	95.0	59.0	32.0
BAROMETRIC PRESSURE, psia	14.630	14.630	14.630	14.630	14.630	14.630
COMBUSTION TURBINE PERFORMANCE:						
GROSS POWER OUTPUT, kW	112,120	126,670	138,020	79,650	90,060	98,190
GROSS HEAT RATE, Btu/kWh (LHV)	10,810	10,160	9,845	11,800	11,155	10,785
GROSS HEAT RATE, Btu/kWh (HHV)	11,740	11,240	10,895	13,050	12,340	11,910
FUEL FLOW, lbm/hr	56,746	61,380	64,827	44,811	47,911	50,416
INJECTION RATE, lbm/hr	-	-	-	-	-	-
EXHAUST FLOW, lbm/hr	2,644,614	2,783,745	2,895,848	2,503,892	2,657,731	2,777,543
EXHAUST FLOW, ACFM	759,168	785,783	813,903	712,717	746,276	773,528
STACK EXIT VELOCITY (ft/sec)	49.7	51.5	53.3	46.7	48.9	50.7
STACK EXHAUST TEMPERATURE (F)	199.0	196.0	195.0	195.0	192.0	191.0
EXHAUST GAS COMPOSITION (BY % VOL):						
OXYGEN	12.16	12.52	12.50	13.41	14.00	14.08
CARBON DIOXIDE	3.72	3.88	3.97	3.13	3.19	3.23
WATER	11.24	8.21	7.57	10.17	6.92	6.19
NITROGEN	71.96	74.44	75.00	72.37	74.94	75.54
ARGON	0.90	0.93	0.94	0.91	0.94	0.95
MOLECULAR WEIGHT	28.08	28.42	28.50	28.14	28.50	28.58
NET EMISSIONS: Based on Westinghouse 21T5520 test methods						
NOx, ppmvd @ 15% O2	6	6	6	6	6	6
NOx, lbm/hr as NO2 (6 ppm case)	30	33	35	24	26	27
NOx, ppmvd @ 15% O2	9	9	9	9	9	9
NOx, lbm/hr as NO2 (9 ppm case)	52	49	45	40	38	36
NOx, ppmvd @ 15% O2	12	12	12	12	12	12
NOx, lbm/hr as NO2 (12 ppm case)	60	65	69	47	51	54
CO, ppmvd	20	20	20	83	82	82
CO, ppmvd @ 15% O2	16	16	16	82	83	82
CO, lbm/hr	50	53	56	198	213	223
SO2, ppmvd	1	1	1	1	1	1
SO2, ppmvd @ 15% O2	1	1	1	1	2	2
SO2, lbm/hr	1	1	1	1	1	1
VOC, ppmvd as CH4	4	4	4	20	20	20
VOC, ppmvd @ 15% O2 as CH4	3	3	3	20	20	20
VOC, lbm/hr as CH4	6	6	6	27	30	31
PARTICULATES, lbm/hr	5.0	5.0	5.0	5.0	5.0	5.0

NOTES:
- Performance based on new and clean condition.
- All data are expected and not guaranteed.
- Gross power output is at the generator terminals.
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Gas fuel composition is 83.4% CH4, 15.8% C2H6, 0.8% N2, and 0.2 grains of sulfur per 100 SCF.
- Gas fuel must be in compliance with the latest revision of the Westinghouse Gas Fuel Spec (21T0306).
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per US EPA Method 5B (front half only) and do not include H2SO4 mist.
- Maximum exhaust temperature is 1160 °F for base and part load.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

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Attachment I

SIEMENS
Westinghouse

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
2-95x200 Air Cooled Generator (0.85 PF)

CTT-1741 rev6
10/21/98

SITE CONDITIONS:	Base Load Case		
FUEL TYPE	OIL	OIL	OIL
LOAD LEVEL	BASE	BASE	BASE
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,586	18,586	18,586
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,845	19,845	19,845
AMBIENT TEMPERATURE, °F	95.0	59.0	32.0
AMBIENT RELATIVE HUMIDITY, %	80%	60%	30%
COMPRESSOR INLET TEMPERATURE, °F	95.0	59.0	32.0
BAROMETRIC PRESSURE, psia	14.630	14.630	14.630
INJECTION FLUID	WATER	WATER	WATER
INJECTION RATIO, lb Water / lb Fuel	0.40	0.40	0.40
COMBUSTION TURBINE PERFORMANCE:			
GROSS POWER OUTPUT, kW	154,100	174,380	190,310
GROSS HEAT RATE, Btu/kWh (LHV)	9,850	9,490	9,295
GROSS HEAT RATE, Btu/kWh (HHV)	10,515	10,140	9,925
FUEL FLOW, lbm/hr	81,651	89,101	95,178
INJECTION RATE, lbm/hr	32,660	35,620	38,070
EXHAUST FLOW, lbm/hr	3,313,485	3,628,843	3,833,887
EXHAUST FLOW, ACFM	1,074,112	1,158,859	1,223,387
STACK EXIT VELOCITY (ft/sec)	70.3	75.8	80.3
STACK EXHAUST TEMPERATURE (F)	291.0	288.0	291.0
EXHAUST GAS COMPOSITION (BY % VOL):			
OXYGEN	11.83	12.56	12.61
CARBON DIOXIDE	4.96	5.01	5.08
WATER	10.56	7.30	6.59
NITROGEN	71.63	74.18	74.76
ARGON	0.90	0.93	0.94
MOLECULAR WEIGHT	28.33	28.69	28.78
NET EMISSIONS: Based on Westinghouse 21T5620 test methods			
NOx, ppmvd @ 15% O2	42	42	42
NOx, lbm/hr as NO2	275	299	320
CO, ppmvd	25	25	25
CO, ppmvd @ 15% O2	20	20	20
CO, lbm/hr	78	87	92
SO2, ppmvd	13	13	13
SO2, ppmvd @ 15% O2	10	10	10
SO2, lbm/hr	87	94	101
VOC, ppmvd as CH4	13	13	13
VOC, ppmvd @ 15% O2 as CH4	10	10	10
VOC, lbm/hr as CH4	23	26	27
PARTICULATES, lbm/hr	16.1	18.0	19.1

NOTES:
- Performance based on new and clean condition.
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- Gross power output is at the generator terminals.
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- Fuel oil composition is 86.139% C, 13.8% H, 0.05% S, 0.015% FBN, and 0.001% ash.
- Liquid fuel must be in compliance with the latest revision of the Westinghouse Liquid Fuel Spec (21T4424).
- Injection ratios may be adjusted during plant commissioning to meet emissions.
- Dry Low NOX Injection ratios are estimated. Actual injection will be set at the minimum required to reach specified NOX levels.
- Particulates are per US EPA Method 5B (front half only) and do not include H2SO4 mist.
- Particulates for oil fuel are based on specific gravity and may vary depending on fuel.
- Maximum gross power is 199 MW.

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Attachment I

SIEMENS Westinghouse

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
2-95x200 Air Cooled Generator (0.85 PF)

CTT-1741 m
10/21/

SITE CONDITIONS:	70% Case			50% Case		
FUEL TYPE	OIL	OIL	OIL	OIL	OIL	OIL
LOAD LEVEL	70%	70%	70%	50%	50%	50%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,586	18,586	18,586	18,586	18,586	18,586
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,845	19,845	19,845	19,845	19,845	19,845
AMBIENT TEMPERATURE, °F	95.0	59.0	32.0	95.0	59.0	32.0
AMBIENT RELATIVE HUMIDITY, %	80%	60%	30%	80%	60%	30%
COMPRESSOR INLET TEMPERATURE, °F	95.0	59.0	32.0	95.0	59.0	32.0
BAROMETRIC PRESSURE, psia	14.630	14.630	14.630	14.630	14.630	14.630
INJECTION FLUID	WATER	WATER	WATER	WATER	WATER	WATER
INJECTION RATIO, lb Water / lb Fuel	0.28	0.28	0.28	0.20	0.20	0.20
COMBUSTION TURBINE PERFORMANCE:						
GROSS POWER OUTPUT, kW	107,480	121,720	132,900	76,310	86,520	94,520
GROSS HEAT RATE, Btu/kWh (LHV)	10,720	10,200	9,880	12,155	11,510	11,155
GROSS HEAT RATE, Btu/kWh (HHV)	11,440	10,885	10,550	12,985	12,285	11,910
FUEL FLOW, lbm/hr	61,959	66,764	70,652	49,931	53,560	56,726
INJECTION RATE, lbm/hr	17,350	18,690	19,780	9,990	10,710	11,350
EXHAUST FLOW, lbm/hr	3,109,825	3,389,603	3,568,317	2,664,386	2,859,230	2,987,108
EXHAUST FLOW, ACFM	1,003,017	1,047,957	1,128,252	853,878	901,144	942,059
STACK EXIT VELOCITY (ft/sec)	65.7	68.6	73.9	55.9	59.0	61.7
STACK EXHAUST TEMPERATURE (F)	289.0	286.0	289.0	285.0	282.0	285.0
EXHAUST GAS COMPOSITION (BY % VOL):						
OXYGEN	13.63	14.33	14.44	14.10	14.73	14.79
CARBON DIOXIDE	3.97	3.97	4.01	3.71	3.76	3.83
WATER	9.01	5.66	4.89	8.47	5.16	4.42
NITROGEN	72.47	75.08	75.69	72.79	75.39	75.99
ARGON	0.91	0.94	0.95	0.91	0.95	0.95
MOLECULAR WEIGHT	28.40	28.76	28.85	28.43	28.80	28.89
NET EMISSIONS: Based on Westinghouse 21T5620 test methods						
NOx, ppmvd @ 15% O2	42	42	42	65	65	65
NOx, lbm/hr as NO2	205	215	234	272	299	313
CO, ppmvd	25	25	25	80	80	80
CO, ppmvd @ 15% O2	25	26	26	88	87	87
CO, lbm/hr	74	81	87	204	224	235
SO2, ppmvd	11	10	10	10	10	10
SO2, ppmvd @ 15% O2	11	10	10	11	11	11
SO2, lbm/hr	66	71	75	53	57	60
VOC, ppmvd as CH4	30	30	30	100	100	100
VOC, ppmvd @ 15% O2 as CH4	30	31	31	108	110	109
VOC, lbm/hr as CH4	51	55	60	147	161	169
PARTICULATES, lbm/hr	20.3	22.6	23.9	23.7	26.0	27.3

NOTES:

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- Fuel oil composition is 86.139% C, 13.8% H, 0.05% S, 0.015% FBN, and 0.001% ash.
- Liquid fuel must be in compliance with the latest revision of the Westinghouse Liquid Fuel Spec (21T4424).
- Injection ratios may be adjusted during plant commissioning to meet emissions.
- Dry Low NOX injection ratios are estimated. Actual injection will be set at the minimum required to reach specified NOX levels.
- Particulates are per US EPA Method 5B (front half only) and do not include H2SO4 mist.
- Particulates for oil fuel are based on specific gravity and may vary depending on fuel.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

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WESTINGHOUSE 501D5A

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SIEMENS Westinghouse

LS Power, SE, USA

Expected 501D5A Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
TLRI 100/30-36 Air Cooled Generator (0.90 PF)

CTT-1923
08/30/99

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7
FUEL TYPE	GAS	GAS	GAS	GAS	GAS	GAS	GAS
LOAD LEVEL	Peak-Paug	BASE	75%	50%	BASE	75%	50%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	20,981	20,981	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299	23,299	23,299	23,299	23,299	23,299	23,299
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	85%	OFF	OFF	OFF	OFF	OFF
AMBIENT TEMPERATURE, °F	95.0	95.0	95.0	95.0	20.0	20.0	20.0
AMBIENT RELATIVE HUMIDITY, %	60%	60%	60%	60%	60%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	84.6	84.6	95.0	95.0	20.0	20.0	20.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696
INLET PRESSURE LOSS, inches of water (Total)	3.8	3.8	3.0	2.1	4.6	3.6	2.3
EXHAUST PRESSURE LOSS, inches of water (Total)	19.5	17.9	13.6	9.6	23.3	17.3	11.5
EXHAUST PRESSURE LOSS, inches of water (Static)	13.4	12.3	9.4	6.6	16.2	12.0	7.9
INJECTION FLUID	STEAM	-	-	-	-	-	-
INJECTION RATIO, lb Steam / lb Fuel	1.4	-	-	-	-	-	-
COMBUSTION TURBINE PERFORMANCE:							
GROSS POWER OUTPUT, kW	123,510	105,950	79,290	52,510	130,770	97,960	64,980
GROSS HEAT RATE, Btu/kWh (LHV)	9,880	10,355	11,190	13,270	9,845	10,305	11,970
GROSS HEAT RATE, Btu/kWh (HHV)	10,970	11,500	12,430	14,735	10,930	11,440	13,290
FUEL FLOW, lbm/hr	58,150	52,280	42,290	33,200	61,340	48,090	37,060
INJECTION RATE, lbm/hr	81,400	-	-	-	-	-	-
HEAT INPUT, mmBtu/hr (LHV)	1,220	1,097	887	697	1,287	1,009	778
HEAT INPUT, mmBtu/hr (HHV)	1,355	1,218	985	774	1,429	1,121	864
EXHAUST TEMPERATURE, °F	1,055	1,021	993	987	972	884	905
EXHAUST FLOW, lbm/hr	2,917,823	2,831,726	2,465,584	2,081,973	3,283,221	2,903,551	2,332,199
EXHAUST GAS COMPOSITION (BY % VOL):							
OXYGEN	12.05	13.33	13.83	14.34	13.87	14.66	14.93
CARBON DIOXIDE	3.32	3.12	2.91	2.70	3.20	2.84	2.72
WATER	14.27	9.82	9.03	8.62	6.59	5.87	5.63
NITROGEN	69.48	72.80	73.24	73.40	75.38	75.66	75.75
ARGON	0.87	0.91	0.92	0.92	0.95	0.95	0.95
MOLECULAR WEIGHT	27.70	28.17	28.24	28.26	28.53	28.58	28.59
NET EMISSIONS: Based on Westinghouse 21T5620 test methods							
NOx, ppmvd @ 15% O2	25	15	18	45	15	18	45
NOx, lbm/hr as NO2	126	68	66	128	79	75	143
CO, ppmvd	50	10	22	200	10	22	200
CO, ppmvd @ 15% O2	43	10	23	227	10	24	232
CO, lbm/hr	132	27	51	394	31	62	450
VOC, ppmvd as CH4	3	3	3	18	3	3	17
VOC, ppmvd @ 15% O2 as CH4	3	3	3	20	3	3	20
VOC, lbm/hr as CH4	4.5	4.5	4.0	20.2	5.4	4.8	21.9
PARTICULATES, lbm/hr	14.6	14.6	12.8	10.9	17.4	15.4	12.4
OPACITY	<= 10%	<= 10%	<= 10%	<= 10%	<= 10%	<= 10%	<= 10%

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- *Gas fuel composition is 98% CH_4, 0.6% C_2H_6, 1.4% N_2, and 0.2 grains of sulfur per 100 SCF.*
- Gas fuel must be in compliance with the latest revision of the Siemens Westinghouse Gas Fuel Spec (21T0306).
- Liquid condensable fuels must be removed from the fuel lines.
- VOC's are non methane, non ethane.
- Particulates are per US EPA Method 5/202 (front and back half).

- Acual IGV may vary. Part load performance will be adjusted accordingly.
- Average temperature of the gas fuel is 280 °F. Sensible heat of the fuel is not included in the fuel heating values, heat input, or heat rate.
- Injection is for power augmentation and not for NO_X control.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.
- Part load is achieved by lowering the firing temperature and is based on percentage unrestricted power output.

SIEMENS
Westinghouse

LS Power, SE, USA

Expected 501D5A Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
TLRI 100/30-36 Air Cooled Generator (0.90 PF)

CTT-1923
06/30/99

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
SITE CONDITIONS:						
FUEL TYPE	OIL	OIL	OIL	OIL	OIL	OIL
LOAD LEVEL	BASE	75%	50%	BASE	75%	50%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	18,450	18,450	18,450	18,450	18,450	18,450
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	19,680	19,680	19,680	19,680	19,680	19,680
EVAPORATIVE COOLER STATUS/EFFICIENCY	85%	OFF	OFF	OFF	OFF	OFF
AMBIENT TEMPERATURE, °F	95.0	95.0	95.0	20.0	20.0	20.0
AMBIENT RELATIVE HUMIDITY, %	60%	60%	60%	60%	60%	60%
COMPRESSOR INLET TEMPERATURE, °F	84.6	95.0	95.0	20.0	20.0	20.0
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696	14.696	14.696	14.696
INLET PRESSURE LOSS, inches of water (Total)	3.8	3.5	2.4	4.6	4.2	2.7
EXHAUST PRESSURE LOSS, inches of water (Total)	18.1	15.1	10.4	23.5	19.3	12.7
EXHAUST PRESSURE LOSS, inches of water (Static)	12.4	10.4	7.2	16.2	13.5	8.8
INJECTION FLUID	WATER	WATER	WATER	WATER	WATER	WATER
INJECTION RATIO, lb Water / lb Fuel	0.4	0.3	0.2	0.4	0.3	0.2
COMBUSTION TURBINE PERFORMANCE:						
GROSS POWER OUTPUT, kW	107,060	80,070	53,030	131,760	98,640	65,440
GROSS HEAT RATE, Btu/kWh (LHV)	10,650	11,465	13,490	10,145	10,605	12,195
GROSS HEAT RATE, Btu/kWh (HHV)	11,360	12,230	14,385	10,825	11,310	13,010
FUEL FLOW, lbm/hr	61,770	49,740	38,760	72,440	56,690	43,250
INJECTION RATE, lbm/hr	24,710	15,920	7,750	28,980	18,140	8,650
HEAT INPUT, mmBtu/hr (LHV)	1,140	918	715	1,337	1,046	798
HEAT INPUT, mmBtu/hr (HHV)	1,216	979	763	1,426	1,116	851
EXHAUST TEMPERATURE, °F	1,023	935	936	975	831	841
EXHAUST FLOW, lbm/hr	2,865,385	2,668,437	2,218,996	3,322,700	3,150,143	2,532,546
EXHAUST GAS COMPOSITION (BY % VOL):						
OXYGEN	13.15	14.28	14.77	13.69	15.05	15.47
CARBON DIOXIDE	4.35	3.73	3.47	4.46	3.64	3.43
WATER	8.97	7.65	7.02	5.72	4.51	3.93
NITROGEN	72.60	73.40	73.80	75.17	75.82	76.20
ARGON	0.91	0.92	0.93	0.94	0.95	0.96
MOLECULAR WEIGHT	28.44	28.52	28.56	28.81	28.86	28.90
NET EMISSIONS: Based on Westinghouse 21T5620 test methods						
NOx, ppmvd @ 15% O2	42	42	65	42	42	65
NOx, lbm/hr as NO2	202	161	192	237	183	214
CO, ppmvd	30	65	1,000	30	65	1,000
CO, ppmvd @ 15% O2	27	71	1,177	28	75	1,229
CO, lbm/hr	80	164	2,112	95	198	2,462
VOC, ppmvd as CH4	11	28	55	11	26	53
VOC, ppmvd @ 15% O2 as CH4	10	30	65	10	30	65
VOC, lbm/hr as CH4	16.9	40.4	66.4	20.0	45.3	74.6
PARTICULATES, lbm/hr	55.0	68.1	84.2	65.2	82.2	98.3
OPACITY	<= 20%	<= 20%	<= 50%	<= 20%	<= 20%	<= 50%

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- VOC's are non methane, non ethane.
- Particulates are per US EPA Method 5/202 (front and back half).

- Fuel oil composition is 86.434% C, 13.5% H, 0.05% S, 0.015% FBN, and 0.001% ash.
- Liquid fuel must be in compliance with the latest revision of the Siemens Westinghouse Liquid Fuel Spec (21T4424).
- Acual IGV may vary. Part load performance will be adjusted accordingly.

- Injection ratios may be adjusted during plant commissioning to meet emissions. Performance will be adjusted to the actual injection rate.
- Dry Low NO_X injection ratios are estimated. Actual injection will be set at the minimum required to reach specified NO_X levels.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.

ABB GT-24

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ABB

GT-24 Units

Conditions																	
Casename	G100N20	G75N20	G60N20	G50N20	G100N16	G75N16	G60N16	G50N16	G100N37	G100E37	G100S37	G100C37	G75N37	G60N37	G50N37	G100E43	G100C43
Fuel Type	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas
GT Load, %	100	75	60	50	100	75	60	50	100	100	100	100	75	60	50	100	100
Evaporative Cooler Status	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	ON	OFF	ON	OFF	OFF	OFF	ON	ON
Steam Injection	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	ON
Ambient Dry Bulb Temperature, F	-5	-5	-5	-5	60	60	60	60	98	98	98	98	98	98	98	109	109
Barometric Pressure, psia	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61	14.61
Relative Humidity, %	60	60	60	60	60	60	60	60	35	35	35	35	35	35	35	35	35
Unit Stack Emissions 2,3,4,5																	
GT Exhaust Flow, klb\hr(each unit)	3341	2690	2409	2205	3044	2570	2301	2111	2850	2938	2930	3095	2461	2204	2028	2883	3039
Stack Temperature, F	199	182	179	176	194	184	181	179	194	198	193	192	187	184	182	205	200
NOx, lb/hr (Method 20)	68	54	44	41	61	49	40	38	57	59	60	65	45	37	35	59	65
NOx, ppmvd	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
CO, lb/hr (Method 10)	23	54	149	277	21	50	136	252	19	20	20	22	46	126	234	20	22
CO, ppmvd	5	15	50	100	5	15	50	100	5	5	5	5	15	50	100	5	5
VOC as C3H8, lb/hr (Method 18 & 25a)	2.8	2.3	1.9	3	2.6	2.1	1.7	2.8	2.4	2.5	2.5	2.8	1.9	1.6	2.6	2.5	2.7
VOC as C3H8, ppmvd (Method 18 & 25a)	0.4	0.4	0.4	0.7	0.4	0.4	0.4	0.7	0.4	0.4	0.4	0.4	0.4	0.4	0.7	0.4	0.4
PM10, lb/hr (Method 5)	24	20	17	15	22	18	16	14	21	22	22	24	17	15	13	21	23
SO2, lb/hr (based on 0.14 grains S/100 scf)	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1	< 1
SO3, lb/hr (based on 0.14 grains S/100 scf)	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
NH3 slip, ppmvd	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Unit Stack Exhaust Gas Composition																	
Mole fraction of N2 in exhaust	0.74667	0.74685	0.7481	0.74909	0.73942	0.74106	0.7423	0.74326	0.73177	0.72592	0.70106	0.66923	0.73403	0.7353	0.73616	0.71875	0.66213
Mole fraction of O2 in exhaust	0.11354	0.11406	0.1177	0.12043	0.11201	0.11669	0.1203	0.12302	0.11123	0.10855	0.10202	0.09207	0.11784	0.1213	0.12401	0.10674	0.09028
Mole fraction of H2O in exhaust	0.08618	0.08571	0.0825	0.08003	0.09525	0.09109	0.0879	0.08546	0.10443	0.11247	0.14424	0.18570	0.09860	0.0955	0.09314	0.12159	0.19472
Mole fraction of CO2 in exhaust	0.04468	0.04444	0.0428	0.04149	0.04447	0.04230	0.0406	0.03937	0.04382	0.04438	0.04430	0.04501	0.04075	0.0391	0.03789	0.04432	0.04495
Mole fraction of Ar in exhaust	0.00893	0.00893	0.0089	0.00896	0.00884	0.00886	0.0089	0.00889	0.00875	0.00868	0.00838	0.00800	0.00878	0.0088	0.00880	0.00859	0.00792

APPENDIX C
CONTROL SYSTEM VENDOR QUOTE

:NGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

ary 26, 1999

ient & Lundy
N: Paula Scholl

Sargent and Lundy / Tampa Electric – Polk Station
GE Fr7FA Simple Cycle Turbine
Oxidation Catalyst Components
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB99318

r Ms Scholl,

provide Engelhard Budgetary Proposal EPB99318 for Engelhard **Camet®** CO Oxidation Catalyst System Components and ‹CAT ZNX™ High Temperature SCR Catalyst system components for the above project. This is per your FAXed request of uary 25, 1999.

Budgetary Proposal is based on:

Given data for GE 7EA Gas Turbine operating in simple cycle mode;
Oxidation Catalysts for 90% CO reduction as noted;
Catalysts for NOx reduction as noted with ammonia slip of 5 ppmvd@15%O_2;
- Option 1: NOx reduction from 10.5 ppmvd @ 15% O_2 to 6 ppmvd @ 15% O_2
- Option 2: NOx reduction from 10.5 ppmvd @ 15% O_2 to 3.5 ppmvd @ 15% O_2
- Option 3: NOx reduction from 12 ppmvd @ 15% O_2 to 6 ppmvd @ 15% O_2
- Option 4: NOx reduction from 12 ppmvd @ 15% O_2 to 3.5 ppmvd @ 15% O_2

Delta P through SCR system - Nominal 3"WG;
Assumed internally insulated ducts with cross sections at the catalysts as illustrated.
Scope as noted. Please note that we have assumed horizontal gas flow through the CO / SCR reactor and the use of 28% aqueous ammonia. The system proposed requires the use of an ambient air cooling system to reduce the gas temperature to the SCR catalyst.
Three (3) Year Performance Guarantee (expected life five to seven years).

ɜ request the opportunity to work with you on this project.

ıcerely yours,

IGELHARD CORPORATION

Frederick A. Booth

ederick A. Booth
ıles Engineer

: Nancy Ellison - Proposal Administrator

NGELHARD

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Sargent and Lundy / Tampa Electric - Polk
GE 7FA Simple Cycle Turbine
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99318
January 26, 1999

ENGELHARD CORPORATION
CAMET™ CO CATALYST SYSTEM
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEM

hard Corporation ("Engelhard") offers to supply to Buyer the CAMET™ metal substrate CO Catalyst System components ie NOxCAT ZNX™ ceramic substrate SCR system components summarized herein.

: of Supply
ngelhard CAMET® CO and NOxCAT ZNX™ SCR catalyst in modules;
iternal support structures for catalyst modules (frames);
iternally insulated reactor ductwork - with stainless steel liner sheets - to house CO catalyst modules, AIG, and SCR atalyst modules;
.mmonia Injection Grid (AIG);
.IG manifold with flow control valves ;
IH_3 Vaporization / Air dilution skid: 28% Aqueous Ammonia to skid;
.mbient air cooling system components as required.

GET PRICES: Per Turbine-	Option 1	Option 2	Option 3	Option 4
CO Catalyst System	$ 885,000	$1,075,000	$ 960,000	$1,100,000
Replacement CO Modules	$ 700,000	$ 850,000	$ 780,000	$ 900,000
SCR Catalyst System	$2,400,000	$3,400,000	$2,600,000	$3,500,000
Replacement ZNX Modules	$1,000,000	$1,800,000	$1,200,000	$2,000,000

.RANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

UMENT / MATERIAL DELIVERY SCHEDULE

/ings / Documentation	6 - 8 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
'ating manuals	
:rial Delivery	20 - 24 weeks after approval and release for fabrication

TEM DESIGN BASIS:

Flow from:	GE Fr7FA - with ambient air cooling
Flow:	Assumed Horizontal
:	Natural Gas
Flow Rate (At catalyst face):	See Performance data
.perature (At catalyst face):	See Performance data
Concentration (At catalyst face):	See Performance data
Reduction:	90%
: Concentration (At catalyst face):	See Performance data
: Reduction:	See Performance data
; Slip:	5 ppmvd@15%O_2
;sure Drop through SCR	Nom. 3"WG through ea. catalyst

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Sargent and Lundy / Tampa Electric - Polk
GE 7FA Simple Cycle Turbine
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99318
January 26, 1999

rmance Data

GIVEN / CALCULATED DATA	OPTION 1	OPTION 2	OPTION 3	OPTION 4
AMBIENT	90	90	90	90
LOAD	BASE	BASE	BASE	BASE
TURBINE EXHAUST TEMPERATURE, F	1,140	1,140	1,140	1,140
TURBINE EXHAUST FLOW, lb/hr	3,280,000	3,280,000	3,280,000	3,280,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.19	74.19	74.19	74.19
O2	12.47	12.47	12.47	12.47
CO2	3.80	3.80	3.80	3.80
H2O	8.65	8.65	8.65	8.65
Ar	0.89	0.89	0.89	0.89
AMBIENT AIR FLOW, lb/hr	443,597	443,597	443,597	443,597
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	3,723,597	3,723,597	3,723,597	3,723,597
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.02	75.02	75.02	75.02
O2	13.21	13.21	13.21	13.21
CO2	3.35	3.35	3.35	3.35
H2O	7.63	7.63	7.63	7.63
Ar	0.79	0.79	0.79	0.79
CALCULATED AIR + GAS MOL. WT.	28.41	28.41	28.41	28.41
GIVEN: TURBINE CO, ppmvd @ 15% O2	15.0	15.0	15.0	15.0
CALC.: TURBINECO, lb/hr	54.5	54.5	54.5	54.5
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	10.5	10.5	12.0	12.0
CALC.: TURBINE NOx, lb/hr	62.7	62.7	71.6	71.6
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	14.4	14.4	14.4	14.4
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	10.1	10.1	11.5	11.5
AMBIENT + EXHAUST GAS TEMP. @ CATALYSTS, F	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS				
CO CATALYST — CO OUT, ppmvd@15%O2	1.4	1.4	1.4	1.4
SCR CATALYST — NOx OUT, ppmvd@15%O2	6.0	3.5	6.0	3.5
NH3 SLIP, ppmvd@15%O2	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	3"	3"	3"	3"
GUARANTEED PERFORMANCE DATA				
CO CATALYST — CO CONVERSION - % Max.	90.0%	90.0%	90.0%	90.0%
CO OUT, ppmvd@15%O2 - Max.	1.4	1.4	1.4	1.4
CO OUT, lb/hr - Max.	5.5	5.5	5.5	5.5
CO PRESSURE DROP, "WG - Max.	1.7	1.1	1.4	1.0
SCR CATALYST — NOx CONVERSION, % - Min.	42.9%	66.7%	50.0%	70.8%
NOx OUT, lb/hr - Max.	35.8	20.9	35.8	20.9
NOx OUT, ppmvd@15%O2 - Max.	5.8	3.4	5.8	3.4
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	77	96	88	108
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	3.0	3.0	3.0	3.0

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Sargent and Lundy / Tampa Electric - Polk
GE 7FA Simple Cycle Turbine
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99318
January 26, 1999

:quipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

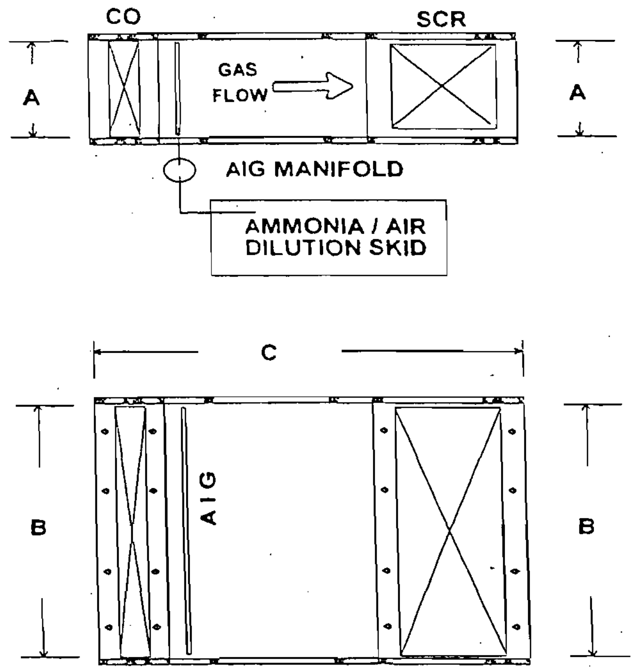
ımed Dimensions / Sketch:

	Option 1
:tor Width	(A) 49'-3"
:tor Height	(B) 32'-3"
:tor Reactor Depth	(C) 15'-0"

	Option 2
:tor Width	(A) 54'-0"
:tor Height	(B) 38'-6"
:tor Reactor Depth	(C) 15'-6"

	Option 3
:tor Width	(A) 45'-0"
:tor Height	(B) 40'-0"
ctor Reactor Depth	(C) 15'-0"

	Option 4
ctor Width	(A) 57'-3"
ctor Height	(B) 38'-6"
ctor Reactor Depth	(C) 16'-0"



luded from Scope of Supply:
ıonia storage and pumping
· duct transitions to and from reactor
:trical grounding equipment
ındations
ɔther items not specifically listed in Scope of Supply
Any interconnecting field piping or wiring
Utilities
All Monitors

Tampa Electric Company
Polk Station Peaking Unit 2

COST ESTIMATE FOR ADDED SCR - LABOR AND COMMODITY COSTS

Project No. 10456-000
January 29, 1999

Item Description	Comments/Assumptions	Material or Equipment	Quantity	Units	Unit Price matl/equip	Total matl or equip Cost	Unit Labor Rate	Total Manhours	Crew Wage Rate	Total Labor Cost	Total Projected Cost
Ambient air fans	Provide 2 blowers and duct work on each side of the exhaust upstream of silencer to inject cool air.	Fans	2	Ea	25,000.00	$50,000	100	200	41.00	$8,200	$58,200
Foundation for ambient air fans	Assume small support pedestals on 4' thick mat. Each mat plan area estimated at 100 sq. ft. Add 30% for pedestals.	Concrete	39	CY	70.17	$2,700	1.885	73	19.57	$1,400	$4,100
		Reinforcing	3.4	TN	562.00	$1,900	23.1	78	32.03	$2,500	$4,400
		Formwork	416	SF	2.18	$900	0.185	77	26.92	$2,100	$3,000
		Piles	8	Ea	1,000.00	$8,000	5.55	44	70.12	$3,100	$11,100
Ambient air cooling ductwork.	Assume 2 ducts 7' x 7' x 40' long. Use a ductwork weight of 20 psf.	Stiffened plate, A36 material	22.4	TN	1,600.00	$35,800	20	448	65.96	$29,600	$65,400
		Support Steel	5.6	TN	1,600.00	$9,000	20	112	65.96	$7,400	$16,400
	Insulation & Lagging	Mineral Wool	2,240	SF	17.04	$38,200	0.146	327	37.00	$12,100	$50,300
Transition duct after silencer, before SCR.	Assume length of 35' and weight of 40 psf to include extensive turning vanes and lower material properties at high temperatures. Transitions from 25'W x 22'H to 63.5'W x 41.75'H	Stiffened plate	118	TN	1,600.00	$189,200	25	2,957	65.96	$195,000	$384,200
		Support Steel	29.6	TN	1,600.00	$47,300	25	739	65.96	$48,800	$96,100
	Insulation & Lagging	Mineral Wool	5,880	SF	17.04	$100,200	0.146	858	37.00	$31,800	$132,000
SCR & CO Catalyst System	Assume that the reactor dimensions are as follows: 63.5'W x 41.75'H x 16"D.		1	Ea	**See Vendor Quote**		12,000	12,000	62.00	$744,000	$744,000

Tampa Electric Company
Polk Station Peaking Unit 2

COST ESTIMATE FOR ADDED SCR - LABOR AND COMMODITY COSTS

Project No. 10456-000
January 29, 1999

Item Description	Comments/Assumptions	Material or Equipment	Quantity	Units	Unit Price matl/equip	Total matl or equip Cost	Unit Labor Rate	Total Manhours	Crew Wage Rate	Total Labor Cost	Total Projected Cost
		Support Steel	40	TN	1,600.00	$64,000	25	1,000	65.96	$66,000	$130,000
	Insulation & Lagging	Mineral Wool	3,368	SF	17.04	$57,400	0.146	492	37.00	$18,200	$75,600
Transition duct after SCR, before stack.	Assume length of 40' and weight of 40 psf to include extensive turning vanes and lower material properties at high temperatures. Transitions from 63.5'W x 41.75'H to 18'W x 41.75'H	Stiffened plate	142	TN	1,600.00	$227,700	25	3,558	65.96	$234,700	$462,400
		Support Steel	35.6	TN	1,600.00	$56,900	25	890	65.96	$58,700	$115,600
	Insulation & Lagging	Mineral Wool	7,101	SF	17.04	$121,000	0.146	1,037	37.00	$38,400	$159,400
Expansion joints	Ambient air ducts	Fabric	56	LF	120.00	$6,700	2	112	62.00	$6,900	$13,600
	Between silencer & transition	Fabric	94	LF	120.00	$11,300	2	188	62.00	$11,700	$23,000
	Between transition and stack	Fabric	120	LF	120.00	$14,300	2	239	62.00	$14,800	$29,100
Galleries to access SCR	Platforms and stairs	Steel	3,000	SF	30.00	$90,000	0.380	1,140	65.96	$75,200	$165,200
Foundation under transition ducts and SCR	Assume 4' thick mat, 91' long and 65' wide. Assumed volume includes allowance for small piers/pads for equipment and duct/SCR support on main mat.	Concrete	964	CY	70.17	$67,600	1.885	1,817	19.57	$35,600	$103,200
		Reinforcing	83.4	TN	562.00	$46,900	23.1	1,926	32.03	$61,700	$108,600
		Formwork	1,373	SF	2.18	$3,000	0.185	254	26.92	$6,800	$9,800
		Piles	54	Ea	1,000.00	$54,000	5.55	300	70.12	$21,000	$75,000
	Total Direct Costs					$1,304,000		30,866		$1,735,700	$3,039,700
Engineering Indirects	7% of total direct costs										$212,800

APPENDIX D
EMISSION RATE CALCULATIONS

GENERAL ELECTRIC 7241FA

Table 1. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Operating Scenarios - General Electric 7241FA CT

Case	Ambient Temperature (oF)	Load (%)	CT-1	CT-2	CT-3	Natural Gas Firing	Fuel Oil Firing
1	20	100	X	X	X	X	X
2	20	75	X	X	X	X	X
3	20	50	X	X	X	X	X
4	59	100	X	X	X	X	X
5	59	75	X	X	X	X	X
6	59	50	X	X	X	X	X
7	90	100	X	X	X	X	X
8	90	75	X	X	X	X	X
9	90	50	X	X	X	X	X

Sources: GPP, 1999.
ECT, 1999.

Table 2. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CT; Natural Gas-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1]		SO_2 [2]		H_2SO_4 [3]		Pb [4]	
			(lb/hr) [5]	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1	100	9.9	1.25	9.8	1.24	1.1	0.14	9.24E-04	1.16E-04
	2	75	9.9	1.25	7.9	0.99	0.9	0.11	7.41E-04	9.34E-05
	3	50	9.9	1.25	6.3	0.79	0.7	0.09	5.92E-04	7.46E-05
59	4	100	9.9	1.25	9.2	1.16	1.1	0.13	8.65E-04	1.09E-04
	5	75	9.9	1.25	7.5	0.94	0.9	0.11	7.01E-04	8.83E-05
	6	50	9.9	1.25	6.0	0.75	0.7	0.09	5.62E-04	7.09E-05
90	7	100	9.9	1.25	8.5	1.07	1.0	0.12	7.96E-04	1.00E-04
	8	75	9.9	1.25	6.9	0.87	0.8	0.10	6.52E-04	8.21E-05
	9	50	9.9	1.25	5.6	0.71	0.6	0.08	5.26E-04	6.63E-05
		Maximums	**9.9**	**1.25**	**9.8**	**1.24**	**1.1**	**0.14**	**9.24E-04**	**1.16E-04**

Temp. (°F)	Case	Load (%)	NO_x			CO			VOC		
			(ppmvd) [6]	(lb/hr) [5]	(g/sec)	(ppmvd) [6]	(lb/hr) [5]	(g/sec)	(ppmvd) [6]	(lb/hr) [5]	(g/sec)
20	1	100	10.5	80.9	10.19	12.1	56.1	7.07	1.2	3.3	0.42
	2	75	10.5	64.2	8.09	12.2	45.1	5.68	1.2	2.6	0.33
	3	50	10.5	50.1	6.31	12.7	37.4	4.71	1.3	2.2	0.28
59	4	100	10.5	75.7	9.54	12.0	52.8	6.65	1.2	3.1	0.39
	5	75	10.5	60.3	7.60	12.2	42.9	5.41	1.2	2.4	0.30
	6	50	10.5	47.5	5.98	12.8	35.2	4.44	1.3	2.0	0.25
90	7	100	10.5	69.3	8.73	11.9	47.3	5.96	1.2	2.9	0.36
	8	75	10.5	56.5	7.11	12.1	39.6	4.99	1.3	2.4	0.30
	9	50	10.5	44.9	5.66	12.8	33.0	4.16	1.3	2.0	0.25
		Maximums	**10.5**	**80.9**	**10.19**	**12.8**	**56.1**	**7.07**	**1.3**	**3.3**	**0.42**

1 As measured by EPA Reference Method 5B or 17.
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 Table 1.4-2, AP-42, March 1998.
5 Includes a 10% margin for variability in stack sampling.
6 Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 3. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CT; Distillate Fuel Oil-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM10[1] (lb/hr)[5]	PM/PM10[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)	Pb[4] (lb/hr)	Pb[4] (g/sec)
20	1	100	18.7	2.36	104.1	13.12	12.0	1.51	0.111	0.014
	2	75	18.7	2.36	84.5	10.64	9.7	1.22	0.090	0.011
	3	50	18.7	2.36	65.9	8.30	7.6	0.95	0.070	0.009
59	4	100	18.7	2.36	98.1	12.36	11.3	1.42	0.104	0.013
	5	75	18.7	2.36	79.7	10.05	9.2	1.15	0.085	0.011
	6	50	18.7	2.36	62.7	7.90	7.2	0.91	0.067	0.008
90	7	100	18.7	2.36	89.2	11.24	10.2	1.29	0.095	0.012
	8	75	18.7	2.36	73.1	9.20	8.4	1.06	0.078	0.010
	9	50	18.7	2.36	57.8	7.28	6.6	0.84	0.061	0.008
		Maximums	**18.7**	**2.36**	**104.1**	**13.12**	**12.0**	**1.51**	**0.111**	**0.014**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[6]	NO_x (lb/hr)[5]	NO_x (g/sec)	CO (ppmvd)[6]	CO (lb/hr)[5]	CO (g/sec)	VOC (ppmvd)[6]	VOC (lb/hr)[5]	VOC (g/sec)
20	1	100	42.0	371.8	46.85	23.1	124.3	15.66	2.7	8.3	1.04
	2	75	42.0	299.2	37.70	21.4	92.4	11.64	2.6	6.1	0.76
	3	50	42.0	231.0	29.11	23.4	78.1	9.84	2.8	5.5	0.69
59	4	100	42.0	350.9	44.21	23.0	116.6	14.69	2.7	7.7	0.97
	5	75	42.0	282.7	35.62	21.9	89.1	11.23	2.6	6.1	0.76
	6	50	42.0	220.0	27.72	24.2	77.0	9.70	2.9	5.0	0.62
90	7	100	42.0	319.0	40.19	23.0	106.7	13.44	2.8	7.2	0.90
	8	75	42.0	258.5	32.57	22.7	84.7	10.67	2.8	6.1	0.76
	9	50	42.0	202.4	25.50	25.2	73.7	9.29	3.0	5.0	0.62
		Maximums	**42.0**	**371.8**	**46.85**	**25.2**	**124.3**	**15.66**	**3.0**	**8.3**	**1.04**

[1] As measured by EPA Reference Method 5B or 17.
[2] Based on fuel oil sulfur content of 0.05 wt percent.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Table 3.1-4., AP-42, October 1996.
[5] Includes a 10% margin for variability in stack sampling.
[6] Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 4. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CT; Natural Gas-Firing
CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 20 °F	100% - 59 °F	100 % - 90 °F
Maximum Hourly Fuel Flow:	10^6 ft^3/hr	1.848	1.729	1.591
Maximum Annual Hours:		N/A	3,000	N/A

Pollutant	Emission Factor[1] (lb/10^6 ft^3)	Emission Rates			
		20 °F (lb/hr)	59 °F (lb/hr)	90 °F (lb/hr)	Annual (ton/yr)
Arsenic	2.00E-04	3.70E-04	3.46E-04	3.18E-04	5.19E-04
Benzene	2.10E-03	3.88E-03	3.63E-03	3.34E-03	5.45E-03
Beryllium	1.20E-05	2.22E-05	2.07E-05	1.91E-05	3.11E-05
Cadmium	1.10E-03	2.03E-03	1.90E-03	1.75E-03	2.85E-03
Chromium	1.40E-03	2.59E-03	2.42E-03	2.23E-03	3.63E-03
Cobalt	8.40E-05	1.55E-04	1.45E-04	1.34E-04	2.18E-04
Dichlorobenzene	1.20E-03	2.22E-03	2.07E-03	1.91E-03	3.11E-03
Formaldehyde	7.50E-02	1.39E-01	1.30E-01	1.19E-01	1.95E-01
Lead	5.00E-04	9.24E-04	8.65E-04	7.96E-04	1.30E-03
Manganese	3.80E-04	7.02E-04	6.57E-04	6.05E-04	9.86E-04
Mercury	2.60E-04	4.81E-04	4.50E-04	4.14E-04	6.74E-04
Naphthalene	6.10E-04	1.13E-03	1.05E-03	9.71E-04	1.58E-03
Nickel	2.10E-03	3.88E-03	3.63E-03	3.34E-03	5.45E-03
Polycyclic Organic Matter	8.82E-05	1.63E-04	1.53E-04	1.40E-04	2.29E-04
Selenium	2.40E-05	4.44E-05	4.15E-05	3.82E-05	6.22E-05
Toluene	3.40E-03	6.28E-03	5.88E-03	5.41E-03	8.82E-03

[1] Section 1.4, Natural Gas Combustion, Tables 1.4-2., 1.4-3 and 1.4-4, EPA AP-42, March 1998.

Source: ECT, 1999.

Table 5. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CT; Distillate Fuel Oil-Firing
CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 20 °F	100% - 59 °F	100 % - 90 °F
Maximum Hourly Fuel Flow:	10^6 Btu/hr	1,905.4	1,795.2	1,632.6
Maximum Annual Hours:		N/A	500	N/A

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates			
		20 °F (lb/hr)	59 °F (lb/hr)	90 °F (lb/hr)	Annual (ton/yr)
Antimony	2.20E-05	4.19E-02	3.95E-02	3.59E-02	9.87E-03
Arsenic	4.90E-06	9.34E-03	8.80E-03	8.00E-03	2.20E-03
Beryllium	3.30E-07	6.29E-04	5.92E-04	5.39E-04	1.48E-04
Cadmium	4.20E-06	8.00E-03	7.54E-03	6.86E-03	1.88E-03
Chromium	4.70E-05	8.96E-02	8.44E-02	7.67E-02	2.11E-02
Cobalt	9.10E-06	1.73E-02	1.63E-02	1.49E-02	4.08E-03
Lead	5.80E-05	1.11E-01	1.04E-01	9.47E-02	2.60E-02
Manganese	3.40E-04	6.48E-01	6.10E-01	5.55E-01	1.53E-01
Mercury	9.10E-07	1.73E-03	1.63E-03	1.49E-03	4.08E-04
Nickel	1.20E-03	2.29E+00	2.15E+00	1.96E+00	5.39E-01
Phosphorus	3.00E-04	5.72E-01	5.39E-01	4.90E-01	1.35E-01
Selenium	5.30E-06	1.01E-02	9.51E-03	8.65E-03	2.38E-03

[1] Section 3.1, Stationary Gas Turbines, Table 3.1-4, EPA AP-42, October 1996.

Source: ECT, 1999.

Table 6. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	227.2	283.9	158.4	198.0	9.2	11.6
CT 1-3	4 - Oil	3	500	1,052.7	263.2	349.8	87.5	23.1	5.8
			Totals	**N/A**	**547.1**	**N/A**	**285.5**	**N/A**	**17.3**

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	29.7	37.1	27.6	34.5	0.003	0.003
CT 1-3	4 - Oil	3	500	56.1	14.0	294.3	73.6	0.31	0.08
			Totals	**N/A**	**51.2**	**N/A**	**108.1**	**N/A**	**0.08**

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,500 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
3. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
4. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
GE, 1999.
GPP, 1999.

Table 7. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CTs
CT Annual Emission Rates - Hazardous Air Pollutants

Pollutant	Annual Emissions (ton/yr)
Antimony	9.87E-03
Arsenic	2.72E-03
Benzene	5.45E-03
Beryllium	1.79E-04
Cadmium	4.74E-03
Chromium	2.47E-02
Cobalt	4.30E-03
Dichlorobenzene	3.11E-03
Formaldehyde	1.95E-01
Lead	2.73E-02
Manganese	1.54E-01
Mercury	1.08E-03
Naphthalene	1.58E-03
Nickel	5.44E-01
Phosphorus	1.35E-01
Polycyclic Organic Matter	2.29E-04
Selenium	2.44E-03
Toluene	8.82E-03
Total HAPS	1.12

Source: ECT, 1999.

Table 8. Hardee County Generating Facility, CT-1, CT-2, and CT-3
General Electric 7241FA CT
NSPS GG NO_x Limits

Fuel	7241FA Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,370	9.886	0.0	109.2
Distillate	10,040	10.593	0.0	102.0

Sources: ECT, 1999.
GE, 1998.

Table 9.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %								
		100 % Load			75 % Load			50 % Load		
Component	MW (lb/mole)	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.89	0.87	0.91	0.88	0.87	0.90	0.89	0.86
N_2	28.013	75.06	74.38	72.32	75.07	74.43	72.37	75.18	74.54	72.50
O_2	31.999	12.56	12.38	11.96	12.59	12.52	12.10	12.90	12.85	12.48
CO_2	44.010	3.87	3.87	3.80	3.85	3.80	3.73	3.71	3.65	3.56
H_2O	18.015	7.61	8.49	11.06	7.59	8.37	10.93	7.31	8.07	10.60
SO_2	64.063	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.00	100.01	100.01	100.01	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.48	28.39	28.10	28.48	28.39	28.10	28.50	28.41	28.12
Exhaust Flow (lb/sec)		1,048.89	977.22	906.39	836.11	798.33	748.61	686.94	662.22	628.33
Exhaust Temp. (°F)		1,081	1,117	1,141	1,111	1,139	1,166	1,160	1,184	1,200
(K)		856	876	889	873	888	903	900	913	922
Exhaust O_2 (Vol %, Dry)		13.59	13.53	13.45	13.62	13.66	13.58	13.92	13.98	13.96

Sources: ECT, 1999.
GE, 1998.

Table 9.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,484,905	2,377,044	2,261,182	2,019,122	1,968,831	1,896,425	1,709,803	1,677,915	1,623,873
Velocity (fps)	162.8	155.7	148.1	132.2	129.0	124.2	112.0	109.9	106.4
Velocity (m/s)	49.6	47.5	45.1	40.3	39.3	37.9	34.1	33.5	32.4
SCFM, Dry[1]	786,605	728,296	663,247	627,104	595,705	548,505	516,533	495,404	461,759
ACFM (15% O_2, Dry)	2,842,518	2,717,722	2,540,365	2,301,008	2,212,655	2,094,306	1,875,628	1,809,694	1,707,709

[1] At 68 °F.

Sources: ECT, 1999.
GE, 1998.

Table 9.C. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

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

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
CO (15% O_2)	12.1	12.0	11.9	12.2	12.2	12.1	12.7	12.8	12.8
VOC (ppmvw)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC (ppmvd)	1.5	1.5	1.6	1.5	1.5	1.6	1.5	1.5	1.6
VOC (15% O_2)	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3

Sources: ECT, 1999.
GE, 1999.

Table 10.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			75 % Load			50 % Load		
Component	(lb/mole)	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.87	0.85	0.85	0.85	0.86	0.85	0.87	0.87	0.85
N_2	28.013	71.82	71.31	70.02	71.53	71.26	70.24	72.47	72.21	71.08
O_2	31.999	11.17	11.04	10.85	10.49	10.63	10.77	11.37	11.59	11.69
CO_2	44.010	5.61	5.61	5.50	6.02	5.88	5.59	5.60	5.40	5.12
H_2O	18.015	10.54	11.19	12.79	11.11	11.37	12.56	9.70	9.94	11.27
SO_2	64.063	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.01	100.00	100.01	100.00	100.00	100.01	100.01	100.01	100.01
Exhaust MW (lb/mole)		28.41	28.33	28.15	28.39	28.34	28.19	28.50	28.45	28.28
Exhaust Flow (lb/sec)		1,081.67	1,017.22	937.50	808.61	781.11	748.06	675.00	665.28	643.33
Exhaust Temp. (°F)		1,067	1,098	1,130	1,184	1,195	1,200	1,200	1,200	1,200
(K)		848	865	883	913	919	922	922	922	922
Exhaust O_2 (Vol %, Dry)		12.49	12.43	12.44	11.80	11.99	12.32	12.59	12.87	13.17

Sources: ECT, 1999.
GE, 1998.

Table 10.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,545,637	2,449,067	2,318,407	2,050,538	1,996,983	1,929,016	1,721,459	1,699,480	1,653,661
Velocity (fps)	166.7	160.4	151.8	134.3	130.8	126.3	112.7	111.3	108.3
Velocity (m/s)	50.8	48.9	46.3	40.9	39.9	38.5	34.4	33.9	33.0
SCFM, Dry	787,445	737,105	671,418	585,400	564,665	536,503	494,436	486,826	466,705
ACFM (15% O_2, Dry)	3,247,689	3,122,059	2,898,752	2,810,978	2,671,783	2,453,761	2,189,083	2,083,315	1,921,209

Sources: ECT, 1999.
GE, 1998.

Table 10.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,545,637	2,449,067	2,318,407	2,050,538	1,996,983	1,929,016	1,721,459	1,699,480	1,653,661
Velocity (fps)	166.7	160.4	151.8	134.3	130.8	126.3	112.7	111.3	108.3
Velocity (m/s)	50.8	48.9	46.3	40.9	39.9	38.5	34.4	33.9	33.0
SCFM, Dry'	787,445	737,105	671,418	585,400	564,665	536,503	494,436	486,826	466,705
ACFM (15% O_2, Dry)	3,247,689	3,122,059	2,898,752	2,810,978	2,671,783	2,453,761	2,189,083	2,083,315	1,921,209

Sources: ECT, 1999.
GE, 1998.

Table 10.C. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

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

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
CO (15% O_2)	23.1	23.0	23.0	21.4	21.9	22.7	23.4	24.2	25.2
VOC (ppmvw)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
VOC (ppmvd)	3.9	3.9	4.0	3.9	3.9	4.0	3.9	3.9	3.9
VOC (15% O_2)	2.7	2.7	2.8	2.6	2.6	2.8	2.8	2.9	3.0

Sources: ECT, 1999.
GE, 1999.

Table 11. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Fuel Flow Rate Data - General Electric PG7241FA (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,706	1,596	1,469	1,368	1,294	1,203	1,092	1,038	971
Fuel Rate (lb/hr)	81,662	76,400	70,320	65,503	61,936	57,608	52,289	49,708	46,486
Fuel Rate (10^6 ft^3/hr)	1.848	1.729	1.591	1.482	1.402	1.304	1.183	1.125	1.052
Fuel Rate (lb/sec)	22.684	21.222	19.533	18.195	17.205	16.002	14.525	13.808	12.913

B. Distillate Fuel Oil-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,905	1,795	1,633	1,546	1,459	1,337	1,206	1,148	1,058
Fuel Rate (lb/hr)	104,120	98,098	89,213	84,481	79,727	73,055	65,874	62,727	57,809
Fuel Rate (10^3 gal/hr)	14.243	13.419	12.204	11.557	10.906	9.993	9.011	8.581	7.908
Fuel Rate (lb/sec)	28.922	27.250	24.781	23.467	22.146	20.293	18.298	17.424	16.058

Sources: ECT, 1999.
GE, 1998.

WESTINGHOUSE 501F

Table 1. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Operating Scenarios - Westinghouse 501F CT

Case	Ambient Temperature (oF)	Load (%)	CT-1	CT-2	CT-3	Natural Gas Firing	Fuel Oil Firing
1	32	100	X	X	X	X	X
2	32	70	X	X	X	X	X
3	32	50	X	X	X	X	
4	59	100	X	X	X	X	X
5	59	70	X	X	X	X	X
6	59	50	X	X	X	X	
7	95	100	X	X	X	X	X
8	95	70	X	X	X	X	X
9	95	50	X	X	X	X	

Sources: GPP, 1999.
ECT, 1999.

Table 2. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CT; Natural Gas-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1] (lb/hr)[5]	PM/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)	Pb[4] (lb/hr)	Pb[4] (g/sec)
32	1	100	9.5	1.19	9.9	1.25	1.1	0.144	9.57E-04	1.21E-04
	2	70	9.5	1.19	7.6	0.96	0.9	0.110	7.34E-04	9.24E-05
	3	50	9.5	1.19	5.9	0.75	0.7	0.086	5.70E-04	7.19E-05
59	4	100	9.5	1.19	9.3	1.17	1.1	0.135	8.96E-04	1.13E-04
	5	70	9.5	1.19	7.2	0.91	0.8	0.104	6.95E-04	8.75E-05
	6	50	9.5	1.19	5.6	0.71	0.6	0.081	5.42E-04	6.83E-05
95	7	100	9.5	1.19	8.5	1.08	1.0	0.124	8.22E-04	1.04E-04
	8	70	9.5	1.19	6.7	0.84	0.8	0.096	6.42E-04	8.09E-05
	9	50	9.5	1.19	5.3	0.66	0.6	0.076	5.07E-04	6.39E-05
		Maximums	**9.5**	**1.19**	**9.9**	**1.25**	**1.14**	**0.144**	**9.57E-04**	**1.21E-04**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[6]	NO_x (lb/hr)[5]	NO_x (g/sec)	CO (ppmvd)[6]	CO (lb/hr)[5]	CO (g/sec)	VOC[7] (ppmvd)[6]	VOC[7] (lb/hr)[5]	VOC[7] (g/sec)
32	1	100	15	125.1	15.77	16	80.3	10.12	3.0	8.8	1.11
	2	70	15	94.9	11.95	16	61.6	7.76	3.0	6.6	0.83
	3	50	15	74.3	9.36	82	245.3	30.91	20.0	34.1	4.30
59	4	100	15	116.9	14.73	16	75.9	9.56	3.0	8.8	1.11
	5	70	15	89.4	11.26	16	58.3	7.35	3.0	6.6	0.83
	6	50	15	70.1	8.84	83	234.3	29.52	20.0	33.0	4.16
95	7	100	15	107.3	13.51	16	68.2	8.59	3.0	7.7	0.97
	8	70	15	82.5	10.40	16	55.0	6.93	3.0	6.6	0.83
	9	50	15	64.6	8.14	82	217.8	27.44	20.0	29.7	3.74
		Maximums	**15**	**125.1**	**15.77**	**83**	**245.3**	**30.91**	**20.0**	**34.1**	**4.30**

1 As measured by EPA Reference Method 5B or 17.
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 Table 1.4-2, AP-42, March 1998.
5 Includes a 10% margin for variability in stack sampling.
6 Corrected to 15% O_2.
7 Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 1998.
Westinghouse, 1998.

Table 3. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CT; Distillate Fuel Oil-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)[5]	PM/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)	Pb[4] (lb/hr)	Pb[4] (g/sec)
32	1	100	21.0	2.65	95.2	11.99	10.9	1.38	0.103	0.013
	2	70	26.3	3.31	70.7	8.90	8.1	1.02	0.076	0.010
	3	50								
59	4	100	19.8	2.49	89.1	11.23	10.2	1.29	0.096	0.012
	5	70	24.9	3.13	66.8	8.41	7.7	0.97	0.072	0.009
	6	50								
95	7	100	17.7	2.23	81.7	10.29	9.4	1.18	0.088	0.011
	8	70	22.3	2.81	62.0	7.81	7.1	0.90	0.067	0.008
	9	50								
		Maximums	**26.3**	**3.31**	**95.2**	**11.99**	**10.9**	**1.38**	**0.103**	**0.013**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[6]	NO_x (lb/hr)[5]	NO_x (g/sec)	CO (ppmvd)[6]	CO (lb/hr)[5]	CO (g/sec)	VOC[7] (ppmvd)[6]	VOC[7] (lb/hr)[5]	VOC[7] (g/sec)
32	1	100	42	352.0	44.35	20	101.2	12.75	10.0	29.7	3.74
	2	70	42	257.4	32.43	26	95.7	12.06	31.0	66.0	8.32
	3	50									
59	4	100	42	328.9	41.44	20	95.7	12.06	10.0	28.6	3.60
	5	70	42	236.5	29.80	26	89.1	11.23	31.0	60.5	7.62
	6	50									
95	7	100	42	302.5	38.12	20	85.8	10.81	10.0	25.3	3.19
	8	70	42	225.5	28.41	25	81.4	10.26	30.0	56.1	7.07
	9	50									
		Maximums	**42**	**352.0**	**44.35**	**26**	**101.2**	**12.75**	**31.0**	**66.0**	**8.32**

[1] As measured by EPA Reference Method 5B or 17.
[2] Based on fuel oil sulfur content of 0.05 wt percent.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Table 3.1-4., AP-42, October 1996.
[5] Includes a 10% margin for variability in stack sampling.
[6] Corrected to 15% O_2.
[7] Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 1998.
Westinghouse, 1998.

Table 4. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CT; Natural Gas-Firing
CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 32 °F	100% - 59 °F	100 % - 95 °F
Maximum Hourly Fuel Flow:	10^6 ft^3/hr	1.914	1.791	1.645
Maximum Annual Hours:		N/A	3,000	N/A

Pollutant	Emission Factor[1] (lb/10^6 ft^3)	Emission Rates			
		32 °F (lb/hr)	59 °F (lb/hr)	95 °F (lb/hr)	Annual (ton/yr)
Arsenic	2.00E-04	3.83E-04	3.58E-04	3.29E-04	5.37E-04
Benzene	2.10E-03	4.02E-03	3.76E-03	3.45E-03	5.64E-03
Beryllium	1.20E-05	2.30E-05	2.15E-05	1.97E-05	3.22E-05
Cadmium	1.10E-03	2.11E-03	1.97E-03	1.81E-03	2.96E-03
Chromium	1.40E-03	2.68E-03	2.51E-03	2.30E-03	3.76E-03
Cobalt	8.40E-05	1.61E-04	1.50E-04	1.38E-04	2.26E-04
Dichlorobenzene	1.20E-03	2.30E-03	2.15E-03	1.97E-03	3.22E-03
Formaldehyde	7.50E-02	1.44E-01	1.34E-01	1.23E-01	2.02E-01
Lead	5.00E-04	9.57E-04	8.96E-04	8.22E-04	1.34E-03
Manganese	3.80E-04	7.27E-04	6.81E-04	6.25E-04	1.02E-03
Mercury	2.60E-04	4.98E-04	4.66E-04	4.28E-04	6.99E-04
Naphthalene	6.10E-04	1.17E-03	1.09E-03	1.00E-03	1.64E-03
Nickel	2.10E-03	4.02E-03	3.76E-03	3.45E-03	5.64E-03
Polycyclic Organic Matter	8.82E-05	1.69E-04	1.58E-04	1.45E-04	2.37E-04
Selenium	2.40E-05	4.59E-05	4.30E-05	3.95E-05	6.45E-05
Toluene	3.40E-03	6.51E-03	6.09E-03	5.59E-03	9.14E-03

[1] Section 1.4, Natural Gas Combustion, Tables 1.4-2., 1.4-3 and 1.4-4, EPA AP-42, March 1998.

Source: ECT, 1999.

Table 5. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CT; Distillate Fuel Oil-Firing
CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 32 °F	100% - 59 °F	100 % - 95 °F
Maximum Hourly Fuel Flow:	10^6 Btu/hr	1,769.0	1,656.0	1,517.6
Maximum Annual Hours:		N/A	500	N/A

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates			
		32 °F (lb/hr)	59 °F (lb/hr)	95 °F (lb/hr)	Annual (ton/yr)
Antimony	2.20E-05	3.89E-02	3.64E-02	3.34E-02	9.11E-03
Arsenic	4.90E-06	8.67E-03	8.11E-03	7.44E-03	2.03E-03
Beryllium	3.30E-07	5.84E-04	5.46E-04	5.01E-04	1.37E-04
Cadmium	4.20E-06	7.43E-03	6.96E-03	6.37E-03	1.74E-03
Chromium	4.70E-05	8.31E-02	7.78E-02	7.13E-02	1.95E-02
Cobalt	9.10E-06	1.61E-02	1.51E-02	1.38E-02	3.77E-03
Lead	5.80E-05	1.03E-01	9.60E-02	8.80E-02	2.40E-02
Manganese	3.40E-04	6.01E-01	5.63E-01	5.16E-01	1.41E-01
Mercury	9.10E-07	1.61E-03	1.51E-03	1.38E-03	3.77E-04
Nickel	1.20E-03	2.12E+00	1.99E+00	1.82E+00	4.97E-01
Phosphorus	3.00E-04	5.31E-01	4.97E-01	4.55E-01	1.24E-01
Selenium	5.30E-06	9.38E-03	8.78E-03	8.04E-03	2.19E-03

[1] Section 3.1, Stationary Gas Turbines, Table 3.1-4, EPA AP-42, October 1996.

Source: ECT, 1999.

Table 6A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,000	350.6	350.6	227.7	227.7	26.4	26.4
CT 1-3	6 - NG	3	500	210.4	52.6	702.9	175.7	99.0	24.8
CT 1-3	4 - Oil	3	500	986.7	246.7	287.1	71.8	85.8	21.5
			Totals	N/A	649.9	N/A	475.2	N/A	72.6

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,000	28.4	28.4	27.9	27.9	0.003	0.003
CT 1-3	6 - NG	3	500	28.4	7.1	16.9	4.2	0.002	0.0004
CT 1-3	4 - Oil	3	500	59.4	14.9	267.3	66.8	0.29	0.07
			Totals	N/A	50.3	N/A	98.9	N/A	0.08

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,000 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with natural gas-firing at 50% load for 500 hours/year (Case 6).
3. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
4. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
5. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
Westinghouse, 1999.
GPP, 1999.

Table 6B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	350.6	438.3	227.7	284.6	26.4	33.0
CT 1-3	6 - NG	3	0	210.4	0.0	702.9	0.0	99.0	0.0
CT 1-3	4 - Oil	3	500	986.7	246.7	287.1	71.8	85.8	21.5
			Totals	N/A	685.0	N/A	356.4	N/A	54.5

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	28.4	35.5	27.9	34.9	0.003	0.003
CT 1-3	6 - NG	3	0	28.4	0.0	16.9	0.0	0.002	0.0000
CT 1-3	4 - Oil	3	500	59.4	14.9	267.3	66.8	0.29	0.07
			Totals	N/A	50.3	N/A	101.7	N/A	0.08

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,500 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with natural gas-firing at 50% load for 0 hours/year (Case 6).
3. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
4. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
5. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
Westinghouse, 1999.
GPP, 1999.

Table 7. Hardee County Generating Facility, CT-1, CT-2, and CT-3 Westinghouse 501F CTs CT Annual Emission Rates - Hazardous Air Pollutants

Pollutant	Annual Emissions (ton/yr)
Antimony	9.11E-03
Arsenic	2.57E-03
Benzene	5.64E-03
Beryllium	1.69E-04
Cadmium	4.69E-03
Chromium	2.32E-02
Cobalt	3.99E-03
Dichlorobenzene	3.22E-03
Formaldehyde	2.02E-01
Lead	2.54E-02
Manganese	1.42E-01
Mercury	1.08E-03
Naphthalene	1.64E-03
Nickel	5.02E-01
Phosphorus	1.24E-01
Polycyclic Organic Matter	2.37E-04
Selenium	2.26E-03
Toluene	9.14E-03
Total HAPS	1.06

Source: ECT, 1999.

Table 8. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501D5A CT
NSPS GG NO_x Limits

Fuel	501D5A Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Gas	10,110	10.667	0.0	101.2
Oil	10,408	10.981	0.0	98.4

Sources: Westinghouse, 1998.
ECT, 1998.

Table 9.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501F CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
Component	MW	100 % Load			70 % Load			50 % Load		
	(lb/mole)	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.94	0.93	0.90	0.94	0.93	0.90	0.95	0.94	0.91
N_2	28.016	75.01	74.42	71.86	75.00	74.44	71.96	75.54	74.94	72.37
O_2	32.000	12.53	12.48	11.84	12.50	12.52	12.16	14.08	14.00	13.41
CO_2	44.010	3.96	3.90	3.87	3.97	3.88	3.72	3.23	3.19	3.13
H_2O	17.008	7.55	8.25	11.51	7.57	8.21	11.24	6.19	6.92	10.17
CO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	99.99	99.98	99.98	99.98	99.98	99.98	99.99	99.99	99.99
Exhaust MW (lb/mole)		28.43	28.33	27.94	28.42	28.34	27.96	28.52	28.43	28.04
Exhaust Flow (lb/sec)		1,055.71	999.50	912.58	804.40	773.26	734.62	771.54	741.04	695.53
Exhaust Temp. (°F)		1,085	1,099	1,123	1,026	1,041	1,064	1,165	1,166	1,200
(K)		858	866	879	825	834	846	903	903	922
Exhaust O_2 (Vol %, Dry)		13.55	13.60	13.38	13.52	13.64	13.70	15.01	15.04	14.93

Sources: ECT, 1999.
Westinghouse, 1998.

Table 9.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501F CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			70 % Load			50 % Load		
	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Exh. Temp. (°F)	1,085	1,099	1,123	1,026	1,041	1,064	1,165	1,166	1,200
ACFM	2,512,232	2,407,886	2,263,696	1,841,412	1,793,375	1,753,177	1,924,588	1,855,565	1,803,036
Velocity (fps)	164.5	157.7	148.3	120.6	117.5	114.8	126.1	121.5	118.1
Velocity (m/s)	50.2	48.1	45.2	36.8	35.8	35.0	38.4	37.0	36.0
SCFM, Dry[1]	793,729	748,221	668,137	604,755	579,055	539,128	586,634	560,849	515,171
ACFM (15% O_2, Dry)	2,892,069	2,732,645	2,553,146	2,127,883	2,025,635	1,899,030	1,802,683	1,715,208	1,639,379

[1] At 68 °F.

Sources: ECT, 1999.
Westinghouse, 1998.

Table 10.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501F CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
		100 % Load			70 % Load			50 % Load		
Component	MW (lb/mole)	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.94	0.93	0.90	0.95	0.94	0.91	0.95	0.95	0.91
N_2	28.016	74.76	74.18	71.63	75.69	75.08	72.47	75.99	75.39	72.79
O_2	32.000	12.81	12.56	11.93	14.44	14.33	13.63	14.79	14.73	14.10
CO_2	44.010	5.08	5.01	4.96	4.01	3.97	3.97	3.83	3.76	3.71
H_2O	17.008	6.59	7.30	10.56	4.89	5.66	9.01	4.42	5.16	8.47
CO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.18	99.98	99.98	99.98	99.98	99.99	99.98	99.99	99.98
Exhaust MW (lb/mole)		28.78	28.62	28.22	28.80	28.71	28.31	28.84	28.75	28.34
Exhaust Flow (lb/sec)		1,064.91	1,008.04	920.41	991.20	941.56	863.87	829.75	794.23	740.11
Exhaust Temp. (°F)		1,071	1,080	1,112	1,099	1,097	1,200	1,200	1,200	1,200
(K)		850	855	873	866	865	922	922	922	922
Exhaust O_2 (Vol %, Dry)		13.71	13.55	13.34	15.18	15.19	14.98	15.47	15.53	15.40

Sources: ECT, 1999.
Westinghouse, 1998.

Table 10.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501F CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft³/min)								
	100 % Load			70 % Load			50 % Load		
	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Exh. Temp. (°F)	1,071	1,080	1,112	1,099	1,097	1,200	1,200	1,200	1,200
ACFM	2,480,708	2,374,946	2,244,563	2,349,090	2,236,087	2,218,013	2,091,189	2,008,088	1,897,988
Velocity (fps)	162.5	155.5	147.0	153.9	146.5	145.3	137.0	131.5	124.3
Velocity (m/s)	49.5	47.4	44.8	46.9	44.6	44.3	41.7	40.1	37.9
SCFM, Dry[1]	799,149	754,826	674,287	756,682	715,369	641,924	635,750	605,759	552,564
ACFM (15% O_2, Dry)	2,822,411	2,742,982	2,572,863	2,165,140	2,041,684	2,025,125	1,838,197	1,732,932	1,618,041

[1] At 68 °F.

Sources: ECT, 1999.
Westinghouse, 1998.

Table 11. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Fuel Flow Rate Data - Westinghouser 501F (Per CT)

A. Natural Gas-Firing

	100 % Load			70 % Load			50 % Load		
	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,774	1,660	1,524	1,359	1,287	1,190	1,057	1,005	940
Fuel Rate (lb/hr)	84,587	79,159	72,683	64,827	61,380	56,746	50,416	47,911	44,811
Fuel Rate (10^6 ft^3/hr)	1.914	1.791	1.645	1.467	1.389	1.284	1.141	1.084	1.014
Fuel Rate (lb/sec)	23.496	21.989	20.190	18.008	17.050	15.763	14.004	13.309	12.448

B. Distillate Fuel Oil-Firing

	100 % Load			70 % Load			50 % Load		
	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,769	1,656	1,518	1,313	1,241	1,152	1,054	995	928
Fuel Rate (lb/hr)	95,179	89,101	81,651	70,652	66,764	61,959	56,726	53,560	49,931
Fuel Rate (10^3 gal/hr)	13.020	12.189	11.169	9.665	9.133	8.476	7.760	7.327	6.830
Fuel Rate (lb/sec)	26.439	24.750	22.681	19.626	18.546	17.211	15.757	14.878	13.870

Sources: ECT, 1999.
Westinghouse, 1998.

WESTINGHOUSE 501D5A

Table 1. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Operating Scenarios - Westinghouse 501D5A CT

Case	Ambient Temperature (°F)	Load (%)	CT-1	CT-2	CT-3	Natural Gas Firing	Fuel Oil Firing
1	20	100	X	X	X	X	X
2	20	75	X	X	X	X	X
3	20	50	X	X	X	X	
4	59	100	X	X	X	X	X
5	59	75	X	X	X	X	X
6	59	50	X	X	X	X	
7	95	100	X	X	X	X	X
8	95	75	X	X	X	X	X
9	95	50	X	X	X	X	

Sources: GPP, 1999.
ECT, 1999.

Table 2. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501D5A CT; Natural Gas-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)[5]	PM/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)	Pb[4] (lb/hr)	Pb[4] (g/sec)
20	1	100	9.6	1.21	7.2	0.91	0.8	0.104	6.94E-04	8.75E-05
	2	75	8.5	1.07	5.6	0.71	0.6	0.082	5.44E-04	6.86E-05
	3	50	6.8	0.86	4.4	0.55	0.5	0.063	4.19E-04	5.28E-05
59 (6)	4	100	8.8	1.10	6.7	0.84	0.8	0.096	6.41E-04	8.07E-05
	5	75	7.7	0.97	5.3	0.67	0.6	0.077	5.10E-04	6.43E-05
	6	50	6.4	0.81	4.1	0.52	0.5	0.060	3.97E-04	5.00E-05
95	7	100	8.0	1.01	6.1	0.77	0.7	0.089	5.92E-04	7.45E-05
	8	75	7.0	0.89	5.0	0.63	0.6	0.072	4.79E-04	6.03E-05
	9	50	6.0	0.76	3.9	0.49	0.4	0.056	3.76E-04	4.73E-05
		Maximums	9.6	1.21	7.2	0.91	0.83	0.104	6.94E-04	8.75E-05

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[7]	NO_x (lb/hr)[5]	NO_x (g/sec)	CO (ppmvd)[7]	CO (lb/hr)[5]	CO (g/sec)	VOC[8] (ppmvd)[7]	VOC[8] (lb/hr)[5]	VOC[8] (g/sec)
20	1	100	15	86.9	10.95	10	34.1	4.3	3.0	5.9	0.75
	2	75	18	82.5	10.40	24	68.2	8.6	3.0	5.3	0.67
	3	50	45	157.3	19.82	232	495.0	62.4	20.0	24.1	3.04
59 (6)	4	100	15	80.6	10.16	10	31.8	4.0	3.0	5.4	0.68
	5	75	18	77.4	9.75	23	61.9	7.8	3.0	4.8	0.61
	6	50	45	148.7	18.74	229	463.0	58.3	20.0	23.1	2.91
95	7	100	15	74.8	9.42	10	29.7	3.7	3.0	5.0	0.62
	8	75	18	72.6	9.15	23	56.1	7.1	3.0	4.4	0.55
	9	50	45	140.8	17.74	227	433.4	54.6	20.0	22.2	2.80
		Maximums	45	157.3	19.82	232	495.0	62.37	20.0	24.1	3.04

1 As measured by EPA Reference Method 5B or 17.
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 Table 1.4-2, AP-42, March 1998.
5 Includes a 10% margin for variability in stack sampling.
6 Estimated from linear interpolation of 20 and 95 °F data.
7 Corrected to 15% O_2.
8 Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 1998.
Westinghouse, 1998.

Table 3. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501D5A CT; Distillate Fuel Oil-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)[5]	PM/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)	Pb[4] (lb/hr)	Pb[4] (g/sec)
20	1	100	35.9	4.52	72.4	9.13	8.3	1.05	0.078	0.010
	2	75	45.2	5.70	56.7	7.14	6.5	0.82	0.061	0.008
	3	50								
59	4	100	32.9	4.15	66.9	8.43	7.7	0.97	0.072	0.009
(6)	5	75	41.2	5.19	53.1	6.69	6.1	0.77	0.057	0.007
	6	50								
95	7	100	30.3	3.81	61.8	7.78	7.1	0.89	0.066	0.008
	8	75	37.5	4.72	49.7	6.27	5.7	0.72	0.053	0.007
	9	50								
		Maximums	45.2	5.70	72.4	9.13	8.3	1.05	0.078	0.010

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[7]	NO_x (lb/hr)[5]	NO_x (g/sec)	CO (ppmvd)[7]	CO (lb/hr)[5]	CO (g/sec)	VOC[8] (ppmvd)[7]	VOC[8] (lb/hr)[5]	VOC[8] (g/sec)
20	1	100	42	260.7	32.85	28	104.5	13.2	10.0	22.0	2.77
	2	75	42	201.3	25.36	75	217.8	27.4	30.0	49.8	6.28
	3	50									
59	4	100	42	240.7	30.33	27	95.9	12.1	10.0	20.2	2.55
(6)	5	75	42	188.7	23.78	73	198.4	25.0	30.0	47.0	5.93
	6	50									
95	7	100	42	222.2	28.00	27	88.0	11.1	10.0	18.6	2.34
	8	75	42	177.1	22.31	71	180.4	22.7	30.0	44.4	5.60
	9	50									
		Maximums	42	260.7	32.85	75	217.8	27.44	30.0	49.8	6.28

1 *As measured by EPA Reference Method 5B or 17.*
2 Based on fuel oil sulfur content of 0.05 wt percent.
3 Based on 7.5% conversion of SO_2 to H_2SO_4.
4 Table 3.1-4., AP-42, October 1996.
5 Includes a 10% margin for variability in stack sampling.
6 Estimated from linear interpolation of 20 and 95 °F data.
7 Corrected to 15% O_2.
8 *Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.*

Sources: ECT, 1998.
Westinghouse, 1998.

Table 4. Hardee County Generating Facility, CT-1, CT-2, and CT-3 Westinghouse 501D5A CT; Natural Gas-Firing CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 32 °F	100% - 59 °F	100 % - 95 °F
Maximum Hourly Fuel Flow:	10^6 ft^3/hr	1.388	1.282	1.183
Maximum Annual Hours:		N/A	3,000	N/A

Pollutant	Emission Factor[1] ($lb/10^6$ ft^3)	Emission Rates			
		32 °F (lb/hr)	59 °F (lb/hr)	95 °F (lb/hr)	Annual (ton/yr)
Arsenic	2.00E-04	2.78E-04	2.56E-04	2.37E-04	3.84E-04
Benzene	2.10E-03	2.92E-03	2.69E-03	2.48E-03	4.04E-03
Beryllium	1.20E-05	1.67E-05	1.54E-05	1.42E-05	2.31E-05
Cadmium	1.10E-03	1.53E-03	1.41E-03	1.30E-03	2.11E-03
Chromium	1.40E-03	1.94E-03	1.79E-03	1.66E-03	2.69E-03
Cobalt	8.40E-05	1.17E-04	1.08E-04	9.94E-05	1.61E-04
Dichlorobenzene	1.20E-03	1.67E-03	1.54E-03	1.42E-03	2.31E-03
Formaldehyde	7.50E-02	1.04E-01	9.61E-02	8.87E-02	1.44E-01
Lead	5.00E-04	6.94E-04	6.41E-04	5.92E-04	9.61E-04
Manganese	3.80E-04	5.28E-04	4.87E-04	4.50E-04	7.31E-04
Mercury	2.60E-04	3.61E-04	3.33E-04	3.08E-04	5.00E-04
Naphthalene	6.10E-04	8.47E-04	7.82E-04	7.22E-04	1.17E-03
Nickel	2.10E-03	2.92E-03	2.69E-03	2.48E-03	4.04E-03
Polycyclic Organic Matter	8.82E-05	1.22E-04	1.13E-04	1.04E-04	1.70E-04
Selenium	2.40E-05	3.33E-05	3.08E-05	2.84E-05	4.61E-05
Toluene	3.40E-03	4.72E-03	4.36E-03	4.02E-03	6.54E-03

[1] Section 1.4, Natural Gas Combustion, Tables 1.4-2., 1.4-3 and 1.4-4, EPA AP-42, March 1998.

Source: ECT, 1999.

Table 5. Hardee County Generating Facility, CT-1, CT-2, and CT-3 Westinghouse 501D5A CT; Distillate Fuel Oil-Firing CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 32 °F	100% - 59 °F	100 % - 95 °F
Maximum Hourly Fuel Flow:	10^6 Btu/hr	1,336.5	1,234.2	1,139.7
Maximum Annual Hours:		N/A	500	N/A

Pollutant	Emission Factor[1]	Emission Rates			
		32 °F	59 °F	95 °F	Annual
	(lb/10^6 Btu)	(lb/hr)	(lb/hr)	(lb/hr)	(ton/yr)
Antimony	2.20E-05	2.94E-02	2.72E-02	2.51E-02	6.79E-03
Arsenic	4.90E-06	6.55E-03	6.05E-03	5.58E-03	1.51E-03
Beryllium	3.30E-07	4.41E-04	4.07E-04	3.76E-04	1.02E-04
Cadmium	4.20E-06	5.61E-03	5.18E-03	4.79E-03	1.30E-03
Chromium	4.70E-05	6.28E-02	5.80E-02	5.36E-02	1.45E-02
Cobalt	9.10E-06	1.22E-02	1.12E-02	1.04E-02	2.81E-03
Lead	5.80E-05	7.75E-02	7.16E-02	6.61E-02	1.79E-02
Manganese	3.40E-04	4.54E-01	4.20E-01	3.87E-01	1.05E-01
Mercury	9.10E-07	1.22E-03	1.12E-03	1.04E-03	2.81E-04
Nickel	1.20E-03	1.60E+00	1.48E+00	1.37E+00	3.70E-01
Phosphorus	3.00E-04	4.01E-01	3.70E-01	3.42E-01	9.26E-02
Selenium	5.30E-06	7.08E-03	6.54E-03	6.04E-03	1.64E-03

[1] Section 3.1, Stationary Gas Turbines, Table 3.1-4, EPA AP-42, October 1996.

Source: ECT, 1999.

Table 6A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501D5A CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,000	241.8	241.8	95.4	95.4	16.3	16.3
CT 1-3	6 - NG	3	500	446.2	111.5	1,388.9	347.2	69.4	17.3
CT 1-3	4 - Oil	3	500	722.0	180.5	287.8	71.9	60.7	15.2
			Totals	N/A	533.9	N/A	514.6	N/A	48.8

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,000	26.3	26.3	20.0	20.0	0.002	0.002
CT 1-3	6 - NG	3	500	19.2	4.8	12.4	3.1	0.001	0.0003
CT 1-3	4 - Oil	3	500	98.8	24.7	200.7	50.2	0.21	0.05
			Totals	N/A	55.8	N/A	73.2	N/A	0.06

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,000 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with natural gas-firing at 50% load for 500 hours/year (Case 6).
3. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
4. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
5. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
Westinghouse, 1999.
GPP, 1999.

Table 6B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501D5A CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	241.8	302.3	95.4	119.3	16.3	20.3
CT 1-3	6 - NG	3	0	446.2	0.0	1,388.9	0.0	69.4	0.0
CT 1-3	4 - Oil	3	500	722.0	180.5	287.8	71.9	60.7	15.2
			Totals	N/A	**482.8**	N/A	**191.2**	N/A	**35.5**

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	26.3	32.9	20.0	24.9	0.002	0.002
CT 1-3	6 - NG	3	0	19.2	0.0	12.4	0.0	0.001	0.0000
CT 1-3	4 - Oil	3	500	98.8	24.7	200.7	50.2	0.21	0.05
			Totals	N/A	**57.6**	N/A	**75.1**	N/A	**0.06**

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,500 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with natural gas-firing at 50% load for 0 hours/year (Case 6).
3. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
4. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
5. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
Westinghouse, 1999.
GPP, 1999.

Table 7. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501D5A CTs
CT Annual Emission Rates - Hazardous Air Pollutants

Pollutant	Annual Emissions (ton/yr)
Antimony	6.79E-03
Arsenic	1.90E-03
Benzene	4.04E-03
Beryllium	1.25E-04
Cadmium	3.41E-03
Chromium	1.72E-02
Cobalt	2.97E-03
Dichlorobenzene	2.31E-03
Formaldehyde	1.44E-01
Lead	1.89E-02
Manganese	1.06E-01
Mercury	7.81E-04
Naphthalene	1.17E-03
Nickel	3.74E-01
Phosphorus	9.26E-02
Polycyclic Organic Matter	1.70E-04
Selenium	1.68E-03
Toluene	6.54E-03
Total HAPS	0.78

Source: ECT, 1999.

Table 8. Hardee County Generating Facility, CT-1, CT-2, and CT-3
Westinghouse 501F CT
NSPS GG NO_x Limits

Fuel	501F Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Gas	9,150	9.654	0.0	111.9
Oil	9,490	10.012	0.0	107.9

Sources: Westinghouse, 1998.
ECT, 1998.

Table 9.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501D5A CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			75 % Load			50 % Load		
Component	(lb/mole)	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.95	0.93	0.91	0.95	0.93	0.92	0.95	0.93	0.92
N_2	28.016	75.38	74.04	72.80	75.66	74.40	73.24	75.75	74.53	73.40
O_2	32.000	13.87	13.59	13.33	14.66	14.25	13.88	14.93	14.62	14.34
CO_2	44.010	3.20	3.16	3.12	2.84	2.88	2.91	2.72	2.71	2.70
H_2O	17.008	6.59	8.27	9.82	5.87	7.51	9.03	5.63	7.18	8.62
CO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	99.99	99.98	99.98	99.98	99.98	99.98	99.98	99.98	99.98
Exhaust MW (lb/mole)		28.47	28.26	28.07	28.52	28.32	28.14	28.53	28.35	28.17
Exhaust Flow (lb/sec)		912.01	846.79	786.59	806.54	743.28	684.88	647.83	611.69	578.33
Exhaust Temp. (°F)		972	997	1,021	884	941	993	905	948	987
(K)		795	810	823	746	778	807	758	782	804
Exhaust O_2 (Vol %, Dry)		14.85	14.81	14.78	15.57	15.41	15.26	15.82	15.76	15.69

Sources: ECT, 1999.
Westinghouse, 1998.

Table 9.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501D5A CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft³/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Exh. Temp. (°F)	972	997	1,021	884	941	993	905	948	987
ACFM	2,008,808	1,912,234	1,817,224	1,664,396	1,609,431	1,548,123	1,356,914	1,329,943	1,300,478
Velocity (fps)	131.6	125.2	119.0	109.0	105.4	101.4	88.9	87.1	85.2
Velocity (m/s)	40.1	38.2	36.3	33.2	32.1	30.9	27.1	26.5	26.0
SCFM, Dry[1]	691,867	635,456	584,248	615,488	561,109	511,767	495,322	463,014	433,630
ACFM (15% O_2, Dry)	1,924,605	1,809,314	1,699,449	1,414,220	1,384,477	1,346,796	1,102,396	1,076,392	1,048,851

[1] At 68 °F.

Sources: ECT, 1999.
Westinghouse, 1998.

Table 10.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501D5A CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			75 % Load			50 % Load		
Component	(lb/mole)	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.94	0.92	0.91	0.95	0.93	0.92	0.96	0.94	0.93
N_2	28.016	75.17	73.83	72.60	75.82	74.56	73.40	76.20	74.95	73.80
O_2	32.000	13.69	13.41	13.15	15.05	14.65	14.28	15.47	15.11	14.77
CO_2	44.010	4.46	4.40	4.35	3.64	3.69	3.73	3.43	3.45	3.47
H_2O	17.008	5.72	7.41	8.97	4.51	6.14	7.65	3.93	5.54	7.02
CO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	99.98	99.98	99.98	99.97	99.98	99.98	99.99	99.99	99.99
Exhaust MW (lb/mole)		28.75	28.54	28.35	28.81	28.62	28.44	28.86	28.67	28.49
Exhaust Flow (lb/sec)		922.97	856.92	795.94	875.04	805.46	741.23	703.49	658.19	616.39
Exhaust Temp. (°F)		975	1,000	1,023	831	885	935	841	890	936
(K)		797	811	824	717	747	775	723	750	775
Exhaust O_2 (Vol %, Dry)		14.52	14.48	14.45	15.76	15.61	15.46	16.10	15.99	15.89

Sources: ECT, 1999.
Westinghouse, 1998.

Table 10.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - Westinghouse 501D5A CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Exh. Temp. (°F)	975	1,000	1,023	831	885	935	841	890	936
ACFM	2,016,948	1,919,067	1,822,918	1,717,054	1,657,582	1,591,702	1,388,519	1,357,387	1,322,179
Velocity (fps)	132.1	125.7	119.4	112.5	108.6	104.2	90.9	88.9	86.6
Velocity (m/s)	40.3	38.3	36.4	34.3	33.1	31.8	27.7	27.1	26.4
SCFM, Dry[1]	699,675	642,609	590,805	670,578	610,701	556,363	541,373	501,346	464,974
ACFM (15% O_2, Dry)	2,056,098	1,932,764	1,815,277	1,428,185	1,395,334	1,354,606	1,084,605	1,066,770	1,044,929

[1] At 68 °F.

Sources: ECT, 1999.

Table 11. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Fuel Flow Rate Data - Westinghouser 501D5A (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,287	1,188	1,097	1,009	946	887	778	735	697
Fuel Rate (lb/hr)	61,340	56,629	52,280	48,090	45,074	42,290	37,060	35,053	33,200
Fuel Rate (10^6 ft^3/hr)	1.388	1.282	1.183	1.088	1.020	0.957	0.839	0.793	0.751
Fuel Rate (lb/sec)	17.039	15.730	14.522	13.358	12.521	11.747	10.294	9.737	9.222

B. Distillate Fuel Oil-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,337	1,234	1,140	1,046	979	918	798	755	715
Fuel Rate (lb/hr)	72,440	66,892	61,770	56,690	53,076	49,740	43,250	40,915	38,760
Fuel Rate (10^3 gal/hr)	9.909	9.150	8.450	7.755	7.261	6.804	5.916	5.597	5.302
Fuel Rate (lb/sec)	20.122	18.581	17.158	15.747	14.743	13.817	12.014	11.365	10.767

Note: 59 °F data estimated from linear interpolation of 20 and 95 °F data.

Sources: ECT, 1999.
Westinghouse, 1998.

ABB GT-24

Table 1. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Operating Scenarios - ABB GT-24 CT

Case	Ambient Temperature (°F)	Load (%)	CT-1	CT-2	CT-3	Natural Gas Firing	Fuel Oil Firing
1	0	100	X	X	X	X	X
2	0	75	X	X	X	X	X
3	0	50	X	X	X	X	
4	60	100	X	X	X	X	X
5	60	75	X	X	X	X	X
6	60	60	X	X	X	X	
7	98	100	X	X	X	X	X
8	98	75	X	X	X	X	X
9	98	60	X	X	X	X	

Sources: GPP, 1999.
ECT, 1999.

Table 2. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CT; Natural Gas-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1]		SO_2[2]		H_2SO_4[3]		Pb[4]	
			(lb/hr)[5]	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
0	1	100	41.8	5.27	10.2	1.28	1.2	0.148	9.83E-04	1.24E-04
	2	75	37.4	4.71	8.1	1.03	0.9	0.118	7.85E-04	9.89E-05
	3	50	28.6	3.60	6.2	0.78	0.7	0.090	5.99E-04	7.54E-05
60	4	100	24.2	3.05	9.2	1.16	1.1	0.133	8.87E-04	1.12E-04
	5	75	19.8	2.49	7.4	0.93	0.8	0.107	7.11E-04	8.96E-05
	6	60	17.6	2.22	6.4	0.80	0.7	0.092	6.13E-04	7.73E-05
98	7	100	23.1	2.91	8.5	1.07	1.0	0.123	8.21E-04	1.03E-04
	8	75	18.7	2.36	6.8	0.86	0.8	0.099	6.58E-04	8.29E-05
	9	60	16.5	2.08	5.9	0.74	0.7	0.085	5.68E-04	7.16E-05
		Maximums	**41.8**	**5.27**	**10.2**	**1.28**	**1.17**	**0.148**	**9.83E-04**	**1.24E-04**

Temp. (°F)	Case	Load (%)	NO_x			CO			VOC[7]		
			(ppmvd)[6]	(lb/hr)[5]	(g/sec)	(ppmvd)[6]	(lb/hr)[5]	(g/sec)	(ppmvd)[6]	(lb/hr)[5]	(g/sec)
0	1	100	25	203.5	25.64	6	31.9	4.0	1.5	4.2	0.53
	2	75	25	162.8	20.51	19	75.9	9.6	1.6	3.6	0.46
	3	50	25	124.3	15.66	132	394.9	49.8	2.8	4.8	0.61
60	4	100	25	183.7	23.15	5	23.1	2.9	1.1	2.9	0.36
	5	75	25	148.5	18.71	15	55.0	6.9	1.1	2.3	0.29
	6	60	25	122.2	15.40	50	149.6	18.8	1.1	1.9	0.24
98	7	100	25	172.7	21.76	5	20.9	2.6	1.1	2.6	0.33
	8	75	25	137.5	17.33	15	50.6	6.4	1.1	2.1	0.26
	9	60	25	113.1	14.25	50	138.6	17.5	1.1	1.8	0.22
		Maximums	**25**	**203.5**	**25.64**	**132**	**394.9**	**49.76**	**2.8**	**4.8**	**0.61**

[1] As measured by EPA Reference Method 5B or 17.
[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] Table 1.4-2, AP-42, March 1998.
[5] Includes a 10% margin for variability in stack sampling.
[6] Corrected to 15% O_2.
[7] Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 1998.
ABB, 1998.

Table 3. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CT; Distillate Fuel Oil-Firing
CT Hourly Criteria and H_2SO_4 Emission Rates (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)[5]	PM/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)	Pb[4] (lb/hr)	Pb[4] (g/sec)
0	1	100	83.0	10.46	111.8	14.08	12.8	1.62	0.120	0.015
	2	75	78.0	9.83	86.7	10.93	10.0	1.25	0.093	0.012
	3	50								
60	4	100	46.2	5.82	97.5	12.28	11.2	1.41	0.105	0.013
	5	75	46.2	5.82	77.6	9.77	8.9	1.12	0.084	0.011
	6	60								
98 (6)	7	100	22.9	2.88	84.3	10.63	9.7	1.22	0.091	0.011
	8	75	26.1	3.28	69.1	8.70	7.9	1.00	0.075	0.009
	9	60								
		Maximums	83.0	10.46	111.8	14.08	12.8	1.62	0.120	0.015

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[7]	NO_x (lb/hr)[5]	NO_x (g/sec)	CO (ppmvd)[7]	CO (lb/hr)[5]	CO (g/sec)	VOC[8] (ppmvd)[7]	VOC[8] (lb/hr)[5]	VOC[8] (g/sec)
0	1	100	42	393.8	49.62	25	141.9	17.9	7.5	24.5	3.09
	2	75	42	305.8	38.53	13	56.1	7.1	7.5	19.0	2.40
	3	50									
60 (9)	4	100	42	342.5	43.15	25	126.6	16.0	7.5	22.7	2.86
	5	75	42	259.4	32.68	13	48.8	6.1	7.5	16.1	2.03
	6	60									
98 (9)	7	100	42	314.6	39.64	25	113.6	14.3	7.5	20.1	2.53
	8	75	42	247.7	31.22	13	44.5	5.6	7.5	14.9	1.88
	9	60									
		Maximums	42	393.8	49.62	25	141.9	17.88	7.5	24.5	3.09

1 As measured by EPA Reference Method 5B or 17.
2 Based on fuel oil sulfur content of 0.05 wt percent.
3 Based on 7.5% conversion of SO_2 to H_2SO_4.
4 Table 3.1-4., AP-42, October 1996.
5 *Includes a 10% margin for variability in stack sampling.*
6 Estimated from 0 and 60 °F data.
7 Corrected to 15% O_2.
8 Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.
9 Estimated from 0 °F ABB data and Westinghouse 501F data.

Sources: ECT, 1998.
ABB, 1998.

Table 4. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CT; Natural Gas-Firing
CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 0 °F	100% - 60 °F	100 % - 98 °F
Maximum Hourly Fuel Flow:	10^6 ft^3/hr	1.965	1.774	1.643
Maximum Annual Hours:		N/A	3,000	N/A

Pollutant	Emission Factor[1] (lb/10^6 ft^3)	Emission Rates			
		0 °F (lb/hr)	60 °F (lb/hr)	98 °F (lb/hr)	Annual (ton/yr)
Arsenic	2.00E-04	3.93E-04	3.55E-04	3.29E-04	5.32E-04
Benzene	2.10E-03	4.13E-03	3.73E-03	3.45E-03	5.59E-03
Beryllium	1.20E-05	2.36E-05	2.13E-05	1.97E-05	3.19E-05
Cadmium	1.10E-03	2.16E-03	1.95E-03	1.81E-03	2.93E-03
Chromium	1.40E-03	2.75E-03	2.48E-03	2.30E-03	3.73E-03
Cobalt	8.40E-05	1.65E-04	1.49E-04	1.38E-04	2.24E-04
Dichlorobenzene	1.20E-03	2.36E-03	2.13E-03	1.97E-03	3.19E-03
Formaldehyde	7.50E-02	1.47E-01	1.33E-01	1.23E-01	2.00E-01
Lead	5.00E-04	9.83E-04	8.87E-04	8.21E-04	1.33E-03
Manganese	3.80E-04	7.47E-04	6.74E-04	6.24E-04	1.01E-03
Mercury	2.60E-04	5.11E-04	4.61E-04	4.27E-04	6.92E-04
Naphthalene	6.10E-04	1.20E-03	1.08E-03	1.00E-03	1.62E-03
Nickel	2.10E-03	4.13E-03	3.73E-03	3.45E-03	5.59E-03
Polycyclic Organic Matter	8.82E-05	1.73E-04	1.56E-04	1.45E-04	2.35E-04
Selenium	2.40E-05	4.72E-05	4.26E-05	3.94E-05	6.39E-05
Toluene	3.40E-03	6.68E-03	6.03E-03	5.59E-03	9.05E-03

[1] Section 1.4, Natural Gas Combustion, Tables 1.4-2., 1.4-3 and 1.4-4, EPA AP-42, March 1998.

Source: ECT, 1999.

Table 5. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CT; Distillate Fuel Oil-Firing
CT Hourly Hazardous Air Pollutant Emission Rates (Per CT)

Parameter	Units	Case		
		100% - 0 °F	100% - 60 °F	100 % - 98 °F
Maximum Hourly Fuel Flow:	10^6 Btu/hr	2,077.5	1,811.6	1,568.1
Maximum Annual Hours:		N/A	500	N/A

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates			
		0 °F (lb/hr)	60 °F (lb/hr)	98 °F (lb/hr)	Annual (ton/yr)
Antimony	2.20E-05	4.57E-02	3.99E-02	3.45E-02	9.96E-03
Arsenic	4.90E-06	1.02E-02	8.88E-03	7.68E-03	2.22E-03
Beryllium	3.30E-07	6.86E-04	5.98E-04	5.17E-04	1.49E-04
Cadmium	4.20E-06	8.73E-03	7.61E-03	6.59E-03	1.90E-03
Chromium	4.70E-05	9.76E-02	8.51E-02	7.37E-02	2.13E-02
Cobalt	9.10E-06	1.89E-02	1.65E-02	1.43E-02	4.12E-03
Lead	5.80E-05	1.20E-01	1.05E-01	9.10E-02	2.63E-02
Manganese	3.40E-04	7.06E-01	6.16E-01	5.33E-01	1.54E-01
Mercury	9.10E-07	1.89E-03	1.65E-03	1.43E-03	4.12E-04
Nickel	1.20E-03	2.49E+00	2.17E+00	1.88E+00	5.43E-01
Phosphorus	3.00E-04	6.23E-01	5.43E-01	4.70E-01	1.36E-01
Selenium	5.30E-06	1.10E-02	9.60E-03	8.31E-03	2.40E-03

[1] Section 3.1, Stationary Gas Turbines, Table 3.1-4, EPA AP-42, October 1996.

Source: ECT, 1999.

Table 6A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,000	551.1	551.1	69.3	69.3	8.6	8.6
CT 1-3	6 - NG	3	500	366.6	91.7	448.8	112.2	5.6	1.4
CT 1-3	4 - Oil	3	500	1,027.4	256.9	379.9	95.0	68.1	17.0
			Totals	**N/A**	**899.6**	**N/A**	**276.5**	**N/A**	**27.0**

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,000	72.6	72.6	27.6	27.6	0.003	0.003
CT 1-3	6 - NG	3	500	52.8	13.2	19.1	4.8	0.002	0.0005
CT 1-3	4 - Oil	3	500	138.6	34.7	292.4	73.1	0.32	0.08
			Totals	**N/A**	**120.5**	**N/A**	**105.5**	**N/A**	**0.08**

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,000 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with natural gas-firing at 50% load for 500 hours/year (Case 6).
3. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
4. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
5. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
ABB, 1999.
GPP, 1999.

Table 6B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CTs
CT Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	551.1	688.9	69.3	86.6	8.6	10.7
CT 1-3	6 - NG	3	0	366.6	0.0	448.8	0.0	5.6	0.0
CT 1-3	4 - Oil	3	500	1,027.4	256.9	379.9	95.0	68.1	17.0
			Totals	N/A	945.7	N/A	181.6	N/A	27.7

Source	Case	No. of CTs	Annual Operations (hrs/yr/CT)	Emission Rates					
				PM/PM_{10}		SO_2		Pb	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT 1-3	4 - NG	3	2,500	72.6	90.8	27.6	34.5	0.003	0.003
CT 1-3	6 - NG	3	0	52.8	0.0	19.1	0.0	0.002	0.0000
CT 1-3	4 - Oil	3	500	138.6	34.7	292.4	73.1	0.32	0.08
			Totals	N/A	125.4	N/A	107.6	N/A	0.08

1. CT-1, CT-2, and CT-3 operating with natural gas-firing at base load for 2,500 hours/year (Case 4).
2. CT-1, CT-2, and CT-3 operating with natural gas-firing at 50% load for 0 hours/year (Case 6).
3. CT-1, CT-2, and CT-3 operating with fuel oil-firing at base load for 500 hours/year at base load (Case 4).
4. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
5. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: ECT, 1999.
ABB, 1999.
GPP, 1999.

Table 7. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CTs
CT Annual Emission Rates - Hazardous Air Pollutants

Pollutant	Annual Emissions (ton/yr)
Antimony	9.96E-03
Arsenic	2.75E-03
Benzene	5.59E-03
Beryllium	1.81E-04
Cadmium	4.83E-03
Chromium	2.50E-02
Cobalt	4.35E-03
Dichlorobenzene	3.19E-03
Formaldehyde	2.00E-01
Lead	2.76E-02
Manganese	1.55E-01
Mercury	1.10E-03
Naphthalene	1.62E-03
Nickel	5.49E-01
Phosphorus	1.36E-01
Polycyclic Organic Matter	2.35E-04
Selenium	2.46E-03
Toluene	9.05E-03
Total HAPS	1.14

Source: ECT, 1999.

Table 8. Hardee County Generating Facility, CT-1, CT-2, and CT-3
ABB GT-24 CT
NSPS GG NO_x Limits

Fuel	GT-24 Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Gas	8,910	9.401	0.0	114.9
Oil	9,241	9.750	0.0	110.8

Note: Oil data estimated from ABB gas data and Westinghouse 501F data.

Sources: ABB, 1998.
ECT, 1998.

Table 9.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - ABB GT-24 CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			75 % Load			60 % Load		
Component	(lb/mole)	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.88	0.88	0.90	0.89	0.88	0.90	0.89	0.89
N_2	28.016	74.60	73.94	73.18	74.60	74.11	73.40	74.80	74.23	73.53
O_2	32.000	11.10	11.20	11.12	11.20	11.67	11.78	11.90	12.03	12.13
CO_2	44.010	4.50	4.45	4.38	4.40	4.23	4.08	4.10	4.06	3.91
H_2O	17.008	9.00	9.53	10.44	8.80	9.11	9.86	8.30	8.79	9.55
CO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.10	100.00	100.00	99.90	100.00	100.00	100.00	100.00	100.01
Exhaust MW (lb/mole)		28.32	28.23	28.11	28.28	28.26	28.16	28.34	28.28	28.18
Exhaust Flow (lb/sec)		937.06	845.56	791.67	757.78	713.89	683.61	620.59	637.39	611.44
Exhaust Temp. (°F)		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
(K)		811	811	811	811	811	811	811	811	811
Exhaust O_2 (Vol %, Dry)		12.20	12.38	12.42	12.28	12.84	13.07	12.98	13.19	13.41

Sources: ECT, 1999.
ABB, 1998.

Table 9.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - ABB GT-24 CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			60 % Load		
	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F
Case	1	4	7	2	5	8	3	6	9
Exh. Temp. (°F)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
ACFM	2,114,956	1,914,688	1,800,017	1,713,112	1,614,826	1,552,024	1,399,847	1,440,606	1,386,914
Velocity (fps)	138.5	125.4	117.9	112.2	105.8	101.7	91.7	94.4	90.8
Velocity (m/s)	42.2	38.2	35.9	34.2	32.2	31.0	27.9	28.8	27.7
SCFM, Dry[1]	696,023	626,481	582,985	565,017	530,796	505,938	464,227	475,192	453,669
ACFM (15% O_2, Dry)	2,838,701	2,501,516	2,316,961	2,282,446	2,005,455	1,855,921	1,723,780	1,717,225	1,592,377

[1] At 68 °F.

Sources: ECT, 1999.
ABB, 1998.

Table 10.A. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - ABB GT-24 CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
		100 % Load			75 % Load			60 % Load		
Component	MW (lb/mole)	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.80	0.80	0.80	0.80	0.80	0.80	0.90	0.90	0.90
N_2	28.016	70.10	70.10	70.10	71.10	71.10	71.10	72.10	72.10	72.10
O_2	32.000	9.00	9.00	9.00	9.70	9.70	9.70	10.60	10.60	10.60
CO_2	44.010	6.70	6.70	6.70	6.40	6.40	6.40	6.00	6.00	6.00
H_2O	17.008	13.30	13.30	13.30	11.90	11.90	11.90	10.50	10.50	10.50
CO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	99.90	99.90	99.90	99.90	99.90	99.90	100.10	100.10	100.10
Exhaust MW (lb/mole)		28.05	28.05	28.05	28.18	28.18	28.18	28.38	28.38	28.38
Exhaust Flow[1] (lb/sec)		940.83	807.02	709.08	766.67	649.87	563.04	626.11	542.53	482.05
Exhaust Temp. (°F)		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
(K)		811	811	811	811	811	811	811	811	811
Exhaust O_2 (Vol %, Dry)		10.38	10.38	10.38	11.01	11.01	11.01	11.84	11.84	11.84

[1] Data for 60 and 98 °F estimated from 0 °F ABB data and Westinghouse 501F data.

Sources: ECT, 1999.
ABB, 1998.

Table 10.B. Hardee County Generating Facility, CT-1, CT-2, and CT-3
CT Exhaust Data - ABB GT-24 CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			60 % Load		
	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F
Case	1	4	7	2	5	8	3	6	9
Exh. Temp. (°F)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
ACFM	2,144,158	1,839,201	1,615,997	1,738,924	1,474,003	1,277,058	1,410,415	1,222,146	1,085,889
Velocity (fps)	140.4	120.5	105.8	113.9	96.5	83.6	92.4	80.0	71.1
Velocity (m/s)	42.8	36.7	32.3	34.7	29.4	25.5	28.2	24.4	21.7
SCFM, Dry[1]	672,290	576,673	506,688	554,035	469,629	406,881	456,511	395,573	351,471
ACFM (15% O_2, Dry)	3,314,468	2,843,062	2,498,030	2,567,978	2,176,752	1,885,912	1,937,647	1,679,000	1,491,809

[1] At 68 °F.

Sources: ECT, 1999.
ABB, 1998.

Table 11. Hardee County Generating Facility, CT-1, CT-2, and CT-3 CT Fuel Flow Rate Data - ABB GT-24 (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			60 % Load		
	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	1,821	1,644	1,522	1,454	1,318	1,220	1,110	1,136	1,053
Fuel Rate (lb/hr)	86,827	78,385	72,583	69,339	62,849	58,173	52,916	54,200	50,221
Fuel Rate (10^6 ft^3/hr)	1.965	1.774	1.643	1.569	1.422	1.317	1.198	1.227	1.137
Fuel Rate (lb/sec)	24.119	21.774	20.162	19.261	17.458	16.159	14.699	15.055	13.950

B. Distillate Fuel Oil-Firing

	100 % Load			75 % Load			60 % Load		
	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F	0 °F	60 °F	98 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - LHV (MMBtu/hr)	2,078	1,812	1,568	1,612	1,442	1,285	1,219	1,080	962
Fuel Rate (lb/hr)	111,779	97,478	84,331	86,707	77,559	69,079	65,576	58,127	51,722
Fuel Rate (10^3 gal/hr)	15.291	13.334	11.536	11.861	10.610	9.450	8.970	7.951	7.075
Fuel Rate (lb/sec)	31.050	27.077	23.425	24.085	21.544	19.189	18.216	16.146	14.367

Note: *Fuel oil data for 60 and 98 °F estimated from 0 °F ABB data and Westinghouse 501F data.*

Sources: ECT, 1999.
ABB, 1998.

EMISSION INVENTORY WORKSHEET

Hardee County Generating Facility

NGH-1

EMISSION SOURCE TYPE

NATURAL GAS COMBUSTION - CRITERIA POLLUTANTS | Figure:

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Natural Gas Heater
Emission Control Method(s)/ID No.(s):	None
Emission Point ID:	NGH-1

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Heat Input (MMBtu/hr) x Pollutant Emission Factor (lb/MMBtu)

Emission (ton/yr) = Heat Input (MMBtu/hr) x Pollutant Emission Factor (lb/MMBtu) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2000.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 24 Hrs/Day 7 Days/Wk 8,760 Hrs/Yr

Criteria Pollutant	Heat Input (MMBtu/hr)	Pollutant Emission Factor [1] (lb/MMBtu)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
SO_2	10.0	0.0006	0.01	0.03
NO_x	10.0	0.10	1.0	4.4
PM/PM_{10} [2]	10.0	0.0019	0.0	0.1
CO	10.0	0.084	0.8	3.7
VOC	10.0	0.0055	0.1	0.2

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours	GPP, 2000.
Maximum Heat Input	GPP, 2000.
Emission Factors	AP-42, EPA, March 1998.

NOTES AND OBSERVATIONS

[1] Emission factors based on natural gas heat content of 1,000 Btu/scf, and density of 0.04419 lb/ft^3.

[2] PM/PM_{10} represents filtrable particulate matter.

DATA CONTROL

Data Collected by:	T. Davis	Date:	1/00
Evaluated by:	T. Davis	Date:	1/00
Data Entered by:	T. Davis	Date:	1/00
Reviewed by:	T. Davis	Date:	1/00

BEST AVAILABLE COPY

Identification

Identification No.:	ST1
City:	Wachula
State:	FL
Company:	HCGF
Type of Tank:	Vertical Fixed Roof

Tank Dimensions

Shell Height (ft):	30.0
Diameter (ft):	110.0
Liquid Height (ft):	21.1
Avg. Liquid Height (ft):	15.0
Volume (gallons):	1500150
Turnovers:	5.1
Net Throughput (gal/yr):	7650765

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft):	2.70
Radius (ft) (Dome Roof):	0.00
Slope (ft/ft) (Cone Roof):	0.0491

Breather Vent Settings

Vacuum Setting (psig):	-0.01
Pressure Setting (psig):	0.01

Meteorological Data Used in Emission Calculations: Tampa, Florida (Avg Atmospheric Pressure = 14.7 psia)

Mixture/Component	Month	Daily Liquid Temperatures Avg.	Surf. (deg F) Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.01	68.83	79.19	72.02	0.0102	0.0086	0.0119	130.000			130.00	Option 3: A=12.1010, B=8907.0

Annual Emission Calculations

Standing Losses (lb):	475.3251
Vapor Space Volume (cu ft):	151102.6
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.037669
Vented Vapor Saturation Factor:	0.991506
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	151102.6
Tank Diameter (ft):	110.0
Vapor Space Outage (ft):	15.90
Tank Shell Height (ft):	30.0
Average Liquid Height (ft):	15.0
Roof Outage (ft):	0.90
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.90
Roof Height (ft):	2.700
Roof Slope (ft/ft):	0.04909
Shell Radius (ft):	55.0
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Daily Avg. Liquid Surface Temp.(deg. R):	533.68
Daily Average Ambient Temp. (deg. R):	531.67
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	531.69
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqftday):	1492.00
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.037669
Daily Vapor Temperature Range (deg.R):	20.71
Daily Vapor Pressure Range (psia):	0.003303
Breather Vent Press. Setting Range(psia):	0.02
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.008631
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.011934
Daily Avg. Liquid Surface Temp. (deg R):	533.68
Daily Min. Liquid Surface Temp. (deg R):	528.50
Daily Max. Liquid Surface Temp. (deg R):	538.86
Daily Ambient Temp. Range (deg.R):	18.90

Annual Emission Calculations

Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.991506
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Vapor Space Outage (ft):	15.90
Working Losses (lb):	240.7235
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010165
Annual Net Throughput (gal/yr):	7650765
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	200520
Maximum Liquid Height (ft):	21.1
Tank Diameter (ft):	110.0
Working Loss Product Factor:	1.00
Total Losses (lb):	716.05

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Working	Total
Distillate fuel oil no. 2	475.33	240.72	716.05
Total:	475.33	240.72	716.05

APPENDIX E
DISPERSION MODELING FILES