CALPINE
BLUE HERON
ENERGY CENTER

Site Certification Application

Volume 3
Chapter 10
Appendix 10.1.1

Submitted by

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Prepared by

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Environmental Consulting & Technology, Inc.

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10.0 APPENDICES

PREVENTION OF SIGNIFICANT DETERIORATION

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INDIAN RIVER COUNTY, FLORIDA

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Blue Heron Energy Center, L.L.C. (Calpine) is planning to construct and operate a new electric power generating plant in Indian River County, Florida. The new power plant, designated as the Blue Heron Energy Center (BHEC), will be a natural gas-fired combustion turbine generator (CTG)-based combined cycle (CC) facility with a nominal generating capacity of 1,080 megawatts (MW). The BHEC is being licensed under the Florida Electrical Power Plant Siting Act.

A prevention of significant deterioration (PSD) air construction permit application for the BHEC project was previously submitted to the Florida Department of Environmental Protection (FDEP) in October 2000. In response, the FDEP issued a final draft PSD permit (PSD-FL-309, PA00-42) for the BHEC project in September 2001. Due to revisions to the original project design and the length of time that has elapsed since the original application was submitted 4 years ago, this PSD permit application package represents a complete replacement of the original application.

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

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

This report is organized as follows:

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

Attachments A through D provide the FDEP Application for Air Permit—Long Form, CTG vendor estimated performance data, emission rate calculations, and national BACT determination tables, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in compact disc (CD) format in Attachment E.

1.2 SUMMARY

The BHEC will consist of four nominal 170-MW Siemens Westinghouse 501F CTGs, four heat recovery steam generators (HRSGs) equipped with supplemental duct burners (DBs), and two nominal 200-MW steam turbine generators (STGs); i.e., two "2 by 2 by 1" configurations. The CTGs will include provisions for inlet air fogging. The BHEC will have a total nominal generation capacity of 1,080 MW. Ancillary equipment includes two mechanical draft cooling towers (north and south 10-cell towers), two fuel gas heaters, one emergency electric generator diesel engine, one emergency fire water pump diesel engine, and water treatment and storage facilities. The CTGs, DBs, and fuel gas heaters will all be fired exclusively with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred dry standard cubic feet (gr S/100 dscf).

Construction of the BHEC is expected to commence in mid 2005. The BHEC is projected to commence commercial operation in mid 2007, following initial equipment startup and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, the BHEC will have the potential to emit 313.4 tpy of nitrogen oxides (NO_x), 156.6 tpy of carbon monoxide (CO), 264.2 tpy of particulate matter (PM), 233.4 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM_{10}), 226.0 tpy of sulfur dioxide (SO_2), 101.4 tpy of volatile organic compounds (VOCs), and 0.02 tpy of lead. Regarding noncriteria pollutants, the BHEC will potentially emit 41.4 tpy of sulfuric acid (H_2SO_4) mist and 0.0029 tpy of mercury. Based on these annual emission rate potentials, NO_x, CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist emissions are each 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, DBs, and fuel gas heaters will utilize the latest burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emission rates, and will be fired exclusively with pipeline-quality natural gas.
- Dry low-NO_x (DLN) combustors (for the CTGs) and low-NO_x burners (for the HRSG DBs), followed by selective catalytic reduction (SCR) are proposed as BACT for NO_x for the CTG/HRSG units. For all operating scenarios, CTG/HRSG NO_x exhaust concentrations will not exceed 2.0 parts per million by volume, dry (ppmvd), corrected to 15 percent oxygen (O_2) on a 24-hour block average basis. This concentration is consistent with recent FDEP BACT determinations for natural gas-fired CTGs and is considered to represent the *top-case* emission limit. An additional NO_x BACT consideration pertinent to the BHEC is the exclusive use of natural gas. CTG facilities using distillate fuel oil as a secondary fuel source will have higher NO_x emissions compared to facilities, such as BHEC, which will use natural gas as the only fuel source.

- Advanced burner design, good combustion practices, and use of oxidation catalyst control technology are proposed as BACT for CO and VOCs for the CTGs and DBs. The use of oxidation catalyst is consistent with recent FDEP BACT determinations for natural gas-fired CTGs and is considered to represent the top-case technology for controlling CO and VOC emissions. For all operating scenarios, CTG/HRSG CO exhaust concentrations will not exceed 5.0 parts ppmvd, corrected to 15 percent O_2 on a 24-hour block average basis. This concentration is consistent with recent FDEP BACT determinations for natural gas-fired CTG/HRSG units and is considered to represent the top-case emission limits. Good combustion practice is proposed as BACT for CO and VOCs for the small fuel gas heaters.
- BACT for SO_2 and H_2SO_4 mist will be achieved through the exclusive use of low-sulfur, pipeline-quality natural gas.
- The BHEC CTGs will not be subject to the requirements of 40 Code of Federal Regulations (CFR) Part 63 Subpart YYYY, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* since the BHEC will not be a major source of hazardous air pollutants (HAPs). In addition, the U.S. Environmental Protection Agency (EPA) has proposed to delist the lean premixed gas-fired turbine subcategory (the type of CTG proposed for the BHEC) from the source subcategories presently addressed by 40 CFR Part 63 Subpart YYYY and has stayed the effectiveness of Subpart YYYY for this turbine subcategory until a final decision is made on the delisting proposal.
- The BHEC is projected to emit NO_x, CO, VOCs, PM/PM_{10}, SO_2, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants, with the exception of VOCs. The BHEC will have potential VOC emissions in excess of 100 tpy and therefore exceeds the PSD *de minimis* monitoring significance level for ozone. Accordingly, with the exception of ozone, BHEC 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. Representative, quality-assured ambient ozone data col-

lected by FDEP at a monitoring site located in Fort Pierce, St. Lucie County, was used to satisfy the PSD preconstruction ambient air monitoring requirements for ozone.

- The BHEC will include four CTG/HRSG CC units that are fired exclusively with natural gas. Each CC unit will employ SCR to control NO_x emissions and oxidation catalyst to control emissions of CO. Each CTG/HRSG CC unit will be subject to the Acid Rain Program and will be equipped with a NO_x/diluent (O_2 or carbon dioxide [CO_2]) continuous emission monitoring system (CEMS) certified and operated in accordance with the requirements of 40 CFR Part 75, *Continuous Emission Monitoring*. In addition, the BHEC CTG/HRSG units will be equipped with CO CEMS. The CTG/HRSG NO_x and CO CEMS will be used to determine compliance with all of the NO_x and CO emission limits included in the FDEP PSD air construction permit; i.e., the NO_x and CO CEMS will serve as *continuous compliance determination* methods. Accordingly, the four CTG/HRSG units are exempt from compliance assurance monitoring requirements with respect to NO_x and CO pursuant to 40 CFR §64.2(b)(vi).
- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.259(259), F.A.C. Accordingly, a multi-source interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was not required.
- Based on refined dispersion modeling, BHEC 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 (Everglades National Park) is located approximately 205 kilometers (km) south of the BHEC site. The Chassahowitzka National Wildlife Refuge Class I area is situated approximately 240 km to the northwest of the

BHEC site. Air quality and visibility impacts on these Class I areas will be negligible.

- Rule 62-210.700(1), F.A.C., allows for excess emissions due to startup, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG/HRSG and STG cold startup and shutdown periods may last for more than 2 hours in a 24-hour period, the following periods of excess emissions above the 2-hour per 24-hour limit are requested: (a) for cold startup of a CC STG system, up to 6 hours in any 24-hour period; (b) for cold startup of a CTG/HRSG unit, up to 4 hours in any 24-hour period; and (c) for shutdown of a CTG/HRSG unit, up to 3 hours in any 24-hour period. Cold startup of a CC STG system is defined as startup of a 2-on-1 CC system following a shutdown of the STG lasting at least 48 hours. Cold startup of a CTG/HRSG unit is defined as a startup following a shutdown of a CTG/HRSG unit lasting at least 48 hours. Further discussion of the BHEC CTG/HRSG startup cycle is provided in Section 2.2.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The BHEC will be located in Indian River County approximately 8 km (5 miles) southwest of the western city limits of Vero Beach. The 50.5-acre plant site (Site) is located approximately 9 km (5.5 miles) south-southeast of the intersection of State Road (SR) 60 and Interstate 95 (I-95). The Site is bordered on the west by I-95, several borrow pit lakes, and undeveloped property; to the north by a single-family residence and the Indian River County correctional institute and solid waste landfill; to the east by a wastewater sprayfield operated by Ocean Spray Cranberries, Inc., and by inactive citrus groves; and to the south by undeveloped lands and I-95. The Spanish Lakes residential development is located southeast of the plant site in St. Lucie County. BHEC site location and vicinity maps are provided in Figures 2-1 and 2-2, respectively.

Major components of the BHEC include:

1. The base CC generating plant consisting of two CC configurations. Each CC configuration will consist of two F-class CTG/HRSG units and one STG for a total of four F-Class CTG/HRSG units and two STGs. Each CC configuration is commonly referred to as a “2 by 2 by 1” configuration with the values referring to the number of CTGs, HRSGs, and STGs, respectively.
2. Two 10-cell mechanical draft cooling towers.
3. Two 9.3 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) fuel gas heaters.
4. One 1,400-kilowatt (kW) emergency diesel-fired electrical generator.
5. One emergency diesel-fired fire water pump.
6. Ancillary equipment, including raw and demineralized water storage tanks.

The CTGs will be Siemens Westinghouse 501F units. Each CTG will have provisions for inlet air fogging. Each CTG will be capable of producing a nominal 170 MW of electricity at International Standards Organization (ISO) conditions of 59 degrees Fahrenheit (°F) ambient air temperature. The HRSGs, which will be equipped with supplemental DBs,

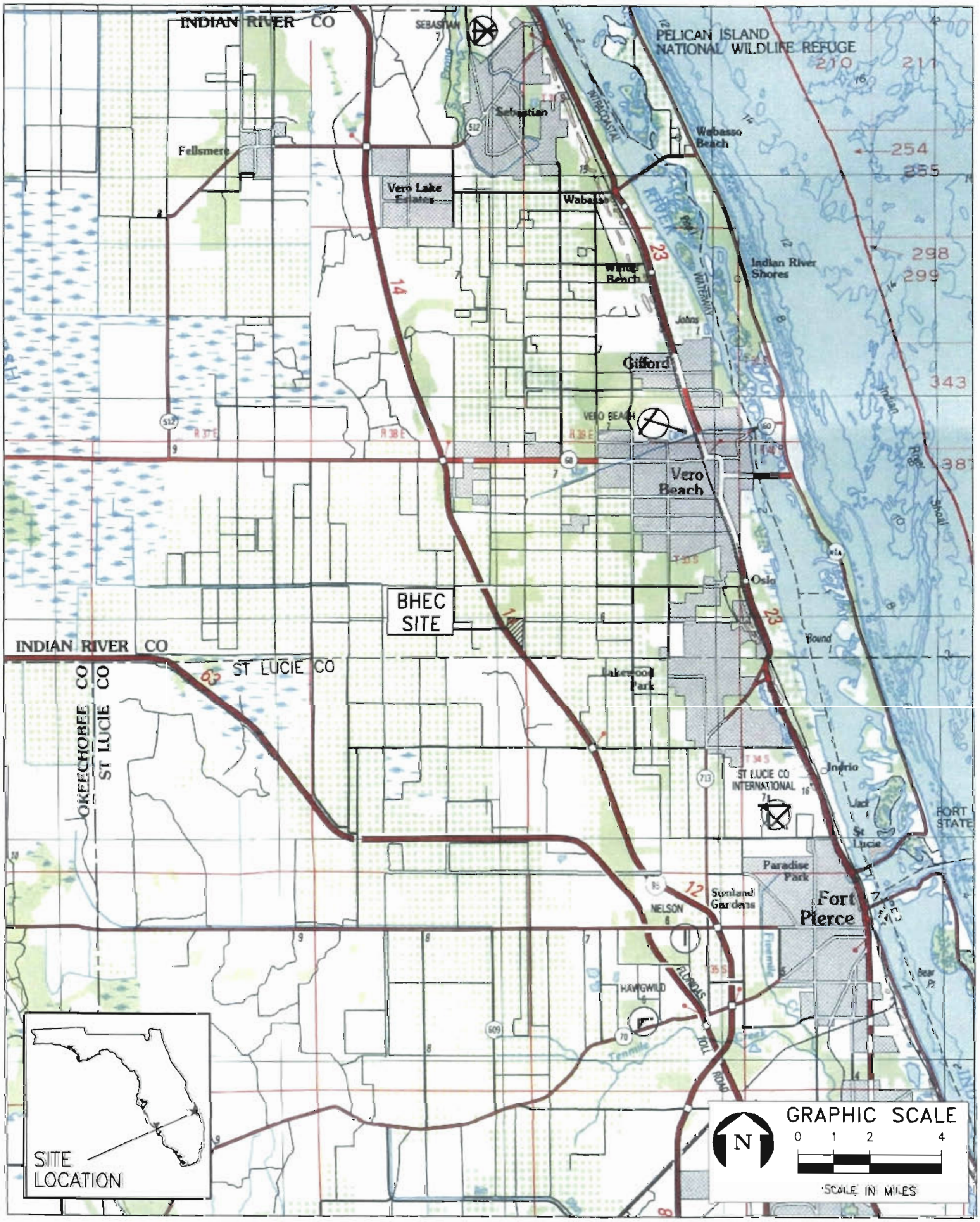

FIGURE 2-1

BHEC SITE LOCATION MAP

Sources: USGS Quad: Ft. Pierce, FL, 1988; ECT, 2000.

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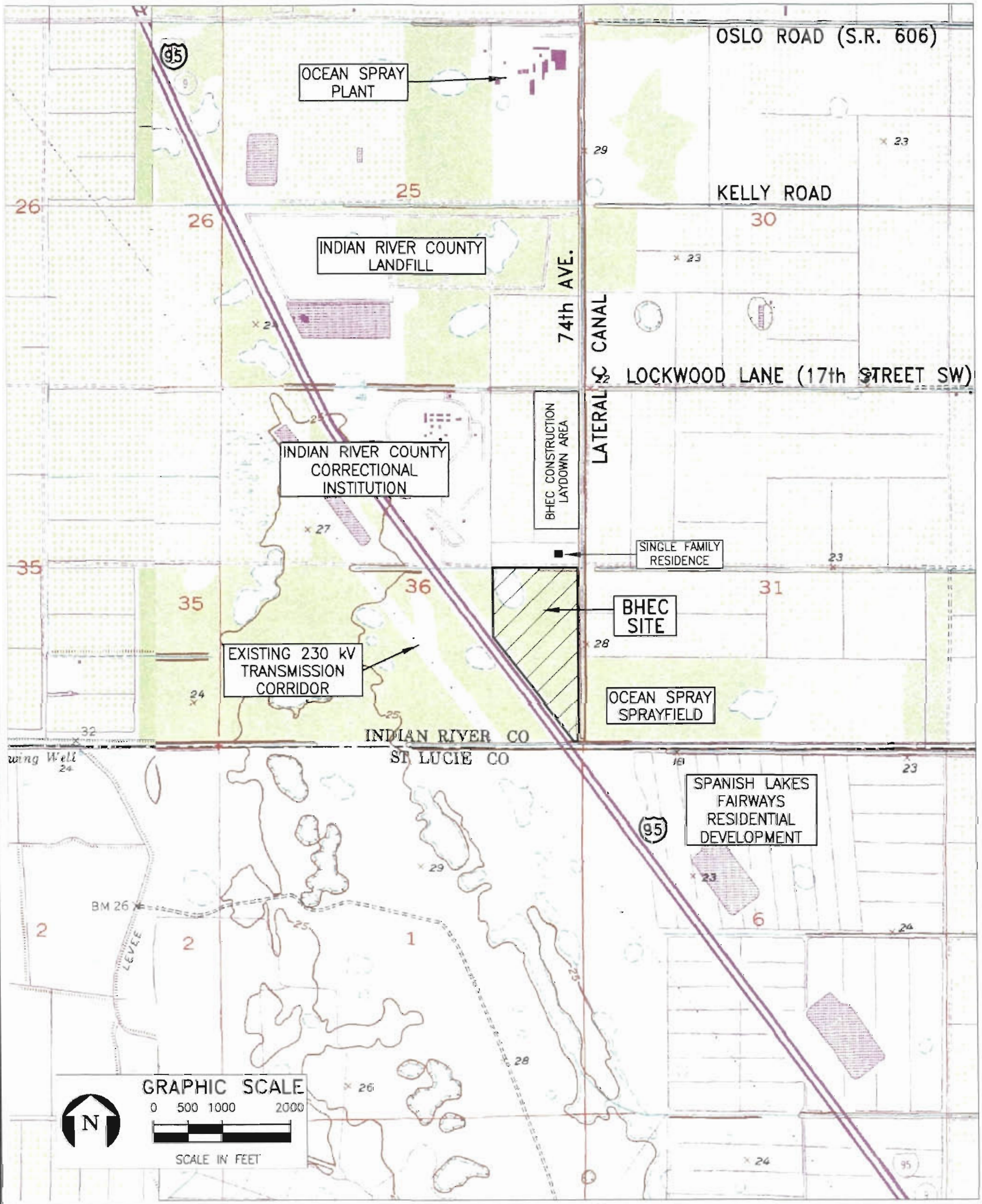

FIGURE 2-2.

SITE VICINITY MAP

Sources: USGS Quads: Oslo and East of Glum Slough, FL, 1983; ECT, 2000.

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will furnish steam to the two STGs for the additional generation of electricity. The two STGs will each be capable of generating an additional nominal 200 MW of power for an overall facility nominal generation capacity of 1,080 MW. The CTGs and DBs will be fired exclusively with pipeline-quality natural gas.

The BHEC CTG/HRSG units will be capable of continuous operation at baseload for up to 8,760 hours per year (hr/yr). The CTGs will normally operate between 35- and 100-percent load, with commensurate STG load. None of the CTGs will be designed to operate in simple cycle mode (i.e., bypassing the HRSG).

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

Emission control systems proposed for the CTG/HRSG units include the use of DLN combustors (for the CTGs) and low-NO_x burners (for the DBs), followed by post-combustion SCR technology for control of NO_x; good combustion practices and oxidation catalyst for abatement of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions. Drift eliminators will be utilized to control PM/PM_{10} emissions from the mechanical draft cooling towers.

A general site layout of the BHEC showing facility property lines, major process equipment and structures, and all emission points is presented in Figure 2-3. Access to the Site will be provided by 74th Avenue (Range Line Road) that terminates at the Site. The BHEC entrance will have security gates to control access. The entire Site perimeter will be fenced at the property boundary.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed BHEC natural gas-fired CC facility will include four nominal 170-MW CTGs, four HRSGs with supplemental DBs, and two nominal 200-MW STGs. At ISO

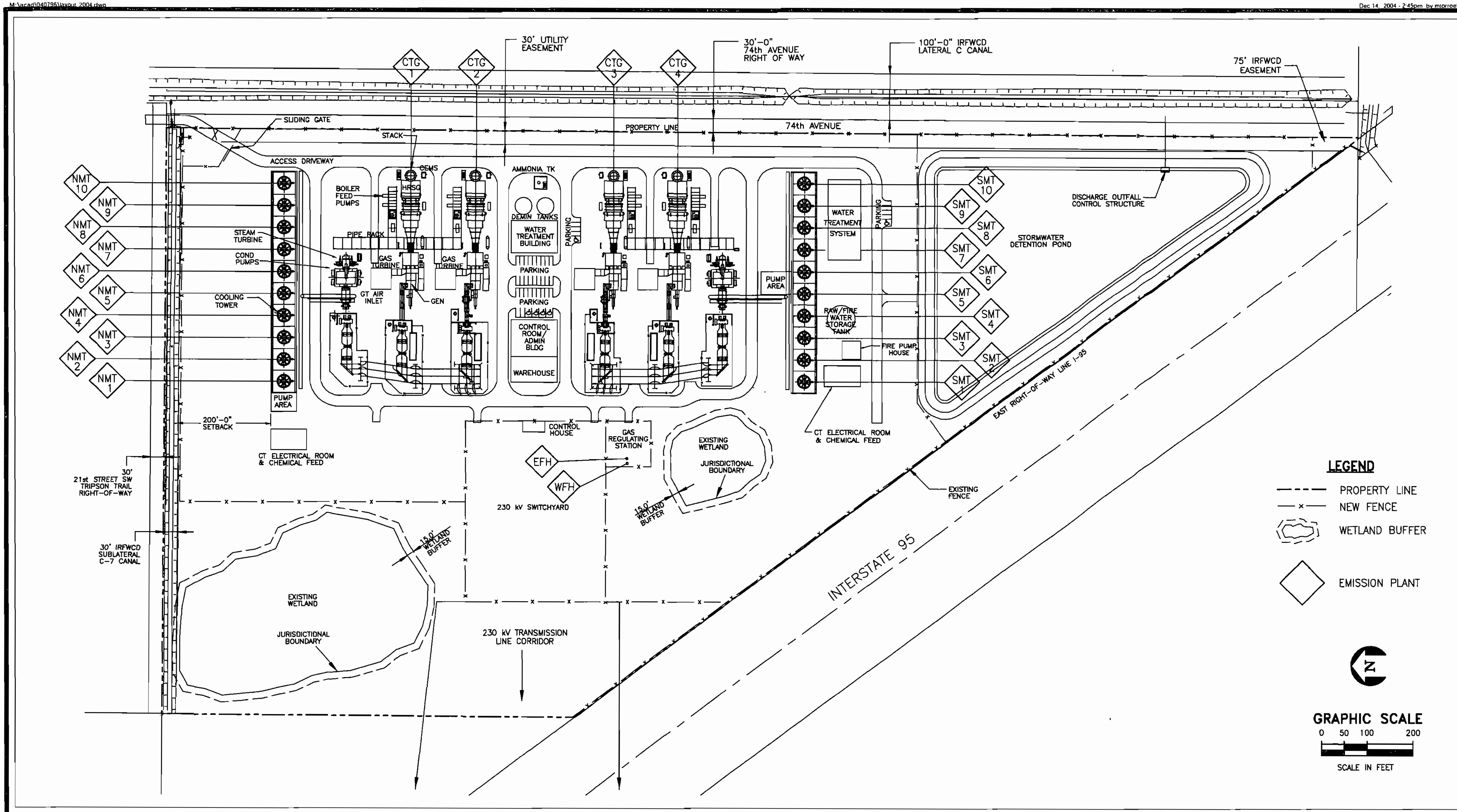

FIGURE 2-3. (REV. 1 - 12/04)

GENERAL SITE LAYOUT

Sources: Burns and Roe, 2000; Calpine, 2002; ECT, 2004.

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conditions of 59°F ambient temperature, the BHEC will generate a nominal 1,080 MW. A process flow diagram of BHEC is presented in Figure 2-4.

CTGs are heat engines that convert latent fuel energy into *work* using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft which is used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. During warm ambient temperature conditions, the turbine inlet ambient air will be cooled by inlet air fogging, thus providing denser air for combustion and increasing the power output. The compressed combustion air is then combined with natural gas fuel and burned in the CTG's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power which is used to drive an electric generator as well as the CTG combustion air compressor.

The hot exhaust gases from the CTGs next flow to the HRSGs for the production of steam. Each CTG will use an HRSG to recover exhaust heat from the CTG and produce steam to power the two STGs. Each STG, in turn, will drive an electric generator having a nominal generation capacity of 200 MW. Each of the four HRSGs will include supplemental DB firing for the production of additional steam during peak demand periods. The DBs, which will be fired exclusively with natural gas, will each have a nominal heat input rating of 430 MMBtu/hr, HHV. Following reuse of the CTG exhaust waste heat by the HRSG, the exhaust gases are discharged to the atmosphere.

Normal operation is expected to consist of all CTG/HRSG units operating at baseload. Alternate operating modes include reduced load (i.e., between 35 and 100 percent of base load) operation for one or more of the CTG/HRSG units depending on power demands, use of CTG inlet air fogging during warm ambient air temperature periods, and supplemental HRSG DB firing during peak demand periods. The CTGs will not be designed

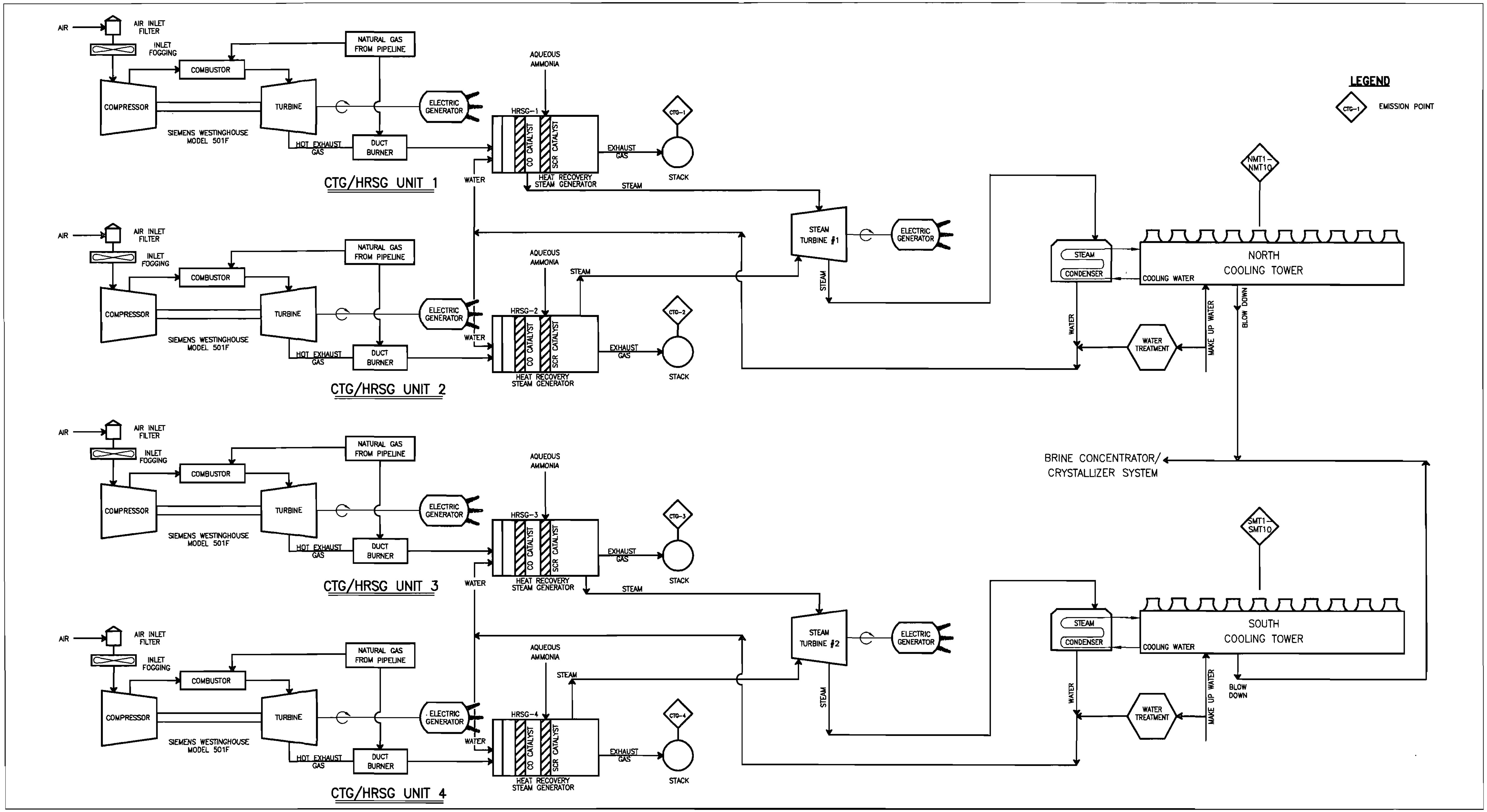

FIGURE 2-4. (REV. 1 - 12/04)

PROCESS FLOW DIAGRAM

Source: ECT, 2004.

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with bypass stacks and will operate only in the CC mode. The CTG/HRSG units are designed for continuous operation (i.e., 8,760 hr/yr) and may operate at up to a 100-percent annual capacity factor.

The BHEC CT/HRSG normal startup procedure consists of gradually ramping the CTG to 60 percent load. At this load and above, the CTG/HRSG unit is thermally stable and able to achieve compliance with all emission limits. If low load (i.e., from 35 to 60 percent CTG load) is required, the CTG load is reduced as necessary following completion of the startup cycle. Although compliance with emission limits will occur at a CTG load of 35 percent or higher during normal operations, for startup periods the CTG must first reach 60 percent load and then reduce load in order to attain thermal stability and compliance with emission limits at low load operations.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to startup, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG/HRSG and CC STG cold startup and shutdown periods may last for more than 2 hours in a 24-hour period, the following periods of excess emissions above the 2-hour per 24-hour limit are requested: (a) for cold startup of a CC STG system, up to 6 hours in any 24-hour period; (b) for cold startup of a CTG/HRSG unit, up to 4 hours in any 24-hour period; and (c) for shutdown of a CTG/HRSG unit, up to 3 hours in any 24-hour period. Cold startup of a CC STG system is defined as startup of a 2-on-1 CC system following a shutdown of the STG lasting at least 48 hours. Cold startup of a CTG/HRSG unit is defined as a startup following a shutdown of a CTG/HRSG unit lasting at least 48 hours.

The CTGs and DBs will utilize DLN combustion technology and SCR to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTGs and DBs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices and oxidation catalyst will be employed to control CO and VOC emissions. The mechanical draft cooling towers (i.e., the two 10-cell towers) will be equipped with drift eliminators achieving a drift loss rate of no more than 0.0005 percent.

2.3 EMISSION AND STACK PARAMETERS

Table 2-1 provides maximum hourly criteria pollutant CTG/HRSG emission rates. Maximum hourly noncriteria pollutant (i.e., H_2SO_4 mist) emission rates are summarized in Table 2-2. The highest hourly emission rates for each pollutant are shown, taking into account load and ambient temperature to develop maximum hourly emission estimates for each CTG/HRSG unit.

With the exception of CO, maximum hourly mass emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for operations at low ambient temperature (i.e., 20°F), CTG baseload with HRSG DB firing. The maximum hourly CO mass emission rate, in units of lb/hr, is projected to occur at part load operation (i.e., 60 percent load) and 20°F ambient temperature. The bases for these emission rates are provided in Attachment C.

Table 2-3 presents projected maximum annualized criteria and noncriteria emissions for the BHEC based on an evaluation of five annual operating profiles. These annual profiles are defined in Attachment C on Table C-1. For all pollutants, maximum annual emission rates are projected to occur under Annual Profile B operating conditions (i.e., CTG baseload operation for 8,760 hr/yr at 80°F with inlet air fogging and HRSG DB firing).

Annual emission rate estimates for the mechanical draft cooling towers, emergency electrical generator and fire-water pump diesel-fired engines, fuel gas heaters, and total BHEC annual emissions are shown in Table 2-3. Details of the annualized emission calculations are also included in Attachment C. Stack parameters for the natural gas-fired CTG/HRSG units, cooling towers, and fuel gas heaters are provided in Tables 2-4 and 2-6, respectively.

Table 2.1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Five Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	ppmvd†	lb/hr	ppmvd†	lb/hr	ppmvd†	lb/hr	ppmvd†	lb/hr	g/s
100	20‡	14.2	1.78	14.2	1.1	18.9	2.0	9.1	1.6	6.0	1.9	0.0012	0.00016
	59††	13.6	1.72	13.4	1.1	17.8	2.0	8.8	1.7	5.8	1.9	0.0012	0.00015
	80††	13.2	1.66	12.9	1.1	17.2	2.0	8.5	1.7	5.8	2.0	0.0011	0.00014
	90††	12.9	1.63	12.6	1.1	16.8	2.0	8.4	1.7	5.7	2.0	0.0011	0.00014
60	20	6.5	0.82	8.0	1.1	10.5	2.0	16.0	5.0	2.8	1.5	0.0007	0.00009
	59	6.1	0.77	7.4	1.1	9.8	2.0	14.9	5.0	2.6	1.5	0.0007	0.00008
	80	5.9	0.74	7.0	1.1	9.3	2.0	14.1	5.0	2.4	1.5	0.0006	0.00008
	90	5.7	0.72	6.9	1.1	9.0	2.0	13.8	5.0	2.4	1.5	0.0006	0.00008
35**	86	4.3	0.54	5.0	1.1	7.4	2.0	5.1	2.7	0.4	0.4	0.0004	0.00005

* As measured by EPA Reference Method 5B.
† Corrected to 15-percent O_2.
‡ With duct burner firing.
†† With inlet fogging and duct burner firing.
** Emissions based on Calpine Morgan Energy Center stack test data.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

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

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4 mist	
		lb/hr	g/s
100	20*	2.61	0.329
	59†	2.46	0.310
	80†	2.36	0.298
	90†	2.32	0.292
60	20	1.47	0.185
	59	1.37	0.172
	80	1.29	0.163
	90	1.26	0.159
35	86	0.91	0.115

Note: g/s = gram per second.

*Emission rates include duct burner firing.
†Emission rates include use of inlet air fogging and duct burner firing.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table 2-3. Maximum Annualized Emission Rates (tpy)

Pollutant	CTG/HRSG Units	Emergency Diesel Engines	Fuel Gas Heaters	Cooling Towers	BHEC Totals
NO_x	300.58	5.03	7.76	N/A	313.4
CO	148.92	1.13	6.52	N/A	156.6
PM	230.56	0.18	0.59	32.90	264.2
PM_{10}	230.56	0.18	0.59	2.07	233.4
SO_2	225.37	0.11	0.47	N/A	226.0
VOCs	100.74	0.24	0.43	N/A	101.4
Lead	0.02	Neg.	Neg.	N/A	0.02
H_2SO_4 mist	41.41	Neg.	Neg.	N/A	41.4

Note: N/A = not applicable.
Neg. = negligible.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

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

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meter	°F	K	fps	m/sec	ft	meter
100	20‡	150	45.7	165	347	69.3	21.1	18.5	5.64
	59††	150	45.7	165	347	65.3	19.9	18.5	5.64
	80††	150	45.7	165	347	62.8	19.2	18.5	5.64
	90††	150	45.7	165	347	61.5	18.7	18.5	5.64
60	20	150	45.7	165	347	49.2	15.0	18.5	5.64
	59	150	45.7	165	347	46.6	14.2	18.5	5.64
	80	150	45.7	165	347	45.2	13.8	18.5	5.64
	90	150	45.7	165	347	44.4	13.5	18.5	5.64
35*	86	150	45.7	165	347	34.7	10.6	18.5	5.64

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

‡ With duct burner firing.
†† With inlet fogging and duct burner firing.
* Stack velocity and temperature based on Calpine Morgan Energy Center stack test data.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table 2-5. Cooling Tower Stack Parameters

	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
	ft	meter	°F	K	fps	m/sec	ft	meter
Main Cooling Towers (Per Cell)	62	18.9	106	314	26.1	7.9	33.0	10.1

Sources: Calpine, 2004.
ECT, 2004.

Table 2-6. Fuel Gas Heater Stack Parameters

	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
	ft	meter	°F	K	fps	m/sec	ft	meter
Fuel Gas Heater (Per Heater)	25	7.6	850	728	30.5	9.3	2.0	0.6

Sources: Calpine, 2004.
ECT, 2004.

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, EPA has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are standards the attainment and maintenance of which in the judgement of the EPA Administrator, based on air quality criteria and allowing an adequate margin of safety, are requisite to protect the public health. Secondary NAAQS are standards the attainment and maintenance of which in the judgement of the EPA Administrator, based on air quality criteria, are requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutants in the ambient air. Florida has also adopted AAQS; reference Section 62-204.240, F.A.C. Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The proposed BHEC will be located in southern Indian River County adjacent to I-95, approximately 5.5 miles south-southeast of the intersection of SR 60 and I-95. Indian River County is presently designated in 40 CFR §81.310 as better than the national standards (for total suspended particulates [TSPs] and SO_2), unclassifiable/attainment (for CO and ozone [1-hour standard]), not designated (for lead), and unclassifiable or better than national standards (for nitrogen dioxide [NO_2]). On April 30, 2004, EPA issued final designations for the new 8-hour ozone NAAQS. For Florida, 40 CFR §81.310 was revised to designate all areas of the State, including Indian River County, as unclassifiable/attainment for the 8-hour ozone NAAQS.

Indian River 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.

Table 3-1. National and Florida Air Quality Standards (μg/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}	24-hour[3]	150	150	150
	Annual[4]	50	50	50
$PM_{2.5}$	24-hour[5]	65	65	
	Annual[6]	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[7]	0.12		0.12
	8-hour[8]	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]The standards are attained when the expected number of days per calendar year with a 24-hour average concentration above 150 μg/m[3], as determined in accordance with Appendix K to this part, is equal to or less than one
[4]The standards are attained when the expected annual arithmetic mean concentration, as determined in accordance with Appendix K to this part, is less than or equal to 50 μg/m[3].
[5]Standards are met when the 98th percentile 24-hour concentration, as determined in accordance with Appendix N, is less than or equal to 65 μg/m[3].
[6]Standards are met when the annual arithmetic mean concentration, as determined in accordance with appendix N of this part, is less than or equal to 15.0 μg/m[3].
[7]Standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is <= 1, as determined by appendix H. The 1-hour ozone standard will be revoked on June 15, 2005, one year following the effective date of the 8-hour ozone standard designations.
[8]To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm.

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

3.2 NONATTAINMENT NSR APPLICABILITY

The BHEC will be located in Indian River County. As noted above, Indian River County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the BHEC emission sources are not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The BHEC CTG/HRSG units will each have a heat input greater than 250 MMBtu/hr, will be located in an attainment area, and will have potential emissions of a regulated pollutant in excess of 100 tpy. Therefore, the BHEC qualifies as a new major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels.

Comparisons of estimated potential annual emission rates for the BHEC Project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, PM, PM_{10}, SO_2, CO, VOCs, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Detailed emission rate estimates for the BHEC are provided in Attachment C.

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

Pollutant	BHEC Project Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	313.4	40	Yes
CO	156.6	100	Yes
PM	264.2	25	Yes
PM_{10}	233.4	15	Yes
SO_2	226.0	40	Yes
Ozone/VOC	101.4	40	Yes
Lead	0.02	0.6	No
Mercury	0.0029	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	41.4	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not Present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not Present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not Present	40	No
Municipal waste combustor metals (measured as PM)	Not Present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not Present	3.5×10^{-6}	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2004.

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 BHEC in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(38), 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(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility shall be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 4-1). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the BHEC 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

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.

below the appropriate Rule 62-210.200(232), F.A.C., significant impact level, as presented in Table 4-2.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

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

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality *baseline concentration* level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

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(232), F.A.C.

On October 17, 1988, EPA promulgated PSD increments for NO_2; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO_2 increment consumption was set at March 28, 1988, for Florida; new major sources or modifications constructed after this date will consume NO_2 increment.

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

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

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

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

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

Pollutant	Averaging Time	Class I	Class II	Class III
PM_{10}	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO_2	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO_2	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year at any one location.

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

2. The allowable emissions of major stationary sources which commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

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

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

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

The ambient impact analysis for the BHEC 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:

1. A projection of the associated industrial, commercial, and residential growth that will occur in the area.
2. An estimate of the air pollution emissions generated by the permanent associated growth.
3. An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

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

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

The additional impact analyses for the BHEC 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 combustion turbine 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, 1990). 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, 2002). Tables 5-1 and 5-2 summarize the specific factors used in estimating capital investment and annual operating costs, respectively. If the most stringent "top case" technically feasible control technology is selected as BACT, assessments of energy and economic impacts are not required.

Table 5-1. Capital Investment Cost Factors

Cost Item	Factor
Direct Capital Costs (DCC)	
Instrumentation	0.10 × equipment cost
Sales tax	0.07 × equipment cost
Freight	0.05 × equipment cost
Purchased Equipment Cost (PEC)	Instrumentation + sales tax + freight
Foundations and supports	0.08 × PEC
Handling and erection	0.14 × PEC
Electrical	0.04 × PEC
Piping	0.02 × PEC
Insulation	0.01 × PEC
Painting	0.01 × PEC
Indirect Capital Costs (IIC)	
General Facilities	0.05 × DCC
Engineering and Home Office Fees	0.10 × DCC
Process Contingency	0.05 × DCC
Project Contingency (PC)	0.15 × (DCC + IIC)
Total Plant Cost (TPC)	DCC + IIC + PC
Other Costs (OC)	
Preproduction Cost	0.02 × TPC
Inventory Capital	initial reagent
Total Capital Investment (TCI)	TPC + OC

Sources: ECT, 2004.
EPA, 2002.

Table 5-2. Annual Operating Cost Factors

Cost Item	Factor
Total Direct Costs (TDC)	
Maintenance labor and materials	0.015 × TCI
Reagent (for SCR control system)	Aqueous NH_3 (cost)
Electricity (for SCR control system)	0.105 × uncontrolled NO_x (lb/hr) × SCR control efficiency (%/100) × hours/year × power cost ($/kW-hr)
Catalyst replacement	Catalyst replacement cost × future worth factor
Energy penalty	0.2 to 1.0% of CT output per inch of pressure drop (dependent on control equipment)
Total Indirect Costs (TIC)	TCI × capital recovery factor
Total Annual Cost (TAC)	TDC + TIC

Sources: ECT, 2004.
EPA, 2002.

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, BHEC potential emission rates of NO_x, CO, SO_2, H_2SO_4 mist, VOCs, PM, and PM_{10} 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 Part 60), NESHAPs (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at 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 BHEC 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 BHEC HRSG DBs each have a rated heat input greater than 250 MMBtu/hr and, therefore, are subject to the requirements of NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*. Specifically, emissions from the DBs are limited to no more than 0.03 lb PM/MMBtu per §60.42a(a)(1); 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity per §60.42a(b); 0.20 lb SO_2/MMBtu (30-day rolling average) per §60.43a(b)(2); and 1.6 lb NO_x/MW-hr (30-day rolling average) per §60.43a(d)(1).

The two fuel gas heaters each have a rated heat input less than 10 MMBtu/hr and, therefore, are not subject to the requirements of NSPS Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.*

There are no 40 CFR Part 61 NESHAPs which are applicable to the BHEC emission sources. The BHEC will have potential emissions of HAPs less than the major source thresholds of 10 tpy for any individual HAP and 25 tpy for total HAPs. Since the BHEC will not be a major source of HAPs, the 40 CFR Part 63 maximum achievable control technology (MACT) NESHAPs and case-by-case MACT requirements of Section 112(g)(2)(B) of the 1990 CAA Amendments are not applicable. In particular, the BHEC CTGs will not be subject to the requirements of 40 CFR Part 63 Subpart YYYY, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, and the BHEC HRSGs and fuel gas process heaters will not be subject to the requirements of 40 CFR 63 Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.* 40 CFR 63 Subpart DDDDD is also not applicable to the BHEC HRSGs since the HRSG DBs do not supply 50 percent or more of the total rated heat input capacity of the HRSG.

FDEP emission standards for stationary sources are contained in Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*. 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 -.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTGs, fuel gas heaters, or cooling towers. Rule 62-296.405(2) contains visible emissions, PM, SO_2, and NO_x limitations for new fossil fuel steam generators with more than 250 MMBtu/hr heat input which are applicable to the BHEC HRSG DBs. For each air contaminant, Rule 62-296.405(2) references Rule 62-204.800(7) and 40 CFR Subpart Da. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subparts Da and GG.

Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment and maintenance areas) and 62-296.700, F.A.C. (for PM nonattainment and maintenance areas). Because BHEC will be located in Indian River 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 NESHAPs, respectively, by reference. As noted previously, NSPS Subpart Da, *Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978* and Subpart GG, *Stationary Gas Turbines* are applicable to the BHEC HRSG DBs and CTGs, respectively. There are no applicable 40 CFR Part 61 or Part 63 NESHAPs requirements.

Applicable federal and state emission standards are summarized in Tables 5-3 and 5-4, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Attachment C, Table C-10. BACT emission limitations proposed for the BHEC are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM_{10}

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

Table 5-3. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	STD = 0.0075 x (14.4/Y) + F

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

where: N = nitrogen content of fuel; percent by weight.

SO_2 = ≤ 0.015 percent by volume at 15 percent O_2 and on a dry basis; or fuel sulfur content ≤ 0.8 weight percent (8,000 ppmw)

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

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

Sources: 40 CFR 60, Subparts Da and GG.

Table 5-4. Florida Emission Limitations

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

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

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/PM_{10} 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/PM_{10} 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/PM_{10} 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 drop 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 natural gas-fired CTGs, HRSG DBs, and fuel gas heaters, none of the previously described control equipment have been applied to these types of combustion sources because exhaust gas PM/PM_{10} concentrations are inherently low. CTGs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The BHEC CTGs and HRSG DBs will be fired exclusively with natural gas. Combustion of natural gas will generate low PM/PM_{10} emissions in comparison to other fuels due to its negligible ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentration for the BHEC CTG/HRSGs at baseload and 59°F is approximately 0.001 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive. Similarly, application of post-combustion PM control technology to the two small, natural gas-fired fuel gas heaters would not be cost effective due to the low PM emission rates from these sources.

PM/PM_{10} emissions will also occur due to cooling tower operations. BHEC will include two 10-cell cooling towers (i.e., the north and south cooling towers). Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM/PM_{10} emissions because of the fine PM/PM_{10} formed by crystallization of the dissolved solids contained in the droplet.

The only feasible technology for controlling PM/PM_{10} from cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. Drift eliminator configurations include herringbone (blade-type), wave form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics, fiber reinforced cement, metal, plastic, and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

Factors affecting cooling tower PM/PM_{10} emission rates include drift droplet loss rate (expressed as a percent of recirculating cooling water flow rate), concentration of dissolved solids in the recirculating cooling water, and the recirculating cooling water flow rate (i.e., size of the tower).

PM/PM_{10} emissions from the BHEC cooling towers will be controlled using high efficiency drift eliminators. The two north and south cooling towers will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

Recent national BACT PM/PM_{10} determinations for combustion turbine projects are provided in Attachment D. All determinations are based on the use of clean fuels and good combustion practice. Attachment D also includes recent national BACT PM/PM_{10} determinations for cooling towers.

Because post-process stack controls for PM/PM_{10} are not appropriate for CTGs, HRSG DBs, and fuel gas heaters, the use of good combustion practices and clean fuels is considered to be BACT. The BHEC CTGs, HRSG DBs, and fuel gas heaters will use the latest, advanced 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, HRSG DBs, and fuel gas heaters will be fired exclusively with pipeline quality natural gas. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTG/HRSG units, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 5-5 summarizes the PM_{10} BACT emission limit proposed for the BHEC CTGs, HRSG DBs, fuel gas heaters, and cooling towers.

5.4 BACT ANALYSIS FOR CO AND VOCS

CO and VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO and VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in CO and VOC emissions.

An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO and VOC emission rates. Emissions of NO_x and CO/VOC are inversely related; i.e., decreasing NO_x emissions will result in an increase in CO and VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and

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

Emission Source	Proposed PM/PM_{10} BACT Emission Limits
Each CTG/HRSG Unit	≤10 percent opacity
Each Fuel Gas Heater	≤10 percent opacity
North and South Cooling Towers	0.0005 percent drift

Sources: Calpine, 2004.
ECT, 2004.

CO/VOC formation in order to develop units that achieve acceptable emission levels for all three pollutants.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

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

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTG and DBs, approximately 99 percent, CO and VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOCs to CO_2 and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO and VOCs up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F; higher temperatures on the order of 900°F are needed to oxidize VOCs. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical CTG VOC control efficiency using an oxidation catalyst control system is 50 percent.

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

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility and Top-Case Control Alternative

Both CTG combustor design and oxidation catalyst control systems are considered to be technically feasible for the BHEC CTGs and DBs. The BHEC CTG/HRSG units will be equipped with oxidation catalyst technology to reduce emissions of CO and VOC with estimated CO and VOC oxidation efficiencies of 90 and 50 percent, respectively. Use of oxidation catalyst technology to control CO and VOC emissions from CTG/HRSG units is considered the top-case control alternative and, therefore, analyses of energy and economic impacts are not required.

Collateral Environmental Issues

In addition to oxidizing CO and VOC, oxidation catalyst technology will also oxidize a small portion of SO_2 to SO_3. The SO_3 so formed will subsequently react with water to form H_2SO_4 mist. Increased H_2SO_4 mist emissions due to the use of oxidation catalyst technology is expected to be minor for the BHEC CTG/HRSG units since: (a) the units will be fired exclusively with pipeline quality natural gas, and (b) current technology oxidation catalysts are formulated to minimize the oxidation of SO_2 to SO_3.

5.4.2 PROPOSED BACT EMISSION LIMITATIONS

Recent national BACT CO and VOC determinations for combustion turbine projects are provided in Attachment D.

Use of state-of-the-art combustor design, good operating practices to minimize incomplete combustion, and oxidation catalyst technology are proposed as BACT for CO and VOCs for the BHEC CTG/HRSG units. These control techniques have been considered by FDEP to represent BACT for CO and VOCs for recent CTG/HRSG projects. The BHEC CTG/HRSG units CO and VOC exhaust concentrations will not exceed 5.0 (on a 24-hour block average basis) and 2.0 ppmvd at 15 percent O_2, respectively, for all operating scenarios, including duct burner firing and low-load operation.

Application of oxidation catalyst control technology is not considered practical for the two small fuel gas heaters. Each fuel gas heater will emit relatively low quantities of CO and VOC; approximately 3.3 and 0.2 tpy, respectively. Use of good combustion practices is proposed as CO and VOC BACT for the fuel gas heaters.

Table 5-6 summarizes the CO and VOC BACT emission limits proposed for the BHEC.

5.5 BACT ANALYSIS FOR NO_X

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

Table 5-6. Proposed CO and VOC BACT Emission Limits

Emission Source	Proposed CO and VOC BACT Emission Limits ppmvd at 15 percent O_2	lb/hr
A. Siemens Westinghouse 501F CTGs and DBs (Per CTG/HRSG Unit)		
All Operating Scenarios		
CO	5.0*	16.0†
VOC	2.0†	6.0†
B. Fuel Gas Heaters		
CO	Good Combustion Practices	
VOC	Good Combustion Practices	

* CEMS 24-hour block average
† Stack test, 3-run average

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

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, nitrogen, 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 FBN to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN (see Table 5-3). 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 and HRSG DBs 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.
- XONON™

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 a NO_x exhaust concentration of 42 ppmvd for gas firing.

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 a NO_x exhaust concentration of 25 ppmvd for gas firing.

Dry Low-NO_x Combustor Design

A number of turbine vendors have 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. A typical DLN combustor incorporates fuel staging using several operating modes as follows:

- Primary Mode—Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation.
- Lean-Lean Mode—Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 50 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.
- Secondary Mode (Transfer to Premix)—At 70-percent load, all fuel is supplied to second stage.

- Premix Mode—Fuel is provided to both stages with approximately 80 percent furnished to the first stage at turbine loads from 70 to 100 percent. Flame is present in the second stage only.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations.

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 25 ppmvd or less using natural gas fuel.

XONON™

The XONON™ Cool Combustion technology, being developed for CTGs by Catalytica Energy Systems, Inc. (CESI), employs a catalyst integral to the CTG combustor to reduce the formation of NO_x. In a conventional CTG combustor, fuel and air are oxidized in the presence of a flame to produce the hot exhaust gases required for power generation. The XONON™ Cool Combustion technology replaces this conventional combustion process with a two-step approach. First, a portion of the CTG fuel is mixed with air and burned in a low-temperature pre-combustor. The main CTG fuel is then added and oxidation of the total fuel/air mixture stream is completed by means of flameless, catalytic combustion. The catalyst module is located within the CTG combustor. NO_x formation is reduced due to the relatively low oxidation temperatures occurring within the pre-combustor and the flameless combustor catalyst module. Information provided by CESI indicates that the XONON™ Cool Combustion technology is capable of achieving CTG NO_x exhaust concentrations of 2.5 ppmvd at 15 percent O_2.

Commercial operation of the XONON™ Cool Combustion technology is limited to one small (1.5 MW) base load, natural gas-fired Kawasaki CTG operated by the Silicon Valley Power municipal utility. This CTG is located in Santa Clara, California. Performance of the XONON™ Cool Combustion technology on larger CTGs has not been demonstrated to date.

Availability of the XONON™ Cool Combustion technology is limited to specific gas turbine manufacturers which have agreements with CESI to adapt the proprietary XONON™ combustion system to gas turbines in their product lines. CESI's website indicates that General Electric Power Systems is engaged in development work to adapt the XONON™ Cool Combustion technology to their GE10 10-MW CTGs. Other CTG vendors having agreements with CESI include Solar Taurus (for the 7.5-MW Solar 70 CTG) and Kawasaki (for the 1.4-MW Kawasaki M1A-13X CTG).

The CTGs planned for the BHEC are Siemens Westinghouse 501F units. The XONON™ Cool Combustion technology is not commercially available for these units. As noted above, Siemens Westinghouse is not a current participant in the XONON™ Cool Combustion technology development program. In addition, XONON™ Cool Combustion technology has not been demonstrated on large, heavy-duty CTGs. Accordingly, the XONON™ Cool Combustion technology is not considered to be an available control technology for the Siemens Westinghouse 501F CTGs.

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. The two commercial applications of SNCR include the Electric Power Research Institute's NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either NH_3 (Thermal $DeNO_x$) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal $DeNO_x$ process are as follows:

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

$$4\ NH_3 + 5\ O_2 \rightarrow 4NO + 6\ H_2O \qquad (2)$$

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1) resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Non-Selective Catalytic Reduction

The NSCR process 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:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (3)$$

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

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F).

Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), 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 (3) and (4) 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 recently been developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. NO_x removal efficiencies for SCR systems typically range from 70 to 90 percent.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. 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.

$SCONO_x$™

$SCONO_x$™ is a NO_x and CO control system offered by ALSTOM Environmental Control Systems (ECS). The $SCONO_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The $SCONO_x$™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (5)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (6)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (7)$$

CO_2 produced by reactions (5) and (7) is released to the atmosphere as part of the CTG/HRSG exhaust stream.

As shown in reaction (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The $SCONO_x$™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4 H_2 + CO_2 \rightarrow K_2CO_3 + 4 H_2O_{(g)} + N_2 \quad (8)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CTG/HRSG exhaust stream. Following regeneration, the $SCONO_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 80 percent of the catalyst sections will be in the oxidation/absorption cycle, while 20 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 8 minutes.

The $SCONO_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For installations below 450°F, the $SCONO_x$™ system uses an inert gas generator for the production of hydrogen and CO_2. The regeneration gas is diluted to under 4 percent hydrogen using steam as a carrier gas; the typical system is designed for 2 percent hydrogen. The regeneration gas reaction is:

$$CH_4 + \tfrac{1}{2} O_2 + H_2O \rightarrow CO_2 + 3\ H_2 \qquad (9)$$

For installations above 450°F, the $SCONO_x$™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the $SCONO_x$™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the $SCONO_x$™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the $SCONO_x$™ and $SCOSO_x$™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:

$$CH_4 + 2\ H_2O \rightarrow CO_2 + 4\ H_2 \qquad (10)$$

The reformer catalyst is placed upstream of the $SCONO_x$™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

A gradual decrease in catalyst temperature is indicative of sulfur masking. ECS recommends the installation of a sulfur filter to reduce the rate of catalyst masking. The sulfur filter is placed in the inlet natural gas feed prior to the regeneration production skid. The sulfur filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a non-hazardous waste.

The $SCONO_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. As necessary, an additional catalytic oxidation/absorption system ($SCOSO_x$™) to remove sulfur compounds is installed upstream of the $SCONO_x$™ catalyst. The $SCOSO_x$™ sulfur removal catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the $SCONO_x$™ system. During regeneration of the $SCOSO_x$™ catalyst, either H_2SO_4 mist or SO_2 is released to the atmosphere as part of the CTG/HRSG exhaust gas stream. The absorption portion of the $SCOSO_x$™ process is proprietary. $SCOSO_x$™ oxidation/absorption and regeneration reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (11)$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \quad (12)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \quad (13)$$

$$[SO_3 + \text{SORBER}] + 4\,H_2 \rightarrow H_2S + 3\,H_2O + [\text{SORBER}] \quad (14)$$

(below 500°F)

$$[SO_3 + \text{SORBER}] + H_2 \rightarrow SO_2 + H_2O + [\text{SORBER}] \quad (15)$$

(above 500°F)

A programmiable logic controller controls the $SCONO_x$™/ $SCOSO_x$™ system. The controller is programmed to control all essential $SCONO_x$™/ $SCOSO_x$™ functions including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

Utility materials needed for the operation of the $SCONO_x$™/$SCOSO_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the $SCONO_x$™ control system is limited to several small CC power plants located in California. Representative of these small power plants is a GE LM2500 turbine equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low temperature $SCONO_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 parts per million by volume (ppmv) resulting in an approximate 85-percent NO_x removal efficiency. A high temperature application of $SCONO_x$™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW Solar CTG located at the Genetics Institute in Massachusetts. Following a 1 year scale-up developmental program, on December 1, 1999, ECS announced the commercial availability of the $SCONO_x$™ for large-scale natural gas-fired CTGs, particularly F-Class units. Although considered commercially available for large natural gas-fired CTGs, there are currently no CTGs larger than 5-MW that have demonstrated successful application of the high temperature $SCONO_x$™ control technology.

Technical Feasibility and Top-Case Control Alternative

All of the combustion process modification technologies mentioned (water or steam injection and standard combustor design, water or steam injection and advanced combustor design, and DLN combustor design) would be feasible for the BHEC CTG/HRSG units. 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 CTG 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 considered technically feasible due to its commercial availability. However, as noted above, there are currently no CTGs larger than 5 MW that have demonstrated successful application of the high temperature $SCONO_x$™ control technology. The CTGs planned for the BHEC, Siemens Westinghouse 501F units, have a nominal generation capacity of 170 MW. Accordingly, the BHEC CTGs are 34 times larger than the nominal 5-MW Solar CTG used at the Genetics Massachusetts facility. The Sunlaw Energy Corporation $SCONO_x$™ installation was a retrofit project; i.e., the $SCONO_x$™ system is located downstream of the HRSG. At this location, the control system operates at a lower temperature range (300 to 350°F) than a system installed within the HRSG (i.e., at a temperature range of 600 to 700°F). Technical problems associated with scale-up of the $SCONO_x$™ technology under higher temperatures remain undemonstrated under actual operating conditions. Additional concerns with $SCONO_x$™ control technology include process complexity (multiple catalytic oxidation/absorption/ regeneration systems), reliance on only one supplier, and limited application of the technology. There are no $SCONO_x$™ control systems installed as BACT in ozone attainment areas.

The BHEC CTG/HRSG units will be equipped with DLN combustor technology and SCR to reduce emissions of NO_x with an estimated NO_x control efficiency of over 90 percent. The BHEC CTG/HRSG units NO_x exhaust concentration will not exceed 2.0 ppmvd at 15 percent O_2 (on a 24-hour block average basis) for all operating scenarios, including duct burner firing and low-load operation. Use of DLN combustor technology and SCR technology to reduce NO_x emissions to 2.0 ppmvd at 15 percent O_2 from CTG/HRSG units is considered the top-case control alternative; therefore, analyses of energy, environmental, and economic impacts are not required.

Collateral Environmental Issues

Use of SCR control technology will result in NH_3 emissions due to ammonia slip. As noted above in the discussion of SCR technology, 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 resulting in unreacted NH_3 (ammonia slip) emissions. The BHEC CTG/HRSG SCR control systems will be designed to achieve the required NO_x emission reduction with a maximum ammonia slip concentration of 5 ppmvd corrected to 15 percent O_2.

NH_3 emissions are estimated to total 228.7 tpy for all four CTG./HRSG units (at baseload, 80°F ambient temperature, with inlet air fogging and HRSG DB firing) for the SCR design NH_3 slip rate of 5 ppmvd.

5.5.2 PROPOSED BACT EMISSION LIMITATIONS

Recent national BACT NO_x determinations for combustion turbine projects are provided in Attachment D.

Use of DLN combustor technology and SCR technology are proposed as BACT for NO_x for the BHEC CTG/HRSG units. These control techniques have been considered by FDEP to represent BACT for NO_x for recent CTG/HRSG projects. The BHEC CTG/HRSG units NOx exhaust concentration will not exceed 2.0 ppmvd at 15 percent O_2 (on a 24-hour block average basis) for all operating scenarios, including duct burner firing and low-load operation.

Application of combustion modifications or post-combustion NO_x control technology is not considered practical for the two small fuel gas heaters. Each fuel gas heater will emit relatively low quantities of NO_x; approximately 3.9 tpy. Use of good combustion practices is proposed as NO_x BACT for the fuel gas heaters.

Table 5-7 summarizes the NO_x BACT emission limits proposed for the BHEC.

5.6 BACT ANALYSIS FOR SO_2 AND H_2SO_4 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).

Table 5-7. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits ppmvd at 15 percent O_2	lb/hr
A. Siemens Westinghouse 501F CTGs and DBs (Per CTG/HRSG Unit)		
All Operating Scenarios	2.0	18.9*
B. Fuel Gas Heaters	Good Combustion Practices	

* CEMS 24-hour block average
† Stack test, 3-run average

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Fuel Treatment

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

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by 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 CTG/HRSG units or fuel gas heaters because low-sulfur fuels are typically used. The BHEC CTGs, HRSG DBs, and fuel gas heaters will be fired exclusively with natural gas. The sulfur content of natural gas is more than 100 times lower than the fuels (e.g., coal) employed in boilers 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 BHEC CTGs, HRSG DBs, and fuel gas heaters. The proposed BACT limits are based on the use of natural gas containing no more than 2.0 gr S/100 dscf. Table 5-8 summarizes the SO_2 and H_2SO_4 mist BACT emission limits proposed for the BHEC.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Tables 5-9 and 5-10 provide summaries of the control technologies and emission limits proposed as BACT for each pollutant subject to review, respectively.

Table 5-8. Proposed SO_2 and H_2SO_4 Mist BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits Fuel Sulfur Content (gr S/100 dscf)
CTG/HRSG Units and Fuel Gas Heaters		
	SO_2	Pipeline Quality Natural Gas (2.0 gr S/100 dscf)
	H_2SO_4 mist	Pipeline Quality Natural Gas (2.0 gr S/100 dscf)

Sources: Calpine, 2004.
ECT, 2004.

Table 5-9. Summary of BACT Control Technologies

Pollutant	Means of Control
CTGs, HRSG DBs, and Fuel Gas Heaters	
PM/PM_{10}	• Exclusive use of pipeline quality natural gas fuel • Good combustion practices
CO and VOC	• Good combustion practices • Oxidation catalyst
NO_x	• Exclusive use of pipeline quality natural gas fuel • Advanced DLN combustors and LNB • Selective catalytic reduction (SCR)
SO_2/H_2SO_4 mist	• Exclusive use of pipeline quality natural gas fuel
Cooling Towers	
PM/PM_{10}	• Efficient drift elimination

Source: ECT, 2004.

Table 5-10. Summary of Proposed BACT Emission Limitations

Pollutant	Proposed BACT Emission Limits (ppmvd @ 15% O_2)	(lb/hr)
Siemens Westinghouse 501F CTG/HRSG (per CTG/HRSG Unit)		
All Operating Scenarios		
PM/PM_{10}	≤10% opacity	
NO_x	2.0*	18.9†
CO	5.0*	16.0†
VOC	2.0†	6.0†
SO_2	Fuel ≤2.0 gr S/100 dscf	
H_2SO_4	Fuel ≤2.0 gr S/100 dscf	
Fuel Gas Heaters		
PM/PM_{10}	≤10% opacity	
NO_x	Good combustion practices	
CO	Good combustion practices	
VOC	Good combustion practices	
SO_2	Fuel ≤2.0 gr S/100 dscf	
H_2SO_4	Fuel ≤2.0 gr S/100 dscf	
Cooling Towers		
PM/PM_{10}	0.0005 percent drift loss rate	

* CEMS 24-hour block average.
† Stack test, 3-run average

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

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 dispersion modeling 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 BHEC Project will have potential emissions of 313.4 tpy NO_x, 156.6 tpy of CO, 264.2 tpy of PM, 233.4 tpy of PM_{10}, 226.0 tpy of SO_2, 101.4 tpy of VOCs, 0.02 tpy of lead, 41.4 tpy of H_2SO_4 mist, and 0.0029 tpy of mercury. Table 3-2 previously provided a comparison of estimated potential annual emission rates for the BHEC Project and the PSD significant emission rate thresholds. As shown in that table, potential emissions of NO_x, CO, PM/PM_{10}, SO_2, VOCs, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C.

The ambient impact analysis addresses NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist. Because VOCs contribute to the formation of ground-level ozone and because ozone modeling is conducted on a regional scale, modeling of ozone impacts due to BHEC VOC emissions was not conducted.

6.3 MODEL SELECTION AND USE

The latest version of EPA's Industrial Source Complex Short-Term (ISCST3) dispersion model (Julian date 02035 [February 4, 2002]), together with 5 years of hour-by-hour National Weather Service (NWS) meteorology, was used in the ambient impact analysis to obtain refined impact predictions for short-term (i.e., periods equal to or less than 24 hours) as well as long-term (i.e., annual averages) for each BHEC CTG/HRSG operating scenario. The ISCST3 model is a steady-state Gaussian plume model that can be used to assess air quality impacts over simple and complex terrain from a wide variety of sources. Also, ISCST3 is capable of calculating concentrations for averaging times ranging from 1 hour to annual.

The BHEC CTG/HRSG units will operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and optional use of inlet air fogging and duct burner firing. 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 16 BHEC CTG/HRSG operating scenarios (see Attachment C, Table C-1) was evaluated for each pollutant of concern to identify the highest air quality impact.

Procedures applicable to the ISCST3 dispersion model specified in EPA's *Guideline for Air Quality Models* (GAQM) (EPA, 2003) 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.

6.4 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.

6.5 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. 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.

U.S. Geological Survey (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. Land use within a 3-km radius of the BHEC is predominantly agricultural (i.e., tree crops and pastureland) with a residential development situated to the southeast of the site. Based on this land use, the area within a 3-km radius would be characterized as rural using the

Auer classification method. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

6.6 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 BHEC Project (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as ranging from flat to simple terrain. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted (i.e., all receptors were assumed to be at the same elevation as the CTG/HRSG stack base for modeling purposes).

6.7 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

The CAA Amendments of 1990 require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters or a height established by applying the formula:

$$Hg = H + 1.5\ L$$

where: Hg = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While 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 heights proposed for the BHEC CTG/HRSGs, fuel gas heaters, and cooling towers (150, 25, and 62 feet [ft], respectively) are each less than the *de minimis* GEP height of 65 meters (213 ft), and, therefore, comply 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 ISC3 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.

For the ambient impact analysis, the complex downwash analysis described previously was performed using the current version of EPA's Building Profile Input Program (BPIP) (Julian Date 04112 [April 22, 2004]). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. 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. A three-dimensional representation of the BHEC downwash structures is shown on Figure 6-1. BPIP output consists of an array of 36 direction-specific (10° to 360°) building heights and projected building widths for each stack suitable for use as input to the ISCST3 model.

6.8 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

Table 6-1. Building/Structure Dimensions

Facility	Elevation* (ft)	Length (ft)	Width (ft)
Inlet air filters	44	50	50
HRSG stacks	150	18.5†	N/A
HRSG	83	100	38
Demineralizer tanks (2)	37	35†	N/A
Control building	55	96	117
Warehouse	27	96	71
Water treatment building	27	96	67
Raw/fire water tank	65	92†	N/A
Cooling towers	52	432	50
Cooling tower stacks	62	28†	N/A

*Above ground surface.
†Diameter.

Source: Calpine, 2004.

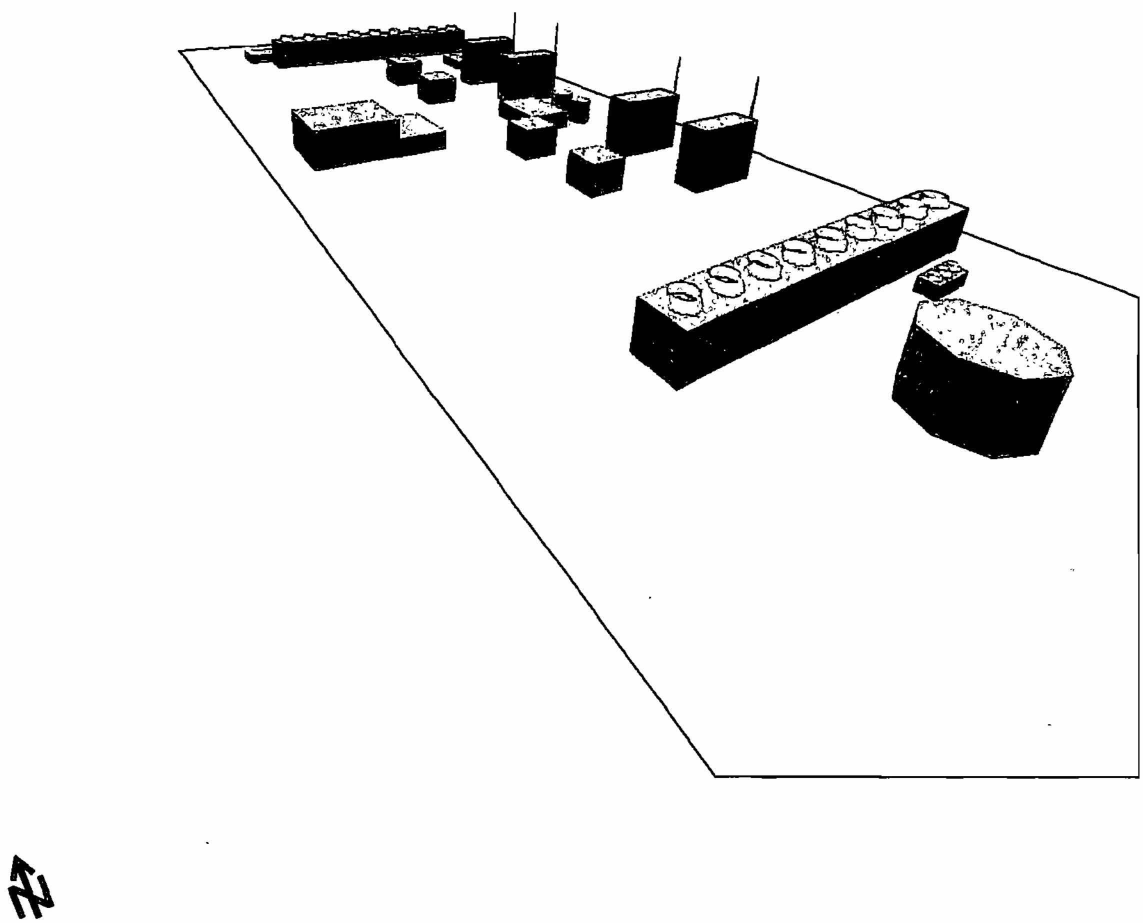

FIGURE 6-1.
DOWNWASH SCHEMATIC

Source: ECT, 2000.

CALPINE
BLUE HERON
ENERGY CENTER

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 15 rings of 36 receptors each (36 radials at 10° radial spacings) at 50-meter intervals beginning 250 meters from the receptor grid origin (Units 7 and 8 common stack) to a distance of 950 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 1,000 meters from the receptor grid origin to a distance of 1,900 meters.
- Far-field Polar receptors—Polar receptors consisting of 10 rings of 36 receptors each (36 radials at 10° radial spacings) at 1,000-meter intervals beginning 2,000 meters from the receptor grid origin to a distance of 10,000 meters.

To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°. Figure 6-2 illustrates a graphical representation of the receptor grids (out to a distance of 1 km). A depiction of the receptor grids (from 1 to 10 km) is shown in Figure 6-3.

6.9 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).

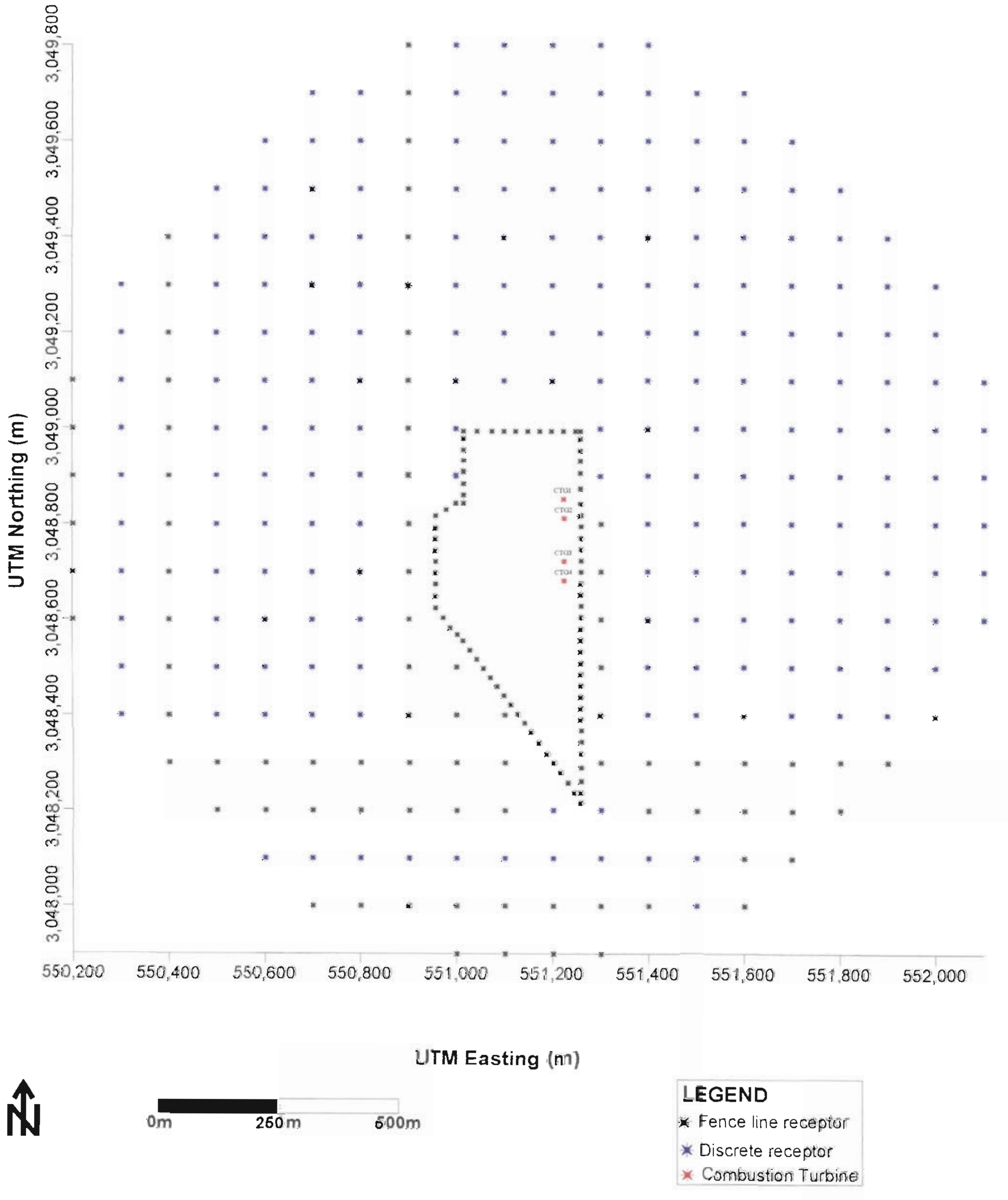

FIGURE 6-2.

RECEPTOR LOCATIONS (WITHIN 1 km)

Source: ECT, 2000.

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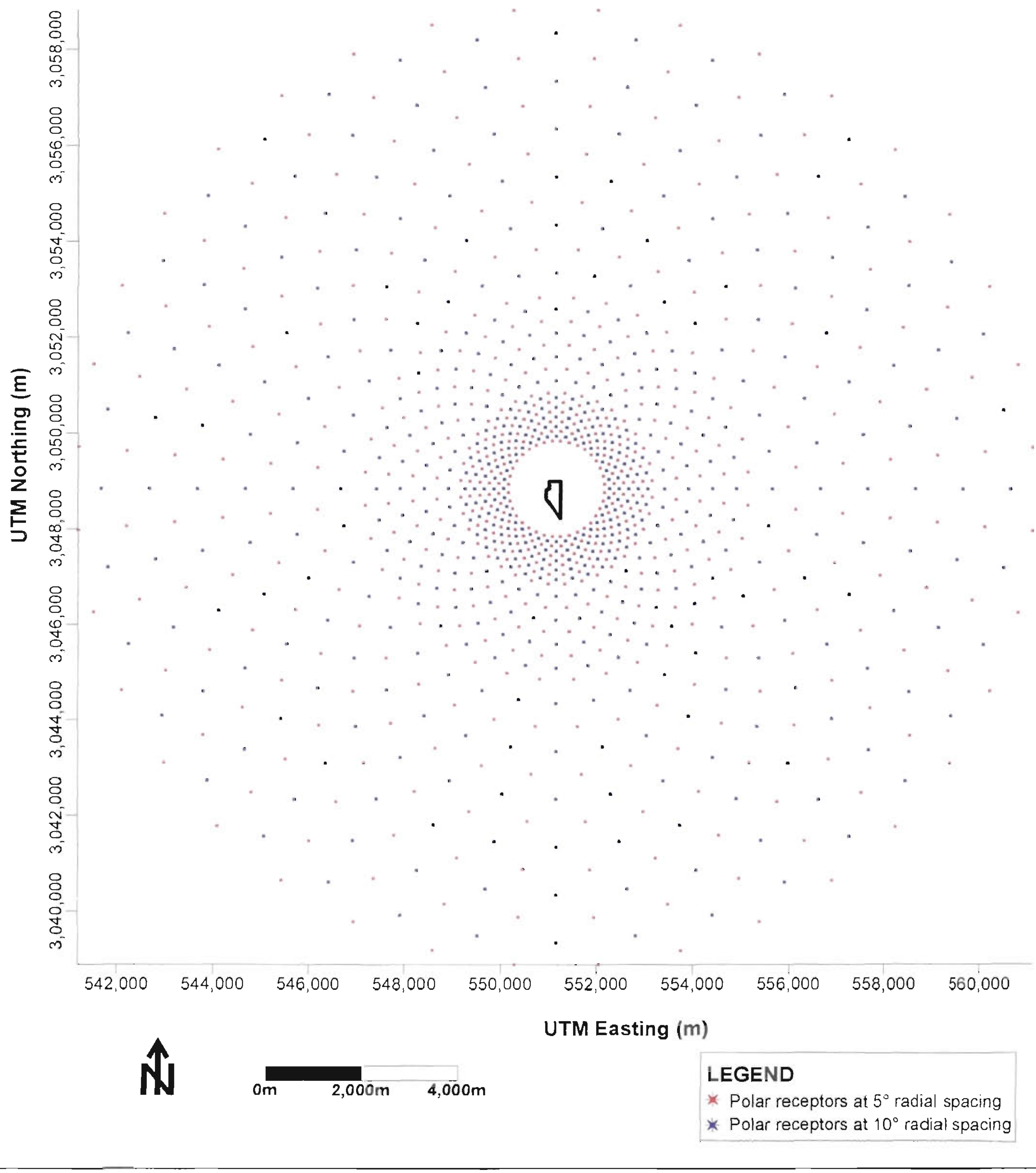

FIGURE 6-3.

RECEPTOR LOCATIONS (From 1 km to 10 km)

Source: ECT, 2000.

CALPINE BLUE HERON ENERGY CENTER

Consistent with the GAQM and FDEP guidance, 5 consecutive years of the most recent, readily available, representative meteorological data were processed for the ambient impact analysis. For Indian River County, FDEP recommends use of West Palm Beach surface and upper air meteorological data in conducting the air quality analyses. The most recent 5 years of West Palm Beach station (West Palm Beach International Airport—Station No. 12844) surface and upper air meteorological data available from EPA's Support Center for Regulatory Air Models (SCRAM) website are calendar years 1987 through 1991. Vero Beach surface data were not recommended by the FDEP because 5 consecutive years are not available.

The surface and mixing height data for each of the 5 years were processed using the current version of EPA's PCRAMMET (Julian Date 99169 [June 18, 1999]) meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model. PCRAMMET input files consist of the surface and mixing height files as obtained from the EPA SCRAM website. The mixing height file for each year must include mixing height records for December 31 of the year preceding the year of record and for January 1 of the year following the year of record. If records for these 2 days are unavailable, duplicate mixing height records are used with the year, month, and day changed appropriately.

In addition to the surface and mixing height meteorological data files, PCRAMMET requires input with respect to: (a) the use of dry or wet deposition calculations; (b) output filename; (c) output file type (UNFORM or ASCII); (d) surface data format (CD144, SAMSON, or SCRAM); and (e) latitude, longitude, and time zone of the surface meteorological station. In processing the West Palm Beach meteorological data, the NONE deposition option was selected, ASCII output file chosen, and the SCRAM surface data format utilized. As obtained from the EPA SCRAM web site, West Palm Beach station latitude and longitude coordinates (in decimal degrees) are 26.683 and 80.117, respectively. The West Palm Beach surface station is located in time zone 5.

Actual anemometer height for the West Palm Beach surface station, obtained from the National Climatic Data Center, is 33 ft (10.1 meters) for the time period of interest (i.e., 1987 through 1991).

Processing of the West Palm Beach station meteorological data did not require any data replacement or substitution.

6.10 MODELED EMISSION INVENTORY

The modeled BHEC emission sources included the four CTG/HRSG units, north and south cooling towers, and two fuel gas heaters. In addition to these emission sources, the BHEC will include one diesel fuel-fired emergency electrical generator engine and one diesel fuel-fired emergency firewater pump engine. Because of the negligible emissions associated with the infrequently operated emergency diesel internal combustion engines, these emission sources were not addressed in the ambient impact analysis. Emission rates and stack parameters for the BHEC emission sources were previously presented in Tables 2-1 through 2-11.

As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the BHEC emission sources resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods. Accordingly, additional, multi-source interactive dispersion modeling was not required.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 MAXIMUM FACILITY IMPACTS

The refined ISCST3 model was used to model each of the 16 BHEC operating cases. These cases include four ambient temperatures (20, 59, 80, and 90°F), three CTG loads (100, 60, and 35), and optional use of CTG inlet air fogging and duct burner firing. ISCST3 refined mode model results for each year of meteorology evaluated (1987 to 1991) are summarized on Table 7-1. This table shows the highest BHEC impacts for each year and each operating case.

The dispersion model results presented in Table 7-1 demonstrate that BHEC impacts, for all pollutants and all averaging times, are below the PS*D de minimis* ambient and significant impact levels previously shown in Tables 4-1 and 4-2, respectively. Table 7-2 provides a summary of maximum BHEC impacts and the PSD significant impact levels. Comparisons of BHEC emission source impacts to the national and state AAQS are also provided in Table 7-2.

7.2 PSD CLASS I IMPACTS

The nearest PSD Class I area (Everglades National Park) is located approximately 205 km south of the Project site. The Chassahowitzka National Wildlife Refuge Class I area is situated approximately 240 km to the northwest of the Project site. The BHEC CTG/HRSG units will be fired exclusively with natural gas and will include SCR control technology for abatement of NO_x emissions, and oxidation catalyst control technology to reduce CO and VOC emissions. Accordingly, Class I impacts due to emissions from the BHEC will be negligible.

7.3 CONCLUSIONS

Comprehensive dispersion modeling using the ISCST3 model demonstrates that BHEC emission sources will result in ambient air quality impacts that are below the PSD significant impact levels and *de-minimis* ambient impact levels for all pollutants and all averaging periods.

Table 7-1. Air Quality Impact Analysis Summary
Blue Heron Energy Center (Page 1 of 2)

	Case 1 (100% Load, 20°F Ambient)					Case 2 (100% Load, 20°F Ambient, DB)					Case 3 (60% Load, 20°F Ambient)					Case 4 (100% Load, 20°F Ambient, Fogging)				
	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991
SO_2																				
High, 3-Hour (μg/m^3)	6.6	10.6	4.9	5.7	13.2	7.9	12.6	5.8	6.8	15.7	8.8	12.5	6.0	6.0	12.5	6.7	10.9	5.0	5.7	13.2
High, 24-Hour (μg/m^3)	2.6	2.3	1.5	3.4	2.6	3.1	2.8	1.7	4.0	3.1	3.0	3.0	2.1	3.8	3.0	2.8	2.4	1.5	3.5	2.7
Annual (μg/m^3)	0.09	0.09	0.10	0.11	0.11	0.11	0.11	0.12	0.13	0.13	0.16	0.11	0.19	0.22	0.18	0.09	0.09	0.10	0.11	0.11
NO_2																				
Tier 1 Annual (μg/m^3)	0.64	0.68	0.66	0.81	0.66	0.64	0.68	0.66	0.81	0.66	0.66	0.69	0.69	0.83	0.68	0.65	0.68	0.66	0.82	0.66
Tier 2 Annual (μg/m^3)	0.48	0.51	0.50	0.61	0.50	0.48	0.51	0.50	0.61	0.50	0.49	0.52	0.52	0.62	0.51	0.48	0.51	0.50	0.61	0.50
PM/PM_{10}																				
High, 24-Hour (μg/m^3)	2.2	2.1	1.3	2.9	2.2	3.2	3.1	1.9	4.3	3.3	2.6	2.8	2.1	3.6	2.7	2.3	2.2	1.6	3.0	2.3
Annual (μg/m^3)	0.09	0.08	0.10	0.12	0.10	0.12	0.11	0.13	0.14	0.13	0.17	0.13	0.21	0.23	0.20	0.10	0.08	0.12	0.13	0.11
CO																				
High, 1-Hour (μg/m^3)	55.3	49.8	36.1	38.0	91.2	103.9	93.7	67.9	71.9	172.0	310.7	280.2	212.7	223.1	**414.7**	57.5	51.7	37.9	37.2	90.9
High, 8-Hour (μg/m^3)	16.9	22.6	15.1	19.3	24.8	31.7	42.5	27.7	36.4	45.9	87.5	130.8	78.8	105.1	121.9	17.2	23.1	15.0	19.4	24.9

	Case 5 (100% Load, 20°F Ambient, Fogging, DB)					Case 6 (100% Load, 59°F Ambient)					Case 7 (60% Load, 59°F Ambient)					Case 8 (100% Load, 80°F Ambient, Fogging)				
	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991
SO_2																				
High, 3-Hour (μg/m^3)	8.1	13.0	6.0	6.9	15.9	6.7	10.8	5.0	5.7	13.1	8.8	12.6	6.2	6.1	12.2	6.8	11.1	5.1	5.8	13.1
High, 24-Hour (μg/m^3)	3.3	2.9	1.8	4.2	3.3	2.7	2.4	1.5	3.5	2.7	3.0	3.0	2.3	3.9	3.1	2.8	2.4	1.5	3.5	2.7
Annual (μg/m^3)	0.11	0.11	0.12	0.13	0.13	0.09	0.11	0.10	0.22	0.11	0.18	0.12	0.21	0.24	0.20	0.09	0.09	0.10	0.11	0.11
NO_2																				
Tier 1 Annual (μg/m^3)	0.65	0.68	0.67	0.82	0.67	0.65	0.68	0.66	0.82	0.66	0.66	0.69	0.70	0.84	0.69	0.65	0.68	0.66	0.82	0.67
Tier 2 Annual (μg/m^3)	0.48	0.51	0.50	0.61	0.50	0.48	0.51	0.50	0.61	0.50	0.50	0.52	0.53	0.63	0.51	0.48	0.51	0.50	0.61	0.50
PM/PM_{10}																				
High, 24-Hour (μg/m^3)	3.5	3.3	2.3	4.6	3.5	2.3	2.2	1.6	3.0	2.3	2.6	2.8	2.3	3.6	2.7	2.3	2.2	1.6	3.1	2.3
Annual (μg/m^3)	0.12	0.12	0.14	0.17	0.14	0.10	0.08	0.12	0.13	0.11	0.18	0.14	0.23	0.25	0.21	0.10	0.08	0.12	0.13	0.11
CO																				
High, 1-Hour (μg/m^3)	111.5	100.3	73.5	72.6	176.9	57.2	51.4	37.8	36.7	57.2	310.2	279.9	213.7	228.0	402.5	57.5	51.7	38.2	36.8	88.4
High, 8-Hour (μg/m^3)	33.3	44.8	28.4	37.7	47.6	17.1	22.9	14.9	19.1	17.1	86.7	**132.0**	80.9	105.5	121.3	17.0	23.1	14.7	19.2	24.5

Table 7-1. Air Quality Impact Analysis Summary
Blue Heron Energy Center (Page 2 of 2)

	Case 9 (100% Load, 80°F Ambient, Fogging, DB)					Case 10 (100% Load, 59°F Ambient)					Case 11 (60% Load, 59°F Ambient)					Case 12 (100% Load, 90°F Ambient, Fogging)				
	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991
SO_2																				
High, 3-Hour (µg/m^3)	8.2	13.3	6.1	6.9	15.8	6.8	11.2	5.1	5.8	13.1	8.7	12.5	6.1	6.0	11.9	6.8	11.3	5.1	5.8	13.1
High, 24-Hour (µg/m^3)	3.3	2.9	1.8	4.2	3.3	2.8	2.6	1.7	3.5	2.8	2.9	2.9	2.2	3.8	3.0	2.8	2.6	1.7	3.5	2.8
Annual (µg/m^3)	0.11	0.11	0.12	0.13	0.13	0.09	0.09	0.10	0.12	0.11	0.18	0.12	0.21	0.24	0.20	0.09	0.09	0.10	0.12	0.11
NO_2																				
Tier 1 Annual (µg/m^3)	0.65	0.68	0.67	0.82	0.67	0.65	0.68	0.67	0.82	0.67	0.66	0.69	0.70	0.84	0.69	0.65	0.68	0.67	0.82	0.67
Tier 2 Annual (µg/m^3)	0.48	0.51	0.50	0.61	0.50	0.48	0.51	0.50	0.61	0.50	0.50	0.52	0.53	0.63	0.52	0.48	0.51	0.50	0.61	0.50
PM/PM_{10}																				
High, 24-Hour (µg/m^3)	3.5	3.4	2.3	4.7	3.6	2.3	2.4	1.6	3.1	2.3	2.6	2.8	2.3	3.6	2.7	2.3	2.4	1.6	3.1	2.3
Annual (µg/m^3)	0.13	0.12	0.15	0.17	0.14	0.11	0.09	0.14	0.16	0.13	0.18	0.14	0.23	0.25	0.21	0.11	0.09	0.14	0.16	0.13
CO																				
High, 1-Hour (µg/m^3)	114.5	102.9	75.8	72.8	177.2	58.2	52.4	38.7	37.7	88.2	304.2	274.6	210.3	226.2	389.2	58.2	52.4	38.7	37.7	88.2
High, 8-Hour (µg/m^3)	33.8	45.8	28.6	38.2	48.0	17.2	23.5	14.8	19.4	24.5	85.7	130.1	80.7	103.7	118.8	17.2	23.5	14.8	19.4	24.5

	Case 13 (100% Load, 90°F Ambient, Fogging, DB)					Case 14 (100% Load, 90°F Ambient)					Case 15 (60% Load, 90°F Ambient)					Case 16 (35% Load, 86°F Ambient)				
	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991	1987	1988	1989	1990	1991
SO_2																				
High, 3-Hour (µg/m^3)	8.3	13.7	6.2	7.0	**16.0**	6.9	6.7	4.5	5.0	6.4	8.8	7.3	5.6	5.4	6.0	8.9	7.1	5.6	5.3	6.5
High, 24-Hour (µg/m^3)	3.4	3.2	2.1	**4.3**	3.4	2.8	2.6	1.7	3.6	2.8	3.0	3.0	2.3	3.9	3.1	2.8	3.0	2.5	3.8	3.1
Annual (µg/m^3)	0.11	0.11	0.12	0.14	0.13	0.09	0.09	0.10	0.13	0.11	0.20	0.14	0.24	0.26	0.23	0.24	0.18	0.28	**0.31**	0.27
NO_2																				
Tier 1 Annual (µg/m^3)	0.65	0.68	0.67	0.82	0.67	0.65	0.68	0.67	0.82	0.67	0.67	0.70	0.71	0.84	0.69	0.68	0.71	0.74	0.87	0.73
Tier 2 Annual (µg/m^3)	0.49	0.51	0.50	0.61	0.50	0.49	0.51	0.50	0.62	0.50	0.50	0.52	0.53	0.63	0.52	0.51	0.54	0.56	**0.65**	0.55
PM/PM_{10}																				
High, 24-Hour (µg/m^3)	3.6	3.6	2.3	**4.8**	3.6	2.3	2.4	1.6	3.1	2.3	2.6	2.8	2.3	3.6	2.7	2.6	3.0	2.5	3.7	2.8
Annual (µg/m^3)	0.11	0.12	0.16	0.20	0.16	0.18	0.09	0.14	0.16	0.13	0.11	0.15	0.25	0.26	0.23	0.22	0.18	0.29	**0.30**	0.27
CO																				
High, 1-Hour (µg/m^3)	118.1	106.2	78.6	76.2	179.6	59.3	53.3	39.6	38.9	88.2	305.7	275.9	212.4	229.3	386.9	146.2	135.9	108.1	119.4	166.8
High, 8-Hour (µg/m^3)	34.7	47.5	30.1	39.4	49.0	17.4	24.0	14.9	19.8	24.7	87.4	131.2	82.1	104.4	119.2	49.1	65.1	44.6	50.8	56.9

Source: ECT, 2004.

Table 7-2. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

A. BHEC Impacts Compared to PSD Significant Impacts

Pollutant	Averaging Time	Maximum Impact (μg/m^3)	Significant Impact (μg/m^3)	Exceed Significant Impact (Y/N)
NO_2	Annual	0.65	1	N
SO_2	Annual	0.31	1	N
	24-hour	4.3	5	N
	3-hour	16.0	25	N
PM_{10}	Annual	0.30	1	N
	24-hour	4.8	5	N
CO	8-hour	132.0	500	N
	1-hour	414.7	2,000	N

B. BHEC Impacts Compared to AAQS

Pollutant	Averaging Time	Maximum Impact (μg/m^3)	AAQS (μg/m^3)	Percent of AAQS (%)
NO_2	Annual	0.65	100	0.6
SO_2	Annual	0.31	80 (NAAQS)	0.4
			60 (FAAQS)	0.5
	24-hour*	3.0	365 (NAAQS	0.8
			260 (FAAQS)	1.2
	3-hour*	7.7	1,300	0.6
PM_{10}	Annual	0.30	50	0.6
	24-hour*	3.3	150	2.2
$PM_{2.5}$	Annual	0.30	15	2.0
	24-hour*	3.3	65	5.0
CO	8-hour*	81.8	10,000	0.8
	1-hour*	332.3	40,000	0.8

* Highest, second highest

Source: ECT, 2004.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring stations to the BHEC are located in Fort Pierce, St. Lucie County, approximately 18 km southeast of the project site. The FDEP monitoring stations in Fort Pierce monitor for PM_{10}, $PM_{2.5}$, NO_2, and ozone. The nearest FDEP station that monitors for CO is located in Palm Beach, approximately 102 km southeast of the project site. The nearest FDEP station that monitors for SO_2 is located in Riviera Beach, Palm Beach County, approximately 95 km southeast of the project site. Summaries of 2002 and 2003 ambient air quality data for these FDEP ambient air quality monitoring stations are provided in Tables 8-1 and 8-2.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 4.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several pollutants will be emitted from the BHEC in excess of their respective significant emission rates, preconstruction monitoring is required. However, the FDEP Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 4-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the proposed BHEC. The results of these analyses are presented in detail in Section 7.1. 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 4.8 micrograms per cubic meter ($\mu g/m^3$). This concentration is below the 10 $\mu g/m^3$ *de minimis* level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring stations to the BHEC are located in Fort Pierce, St. Lucie County, approximately 18 km southeast of the project site. The FDEP monitoring stations in Fort Pierce monitor for PM_{10}, $PM_{2.5}$, NO_2, and ozone. The nearest FDEP station that monitors for CO is located in Palm Beach, approximately 102 km southeast of the project site. The nearest FDEP station that monitors for SO_2 is located in Riviera Beach, Palm Beach County, approximately 95 km southeast of the project site. Summaries of 2002 and 2003 ambient air quality data for these FDEP ambient air quality monitoring stations are provided in Tables 8-1 and 8-2.

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8.2.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 4.8 micrograms per cubic meter ($\mu g/m^3$). This concentration is below the 10 $\mu g/m^3$ *de minimis* level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

Table 8-1. Summary of 2002 FDEP Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site No.	Location Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration ($\mu g/m^3$): 1st High	2nd High	98th Percentile	Arithmetic Mean	Standard
PM_{10}	St. Lucie	Ft. Pierce	12-111-0012	21 SE	24-Hr	Jan-Dec	97	37	34			150[1]
					Annual						18	50[2]
			12-111-1002	15 SE	24-Hr	Jan-Dec	100	55	38			150[1]
					Annual						19	50[2]
$PM_{2.5}$	St. Lucie	Ft. Pierce	12-111-1002	21 SE	24-Hr	Jan-Dec	117	21.1	17.8	16.9		65[3]
					Annual						8	15[2]
SO_2	Palm Beach	Riviera Beach	12-099-3004	138 SE	1-Hr	Jan-Dec	8,670	52	18			
					3-Hr			21	13			1,300[4]
					24-Hr			5	5			260[4]
					Annual						3	60[2]
NO_2	St. Lucie	Ft. Pierce	12-111-1002	15 SE	1-Hr	Jan-Dec	8,671	109	109			
					Annual						19	100[2]
CO	Palm Beach	Palm Beach	12-099-1004	104 SE	1-Hr	Jan-Dec	8,327	4,485	4,370			40,000[4]
					8-Hr			3,795	2,645			10,000[4]
Ozone	St. Lucie	Ft. Pierce	12-111-1002	15 SE	1-Hr	Jan-Dec	245 (Days)	159	153			235[5]
					8-Hr	Jan-Dec	100	147	124			156[5]

[1] 99th percentile.
[2] Arithmetic mean.
[3] 98th percentile.
[4] 2nd high.
[5] 4th highest day with hourly value exceeding standard over a 3-year period.

Sources: FDEP, 2004.
ECT, 2004.

Table 8-2. Summary of 2003 FDEP Ambient Air Quality Data

Pollutant	Site Location		Site No.	Location Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration ($\mu g/m^3$)				
	County	City						1st High	2nd High	98th Percentile	Arithmetic Mean	Standard
PM_{10}	St. Lucie	Ft. Pierce	12-111-0012	15 SE	24-Hr	Jan-Dec	8,297	65	43			150[1]
					Annual						16.9	50[2]
$PM_{2.5}$	St. Lucie	Ft. Pierce	12-111-1002	15 SE	24-Hr	Jan-Dec	117	22.5	22.0	18.0		65[3]
					Annual						8	15[2]
SO_2	Palm Beach	Riviera Beach	12-099-3004	138 SE	1-Hr	Jan-Dec	7,903	21	13			
					3-Hr			10	8			1,300[4]
					24-Hr			5	5			260[4]
					Annual						3	60[2]
NO_2	St. Lucie	Ft. Pierce	12-111-1002	15 SE	1-Hr	Jan-Dec	7,325	96	96			
					Annual						17	100[2]
CO	Palm Beach	Palm Beach	12-099-1004	104 SE	1-Hr	Jan-Dec	8,559	3,450	3,105			40,000[4]
					8-Hr			2,070	1,840			10,000[4]
Ozone	St. Lucie	Ft. Pierce	12-111-1002	15 SE	1-Hr	Jan-Dec	245 (Days)	159	149			235[5]
					8-Hr	Jan-Dec	100	139	139			156[5]

[1] 99th percentile.
[2] Arithmetic mean.
[3] 98th percentile.
[4] 2nd high.
[5] 4th highest day with hourly value exceeding standard over a 3-year period.

Sources: FDEP, 2004.
ECT, 2004.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 132.0 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 in accordance with the PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.7 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 NO_2 in accordance with the FDEP PSD regulations.

8.2.4 SO_2

The maximum 24-hour SO_2 impact was predicted to be 4.3 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 SO_2 in accordance with the FDEP PSD regulations.

8.2.5 OZONE

Preconstruction monitoring for ozone is required if potential VOC emissions from a project subject to PSD review exceed 100 tpy. Because potential VOC emissions from the BHEC will exceed this threshold, current (2002 and 2003) quality-assured ambient ozone data collected at the FDEP's ozone monitoring site located in Fort Pierce, St. Lucie County, was used to satisfy the PSD preconstruction ambient air monitoring requirements for ozone.

9.0 ADDITIONAL IMPACT ANALYSES

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

9.1 GROWTH IMPACT ANALYSIS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed Project and to assess air quality impacts that would result from that growth.

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

The BHEC is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the BHEC are anticipated. When operational, the BHEC is projected to generate approximately 36 new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas fuel demand due to operation of the BHEC 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 SOIL, VEGETATION, AND WILDLIFE

Although any additional increases in pollutant levels resulting from a specific emissions source conceivably could have some impact on air quality related values (AQRVs), it is important to evaluate the level of any expected increase. At the BHEC, the highest predicted SO_2 concentration increases due to the power plant are a 3-hour concentration of 16.0 $\mu g/m^3$, a 24-hour concentration of 4.3 $\mu g/m^3$, and an annual average concentration of 0.31 $\mu g/m^3$. The predicted concentrations of other pollutants are equally low. For instance, the highest modeled annual average NO_2 concentration increase due to the power plant emissions is 0.65 μg/m^3. Based upon these small, predicted concentration increases, no adverse effect on AQRVs is expected within the vicinity of the plant site. This conclusion is based upon the following evaluation of possible effects of the target pollutants on soil, vegetation, and wildlife in the region.

9.2.1 IMPACTS ON SOIL

Emissions of SO_2 and NO_x have the potential to impact soils due to wet and dry deposition of these pollutants. Adsorption by soils of this deposition will result in a lowering of soil pH. Low soil pH will have an influence on most chemical and biological reactions in soil including the level and availability of most plant nutrients in the soil. SO_2 when absorbed by the soil, is primarily converted to sulfite and sulfate; however some may also be converted to organic sulfur. NO_x absorbed by the soil is likewise converted to nitrite and nitrates. Sulfates and nitrates caused by SO_2 and NO_x deposition on soil can have beneficial effects to soil if they are currently lacking. Based on the extremely low maximum incremental and total SO_2 and NO_x impacts predicted and the ambient acidic nature of the soils, no impacts to soils resources at the plant Site or the vicinity are expected.

9.2.2 IMPACTS ON VEGETATION

As described in Section 2.3.5 of the SCA, the vegetation on the proposed power plant Site consists of natural vegetation represented by pine flatwoods with scattered oaks and a palmetto understory, a small cabbage palm forest, a mixed hardwood wetland forest and a fresh water marsh. The land use in the immediate area surrounding the BHEC area is a combination of natural and agricultural vegetation and developed land. The natural vegetation in the immediate vicinity consists of pine flatwoods. Agricultural uses include active and abandoned citrus groves and pasturelands. The developed land includes I-95 to the west and southwest of the Site; a correctional institution, single-family residence, and lateral canals to the north; and a sprayfield and mobile home development to the east.

Potential impacts to vegetation from SO_2, acid rain, NO_x, and CO have been evaluated with respect to dose response curves that have been developed for various plant species and their sensitivity to these pollutants. Vegetation damages are described as impacts, which result in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage as well as changes in secondary metabolites such as tannin and phenolic compounds. Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses of relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages are usually manifested by internal physical damage to foliar tissues which have both functional and visible consequences. Chronic injuries are typically more associated with changes in physiological processes. The following discussion summarizes descriptions from the literature of the effects upon vegetation associated with the pollutants of concern with the proposed power plant project.

<u>SO_2</u>

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

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

Because of relative low chlorophyll content and the absence of a protective covering of the cuticle common in the leaves of higher plants, nonvascular plants such as lichens and bryophytes are relatively more sensitive to SO_2 injury. This injury has been documented on those primitive plants at levels as low as 88 $\mu g/m^3$ (U.S. Department of Health, Education, and Welfare, 1971). Hart *et al.* (1976) showed that *Ramalina* spp., a lichen genus exhibited a reduction of CO_2 uptake and biomass gain at SO_2 exposures of 400 $\mu g/m^3$ for 6 weeks. Tolerant lichens can resist SO_2 concentrations in the range of 79 to 157 $\mu g/m^3$; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975).

The maximum total 3-hour average SO_2 concentrations for the BHEC is projected to be 16.0 $\mu g/m^3$. The maximum total predicted 24-hour average SO_2 concentration is 4.3 $\mu g/m^3$. Annually, the concentration is predicted to be 0.31 $\mu g/m^3$. All of these estimates are lower than doses known to cause vegetative injury.

H_2SO_4 Mist

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

Since the concentration of H_2SO_4 mist from the proposed BHEC is directly dependent upon the availability of SO_2 and SO_2 concentrations are predicted to be well below levels which have been documented as negatively affecting vegetation, no impacts from H_2SO_4 mist are expected. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentration of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well publicized (decline of confer forests in the Appalachians), documented detrimental effects of acid rain on Florida vegetation is lacking (Gholz, 1985; Charles, 1991).

NO_x

During combustion, atmospheric nitrogen is oxidized to NO and small amounts of NO_2 (Taylor *et al.*, 1975). The NO is photochemically oxidized to NO_2, which, in turn is subsequently consumed in the production of ozone and peroxyacetyl nitrate (PAN). The ozone and PAN products have deleterious effects upon vegetation as air pollutants; impacts to vegetation from NO_2 only occur where spillage releases high concentrations during short time periods (Taylor and MacLean, 1970). Spills of this sort will cause necrotic lesions in leaf tissue and excessive defoliation (MacLean *et al.*, 1968). Short-term (acute) exposures of NO_2 of less than 1,880 $\mu g/m^3$ for 1 hour have not caused adverse effects (Taylor *et al.*, 1975). The maximum annual average NO_2 concentrations for the BHEC is 0.65 $\mu g/m^3$. This is well below that reported to cause injury to vegetation.

Synergism (SO_2-NO_x)

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

Recalling that NO_2 emissions are implicated in vegetation impacts based upon conversion to phytotoxic ozone and PANs, the appropriate synergistic reactions involve SO_2-ozone and SO_2-PAN. Typically, injury thresholds for susceptible plants approximate the injury thresholds as reported for SO_2 previously (Reinert *et al.*, 1975).

CO

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

9.2.3 IMPACTS ON WILDLIFE

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

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

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

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

Visibility Impairment Potential

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

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ATTACHMENT A

FDEP APPLICATION FOR AIR PERMIT – LONG FORM

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Blue Heron Energy Center, L.L.C.**	
2. Site Name: **Blue Heron Energy Center**	
3. Facility Identification Number: **0610082**	
4. Facility Location Street Address or Other Locator: **SW 74th Avenue** City: **5 Miles SW of Vero Beach** County: **Indian River** Zip Code: **32968**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: **Benjamin Borsch**
2. Application Contact Mailing Address... Organization/Firm: **Calpine Corporation** Street Address: **2707 North Rocky Point Drive, Suite 1200** City: **Tampa** State: **Florida** Zip Code: **33607**
3. Application Contact Telephone Numbers... Telephone: **(813) 637 - 7305** ext. Fax: **(813) 637 – 7399**
4. Application Contact Email Address: **bborsch@calpine.com**

Application Processing Information (DEP Use)

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

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

[x] Air construction permit.

Air Operation Permit

[ ] Initial Title V air operation permit.

[ ] Title V air operation permit revision.

[ ] Title V air operation permit renewal.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

[ ] Air construction permit and Title V permit revision, incorporating the proposed project.

[ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

[ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Blue Heron Energy Center, L.L.C. (Calpine) is planning to construct and operate a new electric power generating plant in Indian River County, Florida. The new power plant, designated as the Blue Heron Energy Center (BHEC), will be a natural gas-fired combustion turbine generator (CTG)-based combined cycle (CC) facility with a nominal generating capacity of 1,080 megawatts (MW). The BHEC is being licensed under the Florida Electrical Power Plant Siting Act.

The BHEC will consist of four nominal 170-MW Siemens Westinghouse 501F CTGs, four heat recovery steam generators (HRSGs) equipped with supplemental duct burners (DBs), and two nominal 200-MW steam turbine generators (STGs); i.e., two "2 by 2 by 1" configurations. The CTGs will include provisions for inlet air fogging. The BHEC will have a total nominal generation capacity of 1,080 MW. Ancillary equipment includes two mechanical draft cooling towers (north and south ten-cell towers), two fuel gas heaters, one emergency electric generator diesel engine, one emergency fire water pump diesel engine, and water treatment and storage facilities. The CTGs, DBs, and fuel gas heaters will all be fired exclusively with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred dry standard cubic feet (gr S/100 dscf).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	CTG/HRSG Unit No. 1	AC1A	N/A
002	CTG/HRSG Unit No. 2	AC1A	N/A
003	CTG/HRSG Unit No. 3	AC1A	N/A
004	CTG/HRSG Unit No. 4	AC1A	N/A
005	North Fresh Water Cooling Tower	AC1A	N/A
006	South Fresh Water Cooling Tower	AC1A	N/A
007	East Fuel Gas Heater	AC1A	N/A
008	West Fuel Gas Heater	AC1A	N/A

Application Processing Fee

Check one: ☐ Attached - Amount: $__________ ☒ Not Applicable

Note: Application processing fee submitted pursuant to the FPPSA.

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name : **Timothy R. Eves**	
2. Owner/Authorized Representative Mailing Address... Organization/Firm: **Blue Heron Energy Center, L.L.C.** Street Address: **2701 N. Rocky Point Drive, Suite 1200** City: **Tampa** State: **FL** Zip Code: **33607**	
3. Owner/Authorized Representative Telephone Numbers... Telephone: **(813)637-7303** ext. Fax: **(813)637-7399**	
4. Owner/Authorized Representative Email Address: **timeeves@calpine.com**	

5. Owner/Authorized Representative Statement:

I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.

TR Eves
Signature

12/15/04
Date

APPLICATION INFORMATION

Application Responsible Official Certification N/A

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - [ ] For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - [ ] For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - [ ] For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - [ ] The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) –

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   Signature Date

APPLICATION INFORMATION

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: **Florida** Zip Code: **32606-5004**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332 – 0444** ext. Fax: **(352) 332 - 6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.com**
5.	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.

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here [X], if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal 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.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal 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

December 15, 2004
Date

(seal)

*Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **551.2** North (km) **3,048.7**		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 :			

Facility Contact

1. Facility Contact Name: **Timothy R. Eves**
2. Facility Contact Mailing Address... Organization/Firm: **Calpine Corporation** Street Address: **2707 North Rocky Point Drive, Suite 1200** City: **Tampa** State: **Florida** Zip Code: **33607**
3. Facility Contact Telephone Numbers: Telephone: **(813) 637 - 7303** ext. Fax: **(813) 637 – 7399**
4. Facility Contact Email Address: **teves@calpine.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Application Responsible Official Telephone Numbers... Telephone: ( ) – ext. Fax: ( ) –
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. [ ] Small Business Stationary Source		[ ] Unknown
2. [ ] Synthetic Non-Title V Source		
3. [x] Title V Source		
4. [x] Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)		
5. [ ] Synthetic Minor Source of Air Pollutants, Other than HAPs		
6. [ ] Major Source of Hazardous Air Pollutants (HAPs)		
7. [ ] Synthetic Minor Source of HAPs		
8. [x] One or More Emissions Units Subject to NSPS (40 CFR Part 60)		
9. [ ] One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)		
10. [ ] One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)		
11. [ ] Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))		
12. Facility Regulatory Classifications Comment: **CTGs are subject to New Source Performance Standard (NSPS) Subject GG. DBs are subject to NSPS Subpart Da.**		

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NO_x	**A**	**N**
CO	**A**	**N**
VOC	**B**	**N**
SO_2	**A**	**N**
PM	**B**	**N**
PM_{10}	**A**	**N**
SAM	**B**	**N**
NH_3	**B**	**N**

FACILITY INFORMATION

N/A

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: **Fig 2-3** [ ] Previously Submitted, Date:______
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: **Fig 2-4** [ ] Previously Submitted, Date:______
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: **A-1** [ ] Previously Submitted, Date:______

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: [x] Attached, Document ID: **Fig 2-1** [ ] Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: [x] Attached, Document ID: **Section 2-2**
3. Rule Applicability Analysis: [x] Attached, Document ID: **A-2**
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): [x] Attached, Document ID: **A-3** [ ] Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): [ ] Attached, Document ID:________ [x] Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): [x] Attached, Document ID: **Section 8-2** [ ] Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): [x] Attached, Document ID: **Section 7** [ ] Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): [x] Attached, Document ID: **Section 7** [ ] Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): [x] Attached, Document ID: **Section 9** [ ] Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:________ [x] Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

N/A

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_______ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

N/A

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:_______ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:_______ ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:_______ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID: _______ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:_________ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:_________ ☐ Not Applicable

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [x] 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.

Emissions Unit Description and Status

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

   [x] 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. Description of Emissions Unit Addressed in this Section:
Combined cycle unit comprised of one nominal 170-MW Siemens Westinghouse 501F combustion turbine generator (CTG) and one heat recovery steam generator (HRSG) equipped with a 289 MMBtu/hr duct burner (DB). The CTG and HRSG DB are both fired exclusively with pipeline quality natural gas.

3. Emissions Unit Identification Number: **001 (CTG/HRSG Unit 1)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	[x] Yes [ ] No

9. Package Unit:
Manufacturer: **Siemens Westinghouse** Model Number: **501F**

10. Generator Nameplate Rating: **170 MW (nominal)**

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry Low-NO_x (DLN) Combustion – CTG** **Low-NO_x Burners (LNB) – HRSG DB** **Selective Catalytic Reduction (SCR) – CTG/HRSG** **Oxidation Catalyst– CTG/HRSG**	
2. Control Device or Method Code(s): **025 (DLN), 205 (LNB), 139 (SCR), 080 (CatOx)**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **2,031** million Btu/hr **(HHV) – CTG**	
4. Maximum Incineration Rate: pounds/hr **N/A** tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum CTG heat input at 20°F (Case 1). CTG heat input will vary with ambient conditions, load, and optional use of inlet air fogging. Maximum heat input for DBs is 430 MMBtu/hr (HHV).**	

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CTG-1**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **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: **150** feet	7. Exit Diameter: **18.5** feet
8. Exit Temperature: **165°F**	9. Actual Volumetric Flow Rate: **1,048,679** acfm	10. Water Vapor: **N/A** %

11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :
15. Emission Point Comment: **Stack parameters are at 100% load, 59°F ambient temperature with inlet air fogging (Case 4).**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine generator fired with pipeline-quality natural gas.**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **2.136**	5. Maximum Annual Rate: **18,711**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,050 (HHV)**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Duct burner fired with pipeline-quality natural gas.**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.407**	5. Maximum Annual Rate: **3,565**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,050 (HHV)**
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x	025, 205	139	EL
CO	080		EL
VOC	080		EL
SO_2			EL
PM			EL
PM_{10}			EL
SAM			EL
NH_3			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **92**
3. Potential Emissions: **18.9** lb/hour **75.3** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **N/A** Reference: **Vendor Data**	7. Emissions Method Code: **2**

8. Calculation of Emissions:

Potential Hourly Emissions:
100% load, 20°F ambient, DB (Case 2)

Potential Annual Emissions:
100% load, 80°F ambient, inlet air fogging & DB (8,760 hr/yr) (Case 9)

$$17.2 \frac{lb}{hr} \times 8{,}760 \frac{hr}{yr} \times \frac{ton}{2{,}000\ lb} = 75.3 \frac{ton}{yr}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **2.0 ppmvd @ 15-percent oxygen**	4. Equivalent Allowable Emissions: **18.9** lb/hour **75.3** tons/year
5. Method of Compliance: **CEMS 24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **90**
3. Potential Emissions: **16.0** lb/hour **37.2** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **N/A** Reference: **Vendor Data**	7. Emissions Method Code: **2**

8. Calculation of Emissions:

Potential Hourly Emissions:
60% load, 20°F ambient (Case 3)

Potential Annual Emissions:
100% load, 80°F ambient, inlet air fogging & DB (8,760 hr/yr) (Case 9)

$$8.5\frac{lb}{hr}\times 8{,}760\frac{hr}{yr}\times\frac{ton}{2{,}000\ lb}=37.2\ \frac{ton}{yr}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: **5.0 ppmvd @ 15-percent oxygen**	4. Equivalent Allowable Emissions: **16.0** lb/hour **37.2** tons/year
5. Method of Compliance: **CEMS 24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **50**
3. Potential Emissions: **6.0** lb/hour **25.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **N/A** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Potential Hourly Emissions:** 100% load, 20°F ambient, DB (Case 2) **Potential Annual Emissions:** 100% load, 80°F ambient, inlet air fogging & DB (8,760 hr/yr) (Case 9) $5.8\frac{lb}{hr}\times 8{,}760\frac{hr}{yr}\times\frac{ton}{2{,}000\ lb}=25.4\frac{ton}{yr}$	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: **2.0 ppmvd @ 15-percent oxygen**	4. Equivalent Allowable Emissions: **6.0** lb/hour **25.4** tons/year
5. Method of Compliance: **EPA Reference Methods 18, 25, and/or 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **14.2** lb/hour **56.3** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **N/A** Reference: **Vendor Data**	7. Emissions Method Code: **2**

8. Calculation of Emissions:

Potential Hourly Emissions:
100% load, 20°F ambient, DB (Case 2)

Potential Annual Emissions:
100% load, 80°F ambient, inlet air fogging & DB (8,760 hr/yr) (Case 9)

$$2.251\times10^6 \frac{cf}{hr}\times 8{,}760\frac{hr}{yr} = 19{,}718.8\times10^6\frac{cf}{yr}$$

$$19{,}718.8\times10^6\frac{cf}{yr}\times 2.0\frac{gr\ S}{100\ cf}\times\frac{lb}{7{,}000\ gr}\times\frac{ton}{2{,}000\ lb}\times\frac{2\ SO_2}{1\ S} = 56.3\frac{ton}{yr}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **2.0 grains S / 100 scf natural gas**	4. Equivalent Allowable Emissions: **14.2** lb/hour **56.3** tons/year
5. Method of Compliance: **Fuel monitoring in accordance with 40 CFR Part 75, Appendix D.**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: **14.2** lb/hour **57.8** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: **2**

8. Calculation of Emissions:

Potential Hourly Emissions:
100% load, 20°F ambient, DB (Case 2)

Potential Annual Emissions:
100% load, 80°F ambient, inlet air fogging & DB (8,760 hr/yr) (Case 9)

$$13.2\frac{lb}{hr}\times 8{,}760\frac{hr}{yr}\times\frac{ton}{2{,}000\ lb}=57.8\frac{ton}{yr}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **14.2** lb/hour **57.8** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **2.6** lb/hour **10.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **N/A** Reference: **Vendor Data**	7. Emissions Method Code: **2**

8. Calculation of Emissions:

Potential Hourly Emissions:
100% load, 20°F ambient, DB (Case 2)

[(14.2 lb/hr SO_2) x (1 lb S / 2 lb SO_2) x (1 mole S / 32 lb S) x (8 mole SO_3 / 100 mole S) x (1 mole H_2SO_4 / 1 mole SO_3) x (98 lb H_2SO_4 / 1 mole H_2SO_4)] + [(14.2 lb/hr SO_2) x (4 mole SO_3 / 100 mole SO_2) x (1 mole SO_2 / 64 lb SO_2) x (1 mole H_2SO_4 / 1 mole SO_3) x (98 lb H_2SO_4 / 1 mole H_2SO_4)] = 1.7 lb/hr + 0.9 lb/hr = 2.6 lb/hr H_2SO_4

Potential Annual Emissions:
100% load, 80°F ambient, inlet fogging & DB (8,760 hr/yr) (Case 9)

[(12.9 lb/hr SO_2) x (1 lb S / 2 lb SO_2) x (1 mole S / 32 lb S) x (8 mole SO_3 / 100 mole S) x (1 mole H_2SO_4 / 1 mole SO_3) x (98 lb H_2SO_4 / 1 mole H_2SO_4)] + [(12.9 lb/hr SO_2) x (4 mole SO_3 / 100 mole SO_2) x (1 mole SO_2 / 64 lb SO_2) x (1 mole H_2SO_4 / 1 mole SO_3) x (98 lb H_2SO_4 / 1 mole H_2SO_4)] = 1.6 lb/hr + 0.8 lb/hr = 2.4 lb/hr H_2SO_4

= [(2.4 lb/hr H_2SO_4) x (8,760 hr/yr)] x (1 ton / 2,000 lb) =10.5 tpy

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **2.0 grains S / 100 scf natural gas**	4. Equivalent Allowable Emissions: **2.6** lb/hour **10.5** tons/year
5. Method of Compliance: **Fuel monitoring in accordance with 40 CFR Part 75, Appendix D.**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NH_3**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **17.0** lb/hour **67.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **N/A** Reference:	7. Emissions Method Code: **0**

8. Calculation of Emissions:

Potential Hourly Emissions:
100% load, 20°F ambient, DB (Case 2)

$(1.281\ mmft^3/hr) \times (5\ ft^3\ NH_3 / mm\ ft^3) \times (17\ lb\ NH_3 / mole\ NH_3) \times (1\ mole\ NH_3 / 385.3\ ft^3\ NH_3) \times (60\ min / hr) = 17.0\ lb/hr\ NH_3$

Potential Annual Emissions:
100% load, 80°F ambient, inlet fogging & DB (8,760 hr/yr) (Case 9)

$\{[(1.162\ mmft^3/hr) \times (5\ ft^3\ NH_3 / mm\ ft^3) \times (17\ lb\ NH_3 / mole\ NH_3) \times (1\ mole\ NH_3 / 385.3\ ft^3\ NH_3) \times (60\ min / hr) \times (8{,}760\ hr/yr)]\} \times (1\ ton / 2{,}000\ lb) = 67.5\ ton/yr\ NH_3$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **5.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **17.0** lb/hour **67.5** tons/year
5. Method of Compliance: **EPA Conditional Test Method 027**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE 10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10 %** Exceptional Conditions: **N/A %** Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 3

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

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x diluent CEM requirements of 40 CFR 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
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: **Specific CEMS information will be provided to FDEP when available.**	

Continuous Monitoring System: Continuous Monitor __ of __

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Fig 2-4 [ ] Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: A-4 [ ] Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Section 5.0 [ ] Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ____ [ ] Previously Submitted, Date ____ [x] Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ____ [ ] Previously Submitted, Date ____ [x] Not Applicable
6. Compliance Demonstration Reports/Records [ ] Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ [ ] Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ [ ] To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ [x] Not Applicable
7. Other Information Required by Rule or Statute [ ] Attached, Document ID: ____ [x] Not Applicable

FACILITY INFORMATION

EMISSIONS UNIT INFORMATION
Section [1] of [8]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) **To be provided to FDEP when available** [ ] Attached, Document ID: ___________ [ ] Not Applicable

N/A

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ______	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ______	☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: ______	☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _________	☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ______ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

FACILITY INFORMATION

NOTE:

EMISSION UNITS CTG/HRSG UNITS 1 THROUGH 4 ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 001 (CTG/HRSG UNIT 1) IS ALSO APPLICABLE TO EU 002 (CTG/HRSG UNIT 2), EU 003 (CTG/HRSG UNIT 3), AND EU 004 (CTG/HRSG UNIT 4).

EMISSIONS UNIT INFORMATION SECTIONS III.A. THROUGH III.I. ARE IDENTICAL, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [x] 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.

Emissions Unit Description and Status

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

   [x] 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. Description of Emissions Unit Addressed in this Section:
   North fresh water cooling tower. Tower is equipped with drift eliminators for control of PM/PM_{10} emissions.

3. Emissions Unit Identification Number: **EU 005**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	[ ] Yes [x] No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Low velocity mist (drift) eliminators**	
2. Control Device or Method Code(s): **015**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **150,000 gal/min**		
2. Maximum Production Rate: **N/A**		
3. Maximum Heat Input Rate: _______ million Btu/hr		
4. Maximum Incineration Rate: pounds/hr **N/A** tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum process rate (Field 3) is cooling tower water recirculation rate**		

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Cooling Tower: NMT1 – NMT10**	2. Emission Point Type Code: **3**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

Cooling tower consists of 10 cells

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

N/A

5. Discharge Type Code: **V**	6. Stack Height: **62** feet	7. Exit Diameter: **33** feet
8. Exit Temperature: **106** °F	9. Actual Volumetric Flow Rate: **1,421,771** acfm	10. Water Vapor: **N/A** %

11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :

15. Emission Point Comment:

Cooling tower consists of 10 cells with individual exhaust fans.
Stack height and diameter are provided in Fields 6 and 7 for each cell exhaust.
Exhaust volume and temperatures vary with ambient temperatures.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Cooling Tower – process cooling, mechanical draft**		
2. Source Classification Code (SCC): **3-85-001-01**	3. SCC Units: **Thousand gallons transferred**	
4. Maximum Hourly Rate: **9,000**	5. Maximum Annual Rate: **78,840,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Fields 4 and 5 are fresh water cooling tower recirculation water flow rates.**		

Segment Description and Rate: Segment __ of __

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	**015**		**NS**
PM_{10}	**015**		**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.8** lb/hour **16.5** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Potential Hourly Emissions:

$$\left(150{,}000\frac{gal}{\min}\right)\times\left(\frac{0.0005}{100}\right)\times\left(\frac{10{,}000\,lbPM}{1{,}000{,}000\,lb}\right)\times\left(8.345\frac{lb}{gal}\,water\right)\times\left(60\frac{\min}{hr}\right)=3.8\frac{lb}{hr}PM$$

Potential Annual Emissions :

$$\left(3.8\frac{lb}{hr}\right)\times\left(8{,}760\frac{hr}{yr}\right)\times\left(\frac{1\,ton}{2000\,lb}\right)=16.5\frac{ton}{yr}PM$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0005-percent drift loss**	4. Equivalent Allowable Emissions: **3.8** lb/hour **16.5** tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.24** lb/hour **1.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

PM_{10}/PM fraction is 0.063, see Attachment C.

Potential Hourly Emissions:

$$\left(150{,}000\frac{gal}{\min}\right)\times\left(\frac{0.0005}{100}\right)\times\left(\frac{10{,}000\,lbPM}{1{,}000{,}000\,lb}\right)\times\left(8.345\frac{lb}{gal}\,water\right)\times\left(60\frac{\min}{hr}\right)$$

$$\times(0.063)=0.24\frac{lb}{hr}PM_{10}$$

Potential Annual Emissions :

$$\left(0.24\frac{lb}{hr}\right)\times\left(8{,}760\frac{hr}{yr}\right)\times\left(\frac{1\,ton}{2000\,lb}\right)=1.0\frac{ton}{yr}PM_{10}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0005-percent drift loss**	4. Equivalent Allowable Emissions: **0.24** lb/hour **1.0** tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. 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: **Rule 62-296.320(4)(b)1, F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

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

EMISSIONS UNIT INFORMATION
Section [5] of [8]

N/A

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor __ of __

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

Continuous Monitoring System: Continuous Monitor __ of __

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Fig 2-4 [ ] Previously Submitted, Date ______
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: ______ [x] Not Applicable
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: ______ [x] Not Applicable
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date ______
   [x] Not Applicable
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date ______
   [x] Not Applicable
6. Compliance Demonstration Reports/Records
   [ ] Attached, Document ID: ______
   Test Date(s)/Pollutant(s) Tested: ______

   [ ] Previously Submitted, Date: ______
   Test Date(s)/Pollutant(s) Tested: ______

   [ ] To be Submitted, Date (if known): ______
   Test Date(s)/Pollutant(s) Tested: ______

   [x] Not Applicable
7. Other Information Required by Rule or Statute
   [ ] Attached, Document ID: ______ [x] Not Applicable

FACILITY INFORMATION

EMISSIONS UNIT INFORMATION
Section [5] of [8]

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID: ________ [x] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

N/A

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ______
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ______ ☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: ______ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _________ ☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ______ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date:_______ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Not Applicable

Additional Requirements Comment

NOTE:

THE NORTH AND SOUTH FRESHWATER COOLING TOWERS ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 005 (NORTH MAIN FRESHWATER COOLING TOWER) IS ALSO APPLICABLE TO EU 006 (SOUTH MAIN FRESHWATER COOLING TOWER).

EMISSIONS UNIT INFORMATION SECTIONS III.A. THROUGH III.I. ARE IDENTICAL, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [x] 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.

Emissions Unit Description and Status

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

   [x] 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. Description of Emissions Unit Addressed in this Section:
East fuel gas heater. The heater is fired exclusively with pipeline quality natural gas.

3. Emissions Unit Identification Number: **007 (East Fuel Gas Heater)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	[ ] Yes [x] No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **None**
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**		
2. Maximum Production Rate: **N/A**		
3. Maximum Heat Input Rate: **9.3** million Btu/hr **(HHV)**		
4. Maximum Incineration Rate: pounds/hr **N/A** tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **EFH**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **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: **25** feet	7. Exit Diameter: **2.0** feet
8. Exit Temperature: **850**°F	9. Actual Volumetric Flow Rate: **5,750** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm		12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Fuel gas heater fired with pipeline-quality natural gas.**		
2. Source Classification Code (SCC): **1-02-006-03**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.0089**	5. Maximum Annual Rate: **78.0**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,050 (HHV)**
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x			**EL**
CO			**EL**
VOC			**EL**
SO_2			**EL**
PM			**EL**
PM_{10}			**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.89** lb/hour **3.9** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **100 lb / 10^6 ft^3** Reference: **AP-42**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Potential Hourly Emissions:

(0.0089 mmft^3 / hr) x (100 lb NO_x / mm ft^3) = 0.89 lb / hr NO_x

Potential Annual Emissions:

(0.89 lb / hr NO_x) x (8,760 hr / yr) x (1 ton / 2,000 lb) =3.9 tpy

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **0.89** lb/hour **3.9** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.74** lb/hour **3.3** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **84 lb / 10^6 ft^3** Reference: **AP-42**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Potential Hourly Emissions:

(0.0089 mmft^3 / hr) x (84 lb CO / mm ft^3) = 0.74 lb / hr CO

Potential Annual Emissions:

(0.74 lb / hr CO) x (8,760 hr / yr) x (1 ton / 2,000 lb) =3.3 tpy

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **0.74** lb/hour **3.3** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.05** lb/hour **0.2** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **5.5 lb / 10^6 ft^3** Reference: **AP-42**	7. Emissions Method Code: 3
8. Calculation of Emissions: **Potential Hourly Emissions:** *(0.0089 mmft^3 / hr) x (5.5 lb VOC / mm ft^3) = 0.05 lb / hr VOC* **Potential Annual Emissions:** *(0.05 lb / hr VOC) x (8,760 hr / yr) x (1 ton / 2,000 lb) =0.2 tpy*	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **0.05** lb/hour **0.2** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.053** lb/hour **0.23** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **6.0 lb / 10^6 ft^3** Reference: **AP-42**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Potential Hourly Emissions:

$(0.0089\ mmft^3 / hr) \times (6.0\ lb\ SO_2\ / mm\ ft^3) = 0.053\ lb / hr\ SO_2$

Potential Annual Emissions:

$(0.053\ lb / hr\ SO_2) \times (8{,}760\ hr / yr) \times (1\ ton / 2{,}000\ lb) = 0.23\ tpy$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

AP-42 emission factor adjusted to reflect natural gas sulfur content of 2.0 gr S / 100 ft^3.

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.067** lb/hour **0.29** tons/year	4. Synthetically Limited? [ ] Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year **N/A**	
6. Emission Factor: **$7.6\ lb / 10^6\ ft^3$** Reference: **AP-42**	7. Emissions Method Code: **3**

8. Calculation of Emissions:

Potential Hourly Emissions:

$(0.0089\ mmft^3 / hr) \times (7.6\ lb\ PM/PM_{10}\ / mm\ ft^3) = 0.067\ lb / hrPM/PM_{10}$

Potential Annual Emissions:

$(0.067\ lb / hr\ PM/PM_{10}) \times (8{,}760\ hr / yr) \times (1\ ton / 2{,}000\ lb) = 0.29\ tpy$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **0.067** lb/hour **0.29** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE 10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10 %** Exceptional Conditions: **N/A %** Maximum Period of Excess Opacity Allowed: **N/A min/hour**	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

N/A

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor __ of __

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

Continuous Monitoring System: Continuous Monitor __ of __

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Fig 2-4 [ ] Previously Submitted, Date ______
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: A-4 [ ] Previously Submitted, Date ______
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ______ [x] Not Applicable
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date ______ [x] Not Applicable
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date ______ [x] Not Applicable
6. Compliance Demonstration Reports/Records [ ] Attached, Document ID: ______ Test Date(s)/Pollutant(s) Tested: ______ [ ] Previously Submitted, Date: ______ Test Date(s)/Pollutant(s) Tested: ______ [ ] To be Submitted, Date (if known): ______ Test Date(s)/Pollutant(s) Tested: ______ [x] Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute [ ] Attached, Document ID: ______ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID: ________ [x] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

N/A

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: ______

2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: ______ ☐ Not Applicable

3. Alternative Methods of Operation
   ☐ Attached, Document ID: ______ ☐ Not Applicable

4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _________ ☐ Not Applicable

5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID: ______
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: ______
      ☐ Previously Submitted, Date:________
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:___________
      ☐ Previously Submitted, Date:________
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:___________
      ☐ Previously Submitted, Date:________
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:___________
      ☐ Previously Submitted, Date:________
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:___________
      ☐ Previously Submitted, Date:________
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:___________
      ☐ Previously Submitted, Date:________
   ☐ Not Applicable

Additional Requirements Comment

NOTE:

THE EAST AND WEST FUEL GAS HEATERS ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 007 (EAST FUEL GAS HEATER) IS ALSO APPLICABLE TO EU 008 (WEST FUEL GAS HEATER).

EMISSIONS UNIT INFORMATION SECTIONS III.A. THROUGH III.I. ARE IDENTICAL, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

ATTACHMENT A-1

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from BHEC operations include:

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

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

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

ATTACHMENT A-2

RULE APPLICABILITY ANALYSIS

Attachment A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Page 1 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources				
40 CFR Part 60 Subpart A - General Provisions				
Notification and Recordkeeping	60.7(a)		CTG/HRSG-1 thru CTG/HRSG-4	Notification requirements.
	60.7(b) - (h)		CTG/HRSG-1 thru CTG/HRSG-4	General recordkeeping and reporting requirements.
Performance Tests	60.8		CTG/HRSG-1 thru CTG/HRSG-4	Conduct initial performance tests as required by EPA.
Compliance with Standards	60.11(a) thru (f)		CTG/HRSG-1 thru CTG/HRSG-4	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	60.12		CTG/HRSG-1 thru CTG/HRSG-4	Cannot conceal an emission that would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	60.13		CTG/HRSG-1 thru CTG/HRSG-4	Requirements for CEMS and monitoring devices.
Modification	60.14		CTG/HRSG-1 thru CTG/HRSG-4	General requirements regarding modifications **(potential future requirement)**.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 2 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
Reconstruction	60.15		CTG/HRSG-1 thru CTG/HRSG-4	General requirements regarding reconstructions **(potential future requirement)**.
Incorporation by Reference	60.17		CTG/HRSG-1 thru CTG/HRSG-4	Specifies ASTM Methods for collecting and analyzing fuel samples.
General Notification and Reporting Requirements	60.19		CTG/HRSG-1 thru CTG/HRSG-4	General procedures regarding reporting deadlines.
40 CFR Part 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978				
Standard for Particulate Matter	60.42a(a)(1)		HRSG-1 (DB) thru HRSG-4 (DB)	Particulate matter shall not exceed 0.03 lb/MMBtu heat input from the combustion of solid, liquid, or gaseous fuel.
	60.42a(b)		HRSG-1 (DB) thru HRSG-4 (DB)	Opacity shall not exceed 20% (6 minute average) except for one 6-minute period per hour of not more than 27% opacity.
Standard for Sulfur Dioxide	60.43a(b)(1) and (2)		HRSG-1 (DB) thru HRSG-4 (DB)	Sulfur dioxide emissions shall not exceed 0.80 lb/MMBtu heat input and 10 percent of the potential combustion concentration (90 percent reduction) or 100 percent of the potential combustion concentration (0 percent reduction) when emissions are less than 0.20 lb/MMBtu for gaseous fossil fuels.
Standard for Nitrogen Oxides	60.44a(d)(1)		HRSG-1 (DB) thru HRSG-4 (DB)	Nitrogen oxide emissions shall not exceed 1.6 lb/MW-hr.
Compliance Provisions, PM	60.46a(a)		HRSG-1 (DB) thru HRSG-4 (DB)	Compliance with the 0.03 lb/MMBtu particulate matter standard constitutes compliance with the percent reduction requirement.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 3 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
Compliance Provisions, PM and NO_x	60.46a(c)		HRSG-1 (DB) thru HRSG-4 (DB)	The particulate matter and nitrogen oxides standards apply at all times except during periods of startup, shutdown, and malfunction. The sulfur dioxide standards apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures of 60.46a(d) are implemented.
Compliance Provisions, SO_2 and NO_x	60.46a(e)		HRSG-1 (DB) thru HRSG-4 (DB)	After initial performance tests, compliance with the sulfur dioxide and nitrogen oxides emission limits and percentage reduction requirements is based on the average emission rates for 30 successive boiler days.
Compliance Provisions, SO_2 and NO_x	60.46a(g)		HRSG-1 (DB) thru HRSG-4 (DB)	Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.
Compliance Provisions	60.46a(h)		HRSG-1 (DB) thru HRSG-4 (DB)	Requirements pertaining to compliance procedures if the minimum quantity of emissions monitoring data required by 60.47a is not obtained.
Duct Burner Compliance Provisions, NO_x	60.46a(k)		HRSG-1 (DB) thru HRSG-4 (DB)	Compliance provisions for the with the 1.6 lb/MW-hr NO_x standard.
Emissions Monitoring	60.47a		HRSG-1 (DB) thru HRSG-4 (DB)	Requirements for continuous nitrogen oxides, oxygen or carbon dioxide monitoring systems.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 4 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
Compliance Determination Procedures and Methods	60.48a(a) – (e)		HRSG-1 (DB) thru HRSG-4 (DB)	Requirements for compliance determination procedures.
Reporting Requirements, CEMS Evaluations	60.49a(a)		HRSG-1 (DB) thru HRSG-4 (DB)	Requires submittal of continuous monitor performance evaluations to EPA.
Reporting Requirements	60.49a(b)-(j)		HRSG-1 (DB) thru HRSG-4 (DB)	Reporting requirements.
40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines				
Standard for Nitrogen Oxides	60.332		CTG-1 thru CTG-4	Specifies formula for allowable nitrogen oxide emission limit of 75 ppmv at 15% oxygen (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standard for Sulfur Dioxide	60.333		CTG-1 thru CTG-4	Establishes exhaust gas SO_2 limit of 0.015 % by volume (at 15% O2, dry) and maximum fuel sulfur content of 0.8 % by weight.
Monitoring Requirements	60.334(c)		CTG-1 thru CTG-4	CTG-1 thru CTG-4 will use nitrogen oxide CEMS in lieu of continuous monitoring of fuel consumption and the ratio of water to fuel combusted for excess emissions monitoring.
Natural Gas Nitrogen Content Monitoring	60.334(h)(2)		CTG-1 thru CTG-4	An allowance for fuel bound nitrogen (FBN) is not claimed. Therefore no monitoring of natural gas nitrogen content is required.

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
Natural Gas Sulfur Content Monitoring	60.334(h)(3)		CTG-1 thru CTG-4	Gaseous fuel used at the Blue Heron Energy Center will meet the definition of natural gas. Therefore no monitoring of natural gas sulfur content is required.
Excess Emissions Monitoring Requirements	60.334(j)(iii)		CTG-1 thru CTG-4	Excess emissions monitoring requirements for turbines using NO_x and diluent CEMS.
Test Methods and Procedures	60.335(a), (b), (c)		CTG-1 thru CTG-4	Specifies test methods and monitoring procedures.
40 CFR Part 60 - Subparts B, C, Cb, Cc, Cd, Ce, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, N, Na, O, P, Q, R, S, T, U, V, W, X, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP,QQQ, RRR, SSS, TTT, UUU, VVV, and WWW.		X		None of the listed NSPS' contain requirements that are applicable to the Blue Heron Energy Center.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, H, I, J, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF.		X		None of the listed NESHAPS' contain requirements that are applicable to the Blue Heron Energy Center.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines: Subpart YYYY.		X		The Blue Heron Energy Center will not be a major source of hazardous air pollutants (HAPs). 40 CFR Part 63 Subpart YYYY only applies to major HAP sources.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines: Subpart ZZZZ.		X		The Blue Heron Energy Center will not be a major source of hazardous air pollutants (HAPs). 40 CFR Part 63 Subpart ZZZZ only applies to major HAP sources.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 6 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters: Subpart DDDDD.		X		The Blue Heron Energy Center will not be a major source of hazardous air pollutants (HAPs). 40 CFR Part 63 Subpart DDDDD only applies to major HAP sources.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, J, L, M, N, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, FF, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, HHHH, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS, TTTTT, and WWWWW.		X		None of the listed NESHAPS' contain requirements that are applicable to the Blue Heron Energy Center.
40 CFR Part 72 - Acid Rain Program Permits				
40 CFR Part 72 Subpart A - Acid Rain Program General Provisions				
Standard Requirements	72.9		CTG/HRSG-1 thru CTG/HRSG-4	General acid rain requirements.
40 CFR Part 72 Subpart B - Designated Representative				
Designated Representative	72.20 - 72.24		CTG/HRSG-1 thru CTG/HRSG-4	General requirements pertaining to the designated representative.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 7 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
40 CFR Part 72 Subpart C - Acid Rain Application				
Requirements to Apply	72.30(a)		CTG/HRSG-1 thru CTG/HRSG-4	Requirements to submit a complete Acid Rain permit by the applicable deadline.
	72.30(b)(2) (i) and (ii)		CTG/HRSG-1 thru CTG/HRSG-4	Deadline to submit a complete Acid Rain permit application.
Requirements to Apply	72.30(c)		CTG/HRSG-1 thru CTG/HRSG-4	Duty to reapply - The designated representative shall submit a complete Acid Rain permit application for each source with an affected unit at least six 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.
Requirements to Apply	72.30(d)		CTG/HRSG-1 thru CTG/HRSG-4	Requirements to submit an original and three copies of all Phase II permit applications to the State permitting authority where the administrator is not the permitting authority.
Information for Acid Rain Permit Applications	72.31		CTG/HRSG-1 thru CTG/HRSG-4	General permit application requirements.
Permit Application Shield	72.32		CTG/HRSG-1 thru CTG/HRSG-4	Permit application shield provisions for timely and complete Acid Rain permit applications. Application is binding pending issuance of Acid Rain Permit.
40 CFR Part 72 Subpart D – Acid Rain Compliance Plan and Compliance Options				

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 8 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
General	72.40(a)(1)		CTG/HRSG-1 thru CTG/HRSG-4	General Compliance Plan Requirements for SO_2.
40 CFR Part 72 Subpart E - Acid Rain Permit Contents				
Permit Shield	72.51		CTG/HRSG-1 thru CTG/HRSG-4	Permit shield provisions. Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
40 CFR Part 72 Subpart H - Permit Revisions				
General, Additional Information	72.80(g)		CTG/HRSG-1 thru CTG/HRSG-4	Requirement to submit supplementary or corrected information upon becoming aware of a failure to submit relevant information or a prior incorrect submittal **(potential future requirement)**.
Fast-Track Modifications	72.82(a) and (c)		CTG/HRSG-1 thru CTG/HRSG-4	Procedures for fast-track modifications to Acid Rain Permits **(potential future requirement)**.
40 CFR Part 72 Subpart I - Compliance Certification				
Annual Compliance Certification Report	72.90		CTG/HRSG-1 thru CTG/HRSG-4	Requirement to submit an annual compliance report.
40 CFR Part 75 - Continuous Emission Monitoring				
40 CFR Part 75 Subpart A - General				
Compliance Dates	75.4 (a)(3) and (b)(2)		CTG/HRSG-1 thru	Requirement to complete all certification tests for CEMS and COMS.

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
			CTG/HRSG-4	
Prohibitions	75.5		CTG/HRSG-1 thru CTG/HRSG-4	General monitoring prohibitions.
40 CFR Part 75 Subpart B - Monitoring Provisions				
General Operating Requirements	75.10		CTG/HRSG-1 thru CTG/HRSG-4	General acid rain monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	75.11(d)(2)		CTG/HRSG-1 thru CTG/HRSG-4	SO_2 continuous monitoring requirements for gas and oil fired units using Appendix D.
Specific Provisions for Monitoring NO_x Emissions	75.12(a) and (c)		CTG/HRSG-1 thru CTG/HRSG-4	NO_x continuous monitoring requirements.
Specific Provisions for Monitoring Opacity	75.14(c)		CTG/HRSG-1 thru CTG/HRSG-4	Opacity continuous monitoring exemption for gas-fired units.
40 CFR Part 75 Subpart C - Operation and Maintenance Requirement				
Recertification Requirements	75.20(b)		CTG/HRSG-1 thru CTG/HRSG-4	Requires that monitoring systems meet recertification requirements by the deadlines stipulated in 75.4. **(potential future requirement)**
	75.20(a)(1)		CTG/HRSG-1 thru CTG/HRSG-4	Requires notification of recertification and revised test dates at least 45 days prior to certification testing. **(potential future requirement)**

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 10 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
	75.20(a)(2)		CTG/HRSG-1 *thru* CTG/HRSG-4	Requires submittal of recertification applications in accordance *with 75.60*. **(potential future requirement)**
	75.20(a)(5)		CTG/HRSG-1 thru CTG/HRSG-4	Procedures to be used in the event that the agency issues a disapproval of certification application or certification status. **(potential future requirement)**
	75.20(c)(1), (3), (10), and (19)		CTG/HRSG-1 thru CTG/HRSG-4	Recertification procedure requirements. **(potential future requirement)**
	75.20(g)		CTG/HRSG-1 thru CTG/HRSG-4	Recertification procedure requirements for excepted monitoring systems under Appendices D and E.. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	75.21(a), c), (d), and (e)		CTG/HRSG-1 thru CTG/HRSG-4	General QA/QC requirements (excluding COMS).
Reference Test Methods	75.22		CTG/HRSG-1 thru CTG/HRSG-4	Specifies required test methods to be used for certification or recertification testing.
Out-Of-Control Periods and Adjustment for System Bias	75.24 except 75.24(e)		CTG/HRSG-1 thru CTG/HRSG-4	Specifies out-of-control periods and the required actions to be taken when they occur (excluding COMS).
40 CFR Part 75 Subpart D - Missing Data Substitution Procedures				
General Provisions	75.30		CTG/HRSG-1 thru CTG/HRSG-4	General missing data requirements.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 11 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
Determination of Monitor Data Availability for Standard Missing Data Procedures	75.32		CTG/HRSG-1 thru CTG/HRSG-4	Monitor data availability procedure requirements after the first 720 and 2,160 quality-assured monitor operating hours for SO_2 and CO_2 pollutant concentration monitor and flow monitor/NO_x CEMS, respectively.
Standard Missing Data Procedures for SO_x, NO_x, and Flow Rate	75.33		CTG/HRSG-1 thru CTG/HRSG-4	Missing data substitution procedure requirements after the first 720 and 2,160 quality-assured monitor operating hours for SO_2 pollutant concentration monitor and flow monitor/NO_x CEMS, respectively.
Appendix D to Part 75 - Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units				
Missing Data Procedures	Appendix D 2.4		CTG/HRSG-1 thru CTG/HRSG-4	Missing data substitution requirements for units using Appendix D – Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units.
Appendix G to Part 75 – Determination of CO_2 Emissions				
Missing Data Procedures	Appendix G 5		CTG/HRSG-1 thru CTG/HRSG-4	Missing data substitution requirements for units using Appendix G – Determination of CO_2 Emissions.
40 CFR Part 75 Subpart E - Alternative Monitoring Systems				
Alternative Monitoring Systems	75.40 - 75.48	X	CTG/HRSG-1 thru CTG/HRSG-4	Optional requirements for alternative monitoring systems.
40 CFR Part 75 Subpart F - Recordkeeping Requirements				
Monitoring Plan	75.53(a), (b), (e), and (f)		CTG/HRSG-1 thru	Requirement to prepare and maintain a Monitoring Plan

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 12 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
			CTG/HRSG-4	
General Recordkeeping Provisions	75.57		CTG/HRSG-1 thru CTG/HRSG-4	General recordkeeping provisions.
General Recordkeeping Provisions for Specific Situations	75.58(c)		CTG/HRSG-1 thru CTG/HRSG-4	SO_2 recordkeeping provisions for gas-fired or oil-fired units using Appendix D.
Certification, Quality Assurance, and Quality Control Record Provisions	75.59(a) and (b)		CTG/HRSG-1 thru CTG/HRSG-4	General QA/QC recordkeeping requirements.
40 CFR Part 75 Subpart G - Reporting Requirements				
General Provisions	75.60		CTG/HRSG-1 thru CTG/HRSG-4	General reporting requirements.
Notification of Certification and Recertification Test Dates	75.61		CTG/HRSG-1 thru CTG/HRSG-4	Requires written submittal of certification tests, recertification test, and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of certification for 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.
Monitoring Plan	75.62		CTG/HRSG-1 thru CTG/HRSG-4	Monitoring Plan required to be submitted no later than 45 days prior to the certification test.
Certification or Recertification Application	75.63		CTG/HRSG-1 thru	Requires submittal of a certification application within 30 days after completing the certification test.

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
			CTG/HRSG-4	
Quarterly Reports	75.64(a)(1) - (5)		CTG/HRSG-1 thru CTG/HRSG-4	Requirement to submit quarterly data report.
	75.64(b), (c), (d)		CTG/HRSG-1 thru CTG/HRSG-4	Requirement to submit compliance certification in support of each quarterly data report. Requirement to submit quarterly reports in an electronic format to be specified by EPA.
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	77.3		CTG/HRSG-1 thru CTG/HRSG-4	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)**.
Offset Plans for Excess Emissions of Sulfur Dioxide	77.5(b)		CTG/HRSG-1 thru CTG/HRSG-4	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 and Nitrogen Oxides	77.6		CTG/HRSG-1 thru CTG/HRSG-4	Requirement to pay a penalty if excess emissions of SO_2 or NO_x occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 78 - Appeal Procedures for Acid Rain Program				
Appeal Procedures	78.1 - 78.20		CTG/HRSG-1 thru CTG/HRSG-4	Optional appeal procedures for EPA Acid Rain program decisions **(optional future requirement).**

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 14 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		Blue Heron Energy Center will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Blue Heron Energy Center will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted off-site by persons 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		Blue Heron Energy Center will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Blue Heron Energy Center will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	82.154	X		Blue Heron Energy Center personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with 82.154.

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
Required Practices	82.156 except 82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by 82.152—any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes including any air conditioner, refrigerator, chiller, or freezer.	Contractors will maintain, service, repair, and dispose of any appliances in compliance with 82.156 required practices.
Technician Certification	82.161	X		Blue Heron Energy Center Personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recovery and Recycling Equipment	82.162	X		Blue Heron Energy Center Personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
Reporting and Recordkeeping Requirements	82.166(k), (m), and (n)		Appliances as defined by 82.152.	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.

Table A-2A. Summary of Federal EPA Regulatory Applicability and Corresponding Requirements (Continued, Page 16 of 16)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable Emissions Units	Applicable Requirement or Nonapplicability Rationale
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards Requirements		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - 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 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 58, 59, 61, 64, 65, 66, 67, 68, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, and 97		X		The listed regulations do not contain any requirements that are applicable to the Blue Heron Energy Center.

Source: ECT, 2004.

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 18)
Blue Heron Energy Center

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.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040(1)(a) and (b), F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050(1), (2), and (3), F.A.C.		X		General permitting procedures including filing in quadruplicate and PE certification.
Air Pollution Permit Processing Fees	62-4.050(4)(a)1., 4., 5., F.A.C.		X		Processing fees for air pollution permits. Permit processing fees are not required for operating permits or non-PSD construction permits for sources holding a Title V permit. **(potential future requirement)**
Permit Processing, Response to Requests for Additional Information	62-4.055(1), F.A.C.		X		If additional information is requested by FDEP, applicants have 90 days to submit the additional information. Upon request, FDEP will grant an additional 90 period to provided the requested information. Further extensions may be granted if the applicant shows good cause. **(potential future requirement)**

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Processing, Option to Request a Hearing	62-4.055(2), F.A.C.		X		If a FDEP request for additional information is not considered authorized by law or rule, the applicant may request a hearing. **(optional future requirement)**
Permit Processing, Option to Request Department Permit Processing	62-4.055(4), F.A.C.		X		If a FDEP request for additional information is not considered authorized by law or rule, the applicant may request that FDEP process the permit application without the requested information. **(optional future requirement)**
Permit Processing	62-4.055(3), (5), and (6) F.A.C.	X			FDEP permit processing procedures. Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation with FDEP is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes FDEP standard permitting procedures. Contains no applicable requirements.
Modification of Permit Conditions	62-4.080(1) F.A.C		X		For good cause, permittee may be required to conform to new or additional conditions. **(potential future requirement)**
Modification of Permit Conditions	62-4.080(2) and (3) F.A.C		X		Permittee may request a permit modification or permit extension. **(optional future requirement)**

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Renewals	62-4.090, F.A.C.		X		Establishes permit criteria. Requests for renewal of a Title V operating permit are due prior to 180 days before permit expiration. Applications submitted prior to the due date are considered timely and sufficient. For timely and sufficient applications, the existing permit shall remain in effect until the renewal application has been finally acted upon by FDEP. Additional criteria are cited at 62-213.-430(3), F.A.C. **(future requirement)**
Suspension and Revocation	62-4.100, F.A.C.	X			Establishes FDEP permit suspension and revocation criteria. Contains no applicable requirements.
Financial Responsibility	62-4.110, F.A.C.	X			FDEP has not required proof of financial responsibility or posting of a bond for the Blue Heron Energy Center.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not being requested for the Blue Heron Energy Center.
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Permit Review	62-4.150, F.A.C.		X		Failure to request a hearing within 14 days of proposed or final Agency action on a permit application shall be deemed a waiver to the right to an administrative hearing. **(optional**

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
					future requirement)
Permit Conditions	62-4.160, F.A.C.	X			Lists general conditions that FDEP must include in permits. Contains no applicable requirements.
Chapter 62-4, F.A.C. - Part II Specific Permits; 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 new source operation permits. **(future requirement)**
Chapter 62-4, F.A.C. - Part III Procedures for General Permits	62-4.510 thru 62-4.540, F.A.C.	X			Not applicable to the Blue Heron Energy Center.
Chapter 62-204, F.A.C. - Air Pollution Control - General Provisions					
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.

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Federal Regulations Adopted by Reference	62-204.800(8)(a), (b)1., (b)31., and (b)39., (c), (d), and (e), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	All Federal Regulations cited in the rules by the Department are adopted and incorporated by reference. Specifically, the new source performance standards contained in 40 CFR 60 Subpart A (CTG/HRSG-1 thru CTG/HRSG-4), Subpart Da (HRSG-1 DB thru HRSG-4 DB2) and Subpart GG (CTG-1 thru CT-4) are applicable to the Blue Heron Energy Center.
Federal Regulations Adopted by Reference	62-204.800(15), F.A.C.		X		State (FDEP) Part 70 (Title V Permit) Program requirements; see Table A-2A for detailed federal regulatory citations. Contains no applicable requirements.
Federal Regulations Adopted by Reference	62-204.800(16), (17), (18), (20), and (21), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Acid Rain Program; see Table A5-1 for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800 (19), F.A.C.	X			Acid Rain NO_x Emission Reduction Program; see Table A-2A for detailed federal regulatory citations.
Federal Regulations Adopted by Reference	62-204.800(23)(e), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-2A 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.

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required, Air Construction	62-210.300(1), F.A.C.		X		Requirements for air construction permits.
Permits Required, Air Operation	62-210.300(2)(a), F.A.C.		X		Air operation permits required, including permits. **(future requirement).**
Permits Required, Exemptions	62-210.300(3), F.A.C.		X		Permit exemptions for certain facilities and sources.
Emission Unit Startup, Reclassification, and Transfer of Air Permits	62-210.300(5), (6), and (7) F.A.C.		X		Startup notification required if a permitted source has been shut down for more than 1 year. Emission unit reclassification and air permit transfer procedures. **(potential future requirements).**
Public Notice and Comment	62-210.350(1), F.A.C.		X		All permit applicants, including those for renewals and revisions, are 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		PSD permit application notice requirements.
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 permits, renewals, and revisions. **(future requirement).**
Administrative Permit Corrections	62-210.360(1), F.A.C.		X		Facility owner shall notify the FDEP by letter of minor corrections to information contained

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
					in a permit. **(potential future requirements).**
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3)(a)1. and (c), F.A.C.		X		Title V sources are required to submit an annual operating report. **(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.
Circumvention	62-210.650, F.A.C.		X		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), (4), (5), and (6) F.A.C.		X		Excess emissions due to startup, shutdown, and malfunction are permitted. Excess emissions due to malfunction must be reported. Excess emissions due to certain other causes are prohibited. **(potential future requirement)**
Forms and Instructions	62-210.900, F.A.C.		X		List required FDEP forms for stationary sources.
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	62-212.300, F.A.C.		X		Air construction permit requirements.

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Requirements					
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit requirements.
Prevention of Significant Deterioration	62-212.400(7)(b), F.A.C.		X		The operation permit shall contain all operating conditions and provisions required under 62-212.400(7)(a) and set forth in the original or amended construction permit. **(future requirement)**
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			The Blue Heron Energy Center is not located in any nonattainment area or 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(2), (3), (5), and (6) F.A.C.		X		Applicant requirements for an air emissions bubble including permit applications, ambient impact analysis, monitoring, and recordkeeping. **(optional future requirement)**
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.
Responsible Official	62-213.202, F.A.C.		X		Title V sources must designate a responsible official. **(future requirement)**

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Annual Emissions Fee	62-213.205, F.A.C.		X		Title V sources must pay an annual emissions fee. **(future requirement)**
Title V Air General Permits	62-213.300, F.A.C.	X			Not applicable to the Blue Heron Energy Center.
Permits Required	62-213.400(1), F.A.C.		X		Title V sources must operate in compliance with Chapter 62-213. **(future requirement)**
Permit Revisions Required	62-213.400(2), F.A.C.		X		Lists changes for which a permit revision is required. **(potential future requirement)**.
Concurrent Processing of Permit Applications	62-213.405, F.A.C.		X		Applicant may request concurrent processing of a construction permit and Title V permit revision or renewal. **(optional 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.			CTG/HRSG-1 thru CTG/HRSG-4	Optional provisions for Acid Rain permit revisions. **(optional future requirement)**
Trading of Emissions within a Source	62-213.415, F.A.C.		X		Defines the conditions under which emissions trading is allowable. **(optional future requirement)**

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Applications, Timely Submittal	62-213.420(1)(a)3., F.A.C.		X		Title V operating permit application is timely if submitted in accordance with Rule 62-4.090, F.A.C. **(future requirement)**
Permit Applications, New or Modified Emission Units	62-213.420(1)(a)4., F.A.C.		X		A Title V source that contains an emissions unit that commences operation or is modified after 10/25/95 is required to submit an application for Title V permit revision at least 90 days prior to the unit's air construction permit expiration , but no later than 180 days after the unit commences operation. **(future requirement)**
Permit Applications, Standard Information Required	62-213.420(1)(b)1., (3) and (4), F.A.C.		X		Title V operating permit application must contain all the information specified by 62-213.420(3), F.A.C. and be certified by the responsible official. **(future requirement)**
Permit Applications, Additional Time to Provide Requested Information	62-213.420(1)(b)6., F.A.C.		X		If requested in writing by the applicant prior to the initial due date, FDEP will grant up to 60 additional days to respond to requests for additional information. FDEP may grant additional time beyond 60 days for good cause. **(optional future requirement)**
Permit Applications, Certification by Responsible Official	62-213.420(4), F.A.C.		X		Requires submittal of a Responsible Official (RO) certification for any application form, report, compliance statement, compliance plan, and compliance schedule. **(future requirement)**
Permit Applications, Acid Rain Part	62-213.420(5), F.A.C.		X		Applicants may request separate processing of the Title V permit and Acid Rain Part.

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
					(optional future requirement)
Permit Issuance, Renewal, and Revision	62-213.430(3), F.A.C.		X		Permits being renewed are subject to the same requirements that apply to permit issuance. Permit applications shall contain the information specified in 62-210.900(1) and 62-213.420(3), F.A.C. **(future requirement)**
Permit Issuance, Renewal, and Revision – Insignificant Emission Units and Activities	62-213.430(6), F.A.C.		X		Specifies criteria for insignificant emissions units and activities. Applicants may request FDEP determinations of insignificant emission units or activities. Such requests will be processed in conjunction with a permit or revision application. Insignificant emission units added after issuance of a Title V permit shall be incorporated into the permit at its next renewal. **(potential future requirement)**
Permit Content	62-213.440, F.A.C.	X			FDEP standard permit requirements. Contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			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), (7), and (8), F.A.C.		X		Lists applicable forms including "Major Air Pollution Source Annual Emissions Fee," Statement of Compliance," and "Responsible Official Notification" forms. **(potential future requirement)**

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-214 F.A.C. - 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.			CTG/HRSG-1 thru CTG/HRSG-4	Blue Heron Energy Center includes Acid Rain units. Therefore, facility compliance with 62-213 and 62-214, F.A.C., is required.
Applications, Renewals	62-214.320(1)(i), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Requires Title V sources having Acid Rain unit(s) to submit an Acid Rain Renewal Application to FDEP. Operation without a Title V permit that includes an Acid Rain Part is prohibited.
Applications, Information Requirements	62-214.320(2), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Specifies required contents of Acid Rain Part applications.
Acid Rain Compliance Plan and Compliance Options, SO_2	62-214.330(1)(a), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Acid rain compliance plan requirements for sulfur dioxide emissions.
Acid Rain Compliance Plan and Compliance Options, NO_x	62-214.330(1)(b), F.A.C.	X			Acid rain compliance plan requirements for nitrogen oxides emissions.
Exemptions	62-214.340(2), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Notice may be submitted for retired exemptions (**potential future requirement**).

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 13 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Certification	62-214.350(2), (3), (5), (6), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Submittal of a copy of the Certificate of Representation form to FDEP is required. Specifies required Designated Representative (DR) certifications.
Department Action on Applications	62-214.360, F.A.C.	X			FDEP application processing procedures. Contains no applicable requirements.
Revisions and Administrative Corrections	62-214.370(1), (3), (4), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Specifies applicant permit revision requirements. **(potential future requirement)**.
Revisions and Administrative Corrections, Agency Procedures	62-214.370(2), (5), (6), and (7) F.A.C.	X			FDEP application processing procedures. Contains no applicable requirements.
Acid Rain Part Content	62-214.420, F.A.C.	X			FDEP requirements - defines content of Acid Rain Part. Contains no applicable requirements.
Implementation and Termination of Compliance Options	62-214.430, F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Defines permit activation and termination procedures. Presently not applicable to the Blue Heron Energy Center. **(potential future requirement)**.
Chapter 62-252 - Gasoline Vapor Control					
Rules for gasoline vapor control equipment	62-252, F.A.C.	X			The Blue Heron Energy Center is not located in an ozone nonattainment area or an air quality maintenance area for ozone.
Chapter 62-256, F.A.C. - Open Burning and Frost Protection					

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 14 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
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 certain types of open burning.
Agricultural and Silvicultural Fires	62-256.400, F.A.C. [Transferred to Division of Forestry, Chapter 5I-2]	X			Contains no applicable requirements.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	62-256.500, F.A.C.[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	62-256.600, F.A.C.[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700(3), (5), and (6) F.A.C.		X		Defines allowed open burning. For recreational and training purposes.
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Program		X			
Chapter 62-281 - Motor Vehicle					

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Air Conditioning Refrigerant Recovery and Recycling					
Establishes installation and proper use of motor vehicle refrigerant recycling equipment.	62-281.100, F.A.C.	X			Requirements for the installation and proper use of motor vehicle refrigerant recycling equipment. Adopts definitions of 40 CFR Part 82 with some exceptions. No vehicle maintenance involving air conditioning systems will be conducted at the Blue Heron Energy Center.
Chapter 62-296 - Stationary Sources - 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. **(potential future requirement)**
General Particulate Emission Limiting Standard, Process	62-296.320(4)(a), F.A.C.	X			Blue Heron Energy Center does not have any applicable emission units. Combustion

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 16 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Weight Table					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.
New Fossil Fuel Fired Steam Generators with More Than 250 MMBtu/hr Heat Input	62-296.405(2), F.A.C.			HRSG-1 (DB) thru HRSG-4 (DB)	Required to meet applicable New Source Performance Standards (Subpart Da). See Table A-2A for details.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.404 and 62-296.406 through 62-296.417, F.A.C.	X			Not applicable to the Blue Heron Energy Center emission units.
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			The Blue Heron Energy Center 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			The Blue Heron Energy Center is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (Broward, Dade and Palm Beach Counties).

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 17 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			The Blue Heron Energy Center 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			The Blue Heron Energy Center is not located in a PM nonattainment area or a PM air quality maintenance area.
Chapter 62-297, Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Test Requirements	62-297.310, F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Specifies general compliance test requirements including the number of runs, operating rates, emission rate calculation, applicable test procedures, determination of process variables, required stack sampling facilities, frequency of tests, and content of test reports.
Standards for Visible Emissions Observations	62-297.320(1), F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Specifies training and certification requirements for persons conducting the opacity of visible emissions.
Compliance Test Methods	62-297.401, F.A.C.		X		List methods to be used for compliance testing.
Supplementary Test Procedures	62-297.440, F.A.C.		X		Contains other test procedures adopted by reference.

Table A-2B. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 18 of 18)
Blue Heron Energy Center

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to the Blue Heron Energy Center.
EPA CEMS Performance Specifications	62-297.520(1), (2), and (3) F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Contains 40 CFR Part 60 performance specifications for NO_x and O_2 continuous emissions monitoring. CEMS meeting 40 CFR Part 75 requirements may be used in lieu of 40 CFR Part 60 requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.			CTG/HRSG-1 thru CTG/HRSG-4	Exceptions or alternate testing procedures may be requested. **(optional future requirement).**
Chapter 5I-2, Open Burning Rule					
Definitions	5I-2.003, F.A.C.	X			Contains no applicable requirements.
Open Burning Not Allowed	5I-2.004, F.A.C.		X		*Prohibits certain types of open burning.*
Open Burning Allowed	5I-2.006, F.A.C.		X		Requirements for agricultural, silvicultural, and rural land clearing open burning.

[1] State requirement only; not federally enforceable.

Source: ECT, 2004.

ATTACHMENT A-3

LIST OF EXEMPT EMISSION UNITS

LIST OF EXEMPT EMISSION UNITS

The BHEC will include one emergency 1,400-kW diesel-fired electrical generator and one emergency diesel-fired fire water pump.

The two emergency diesel engines will not be subject to the Acid Rain Program; and total BHEC fuel consumption for all emergency generators will not exceed 32,000 gallons per year of diesel fuel.

Accordingly, the emergency diesel engines will meet the permit exemption criteria of Rule 62-210.300(3)(a)20. and Rule 62-210.300(3)(a)21, F.A.C., and therefore are exempt from permitting requirements.

ATTACHMENT A-4

FUEL ANALYSIS OR SPECIFICATION

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
Other Characteristics	
Heat content (HHV)	1,056 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5925
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, 2004.

ATTACHMENT B

SIEMENS WESTINGHOUSE
ESTIMATED GAS TURBINE
PERFORMANCE DATA

SIEMENS Westinghouse

Calpine Generic

Estimated W501F Gas Turbine Performance
Combined Cycle / Dry Low NOx Combustor
2-102x180 / 0.90 Power Factor

CTT-2197
9-Jan-02

SITE CONDITIONS:	CASE 1	CASE 3	CASE 4	CASE 6	CASE 7	CASE 8	CASE 10	CASE 11	CASE 12	CASE 14	CASE 15
FUEL TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
LOAD LEVEL	BASE	60%	BASE	BASE	60%	BASE	BASE	60%	BASE	BASE	60%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	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	23,299	23,299	23,299	23,299
INLET FOGGING STATUS	OFF	OFF	ON	OFF	OFF	ON	OFF	OFF	ON	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	20.0	20.0	59.0	59.0	59.0	80.0	80.0	80.0	90.0	90.0	90.0
AMBIENT WET BULB TEMPERATURE, °F	17.1	17.1	51.5	51.5	51.5	69.6	69.6	69.6	78.0	78.0	78.0
AMBIENT RELATIVE HUMIDITY, %	60%	60%	60%	60%	60%	60%	60%	60%	59%	59%	59%
BAROMETRIC PRESSURE, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
COMPRESSOR INLET TEMPERATURE, °F	20.0	20.0	53.5	59.0	59.0	71.6	80.0	80.0	80.0	90.0	90.0
INLET PRESSURE LOSS, inches of water (Total)	4.6	2.3	4.4	4.3	2.3	4.1	4.0	2.2	4.0	3.9	2.2
EXHAUST PRESSURE LOSS, inches of water (Total)	19.8	10.4	18.1	17.7	9.4	16.6	16.0	8.8	16.0	15.3	8.5
EXHAUST PRESSURE LOSS, inches of water (Static)	16.3	8.5	14.8	14.5	7.7	13.6	13.1	7.2	13.1	12.5	7.0
INJECTION FLUID	-	-	-	-	-	-	-	-	-	-	-
INJECTION RATIO	-	-	-	-	-	-	-	-	-	-	-
COMBUSTION TURBINE PERFORMANCE:											
FUEL FLOW, lbm/hr	89,690	60,250	83,610	82,290	56,160	79,600	77,480	53,170	77,710	75,250	51,920
EXHAUST TEMPERATURE, °F	1,075	1,070	1,092	1,094	1,097	1,106	1,110	1,101	1,114	1,119	1,107
EXHAUST FLOW, lbm/hr	4,151,902	2,971,338	3,912,178	3,869,176	2,811,178	3,732,728	3,660,570	2,711,366	3,640,878	3,557,522	2,660,915
EXHAUST GAS COMPOSITION (BY % VOL):											
OXYGEN	12.64	13.14	12.55	12.62	13.11	12.37	12.48	13.06	12.22	12.35	12.97
CARBON DIOXIDE	3.76	3.54	3.71	3.70	3.48	3.69	3.66	3.40	3.68	3.65	3.38
WATER	7.68	7.23	8.53	8.31	7.87	9.61	9.27	8.75	10.36	9.96	9.41
NITROGEN	75.03	75.20	74.32	74.48	74.65	73.46	73.70	73.90	72.87	73.16	73.37
ARGON	0.90	0.90	0.89	0.89	0.89	0.88	0.88	0.88	0.87	0.87	0.88
MOLECULAR WEIGHT	28.46	28.49	28.36	28.38	28.41	28.24	28.28	28.31	28.16	28.20	28.23
NET EMISSIONS: Based on Westinghouse 21T5620 test methods											
NOx, ppmvd @ 15% O2	25	25	25	25	25	25	25	25	25	25	25
NOx, lbm/hr as NO2	195	131	182	179	122	173	169	116	169	164	113
CO, ppmvd @ 15% O2	10	50	10	10	50	10	10	50	10	10	50
CO, lbm/hr	48	160	45	44	149	42	41	141	41	40	138
SO2, lbm/hr	1.3	0.9	1.2	1.2	0.8	1.1	1.1	0.8	1.1	1.1	0.8
VOC, ppmvd @ 15% O2 as CH4	1.2	3.0	1.2	1.2	3.0	1.2	1.2	3.0	1.2	1.2	3.0
VOC, lbm/hr as CH4	3.3	5.5	3.0	3.0	5.1	2.9	2.8	4.8	2.8	2.7	4.7
PARTICULATES, lbm/hr	18.0	13.0	16.9	16.7	12.2	16.0	15.7	11.7	15.5	15.2	11.4

NOTES:

- Performance based on new and clean condition.
- All data is estimated and not guaranteed.
- Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Siemens Westinghouse is available to review permit application data upon request.
- Gross power output is at the generator terminals.
- Estimated GT Performance values are dependent upon receiving test tolerances equal to measurement uncertainty calculated in accordance with ASME PTC 19.1-1998.
- Emission flowrates are calculated based on the maximum achievable exhaust flow. For further details on flowrate calculation contact SWPC.
- VOC's consist of total unburned hydrocarbons excluding methane and ethane. The concentration is expressed in terms of methane.
- Gas fuel composition is 98% CH4, 0.6% C2H6, 1.4% N2, 0.2 grains of sulfur per 100 SCF.
- Gas fuel must be in compliance with the Siemens Westinghouse Gas Fuel Spec (21T0306 Rev.10).
- Particulates are per US EPA Method 5/202 (front and back half).
- 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.
- Inlet fogging calculations were performed based on maintaining the compressor inlet temperature 2°F higher than the ambient wet bulb temperature.
- Injection is for power augmentation and not for NOx control.
- IGV schedule may be adjusted during commissioning. Part load performance will be adjusted accordingly.
- 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.
- Part load is achieved by lowering the firing temperature and is based on percentage unrestricted power output.
- Maximum gross power is 215000 kW.

TEST REPORT
ON
COMPLIANCE AIR EMISSION TESTING

OF THREE
WESTINGHOUSE 501FD
TURBINE GENERATORS

AT THE
MORGAN ENERGY CENTER, LLC
DECATUR ENERGY CENTER

LOCATED IN
DECATUR, MORGAN COUNTY, ALABAMA

PREPARED FOR

MORGAN ENERGY CENTER, LLC
AND
CALPINE CORPORATION

JUNE, 2004

CUBIX JOB NO. 7464

TABLE 1:
Background Data

Source Owner/Operator:	Calpine Eastern Corporation 2701 North Rocky Point Drive Suite 1200 Tampa, Florida 33607 Attn.: Heidi Whidden, Environmental Specialist TEL: 813/637-7316 FAX: 813/637-7399
Test Contractor:	Cubix Corporation 9225 US Highway 183 South Austin, Texas 78747 Attn: Jeff Thomason TEL 512/243-0202 FAX 512/243-0222
Process Description:	This report addresses two combined-cycle turbines (Westinghouse Model 501FD) that are utilized for generation of electricity. Dry-low NOx (DLN) combustors and selective catalytic reduction (SCR) technology are utilized for NOx control. The turbines tested are designated as CT2 and CT3.
Test Dates:	June 10-11, 2004
Location:	Morgan Energy Center, Decatur, Morgan County, Alabama
Applicable Regulations	ADEM Permit Number 712-0080-X001
Sampling Points:	Four perpendicular 6" flanged NPT sample ports are located in the HRSG exhaust stack of each identical source. Access to each source is by stairs and ladder (please see Appendix A for a diagram of the identical stack).

Test Participants:	Calpine Corporation Dan Stone Cubix Corporation Jeff Thomason Mike Schuster
Test Methods:	EPA Method 3A for oxygen (O_2) concentrations EPA Method 7E for oxides of nitrogen (NO_X) concentrations EPA Method 10 for carbon monoxide (CO) EPA Method 19 stoichiometric volumetric flow and moisture calculations based on O_2 and CO_2 "F- EPA Method 25A for Total Hydrocarbons (THC) (measured on a propane basis) ASTM D1945 for fuel composition ASTM D3588 for fuel heating value and specific gravity ASTM D3246 for fuel sulfur

Table 2
CT3 Reduced Load Summary of Results

Company:	Calpine Corporation				
Location:	Morgan Energy Center, Decatur, Morgan County, AL				
Source:	Westinghouse 501 D Combustion Turbine				
Designation:	Unit 3/CT3				
Technicians	JNT, WMS				
Test Run No.	**8611-CT3-C1**	**8611-CT3-C2**	**8611-CT3-C3**		
Load Condition	**TO, Reduced**	**TO, Reduced**	**TO, Reduced**		
Date	**6/10/04**	**6/10/04**	**6/10/04**		
Start Time	09:01	10:20	11:39		
Stop Time	10:01	11:20	12:39		
Turbine/Compressor Operation					
Turbine Active Power (MW)	59.95	59.98	59.99		
Steam Turbine Generator Active Power (MW)	126.01	131.27	151.91		
Internal Guide Vane Position (%)	42.88	42.89	42.91		
Compressor Exhaust Temperature (°F)	1116.8	1123.7	1123,6		
Fuel Data					
Fuel Heating Value (Btu/lb, GHV)	23283	23283	23283		
Volatile fraction (non-methane,non-ethane % from fuel analysis)	2.33%	2.33%	2.33%		
CO2 F-Factor (DSCF/MMBtu)	1024	1024	1024		
O2 F-Factor (DSCF/MMBtu)	8636	8636	8636		
Total Fuel Sulfur (ppm/wt. from fuel analyses)[reported as<1]	1.0	1.0	1.0		
Fuel Flow Rate (klb/hr)	37.5	37.5	37.5		
Fuel Flow (Btu/hr)	8.73E+08	8.73E+08	8.73E+08		
Calc. Moisture Content (vol % at stack)	8.28	8.07	7.96		
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.38	29.36	29.36		
Temperature (°F) : Dry bulb	82	85	88		
(°F) Wet bulb	76	75	75		
Humidity (lb/lb air)	0.0178	0.0163	0.0156		
Measured Exhaust Emissions *(corrected using Equation 6c-1)*				**Average**	
NOx (ppmv)	1.7	2.2	2.1	**2.0**	
CO (ppmv)	27.7	22.9	19.6	**23.4**	
O2 (vol %)	14.89	14.84	14.84	**14.85**	
CO2 (vol %)	3.44	3.42	3.42	**3.43**	
THC as C3H8 (ppmv)(wet)	0.16	0.21	0.24	**0.2**	
THC AS C3H8 (ppmv)(dry)	0.17	0.23	0.26	**0.22**	
Fo Factor	1.75	1.77	1.77	**1.76**	
Exhaust Flow Rate					
via EPA Method 19's O2 F-factor (SCFH, dry)	2.62E+07	2.60E+07	2.60E+07	**2.61E+07**	
Calculated Mass Emission Rates (via EPA Method19)					**Permit Limit**
NOx (lbs/hr)	5.43	6.72	6.63	**6.3**	**31.2**
CO (lbs/hr)	52.82	43.24	37.10	**44.4**	**156.0**
SO2 (lbs/hr)	0.08	0.08	0.08	**0.1**	
THC (lbs/hr)	0.51	0.67	0.78	**0.66**	**30.0**
NOx (lbs/MMBtu)	0.006	0.008	0.008	**0.007**	**0.013**
CO (lbs/MMBtu)	0.060	0.050	0.042	**0.051**	**0.117**
THC (lbs/MMBtu)	0.001	0.001	0.001	**0.001**	**0.0131**

Table 3
CT2 Reduced Load Summary of Results

Company:	Calpine Corporation				
Location:	Morgan Energy Center, Decatur, Morgan County, AL				
Source:	Westinghouse 501 D Combustion Turbine				
Designation:	Unit 2/CT2				
Technicians	JNT, WMS				
Test Run No.	**8611-CT2-C1**	**8611-CT2-C2**	**8611-CT2-C3**		
Load Condition	**TO, Reduced**	**TO, Reduced**	**TO, Reduced**		
Date	**6/11/04**	**6/11/04**	**6/11/04**		
Start Time	08:30	09:48	11:05		
Stop Time	09:30	10:48	12:05		
Turbine/Compressor Operation					
Turbine Active Power (MW)	60.00	59.99	60.86		
Steam Turbine Generator Active Power (MW)	180.6	200.3	216.5		
Internal Guide Vane Position (%)	42.90	42.90	42.74		
Compressor Exhaust Temperature (°F)	1117.1	1117.9	1117.9		
Fuel Data					
Fuel Heating Value (Btu/lb, GHV)	23283	23283	23283		
Volatile fraction (non-methane,non-ethane % from fuel analysis)	2.33%	2.33%	2.33%		
CO2 F-Factor (DSCF/MMBtu)	1024	1024	1024		
O2 F-Factor (DSCF/MMBtu)	8636	8636	8636		
Total Fuel Sulfur (ppm/wt. from fuel analyses)[reported as<1]	1.0	1.0	1.0		
Fuel Flow Rate (klb/hr)	37.35	37.26	37.57		
Fuel Flow (Btu/hr)	8.70E+08	8.68E+08	8.75E+08		
Calc. Moisture Content (vol % at stack)	8.23	8.09	7.95		
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.30	29.30	29.30		
Temperature (°F) : Dry bulb	83	87	90		
(°F) Wet bulb	76	76	76		
Humidity (lb/lb air)	0.0177	0.0167	0.0160		
Measured Exhaust Emissions *(corrected using Equation 6c-1)*				**Average**	
NOx (ppmv)	2.1	2.0	2.0	**2.0**	
CO (ppmv)	24.8	17.6	18.1	**20.2**	
O2 (vol %)	14.91	14.90	14.93	**14.91**	
CO2 (vol %)	3.43	3.40	3.36	**3.40**	
THC as C3H8 (ppmv)(wet)	0.1	0.1	0.2	**0.2**	
THC as C3H8 (ppmv)(dry)	0.12	0.16	0.25	**0.18**	
Fo Factor	1.75	1.77	1.78	**1.76**	
Exhaust Flow Rate					
via EPA Method 19's O2 F-factor (SCFH, dry)	2.62E+07	2.61E+07	2.64E+07	**2.62E+07**	
Calculated Mass Emission Rates (via EPA Method19)					**Permit Limit**
NOx (lbs/hr)	6.69	6.24	6.31	**6.4**	**31.2**
CO (lbs/hr)	47.15	33.39	34.85	**38.5**	**156.0**
SO2 (lbs/hr)	0.07	0.07	0.08	**0.1**	
THC (lbs/hr)	0.37	0.46	0.75	**0.53**	**30.0**
NOx (lbs/MMBtu)	0.008	0.007	0.007	**0.007**	**0.013**
CO (lbs/MMBtu)	0.054	0.038	0.040	**0.044**	**0.117**
THC (lbs/MMBtu)	0.000	0.000	0.001	**0.001**	**0.0131**

ATTACHMENT C

EMISSION RATE CALCULATIONS

Calpine Blue Heron
Emission Rate Calculations - Table List

Table C-1. Calpine Blue Heron
CTG/HRSG Operating Scenarios

Case No.	Ambient Temperature (°F)	Turbine Inlet Temperature (°F)	Load (%)	CTG 1-4	Annual Profile A (hr/yr)	Annual Profile B (hr/yr)	Annual Profile C (hr/yr)	Annual Profile D (hr/yr)	Annual Profile E (hr/yr)	Inlet Air Fogging	Duct Burner Firing
	Winter										
1	20.0	20.0	100	X							
2	20.0	20.0	100	X							X
3	20.0	20.0	60	X							
	ISO										
4	59.0	53.5	100	X	8,760		5,700	4,380	3,800	X	
5	59.0	53.5	100	X						X	X
6	59.0	59.0	100	X							
7	59.0	59.0	60	X			1,500	1,500			
	Annual Average										
8	80.0	71.6	100	X						X	
9	80.0	71.6	100	X		8,760				X	X
10	80.0	80.0	100	X							
11	80.0	80.0	60	X							
	Summer										
12	90.0	80.0	100	X						X	
13	90.0	80.0	100	X			1,560	2,880	2,880	X	X
14	90.0	90.0	100	X							
15	90.0	90.0	60	X							
16	85.8	85.8	35	X					2,080		
				Totals	8,760	8,760	8,760	8,760	8,760		

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-2. Calpine Blue Heron (Page 1 of 2)
CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Amb. Temp. (^oF)	Case	Load (%)	PM_{10} [1] (lb/hr)	PM_{10} [1] (g/sec)	SO_2 [2] (lb/hr)	SO_2 [2] (g/sec)	H_2SO_4 [3] (lb/hr)	H_2SO_4 [3] (g/sec)	Lead [4] (lb/hr)	Lead [4] (g/sec)
20	1	100	9.0	1.134	11.9	1.496	2.18	0.275	0.0010	0.00013
	2	100	**14.2**	1.784	**14.2**	1.789	**2.61**	0.329	**0.0012**	0.00016
	3	60	6.5	0.819	8.0	1.005	1.47	0.185	0.0007	0.00009
59	4	100	8.5	1.065	11.1	1.395	2.03	0.256	0.0010	0.00012
	5	100	13.6	1.715	13.4	1.688	2.46	0.310	0.0012	0.00015
	6	100	8.4	1.052	10.9	1.373	2.00	0.252	0.0010	0.00012
	7	60	6.1	0.769	7.4	0.937	1.37	0.172	0.0007	0.00008
80	8	100	8.0	1.008	10.5	1.328	1.94	0.244	0.0009	0.00012
	9	100	13.2	1.658	12.9	1.621	2.36	0.298	0.0011	0.00014
	10	100	7.9	0.989	10.3	1.292	1.88	0.237	0.0009	0.00011
	11	60	5.9	0.737	7.0	0.887	1.29	0.163	0.0006	0.00008
90	12	100	7.8	0.977	10.3	1.296	1.89	0.238	0.0009	0.00011
	13	100	12.9	1.627	12.6	1.589	2.32	0.292	0.0011	0.00014
	14	100	7.6	0.958	10.0	1.255	1.83	0.231	0.0009	0.00011
	15	60	5.7	0.718	6.9	0.866	1.26	0.159	0.0006	0.00008
	16	35	4.3 [9]	0.539	5.0	0.625	0.91	0.115	0.0004	0.00005
		Maximums	**14.2**	**1.784**	**14.2**	**1.789**	**2.61**	**0.329**	**0.0012**	**0.00016**

Table C-2. Calpine Blue Heron (Page 2 of 2)
CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Amb. Temp. (°F)	Case	Load (%)	NOx (ppmvd)[5]	NOx (lb/hr)	NOx (g/sec)	CO[6] (ppmvd)[5]	CO[6] (lb/hr)	CO[6] (g/sec)	VOC[7,8] (ppmvd)[5]	VOC[7,8] (lb/hr)	VOC[7,8] (g/sec)
20	1	100	2.0	15.6	1.97	1.0	4.8	6.05	0.6	1.7	0.208
	2	100	2.0	**18.9**	2.38	1.6	9.1	11.47	1.9	**6.0**	0.750
	3	60	2.0	10.5	1.32	**5.0**	**16.0**	20.16	1.5	2.8	0.347
59	4	100	2.0	14.6	1.83	1.0	4.5	5.67	0.6	1.5	0.189
	5	100	2.0	17.8	2.24	1.7	8.8	11.09	1.9	5.8	0.731
	6	100	2.0	14.3	1.80	1.0	4.4	5.54	0.6	1.5	0.189
	7	60	2.0	9.8	1.23	**5.0**	14.9	18.77	1.5	2.6	0.321
80	8	100	2.0	13.8	1.74	1.0	4.2	5.29	0.6	1.5	0.183
	9	100	2.0	17.2	2.16	1.7	8.5	10.71	2.0	5.8	0.725
	10	100	2.0	13.5	1.70	1.0	4.1	5.17	0.6	1.4	0.176
	11	60	2.0	9.3	1.17	**5.0**	14.1	17.77	1.5	2.4	0.302
90	12	100	2.0	13.5	1.70	1.0	4.1	5.17	0.6	1.4	0.176
	13	100	2.0	16.8	2.12	1.7	8.4	10.58	**2.0**	5.7	0.718
	14	100	2.0	13.1	1.65	1.0	4.0	5.04	0.6	1.4	0.170
	15	60	2.0	9.0	1.14	**5.0**	13.8	17.39	1.5	2.4	0.296
	16[10]	35	2.0	7.4	0.93	2.7	5.1	6.43	0.3	0.4	0.047
		Maximums	**2.0**	**18.9**	**2.38**	**5.0**	**16.0**	**20.16**	**2.0**	**6.0**	**0.750**

[1] As measured by EPA Reference Method 5B.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft³.
[3] Based on 8.0% conversion of fuel S to SO_3 (CTG), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
[4] Based on EPA AP-42 emission factor, Table 1.4-2.
[5] Corrected to 15% O_2.
[6] Controlled by oxidation catalyst at 90% efficiency.
[7] Controlled by oxidation catalyst at 50% efficiency.
[8] Non-methane, non-ethane VOCs expressed as methane equivalents.
[9] Based on linear interpolation of Siemens Westinghouse PM_{10} data.
[10] Mass emission estimates derived from Morgan Energy Center stack test data (2004), plus 15% margin.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-3. Calpine Blue Heron
Duct Burner Hourly Emission Rates - Without SCR (Per Duct Burner)

Load (%)	Heat Input (MMBtu/hr)	PM/PM_{10} [1] (lb/MMBtu)	PM/PM_{10} [1] (lb/hr)	PM/PM_{10} [1] (g/sec)	SO_2 [2] (lb/MMBtu)	SO_2 [2] (lb/hr)	SO_2 [2] (g/sec)	H_2SO_4 [3] (lb/MMBtu)	H_2SO_4 [3] (lb/hr)	H_2SO_4 [3] (g/sec)
100	430	0.012	5.2	0.65	0.0054	2.3	0.29	0.00099	0.43	0.054
75	323	0.012	3.9	0.49	0.0054	1.7	0.22	0.00099	0.32	0.040
50	215	0.012	2.6	0.33	0.0054	1.2	0.15	0.00099	0.21	0.027
Maximum		**0.012**	**5.2**	**0.65**	**0.0054**	**2.3**	**0.29**	**0.00099**	**0.43**	**0.054**

Load (%)	Heat Input (MMBtu/hr)	NO_x (lb/MMBtu)	NO_x (lb/hr)	NO_x (g/sec)	CO (lb/MMBtu)	CO (lb/hr)	CO (g/sec)	VOC [4] (lb/MMBtu)	VOC [4] (lb/hr)	VOC [4] (g/sec)
100	430	0.080	34.4	4.33	0.100	43.0	5.42	0.020	8.6	1.08
75	323	0.080	25.8	3.25	0.100	32.3	4.06	0.020	6.5	0.81
50	215	0.080	17.2	2.17	0.100	21.5	2.71	0.020	4.3	0.54
Maximum		**0.080**	**34.4**	**4.33**	**0.100**	**43.0**	**5.42**	**0.020**	**8.6**	**1.08**

[1] As measured by EPA Reference Method 5B.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 8.0% conversion of fuel S to SO_3 (DB), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
[4] Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: Calpine, 2004.
ECT, 2004.

Table C.4.A. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile A

Parameter	Units	Annual Profile A Case 4
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	2,045
Maximum Annual Hours:	hrs/yr	8,760

Pollutant	Emission Factor [a], [b] (lb/10^6 Btu)	Emission Rates (Per CTG) Case 4 (lb/hr)	Emission Rates (Per CTG) Annual (ton/yr)	CTG 1-4 Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0005	0.0022
Acetaldehyde	4.31E-05	0.088	0.3861	1.54
Acrolein	5.60E-06	0.011	0.0502	0.20
Arsenic	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.037	0.164	0.66
Cadmium	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.047	0.204	0.82
Formaldehyde	1.14E-04	**0.233**	**1.021**	**4.09**
Lead	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000016	0.000007	0.000028
Naphthalene	6.33E-07	0.001	0.006	0.023
Nickel	N/A	N/A	N/A	N/A
Phosphorus	N/A	N/A	N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.004	0.017
Propylene Oxide	2.86E-05	0.058	0.256	1.025
Toluene	6.80E-05	0.139	0.609	2.437
Xylene	6.51E-05	0.133	0.583	2.333
Maximum Individual HAP		0.233	1.021	4.085
Total HAPs		0.750	3.285	13.140

[a] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.

[b] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C.4.B. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile B

Parameter	Units	Annual Profile B
		Case 9
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,947
Maximum Annual Hours:	hrs/yr	8,760

Pollutant	Emission Factor [a], [b] ($lb/10^6$ Btu)	Emission Rates (Per CTG)		CTG 1-4
		Case 9 (lb/hr)	Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0005	0.002
Acetaldehyde	4.31E-05	0.084	0.3676	1.470
Acrolein	5.60E-06	0.011	0.0478	0.191
Arsenic	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.036	0.1561	0.624
Cadmium	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.044	0.1945	0.778
Formaldehyde	1.14E-04	**0.222**	**0.972**	**3.889**
Lead	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000015	0.0000	0.000027
Naphthalene	6.33E-07	0.001	0.0054	0.022
Nickel	N/A	N/A	N/A	N/A
Phosphorus	N/A	N/A	N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.0040	0.016
Propylene Oxide	2.86E-05	0.056	0.2439	0.976
Toluene	6.80E-05	0.132	0.5800	2.320
Xylene	6.51E-05	0.127	0.5553	2.221
Maximum Individual HAP		0.222	0.972	3.889
Total HAPs		0.714	3.127	12.510

[a] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.

[b] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C.4.C. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile C

Parameter	Units	Annual Profile C		
		Case 4	Case 7	Case 13
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	2,045	1,374	1,901
Maximum Annual Hours:	hrs/yr	5,700	1,500	1,560

Pollutant	Emission Factor [(a), (b)] (lb/10^6 Btu)	Emission Rates (Per CTG)				CTG 1-4
		Case 4 (lb/hr)	Case 7 (lb/hr)	Case 13 (lb/hr)	Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0005	0.002
Acetaldehyde	4.31E-05	0.088	0.059	0.082	0.3596	1.438
Acrolein	5.60E-06	0.011	0.008	0.011	0.0467	0.187
Arsenic	N/A	N/A	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.037	0.025	0.035	0.1527	0.611
Cadmium	N/A	N/A	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.047	0.031	0.043	0.1902	0.761
Formaldehyde	1.14E-04	**0.233**	**0.157**	**0.217**	**0.9511**	**3.804**
Lead	N/A	N/A	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000016	0.0000011	0.0000015	0.0000065	0.000026
Naphthalene	6.33E-07	0.001	0.001	0.001	0.0053	0.021
Nickel	N/A	N/A	N/A	N/A	N/A	N/A
Phosphorus	N/A	N/A	N/A	N/A	N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.001	0.0039	0.016
Propylene Oxide	2.86E-05	0.058	0.039	0.054	0.2386	0.954
Toluene	6.80E-05	0.139	0.093	0.129	0.5673	2.269
Xylene	6.51E-05	0.133	0.089	0.124	0.5431	2.172
Maximum Individual HAP		0.233	0.157	0.217	0.951	3.804
Total HAPs		0.750	0.504	0.697	3.059	12.236

[(a)] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.

[(b)] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C.4.D. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile D

Parameter	Units	Annual Profile D		
		Case 4	Case 7	Case 13
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	2,045	1,374	1,901
Maximum Annual Hours:	hrs/yr	4,380	1,500	2,880

Pollutant	Emission Factor [(a), (b)] (lb/10^6 Btu)	Emission Rates (Per CTG)				CTG 1-4
		Case 4 (lb/hr)	Case 7 (lb/hr)	Case 13 (lb/hr)	Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0005	0.002
Acetaldehyde	4.31E-05	0.088	0.059	0.082	0.3555	1.422
Acrolein	5.60E-06	0.011	0.008	0.011	0.0462	0.185
Arsenic	N/A	N/A	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.037	0.025	0.035	0.1509	0.604
Cadmium	N/A	N/A	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.047	0.031	0.043	0.1880	0.752
Formaldehyde	1.14E-04	**0.233**	**0.157**	**0.217**	**0.9402**	**3.761**
Lead	N/A	N/A	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000016	0.0000011	0.0000015	0.0000064	0.000026
Naphthalene	6.33E-07	0.001	0.001	0.001	0.0052	0.021
Nickel	N/A	N/A	N/A	N/A	N/A	N/A
Phosphorus	N/A	N/A	N/A	N/A		
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.001	0.0039	0.016
Propylene Oxide	2.86E-05	0.058	0.039	0.054	0.2359	0.944
Toluene	6.80E-05	0.139	0.093	0.129	0.5608	2.243
Xylene	6.51E-05	0.133	0.089	0.124	0.5369	2.148
Maximum Individual HAP		0.233	0.157	0.217	0.940	3.761
Total HAPs		0.750	0.504	0.697	3.024	12.096

(a) - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
(b) - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C.4.E. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile E

Parameter	Units	Annual Profile E Case 4	Case 13	Case 16
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	2,045	1,901	917
Maximum Annual Hours:	hrs/yr	3,800	2,880	2,080

Pollutant	Emission Factor [(a), (b)] (lb/10^6 Btu)	Emission Rates (Per CTG) Case 4 (lb/hr)	Case 13 (lb/hr)	Case 16 (lb/hr)	Annual (ton/yr)	CTG 1-4 Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0005	0.002
Acetaldehyde	4.31E-05	0.088	0.082	0.040	0.3266	1.306
Acrolein	5.60E-06	0.011	0.011	0.005	0.0424	0.170
Arsenic	N/A	N/A	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.037	0.035	0.017	0.1387	0.555
Cadmium	N/A	N/A	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.047	0.043	0.021	0.1728	0.691
Formaldehyde	1.14E-04	**0.233**	**0.217**	**0.104**	**0.8638**	**3.455**
Lead	N/A	N/A	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000016	0.0000015	0.0000007	0.0000059	0.000024
Naphthalene	6.33E-07	0.001	0.001	0.001	0.0048	0.019
Nickel	N/A	N/A	N/A	N/A	N/A	N/A
Phosphorus	N/A	N/A	N/A	N/A		
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.000	0.0036	0.014
Propylene Oxide	2.86E-05	0.058	0.054	0.026	0.2167	0.867
Toluene	6.80E-05	0.139	0.129	0.062	0.5153	2.061
Xylene	6.51E-05	0.133	0.124	0.060	0.4933	1.973
Maximum Individual HAP		0.233	0.217	0.104	0.864	3.455
Total HAPs		0.750	0.697	0.336	2.778	11.113

(a) - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
(b) - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C.5. Calpine Blue Heron
Duct Burner (DB): Hazardous Air Pollutants

Parameter	Units	Annual Profile 100%
Maximum DB Hourly Heat Input:	10^6 Btu/hr, HHV	430.0
Maximum Annual Hours:	hrs/yr	8,760

Pollutant	Emission Factor [(a), (b)] ($lb/10^{12}$ Btu)	Emission Rates (Per DB) 100% (lb/hr)	Emission Rates (Per DB) Annual (ton/yr)	DB 1-4 Annual (ton/yr)
1,3-Butadiene	N/A	N/A	N/A	N/A
Acetaldehyde	N/A	N/A	N/A	N/A
Acrolein	N/A	N/A	N/A	N/A
Arsenic	0.140	0.000060	0.00026	0.00105
Benzene	1.400	0.000602	0.00264	0.01055
Cadmium	0.044	0.000019	0.00008	0.00033
Chromium	0.960	0.000413	0.00181	0.00723
Cobalt	0.120	0.000052	0.00023	0.00090
Ethylbenzene	N/A	N/A	N/A	N/A
Formaldehyde	35.500	**0.015265**	**0.06686**	**0.26744**
Lead	0.370	0.000159	0.00070	0.00279
Manganese	0.300	0.000129	0.00057	0.00226
Mercury	0.380	0.000163	0.00072	0.00286
Naphthalene	0.700	0.000301	0.00132	0.00527
Nickel	2.300	0.000989	0.00433	0.01733
Phosphorus	2.200	0.000946	0.00414	0.01657
Polycyclic Aromatic Hydrocarbons	0.049	0.000021	0.00009	0.00037
Propylene Oxide	N/A	N/A	N/A	N/A
Toluene	N/A	N/A	N/A	N/A
Xylene	N/A	N/A	N/A	N/A
Maximum Individual HAP		0.015	0.067	0.267
Total HAPs		0.019	0.084	0.335

[(a)] - All inorganic emission factors from Table C-1.3, Draft Study of HAP Emissions from Electric Utilitiy Steam Generating Units, EPA, June 1995.

[(b)] - All organic emission factors from Table C-1.6, Draft Study of HAP Emissions from Electric Utilitiy Steam Generating Units, EPA, June 1995.

Sources: Calpine, 2004.
ECT, 2004.

Table C.6. Calpine Blue Heron
CTG/DB Annual Emission Rate Summary
Hazardous Air Pollutants

Pollutant	CTG 1-4 Emissions (ton/yr)	DB 1-4 Emissions (ton/yr)	Total Emissions (ton/yr)
1,3-Butadiene	0.002	N/A	0.0022
Acetaldehyde	1.545	N/A	1.5445
Acrolein	0.201	N/A	0.2007
Arsenic	N/A	0.00105	0.0011
Benzene	0.656	0.01055	0.6663
Cadmium	N/A	0.00033	0.00033
Chromium	N/A	0.00723	0.0072
Cobalt	N/A	0.00090	0.0009
Ethylbenzene	0.817	N/A	0.8171
Formaldehyde	**4.085**	**0.26744**	**4.3527**
Lead	N/A	0.00279	0.0028
Manganese	N/A	0.00226	0.0023
Mercury	0.000028	0.00286	0.0029
Naphthalene	0.023	0.00527	0.0280
Nickel	N/A	0.01733	0.0173
Phosphorus	N/A	0.01657	0.0166
Polycyclic Aromatic Hydrocarbons	0.017	0.00037	0.0173
Propylene Oxide	1.025	N/A	1.0249
Toluene	2.437	N/A	2.4368
Xylene	2.333	N/A	2.3329
Maximum Individual HAP	4.085	0.267	4.353
Total HAPs	13.140	0.335	13.475

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-7.A. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile A
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	4	4	8,760	58.2	255.1	18.0	78.8	6.0	26.3
		Totals	**8,760**	**N/A**	**255.1**	**N/A**	**78.8**	**N/A**	**26.3**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	4	4	8,760	33.8	148.0	44.3	193.9	0.004	0.017	8.1	35.6
		Totals	**8,760**	**N/A**	**148.0**	**N/A**	**193.9**	**N/A**	**0.017**	**N/A**	**35.6**

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-7.B. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile B
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	9	4	8,760	68.6	300.6	34.0	148.9	23.0	100.7
		Totals	**8,760**	**N/A**	**300.6**	**N/A**	**148.9**	**N/A**	**100.7**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	9	4	8,760	52.6	230.6	51.5	225.4	0.005	0.020	9.5	41.4
		Totals	**8,760**	**N/A**	**230.6**	**N/A**	**225.4**	**N/A**	**0.020**	**N/A**	**41.4**

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-7.C. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile C
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	4	4	5,700	58.2	166.0	18.0	51.3	6.0	17.1
CTG/HRSG1-4	7	4	1,500	39.0	29.3	59.6	44.7	10.2	7.7
CTG/HRSG1-4	13	4	1,560	67.4	52.5	33.6	26.2	22.8	17.8
		Totals	**8,760**	**N/A**	**247.8**	**N/A**	**122.2**	**N/A**	**42.5**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	4	4	5,700	33.8	96.3	44.3	126.2	0.004	0.011	8.1	23.2
CTG/HRSG1-4	7	4	1,500	24.4	18.3	29.7	22.3	0.003	0.002	5.5	4.1
CTG/HRSG1-4	13	4	1,560	51.6	40.3	50.5	39.4	0.004	0.003	9.3	7.2
		Totals	**8,760**	**N/A**	**154.9**	**N/A**	**187.8**	**N/A**	**0.016**	**N/A**	**27.3**

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-7.D. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile D
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	4	4	4,380	58.2	127.5	18.0	39.4	6.0	13.1
CTG/HRSG1-4	7	4	1,500	39.0	29.3	59.6	44.7	10.2	7.7
CTG/HRSG1-4	13	4	2,880	67.4	97.0	33.6	48.4	22.8	32.8
		Totals	**8,760**	**N/A**	**253.8**	**N/A**	**132.5**	**N/A**	**53.6**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	4	4	4,380	33.8	74.0	44.3	97.0	0.004	0.008	8.1	17.8
CTG/HRSG1-4	7	4	1,500	24.4	18.3	29.7	22.3	0.003	0.002	5.5	4.1
CTG/HRSG1-4	13	4	2,880	51.6	74.4	50.5	72.7	0.004	0.006	9.3	13.4
		Totals	**8,760**	**N/A**	**166.7**	**N/A**	**191.9**	**N/A**	**0.017**	**N/A**	**35.3**

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-7.E. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile E
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates NO$_x$ (lb/hr)	NO$_x$ (tpy)	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)
CTG/HRSG1-4	4	4	3,800	58.2	110.7	18.0	34.2	6.0	11.4
CTG/HRSG1-4	13	4	2,880	67.4	97.0	33.6	48.4	22.8	32.8
CTG/HRSG1-4	16	4	2,080	29.5	30.7	20.4	21.2	1.5	1.6
		Totals	**8,760**	**N/A**	**238.3**	**N/A**	**103.8**	**N/A**	**45.8**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates PM/PM$_{10}$ (lb/hr)	PM/PM$_{10}$ (tpy)	SO$_2$ (lb/hr)	SO$_2$ (tpy)	Lead (lb/hr)	Lead (tpy)	H$_2$SO$_4$ (lb/hr)	H$_2$SO$_4$ (tpy)
CTG/HRSG1-4	4	4	3,800	33.8	64.2	44.3	84.1	0.004	0.007	8.1	15.5
CTG/HRSG1-4	13	4	2,880	51.6	74.4	50.5	72.7	0.004	0.006	9.3	13.4
CTG/HRSG1-4	16	4	2,080	17.1	17.8	19.8	20.6	0.002	0.002	3.6	3.8
		Totals	**8,760**	**N/A**	**156.4**	**N/A**	**177.4**	**N/A**	**0.016**	**N/A**	**32.6**

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-7.F. Calpine Blue Heron
CTG/HRSG Annual Emission Rate Summary
Criteria Air Pollutants and Sulfuric Acid Mist

Annual Profile	Annual Emissions (ton/yr)						
	NO_x	CO	VOC	PM/PM_{10}	SO_2	Pb	H_2SO_4
A	255.1	78.8	26.3	148.0	193.9	0.017	35.6
B	**300.6**	**148.9**	**100.7**	**230.6**	**225.4**	**0.020**	**41.4**
C	247.8	122.2	42.5	154.9	187.8	0.016	27.3
D	253.8	132.5	53.6	166.7	191.9	0.017	35.3
E	238.3	103.8	45.8	156.4	177.4	0.016	32.6
Maximums	300.6	148.9	100.7	230.6	225.4	0.020	41.4

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-8. Calpine Blue Heron
CTG/HRSG Exhaust Flow Rates (Per CTG/HRSG)

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole)											60 % Load				35% Load[1]
		20 °F	20 °F	59 °F	59 °F	59 °F	80 °F	80 °F	80 °F	90 °F	90 °F	90 °F	20 °F	59 °F	80 °F	90 °F	85.8 °F
	Case	1	2	4	5	6	8	9	10	12	13	14	3	7	11	15	16
Ar	39.944	0.90	0.89	0.89	0.88	0.89	0.88	0.87	0.88	0.87	0.86	0.87	0.90	0.89	0.88	0.88	0.88
N_2	28.013	75.03	74.44	74.32	73.71	74.48	73.46	72.82	73.70	72.87	72.23	73.16	75.20	74.65	73.90	73.37	74.22
O_2	31.999	12.64	10.98	12.55	10.79	12.62	12.37	10.54	12.48	12.22	10.35	12.35	13.14	13.11	13.06	12.97	13.65
CO_2	44.010	3.76	4.51	3.71	4.51	3.70	3.69	4.52	3.66	3.68	4.53	3.65	3.54	3.48	3.40	3.38	3.15
H_2O	18.015	7.68	9.18	8.53	10.11	8.31	9.61	11.25	9.27	10.36	12.03	9.96	7.23	7.87	8.75	9.41	8.10
	Totals	100.01	100.00	100.00	100.00	100.00	100.01	100.00	99.99	100.00	100.00	99.99	100.01	100.00	99.99	100.01	100.00
Exhaust MW (lb/mole)		28.46	28.36	28.36	28.26	28.38	28.24	28.14	28.27	28.16	28.05	28.19	28.49	28.41	28.31	28.24	28.36
Exhaust Flow (lb/sec)		1,153.31	1,158.43	1,086.72	1,086.72	1,074.77	1,036.87	1,042.00	1,016.83	1,011.36	1,016.48	988.20	825.37	780.88	753.16	739.14	579.87
Exhaust Temp. (°F)		165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
(K)		347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347
Ambient Temp. (°F)		20	20	59	59	59	80	80	80	90	90	90	20	59	80	90	86
(K)		266	266	288	288	288	300	300	300	305	305	305	266	288	300	305	303
Exhaust O_2 (Vol %, Dry)		13.69	12.09	13.72	12.01	13.76	13.69	11.87	13.76	13.63	11.76	13.72	14.16	14.23	14.31	14.32	14.85

B. Exhaust Flow Rates

Case											60 % Load				35% Load[1]
	20 °F	20 °F	59 °F	59 °F	59 °F	80 °F	80 °F	80 °F	90 °F	90 °F	90 °F	20 °F	59 °F	80 °F	90 °F	85.8 °F
	1	2	4	5	6	8	9	10	12	13	14	3	7	11	15	16
ACFM	1,109,006	1,117,862	1,048,679	1,052,459	1,036,305	1,004,712	1,013,558	984,315	983,002	991,747	959,217	792,840	752,184	728,214	716,364	559,658
Stack Diameter (ft)	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Stack Area (ft^2)	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8	268.8
Velocity (fps)	68.8	69.3	65.0	65.3	64.3	62.3	62.8	61.0	60.9	61.5	59.5	49.2	46.6	45.2	44.4	34.7
Velocity (m/s)	21.0	21.1	19.8	19.9	19.6	19.0	19.2	18.6	18.6	18.7	18.1	15.0	14.2	13.8	13.5	10.6
SCFM, Dry[2]	864,851	857,558	810,276	799,120	802,641	767,139	759,837	754,391	744,334	736,948	729,565	621,305	585,379	561,311	548,183	434,444
SCFM, Dry @ 15% O_2	1,056,656	1,281,221	986,017	1,204,567	970,819	938,101	1,162,634	913,568	916,880	1,141,113	888,323	709,334	661,786	626,734	611,619	445,490

[1] Data derived from Morgan Energy Center stack test, 2004.
[2] At 68 °F.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-9. Calpine Blue Heron
CTG/HRSG Hourly Fuel Flow Rates (Per CTG/HRSG)

												60 % Load				30% Load[5]
	20 °F	20 °F	59 °F	59 °F	59 °F	80 °F	80 °F	80 °F	90 °F	90 °F	90 °F	20 °F	59 °F	80 °F	90 °F	85.8 °F
Case	1	2	4	5	6	8	9	10	12	13	14	3	7	11	15	16
Heat Input - HHV[1] (MMBtu/hr)	2,194	2,624	2,045	2,475	2,013	1,947	2,377	1,895	1,901	2,331	1,841	1,474	1,374	1,301	1,270	917
Heat Input - LHV[2] (MMBtu/hr)	1,976	2,363	1,842	2,229	1,813	1,754	2,141	1,707	1,712	2,099	1,658	1,327	1,237	1,171	1,144	825
Fuel Rate[3] (lb/hr)	94,175	112,630	87,791	106,246	86,405	83,580	102,036	81,354	81,596	100,051	79,013	63,263	58,968	55,829	54,516	39,343
Fuel Rate (lb/sec)	26.160	31.286	24.386	29.513	24.001	23.217	28.343	22.598	22.665	27.792	21.948	17.573	16.380	15.508	15.143	10.929
Fuel Rate[4] (10^6 ft^3/hr)	2.078	2.485	1.937	2.344	1.906	1.844	2.251	1.795	1.800	2.207	1.743	1.396	1.301	1.232	1.203	0.868

[1] Based on natural gas heat content of 23,299 Btu/lb (HHV).
[2] Based on natural gas heat content of 20,981 Btu/lb (LHV).
[3] Includes 5.0 % margin.
[4] Based on natural gas density of 0.04533 lb/ft^3.
[5] Data derived from Morgan Energy Center stack test, 2004.

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

Table C-10. Calpine Blue Heron
CTG NSPS Subpart GG Limit (Per CTG)

Fuel	501F Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,240	9.749	0.0	110.8

Sources: ECT, 2004.
Siemens Westinghouse, 2002.

POTENTIAL EMISSION INVENTORY WORKSHEET

C.11. GAS-HTR

Calpine Blue Heron Energy Center

EMISSION SOURCE TYPE

EXTERNAL COMBUSTION SOURCES - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Two Natural Gas Fuel Heaters	
Emission Control Method(s)/ID No.(s):	None	
Emission Point Description:	9.30	MMBtu/hr (HHV) Rated Capacity, Each Heater

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/MMBtu) x Rated Capacity (MMBtu/hr)

Emission (ton/yr) = Emission Factor (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2004.

INPUT DATA AND EMISSIONS CALCULATIONS

Heater Data (Per Heater)		
Operating Hours:	8,760	hrs/yr
Maximum Heat Input:	9.30	MMBtu/hr (HHV)
Fuel Consumption:	0.0089	$MMft^3/hr$
No. of Heaters:	2	

Criteria Pollutant	Emission Factor ($lb/MMft^3$)	Potential Emission Rates (Per Heater)		Potential Emission Rates (All Heaters)	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)
NO_x	100	0.886	3.88	1.77	7.76
CO	84	0.744	3.26	1.49	6.52
VOC	5.5	0.049	0.21	0.10	0.43
SO_2	6.0	0.053	0.23	0.11	0.47
PM	7.6	0.067	0.29	0.13	0.59
PM_{10}	7.6	0.067	0.29	0.13	0.59

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2004.
Maximum Heat Input (MMBtu/hr, HHV)	Calpine, 2004.
Emission Factors (NO_x and CO)	AP-42, Table 1.4-1, EPA, July 1998.
Emission Factors (SO_2,PM/PM_{10}, and VOC)	AP-42, Table 1.4-2, EPA, July 1998.

NOTES AND OBSERVATIONS

AP-42 SO_2 emission factor adjusted to reflect natural gas sulfur content of 2.0 gr S/100 ft^3.

DATA CONTROL

Data Collected by:	T.Davis, ECT	Date:	Nov-04
Data Entered by:	T.Davis, ECT	Date:	Nov-04
Reviewed by:	T.Davis, ECT	Date:	Nov-04

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

C.12
EG-ENG

EMISSION SOURCE TYPE

DIESEL ENGINES - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Stationary Diesel Engine
Emission Control Method(s)/ID No.(s):	None
Emission Point Description:	1,400 kW Emergency Generator Diesel Engine

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/hr)

Emission (ton/yr) = Emission Factor (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2004.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours:	250	hrs/yr
Fuel Flow:	29,200	gal/yr
Fuel Flow:	116.8	gal/hr
Diesel Fuel Oil Sulfur Content:	0.05	weight %
Diesel Fuel Oil Heat Content:	141,000	Btu/gal (HHV)
Heat Input:	16.47	MMBtu/hr (HHV)

Criteria Pollutant	Emission Factor (lb/hr)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
NO_x	37.24	37.24	4.66
CO	8.34	8.34	1.04
TOC	1.48	1.48	0.19
SO_2	0.820	0.82	0.10
PM	1.380	1.38	0.17
PM_{10}	1.380	1.38	0.17

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2004.
Fuel Flow Rate (gal/yr)	Calpine, 2004.
Emission Factors (all except TOC)	Calpine, 2000.
Emission Factor (TOC)	AP-42, Table 3.4-1, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Davis, ECT	Date:	Nov-04
Data Entered by:	T.Davis, ECT	Date:	Nov-04
Reviewed by:	T.Davis, ECT	Date:	Nov-04

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

C.13. FW-ENG

EMISSION SOURCE TYPE

DIESEL ENGINES - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	*Stationary Diesel Engine*
Emission Control Method(s)/ID No.(s):	None
Emission Point Description:	Fire Water Pump Diesel Engine

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/hr)

Emission (ton/yr) = Emission Factor (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2004.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours:	100	hrs/yr
Fuel Flow:	2,000	gal/yr
Fuel Flow:	20.0	gal/hr
Diesel Fuel Oil Sulfur Content:	0.05	weight %
Diesel Fuel Oil Heat Content:	141,000	Btu/gal (HHV)
Heat Input:	2.82	MMBtu/hr (HHV)

Criteria Pollutant	Emission Factor (lb/hr)	Potential Emission Rates (lb/hr)	(tpy)
NO_x	7.41	7.41	0.37
CO	1.75	1.75	0.09
TOC	1.02	1.02	0.05
SO_2	0.140	0.14	0.007
PM	0.130	0.13	0.007
PM_{10}	0.130	0.13	0.007

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2004.
Fuel Flow Rate (gal/yr)	Calpine, 2004.
Emission Factors (all except TOC)	Calpine, 2000.
Emission Factor (TOC)	AP-42, Table 3.3-1, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Davis, ECT	Date:	Nov-04
Data Entered by:	T.Davis, ECT	Date:	Nov-04
Reviewed by:	T.Davis, ECT	Date:	Nov-04

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

C.14. MAIN-CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Cooling Towers
Emission Control Method(s)/ID No.(s):	*Mist Eliminators*
Emission Point Description:	North and South Cooling Towers

EMISSION ESTIMATION EQUATIONS

PM Emission (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) $/10^6$) x 60 min/hr

PM Emission (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

PM_{10} Emission (lb/hr) = PM Emissions (lb/hr) x PM_{10}/PM Fraction

PM_{10} Emission (ton/yr) = PM_{10} Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2004.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data (Per Tower)

Operating Hours:	8,760	hrs/yr
Number of Cells:	10	
Recirculating Water Flow Rate:	150,000	gal/min
Drift Loss Rate:	0.0005	%
Total Dissolved Solids (TDS):	10,000	ppmw
PM_{10}/PM Fraction:	0.063	
Number of Towers:	2	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.38	1.64	7.51	32.90
PM_{10}	0.024	0.10	0.47	2.07

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2004.
Recirculating Water Flow Rate (gpm)	Calpine, 2004.
Drift Loss Rate (%)	Calpine, 2004.
Total Dissolved Solids (ppmw)	*Calpine, 2004.*
PM_{10}/PM Fraction:	ECT, 2004.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Davis, ECT	Nov-04
Data Entered by:	T.Davis, ECT	Nov-04
Reviewed by:	T.Davis, ECT	Nov-04

Table C.15. - Calpine Blue Heron Energy Center
Cooling Tower PM_{10} Fraction - Cooling Towers

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM_{10} Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	10,000	ppmw
Cooling Tower PM_{10} Density (assumed NaCl):	2.2	g/cm^3

Particle Size Distribution:

Droplet Diameter (μm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (μm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	5.24E-12	2.38E-18	1.657	0.000
20	4.19E-15	4.19E-09	4.19E-11	1.90E-17	3.313	0.196
30	1.41E-14	1.41E-08	1.41E-10	6.43E-17	4.970	0.226
40	3.35E-14	3.35E-08	3.35E-10	1.52E-16	6.626	0.514
50	6.54E-14	6.54E-08	6.54E-10	2.97E-16	8.283	1.816
60	1.13E-13	1.13E-07	1.13E-09	5.14E-16	9.939	5.702
70	1.80E-13	1.80E-07	1.80E-09	8.16E-16	11.596	21.348
90	3.82E-13	3.82E-07	3.82E-09	1.74E-15	14.909	49.812
110	6.97E-13	6.97E-07	6.97E-09	3.17E-15	18.222	70.509
130	1.15E-12	1.15E-06	1.15E-08	5.23E-15	21.535	82.023
150	1.77E-12	1.77E-06	1.77E-08	8.03E-15	24.848	88.012
180	3.05E-12	3.05E-06	3.05E-08	1.39E-14	29.817	91.032
210	4.85E-12	4.85E-06	4.85E-08	2.20E-14	34.787	92.468
240	7.24E-12	7.24E-06	7.24E-08	3.29E-14	39.756	94.091
270	1.03E-11	1.03E-05	1.03E-07	4.68E-14	44.726	94.689
300	1.41E-11	1.41E-05	1.41E-07	6.43E-14	49.695	96.288
350	2.24E-11	2.24E-05	2.24E-07	1.02E-13	57.978	97.011
400	3.35E-11	3.35E-05	3.35E-07	1.52E-13	66.260	98.340
450	4.77E-11	4.77E-05	4.77E-07	2.17E-13	74.543	99.071
500	6.54E-11	6.54E-05	6.54E-07	2.97E-13	82.825	99.071
600	1.13E-10	1.13E-04	1.13E-06	5.14E-13	99.390	100.000

Linear Interpolation:

Droplet Diameter (μm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (μm)	Mass Fraction (%)
60	1.13E-13	1.13E-07	1.13E-09	5.14E-16	9.939	5.702
70	1.80E-13	1.80E-07	1.80E-09	8.16E-16	11.596	21.348
					10.000	**6.278**

Mass Fraction of Cooling Tower PM ≤ PM_{10}:	0.063

Sources: Calpine, 2004.
ECT, 2004.

Table C-16. Calpine Blue Heron
Total Facility Annual Emission Rate Summary
Criteria Air Pollutants and Sulfuric Acid Mist

Emission Source	Annual Emissions (ton/yr)							
	NO_x	CO	VOC	PM	PM_{10}	SO_2	Pb	H_2SO_4
CTG/HRSGs	300.58	148.92	100.74	230.56	230.56	225.37	0.020	41.41
Cooling Towers	N/A	N/A	N/A	32.90	2.07	N/A	N/A	N/A
Fuel Gas Heaters	7.76	6.52	0.43	0.59	0.59	0.47	Neg.	Neg.
Generator Diesel	4.66	1.04	0.19	0.17	0.17	0.10	Neg.	Neg.
Fire Water Pump Diesel	0.37	0.09	0.05	0.01	0.01	0.01	Neg.	Neg.
Totals	313.36	156.57	101.40	264.23	233.40	225.95	0.020	41.41

Sources: Calpine, 2004.
ECT, 2004.
Siemens Westinghouse, 2002.

ATTACHMENT D

NATIONAL BACT DETERMINATIONS

EPA REGION 4 CT LIST - JUL:Y 2004 UPDATE

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
Region 1																				
CT	Bridgeport Energy	520	07/01/1997		06/29/1998	12	Sip Approved	2		SW V84.3A	NG; FO	CC	8,760; 720 FO	6.0 ppm NG; 42 ppm FO	DLN with SCR		10 ppm	GCP	1-hr	Operational
CT	PDC-EL Paso Milford LLC	540	02/17/1998		04/16/1999	14	Sip Approved	2		ABB GT-24	NG; FO	CC	8,760; 720 FO	2.0 ppm NG; 9 ppm FO	SCR	3-hr	2 ppm	CatOx	1-hr	Undergoing testing, Fall 2001
CT	Lake Road Generating	792	?		final		Sip Approved	3		ABB GT-24	NG; FO	CC	8,760; 720 FO	2.0 ppm NG; 9 ppm FO	SCR	3-hr	3 ppm	CatOx	1-hr	
CT	PDC-El Paso, Meriden	544			final	2	Sip Approved	2	?	ABB GT-24	NG; FO?	CC	8,760; 720 FO	2 ppm	SCR	3-hr	52..4 lb/hr	CatOx	1-hr	
CT	PPL Wallingford Energy, LLC	250			final		Sip Approved	5		S & S LM 6000	NG	SC	4,000	2.5 ppm	SCR	1-hr	1.24 Lbs/hr	CatOx	1 Hr	
CT	Towantic Energy Project	540	1201/98		draft 01/12/01		Sip Approved	2		GE Model 7241	NG, FO	CC		2 ppm NG; 5.9 ppm FO	SCR	1-hr	5 ppm	CatOx	1-hr	
MA	Fore River Station, Weymouth	755	?		?		Delegated	2	?	Mitsubishi 501G	NG; FO	CC	8760; 720 FO	2 ppm NG; 6 ppm FO	SCR	1-hr	2 ppm	CatOx	1-hr	
MA	Berkshire Power	272	05/06/1997		09/22/1997	5	Delegated	1		ABB GT24 178 MW, 272 MW total	NG; FO	CC	8,760; 720 FO	3.5 ppm NG/ 9 ppm FO	DLN & SCR & WI &SCR FO		4 ppm	CatOx		Operational
MA	Millennium Power	360	11/21/1997		Final	3	Delegated	1		SW 501G	NG; FO	CC	8,760; 720 FO	3.5 ppm NG/ 9 ppm FO	SCR		4 ppm	CatOx	1-hr	Testing-Problems with engine
MA	Dighton Power Assoc.	170	09/29/1997		Final		Delegated	1		ABB GT11N2, 170 MW	NG	CC	8,760	3.5ppm	DLN, SCR	1-hr	4 ppm	CatOx	?	Operational
MA	ANP Bellingham	580	?		Final		Delegated	2		ABB GT-24	NG	CC	8,760	2.0 ppm	SCR	1-hr	3 ppm	CatOx	1-hr	NOx 3.5 ppm/ Steam Augmentation
MA	ANP Blackstone	580	?		Final		Delegated	2		ABB GT-24	NG	CC	8,760	2.0 ppm	SCR	1-hr	3 ppm	CatOx	1-hr	NOx 3.5ppm/ Steam Augmentation
MA	Sithe Mystic Development	1,550	?		final 1/00		Delegated	4		Mitsubishi 501G	NG	CC	8,760	2.0 ppm	SCR	1-hr	2 ppm	CatOx	1-hr	Netted out of PSD/NSR for NOx & SO2, under construction
MA	Cabot Power	350	?		Final		Delegated	1		SW 501G	NG	CC	8,760	2.0 ppm	SCR	1-hr	2 ppm	CatOx	1-hr	
MA	Sithe West Medway	540			final		Delegated	3		GE 7FA	NG	SC	2,500	9.0 ppm	DLN	1-hr	9 ppm	Good Combustion	1-hr	
ME	Androscoggin Energy LLC	150	09/12/1997		03/31/1998	7	Sip Approved	3	3	SW 251B 12A	NG; FO	Cogen	8,760; 720 FO	6 ppm/42 ppm	LNB & SCR gas only	1-hr	5-10ppm	CatOx		Operational
ME	Rumford Power Associates	265	12/23/1997		05/01/1998	4	Sip Approved	1		?	NG; FO	CC	8,760; 720 FO	3.5ppm	SCR	24-hr	15 ppm	GCP	24-hr	almost completed
ME	Casco Bay Energy Co.	520	02/17/1998		07/13/1998	5	Sip Approved	2			NG	CC	8,760	3.5ppm	SCR	24-hr	20 ppm	GCP	24-hr	PSD Review only, alomost completed
ME	Champion International	250	05/14/1998		09/14/1998	4	Sip Approved	1			NG; FO	CC	8,760; 720 FO	9 ppm/ 42 ppm	GCP, DLN for oil	24-hr	9 ppm/ 30 ppm	GCP	24-hr	Netted out of PSD/NSR review, SCR required if 9 ppm not achievable, almost completed
ME	Westbrook Power	528	08/07/1998		12/21/1998	4	Sip Approved	2		GE 7FA	NG; FO	CC	8,760; 720 FO	3.5ppm	SCR	24-hr	15 ppm	GCP	24-hr	almost completed
ME	Gorham Energy	900	04/02/1998		12/04/1998	8	Sip Approved	3		ABB GT-24	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 9 ppm FO	SCR (LAER)	24-hr	5 ppm	CatOx ?	24-hr	3.5ppm NOx Steam injection, under construction
NH	Newington Energy	525			Final 4/99		Partial Delegation	2		GE 7FA	NG; FO	CC	8,760; 720 FO	2.5 ppm	SCR	3-hr	15 ppm	GCP	1-hr	Under construction
NH	AES Londonderry LLC	720			Final 4/99		Partial Delegation	2		SW 501G	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 9 ppm FO	SCR	3-hr	15 ppm	GCP	1-hr	under construction
RI	Tiverton Power Associates	265	02/14/1997		02/13/1998	12	Sip Approved	1		GE 7FA	NG	CC	8,760	3.5 ppm	SCR	1-hr	12 ppm	GCP	1-hr	Operational
RI	Reliant Energy: Hope Generating Facility	522			Final		Sip Approved	2		SW 501F	NG	CC	8,760	2.5 ppm	SCR	1-hr	15 ppm	GCP	1-hr	Advised NOx LAER at 2.0ppm (1 hour), under construction
Region 2																				
NY	Athens Generating Co.	1,080	08/15/1998		02/02/2000	17	Delegated	3	3	SW 501 G	NG; FO	CC	8,760	2.0 ppm NG; 9.0 ppm FO	DLN/SCR	1 hour	15 ppm NG; 50 ppm FO	GCP	1 hour	
NY	Bethlehem Energy Center	750	pending				Delegated				NG	CC	8,760			1 hour				Response to stack height inter. TOA2 in 6/5/99. Our comments out 9/28/99.
NY	NYPA Poletti	500	pending				Delegated				NG; FO	CC	8,760			1 hour				EPA monitoring waiver approval 12/28/99. Protocol comments out 12/10/99

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NY	Sithe Energy -Torne Valley	827	pending				Delegated				NG	CC	8,760			1 hour				PSD application in 3/28/00. Article X application
NY	TwinTier Power (Summit Energy)	520	pending				Delegated				NG	CC	8,760			1 hour				EPA waiver approval middle of May. Revised protocol O.K., contingencies: 12/13/99.
NY	Sunset Energy Fleet	520	pending				Delegated				NG; FO	CC	8,760			1 hour				Inventory approval in
NY	Amr. Nat. Power Ramapo Energy	1,100	pending				Delegated				NG	CC	8,760			1 hour				Monitoring waiver approved on 12/28/99. Protocol approved 3/21/00.
NY	Sithe Energy Heritage Station	800	08/09/2000		11/01/2000	3	Delegated	2	0	GE 107H	NG only	CC	8,760	2.0 ppm NG only	DLN/SCR	1 hour	3 ppm	CatOx	1 hour	Application in 2/23/00; in compliance/complete on 4/21/00.
NY	Southern Energy at Bowline	750					Delegated				NG; FO	CC	8,760			1 hour				Application in 3/21/00. EJ issue for PSD completeness.
NY	Con Edison - East River	450	pending				Delegated				NG; FO	CC	8,760			1 hour				Revised protocol in 4/11/00. PSD and NSR applicability analysis in 5/3/00.
NY	SCS Energy - Astoria	1,000	pending				Delegated				NG; FO	CC	8,760			1 hour				Protocol comments 12/21/99. Revised waiver comments out 5/8/00.
NY	Grassy Point - Havestraw Bay	550	pending				Delegated				NG; FO	CC	8,760			1 hour				Protocol comments out 1/4/00. EPA approval of onsite data 4/28/00.
NY	Keyspan - Ravenswood	250	pending				Delegated				NG; FO	CC	8,760			1 hour				Protocol comments out 3/16/00 (EPA
NY	Glenville Energy Park	520	pending				Delegated				NG	CC	8,760			1 hour				Revised data for Preliminary Scoping Statement in 5/4/00
NY	Brookhaven Energy Project	580	pending				Delegated				NG	CC	8,760			1 hour				Preliminary Scoping Statement in 3/24/00
NY	Oak Point Energy - Bronx	1,075	pending				Delegated				NG	CC	8,760			1 hour				Responses from the applicant received on 11/27/00.
NY	Orion Astoria - Queens	1,842	pending				Delegated				NG; FO	CC	8,760			1 hour				Applicant submitted a modeling protocol and a source inventory request on 12/20/00.
NY	Caithness Island - Brookhaven	750	pending				Delegated				NG; FO	CC	8,760			1 hour				
NY	Kings Park - Smithtown	300	pending				Delegated				NG; FO	SC	8,760			1 hour				Not PSD-affected (simple cycle)
NY	Wawayanda - Orange County	710	pending				Delegated				NG; FO	CC	8,760			1 hour				Modeling protocol submitted on 12/22/00.
NY	NYPA's Simple Cycle Turbines at 7 different locations in NYC	460	12/01/2000		01/12/2001	2	Delegated	11	0	GE LM 6000	NG	SC	8,760	2.5 ppm NG	SCR	1 hour	5 ppm	CatOx	1 hour	These 11 turbines are not subject to NSR/PSD. The one located in Staten Island (#11) has not yet been issued. Installation will begin soon and operation will be in the summer of 2001.
NJ	Mantua Creek Generating	800	10/15/1999		01/10/2000	3	Delegated	3	0	ABB GT-24	NG; FO	CC	8,760	2.5 ppm NG; 6 ppm FO	DLN/SCR	1 hour	3 ppm	CatOx	1 hour	Final permit issued. Expected start of construction: March 2001.
NJ	Cogen Technology - Linden	181	09/15/1999		12/01/1999	2.5	Delegated	1	0	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 6 ppm FO	DLN/SCR	1 hour	2 ppm - gas 6 ppm - oil	CatOx	1 hour	Final permit issued.
NJ	AES Red Oak Project	816	12/06/1999		01/28/2000	2	Delegated	4	0	SW 501G	NG	CC	8,760	3 ppm	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Final permit issued.
NJ	PSEG Fossil LLC - Linden	170	12/15/2000		02/10/2000	2	Delegated	2	0	GE 7EA	NG; FO	SC	8,760	12 ppm NG; 42 ppm FO	DLN	1 hour	n/a	n/a	n/a	Not subject to NSR/PSD. Unit started operation in April, 2000.
NJ	PSEG Fossil LLC - Burlington	170	03/15/2000		05/07/2000	4	Delegated	4	0	GE LM 6000	NG	SC	8,760	25 ppm	water injection	1 hour	70 ppm	n/a	n/a	Not subject to NSR/PSD. Unit started operation in May, 2000.
NJ	Tosco Bayway Refinery Cogen Project	130	pending		on hold		Delegated	1	0	SW 501D5	NG; refin. gas	CC	8,780	3 ppm - gas 10 ppm- ref. gas	DLN	1 hour	4 ppm - Gas 10 ppm - ref. gas	CatOx	1 hour	Application is on hold. Ownership may change to PP&L Global.
NJ	Liberty Generating Project	1,090	pending		applic. under review		Delegated	3	3	SW 501G	NG	CC	8,760	2.5 ppm	DLN/SCR	1 hour	1.5 ppm	CatOx	1 hour	SW turbines with GE
NJ	PSEG Fossil LLC - Kearney	750	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application to be revised by PSE&G.

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NJ	PSEG Fossil LLC - Bergen	500	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application under review.
NJ	PSEG Fossil LLC - Linden	1,186	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application under review.
NJ	PSEG Fossil LLC - Sewaren	500	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application under review.
NJ	Sithe Energy (GPU) - Reliant Energy	520	pending		applic. under review		Delegated	3	0	unk	NG	SC	8,760	9 ppm	DLN	1 hour	9 ppm	n/a	1 hour	Application under review.
NJ	Statoil Celtic, Inc.	750	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	3.5 ppm	DLN/SCR	1 hour	3 ppm	CatOx	1 hour	Application on hold. Ownership may change to Calpine Corp.
NJ	PSEG Fossil LLC - Kearney	170	pending		applic. under review		Delegated	4	0	GE LM 6000	NG; FO	SC	8,760	25 ppm NG; 42 ppm FO	water injection	1 hour	n/a	n/a	n/a	Not subject to NSR/PSD.
NJ	PSEG Fossil LLC - Burlington	340	pending		applic. under review		Delegated	4	0	GE 7EA	NG; FO	SC	8,760	9 ppm NG; 42 ppm FO	DLN	1 hour		CatOx	1 hour	Application under review.
NJ	Sithe Energy (GPU) - Belvidere	85	withdrawn		withdrawn		Delegated	1		(85 MW)	NG	SC	8,760	9 ppm		1 hour	4 ppm	CatOx	1 hour	
NJ	Sithe Energy (GPU) - Forked River	130	withdrawn		withdrawn		Delegated	2		GE Frame 6	NG	SC	8,760			1 hour	4 ppm	CatOx	1 hour	
NJ	Sithe Energy (GPU) - Sayerville	840	withdrawn		withdrawn		Delegated	3		(840 MW total)	NG	CC	8,760			1 hour	4 ppm	CatOx	1 hour	
NJ	Sithe Energy (GPU) - Gilbert	100	withdrawn		withdrawn		Delegated	-		100 MW total	NG	CC	8,760		DLN/SCR	1 hour	4 ppm	CatOx	1 hour	addition of HRSG and steam generator to existing turbine
PR	PREPA-San Juan	464	03/16/2000		03/02/2000	22	EPA-lead	2	0	SW 501	FO	CC	8,760	no PSD affected	n/a	n/a	25 ppm FO	GCP	3 hours	Subject to PSD for CO and VOC only
VI	VIWAPA-St Thomas	24	07/28/2000		01/03/2001	5	EPA-lead	1	0	UT FT8-1 Power Pac	FO	SC	8,760	42 ppm	WI	24 hours	10 ppm FO at 100% load	GCP	3 hours	UT = United Technologies
Region 3																				
DC	BUZZARD POINT	288						2	0		FO2				?					
DE	Hay Road - Delaware	550	06/19/2000		10/17/2000	6	SIP Approved	3		SW	NG/FO	SC/CC	No LSLP	9 ppm	LNB - SC and SCR CC	1 hour	9 ppm	GCP		SC by 2001 then CC by 2003, + 550 MW
DE	NRG Energy	100	08/24/2000		10/20/2000	3	SIP Approved	2		LM 6000	NG/FO	SC		73 lb/hr on oil	LNB	1 hour	165 lb/hr on ng	GCP	1 hour	SYNTHETIC MINOR - BASED ON DE DUAL DEFINITION EACH POLLUTANT LESS THAN 24.9 TONS EACH TURBINE
DE	DELAWARE CITY PLANT																			
DE	HAY ROAD	470.5						3	0	SW	NG/FO	CTSC								
DE	SEEFORD DE PLANT	30																		
DE	DEMEC (Delaware Municipal)	45						1	0	LM6000	NG/FO	CTSC			SCR					
DE	CHRISTIANA	56.64									FO									
MD	ODEC Rock Springs - Cecil Co., MD	1020	08/06/1999		10/30/2000	14	SIP Approved	6		GE 7FA	NG	SC		9ppm	Dry LNB		9ppm	GCP		
MD	Kelson Ridge	1850	Application under review by state Feb 2001				SIP Approved	6		Siemens	NG	CC		2.5 ppm	SCR	1 hour		Cat Ox		Major NSR Review
MD	Perryman Expansion	280	no application yet								NG	Conversion to CC								Modification to existing permit
MD	Dickerson Expansion	425	no application yet					2		GE 7FA	NG	CC								Modification to existing permit (add 2 CTs, repower 2 CTs)
MD	Duke Energy Point of Rocks	620	no application yet								NG	CC								Major NSR
MD	BALTIMORE REFUSE ENERGY SYS	60.22																		
MD	SMECO	84																		
MD	SPARROWS POINT	170									FO									
MD	LUKE MILL	65																		
MD	CONOWINGO	474.48						2			FO2									
MD	MONTGOM CO. RESOURCE RECOV	67.81																		
MD	AES WARRIOR RUN COGEN	229																		
MD	NOTCH CLIFF	144																		
MD	PHILADELPHIA	82.8																		

EPA REGION 4 CT LIST - JUL:Y 2004 UPDATE

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
VA	Virginia Power - Remington, VA	550	02/01/1999		09/01/1999	7	SIP Approved	3		GE 7FA	NG/FO	SC		9ppm/42 ppm fo	LNB/WI	1hour	9 ppm	GCP	3 hour	synthetic minor 249 tons/NOx
VA	AIRSIDE IND PARK	870			12/2002			2			NG	CTCC			?					
VA	BIRCHWOOD														?					suspended 01/31/02
VA	BUCHANAN COUNTY PLANT	88													?					
VA	BUCHANAN GENERATION	100			01/31/2002			2		LM 6000	NG	CTSC			?					
VA	CHICKAHOMINY POWER	675			01/10/2003			4		Siemens 5	NG	CTSC		15.0 ppm	LNB		25 ppm GC			
VA	Cogentrix - henry County	1600	Pre application meeting with state only					6				CC								PSD Review
VA	COMMONWEALTH ATLANTIC LP	389						3			NG / FO				?					
VA	Commonwealth Chesapeake	350	08/05/2000		10/05/2000	3	SIP Approved	4		LM6000	Fuel Oil	SC		42 ppm	WI	1 hour	30	GCP	1 hour	
VA	COMMONWEALTH CHESAPEAKE	350	08/05/2000		10/05/2000			7		LM6000	FO	CTSC		42 ppm	WI	1 hour	30	GCP	1 hour	
VA	Competitive Power Ventures Fluvanna County	530	Project Cancelled - Zoning Denied					4				CC								______Cancelled ____
VA	COVINGTON FACILITY	98									MULTI FUEL				?					
VA	CPV FLUVANNA	520			6/2002			2		Siemens 5	NG	CTCC		3.5 ppm	SCR			Cat ox		http://www.cpowerventures.com/projects.htm
VA	CPV WARREN	520			12/2002			2			NG	CTCC			?					
VA	Cynergy - Henry County	320	pre app meeting with state only					4				SC								syn minor
VA	DARBYTOWN	369						4			NG				?					
VA	Dominion Energy - Caroline County, VA	550			07/02/2000		SIP Approved	5		GE 7FA	NG/FO	SC		9ppm/42 ppm	LNB/WI			GCP		synthetic minor 249/NOx
VA	Doswell - Hanover Co., VA	190			04/01/2000		SIP Approved	2		LM 6000		SC								Expansion Existing Facility
VA	DOSWELL COMBINED CYCLE FACILITY	743						4			NG				?					
VA	FAUQUIER COUNTY	550	02/01/1999		09/01/1999			3		GE 7FA	NG/FO	CTSC		9 ppm/42	LNB/WI	1 hour	9 ppm	GCP	1 hour	
VA	GORDONSVILLE ENERGY LP	301						2			NG				?					
VA	GRAVELNECK	408						6			NG/FO				?					
VA	Henry County Power	1100	01/31/2002		05/01/2002			4			NG	CTCC		3.0 ppm	SCR			GCP		
VA	HOPEWELL COGENERATION	399						3			NG				?					
VA	I 95 ENERGY RESOURCE RECOVERY										MWC				?					
VA	James City Energy	580			12/2002			2			NG	CTCC			?					
VA	KINDER-MORGAN BRUNSWICK	560									NG	CC			?					
VA	LADYSMITH	800			07/02/2000			5		GE 7FA	NG/FO	CTSC		9ppm/42 p	LNB/WI			GCP		
VA	LOUISA COUNTY	1000									NG				?					
VA	LOUSIA GENERATING	600			01/14/2002			5	2		NG	SC			?					under construction
VA	LOW MOOR	83									FO				?					
VA	MARTINSVILLE	330			01/08/2003			4			NG	CTSC			?					Cinergy Capital & Trading Inc
VA	Mirant - Danville	320	announced 6/21/01									SC								
VA	NORTHERN NECK	83						4			FO2				?					
VA	OAK HALL POWER														?					
VA	ODEC - Faquier County	500																		Synthetic Minor - 249 Tons/Nox; Zoning Application not yet approved/disapproved, no application to state
VA	ODEC - Louisa County	570	applic. under review				SIP Approved	3				SC								Synthetic Minor 249 tons/NOx
VA	POSSUM POINT CC	550			10/05/2001			2			NG	CC	540		?					
VA	REMMINGTON	800						5				SC			?					
VA	SPSA POWER PLANT	60									MWC				?					
VA	ST LAURENT PAPER PRODUCTS CORP	107													?					
VA	TASLEY	27						1			FO2				?					
VA	Tenaska Bear Garden	900	04/01/2002		04/30/2002			4			NG	CC		3.0 ppm	SCR			GCP		

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VA	Tenaska Fluvanna	900			01/20/2002		SIP Approved	3	3	GE 7FA	NG/FO	CC	8760	3.0 ppm	SCR		21	GCP		
VA	US Dataport/ Calpine	250			06/15/2001			5			NG	CC								
VA	Virginia Power	540			10/05/2001			2												
VA	White Oak Power	680			08/29/2002			4		GE 7 FA	NG	SC		63 lb/hr	LNB					
VA	Wolf Hills - Washington Co., VA	250	03/14/2000		05/01/2000	3	SIP Approved	10		Pratt & Whitney/FT8 (57MW)	NG	SC	Fuel limitation (4700 mmscf/year NG	25 ppm and 29.6 lb/hr at base/peak load	WI	1 hour	18 ppm	Cat Ox	1 hour	Synthetic Minor 249 tons/NOx - Each turbine limited to no more than 27 TPY
VA	Wythe Energy	620	09/05/2001					4	yes	GE 7 FA	NG	CC		3.5 ppm	SCR			State com		
PA	Ontelaunee Energy - PA	544	01/20/2000		10/01/2000	10	SIP Approved	2		Siemens 501F	NG	CC		2.5 ppm	SCR		10 ppm	GCP		
PA	AES Hoytdale, LLC	850	07/06/2001					3		GE 7FA or	NG	CTCC		2.5 PPM	DLNC+SC					
PA	AES Ironwood, LLC	700	05/19/1998		03/29/1999	10	SIP Approved	2			NG; FO	CC	8760 744 (oil)	4.5/10	ALNB, SCR & WI (oil) (LAER)	?	0.5	Intrin	?	Load restriction 85%
PA	ALLEGHENY ENERGY UNIT 8, 9	87.7			07/06/2000			2		SC	NG	CTSC			?					
PA	ALLEGHENY ENERGY UNITS 1, 2	88	Existing		Existing										?					
PA	Allegheny Franklin	88	01/12/2001		06/26/2001			2		GE LM6000	NG/FO	CTCC	4000(NG) 450(FO)	0.59523	WI	CEM	12lb	none		4000 hr NG, 450 hr FO
PA	Allegheny Harrison	88	05/08/2000		pending	delayed by Storage Tank Issues	SIP Approved	2		LM 6000	NG/FO	SC	4050 hours / 450 diesel		SCR					
PA	ALLEGHENY WESTMORELAND	500			02/01/2001			0		LM6000	NG/FO	CTSC		3.5	DLC+SCR					
PA	AMERICAN REF-FUEL CO	90						0		N/A	REFUSE				?					
PA	ARCHBALD POWER STATION	23.29						1		CT	NG				?					
PA	Armstrong	660	08/17/2000		12/07/2000	12	SIP Approved	4		GE 7FA	NG/FO	SC	8900 unit hours NG/ 770 unit hours on FO	9 ppm ng/42 ppm fo	LNB	1 hour	20 ppm (31 lb/hr NG; 79 lb/hr Oil)	GCP	1 Hour	Total Plant 253 TPY NOx 124.6 TPY CO 11.6 TPY VOC
PA	BRUNOT ISLAND	429	06/30/2000		03/15/2001			7		3CT/3CC	FO2	CTCC		3.5	SCR+wi					UNIT 4 IS ON COLD STANDBY
PA	CHESTER	58	Existing		Existing			3			FO2				?					
PA	Connectiv - Bethlehem North	1100	01/16/2002		01/16/2002			6		Siemens V		CTSC		2.5	SCR		2.5	GCP		
PA	Connectiv - Delta Project - York County	1100	*Application received by State (2/01)*				SIP Approved	6		Siemens V84.2		CC			SCR proposed			GCP proposed		
PA	Connectiv - Indiana County	1000	App. Rec'd by state on 2/12/01				SIP Approved	6		Siemens V84.2		SC and CC			SCR proposed for CC					
PA	Connecliv - Lancaster	500	Application received by State (2/01) - no information to EPA as of 2/12/01				SIP Approved													
PA	Connectiv - Mid Merit Inc	1100	02/05/2001					6		Siemens V	NG	CTCC			DLNC+SC			GCP pr		
PA	DELAWARE	393						4			FO2 / FO6				?					
PA	Electrogenerator, Titusville	30						2			NG	CTCC			?					
PA	Fairless Energy (Formerly Swec) - newer entry?	1190						0			NG	CTCC		3.5	DLNC+SC					
PA	Fairless Energy (Formerly Swec)	1190			05/04/2001			4	2	GE 7FA	NG/FO	CTCC	720 on	2.5	SCR/LNB	1 hour	3 pp	cat ox		
PA	FALLS	88	EXISTING		EXISTING						FO2				?					
PA	FOSTER WHEELER - MT CARMEL	46						0	0	N/A					?					

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PA	FPL MARCUS HOOK	750			05/04/2001		SIP Approved	3		GE 7FB		CTCC		3.5	SCR					UNDER CONSTRUCTION
PA	Grays Ferry (Mod)	150			03/08/2001			0			NG	CTCC		9	DLNC					
PA	G.E. PA POWER STATION	28							0						?					
PA	Handsome Lake Energy	280			09/29/2000			10		Pratt and Whitney/ FT8 (57MW)	NG	SC	Fuel limitation (1871 mmscf/year nat gas	25 ppm and 30.1 lb/hr at base/peak load	Wi	1 hour	25 ppm	Cat Ox	1 hour	Synthetic Minor 95 tons/NOx 12 month rolling CO 60.4 ton/year VOC 7.5 ton/year
PA	INDIANA UNIVERSITY	25						4			NG				?					
PA	JOHNSONBURG MILL	60													?					
PA	KLEIN TOWNSHIP COGEN	58													?					
PA	LANCASTER COUNTY RESOURCE RECOV	35.7													?					
PA	Liberty Electric - Eddystone PA	500	12/01/1999		05/01/2000	8	SIP Approved	2	2	GE 7FA	NG/FO	CC	(NG 2117 mscf/12 month rolling) 8760 hours	3.5 ppm CT and 5.0 ppm CT + DB	SCR	1 hour	9ppm CT + 20 ppm CT + DB0	GCP	1 hour	12 month rolling limit each turbine NOx 113.4 ton CO 253.7 ton VOC 25.1 ton
PA	LIBERTY ELECTRIC EDDYSTONE - newer entry?	568	12/01/1999		05/03/2000	8	SIP Approved	2	2	GE 7FA	NG/FO	CTCC		3.5 ppm	DLNC+SC	1 hour		GCP		
PA	Limerick - Limerick, PA	500			applic. under review		SIP Approved	2	2	GE 7FA	NG	CC		2.0 ppm	SCR		8.1	cat ox		
PA	Lower Mount Bethel PPL	600	01/25/2001		Expected March 2001	delayed by public comment	SIP Approved	2	2	Siemens W501F	ng	CC w/DB		3.5 ppm	Dry LNB + SCR		6 PPM	Cat Ox		
PA	MARCUS HOOK REFINERY COGEN	50.5	Existing		Existing			0			NG/FO				?					
PA	MEHOOPANY	53.6													?					
PA	MON VALLEY WORKS	50									NG/FO				?					
PA	MONTENY MONTGOMERY LP	33									NG/O				?					
PA	MOSER	64									FO				?					
PA	MOUNTAIN	53									NG				?					
PA	MUDDY RUN	800													?					
PA	NORTHEAST COGENERATION PLANT	85.64													?					
PA	ONTELAUNEE ENERGY CENTER	544	01/20/2000		10/20/2000			2		Siemens 5	NG	CTCC		3.5	DLNC+SC		10 p	GCP		
PA	Panda Perkiomen - Montgomery Co., PA	1000			applic. under review		SIP Approved			LM 6000		CC								Strong Public Opposition and Water reuse issues
PA	Philadelphia Energy	550	03/23/2001					2	2	GE 7FA	NG	CTCC		3.5	SCR	1 hour	14 p	GCP		3.5 li
PA	PHILADELPHIA REFINERY	30									FO/NG				?					
PA	PPL- FISHBACK	38						2							?					
PA	PPL- MARTINS CREEK LOCK HAVEN	32									FO2			194 LB/HR						50% CAPACITY FACTOR
PA	PPL- Upper Hanover, LLC	90						0			NG	CTSC			?					
PA	PPL- WALLENPAUPACK														?					
PA	PPL- WILLIAMSPORT	32													?					
PA	PPL-HARRISBURG	64						4			FO2				?					
PA	PPL-HARWOOD	32						2			FO2				?					
PA	PPL-LOWER MT BETHEL	600	01/25/2001		10/29/2001			2	2	Siemens W	NG	CTCC		3.5 ppm	Dry LNB		6 PP	Cat Ox		
PA	PPL-MARTINS CREEK JENKINS	32						2			FO2				?					
PA	PPL-WEST SHORE	37.18													?					
PA	PPL Global, LLC, West Earl	450	09/26/2000					10			NG	CTSC			SCR					
PA	PPL MARTINS CREEK-ALLENTOWN	64						4		GE	FO		4380		?					
PA	Reliant - Lower Mt. Bethel	600	06/10/1999		10/29/2001			0			NG	CTCC		3.5	DLNC+SC					
PA	Reliant Hunterstown	1600	04/17/2000					3	3	GE 7FB	NG	CTCC	DB 4000	3.5 ppm	SCR	1 hour	14 p	GCP		permit
PA	Reliant Upper Mount Bethel	920			08/16/2001			2	2	Siemens	NG	CTCC		2.5	DLNC+			Cat ox		
PA	SWEC - Falls Township, PA	500					SIP Approved	2	2	GE 7FA	NG/FO	CC	720 on fuel oil	3 ppm	SCR	1 hour	3 ppm	CatOx	1 hour	EPA comment 4/20/01
PA	TOLNA	53.2						2		See Comment	FO				?					2 IC UNITS

State	Facility	# of New MW	Application Date	App Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
PA	United Supply	180	01/30/2000		08/01/2001			0			NG	CTCC		2	WI+SCR					
PA	WAYNE	54						1			FO	CT			?					
PA	WEST POINT	44			08/26/1999			0			NG	CTCC		9	DLNC					
PA	WHEELBRATOR FALLS														?					
PA	WHEELER FRACKVILLE ENERGY CO INC	49													?					
PA	YORK COGEN FACILITY	69						6							?					
PA	YORK COUNTY RESOURCE RECOVERY CTR	37													?					
WV	Panda	1000	App with state no draft to EPA as of 2/12/01				SIP Approved				NG	CC								
WV	Big Sandy	330			07/10/2000			0		P&W FT8 T	NG	SC	1314	25ppm	water i	Subp ar	19.9	cataly		
WV	Pleasants	335			Issued			2		GE 7FA	NG/FO	CTSC	3708	9ppm	wi/LNB	Subp ar	32	none		
WV	Twelvepole Creek	510			05/18/2000			6		GE 7121	NG	SC	2525	9ppm	LNB	Subp ar	44	cataly		
WV	MegaEnergy, Inc.	10			11/20/2000			1		Solar Mod	NG	CTSC	8760	25ppm	none	Subp ar	7.63	none		
Region 4																				
AL	Alabama Power - Olin Cogeneration	137	07/31/1997		12/01/1997	4	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	15 ppm	DLN		0.07 lb/MMBtu	GCP		Power Augmentation
AL	US Alliance Coosa Pines CoGen	89	02/13/1998		10/01/1998	8	SIP Approved													
AL	Alabama Power - GE Plastics Cogeneration	100	10/01/1997		05/01/1998	7	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	9 ppm; 0.20 lb/MMBtu (DB)	DLN		0.08 lb/MMBtu (combined)	GCP		
AL	Alabama Power, Plant Barry	800	03/30/1998		08/01/1998	4	SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		0.057 lb/MMBtu	GCP		
AL	Alabama Power, Plant Barry	200	04/02/1999		08/01/1999	4	SIP Approved	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		0.060 lb/MMBtu	GCP		
AL	Mobile Energy, LLC - Hog Bayou	200	06/08/1998		1-99	7	SIP Approved	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR; WI		0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
AL	Alabama Power - Theodore Cogeneration Facility	210	10/05/1998		3-99	5	SIP Approved	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		0.086 lb/MMBtu	GCP		
AL	Tenaska Alabama Partners	846	06/09/1999		11-99	5	SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		32.9 ppm NG; 46.7 ppm NG/FO	GCP		
AL	Georgia Power - Goat Rock	-	11/30/1999		4-00	5	SIP Approved	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		0.086 lb/MMBtu	GCP		
AL	Georgia Power - Goat Rock (revision of above PSD application)	2,460	10/17/2000		4-01	6	SIP Approved	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		0.086 lb/MMBtu	GCP		
AL	Alabama Electric Cooperative - Gantt Plant	500	12/02/1999		3-00	3	SIP Approved	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		0.057 lb/MMBtu	GCP		
AL	South Eastern Energy Corp.	1,500	01/18/2000		1-01	12	SIP Approved	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		9 or 19 or 22 ppm	GCP		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
AL	Calpine Solutia - Decatur	700	01/24/2000		6-00	8	SIP Approved	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		0.117 lb/mmBtu	GCP		
AL	Calpine BP Amoco	700	02/02/2000		6-00	5	SIP Approved	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		0.117 lb/mmBtu	GCP		
AL	Tenaska Alabama II Generating Station	900	05/01/2000		2-01	9	SIP Approved	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.048 lb/mmbtu NG/FO - Mit	SCR/WI		0.037/0.047/0.089 lb/mmbtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
AL	Hillabee Energy Center	700	05/01/2000		1-01	8	SIP Approved	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
AL	Duke Energy - Alexander City	1,260	07/13/2000		2-01	7	SIP Approved	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
AL	GenPower - Kelly, LLC	1,260	08/10/2000		1-01	5	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		9 ppm, 14 ppm (w/DB)	GCP		
AL	Blount County Energy	800	08/31/2000		1-01	5	SIP Approved	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
AL	Calhoun Power Company	680	08/30/2000		1-01	5	SIP Approved	4	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 1,000 FO	0.033/0.044/0.055 lbmmbtu NG; 0.183 lb/mmbtu (327 lb/hr) FO	DLN; WI		0.017/0.064/0.026 lbmmbtu (NG/FO/peak)	GCP		NOx-(annual avg./1-hr avg./peak mode)

EPA REGION 4 CT LIST - JUL:Y 2004 UPDATE

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
AL	Alabama Power - Autaugaville	1,260	09/05/2000		1-01	4	SIP Approved	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		0.035 lb/mmBtu	GCP		
AL	Tenaska Alabama III Partners	510	08/28/2000		1-01	5	SIP Approved	3	0	GE 7FA (170 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		15 ppm	GCP		
AL	Tenaska Alabama IV Partners	1,840	03/02/2001	06/06/2001	10/09/2001	7	SIP Approved	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NOX; CatOx- $1,506/ton CO
AL	Duke Energy Autauga, LLC	630	05/11/2001		10/29/2001	5	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		15 ppm	GCP		SCONOx - $18760/ton NOX; CatOx- $5,006/ton CO
AL	Duke Energy Dale, LLC	630	06/27/2001		12/17/2001	8	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmbtu)	SCR		0.033 lb/mmbtu	GCP		SCONOx - $18,403/ton NOX; CatOx- $2,634/ton CO+VOC
AL	Barton Shoals Energy, LLC	1,200	01/15/2002		07/15/2002	7	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm (0.0092 lb/mmbtu)	SCR		10 ppm (0.022 lb/mmbtu); 0.041 lb/mmbtu w/DB	GCP		EPA did not received application until 5/24/02
FL	City of Lakeland, McIntosh Power Plant	250	12/09/1997		7-10-98	7	SIP Approved*	1	0	SW 501G (230 MW)	NG; FO	SC (later CC)	7,008; 250 FO	25 ppm until 5/2002, 9 ppm after, 7.5 ppm if CC. NG; 42 ppm or 15 ppm FO	DLN or SCR; WI or SCR		25 ppm NG; 90 ppm FO	GCP		Power Augmentation
FL	Santa Rosa Energy Center, Sterling Fibers Mfg. Facility	241	07/08/1998		12-4-98	5	SIP Approved*	1	1	GE 7FA (167 MW)	NG	CC	8,760	9 ppm, 9.8 ppm w/ DB	DLN		9 ppm; 24 ppm w/ DB	GCP		If a different CT is used, SCR may be required to meet 6 ppm NOx)
FL	Kissimmee Utility Authority, Cane Island Power Park -Unit 3	250	07/31/1998		draft permit		SIP Approved*	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
FL	Duke Energy - New Smyrna Beach	500	10/19/1998		draft permit		SIP Approved*	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		12 ppm	GCP		
FL	Polk Power (TECO)	330	02/23/1999		10-99	8	SIP Approved*	2	0	GE 7 FA (185 MW)	NG; FO	SC	5,130; 750 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		15 ppm NG; 33 ppm FO	GCP		
FL	Oleander Power	950	03/19/1999		11-99	8	SIP Approved*	5	0	GE 7FA (190 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		
FL	City of Tallahassee - Purdom	250	03/17/1997		5-98	14	SIP Approved*	1	0	GE 7FA (160 MW)	NG; FO	CC	8,760	12 ppm NG; 42 ppm FO	DLN; WI	30-day	25 ppm NG; 90 ppm FO	GCP	3-hr test	
FL	Hardee Power Partners (TECO)	75	06/29/1999		10-99	4	SIP Approved*	1	0	GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Reliant Energy Osceola	510	08/08/1999		12-99	4	SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,000; 2,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		10.5 ppm NG; 20 ppm FO	GCP		
FL	Florida Power Corp., Intercession City	261	08/01/1999		12-99	6	SIP Approved*	3	0	GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Jacksonville Electric Authority - Brandy Branch	510	05/26/1999		10-99	5	SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
FL	Gulf Power - Smith Station	340	06/14/1999		7-00	13	SIP Approved*	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NOx and CO; SA = steam augmentation
FL	Florida Power & Light - Sanford	2,200	06/21/1999		9-99	3	SIP Approved*	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
FL	IPS Avon Park Corp. - Vandola Power Project	880	09/03/1999		12-99	3	SIP Approved*	4	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		Netting out of PSD for NOx and CO
FL	Gainesville Regional Utilities, Kelly Generating Station	133	09/08/1999		2-00	5	SIP Approved*	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NOx
FL	IPS Avon Park - Shady Hills	510	10/28/1999		1-00	3	SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		
FL	Palmetto Power	540	10/25/1999		6-00	8	SIP Approved*	3	0	SW 501F (180 MW)	NG	SC	3,750	15 ppm	DLN		25 ppm (15 ppm after 1st yr.)	GCP		
FL	Granite Power Partners	540	01/19/2000		8-00	7	SIP Approved*	3	0	GE/SW (180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15 ppm NG; 42 ppm FO (GE only)	DLN		12/16/10 ppm NG; 20 ppm FO (GE only)	GCP		3 vendor options: GE 7FA (500 hr/yr FO)/SW 501F/SW 501D5A
FL	IPS Avon Park Corp. - DeSoto Power Project	510	02/11/2000		6-00	4	SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		
FL	Florida Power & Light - Martin Power Plant	340	02/23/2000		7-00	5	SIP Approved*	2	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 500 FO	9/12/15 ppm NG; 42 ppm FO	DLN; WI		9/15/20 ppm NG; 20 ppm FO	GCP		normal/power aug./peaking
FL	Calpine Osprey Energy Center	527	04/03/2000		07/05/2001	15	SIP Approved*	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
FL	Peace River Station	510	06/14/2000		12-00	6	SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 720 FO	9/10 ppm NG; 42 ppm FO	DLN; WI	3-hr test/rolling	8.2 ppm NG; 14.2 ppm FO	GCP	3-hr test	
FL	Hines Energy (FPC)	530	08/02/2000		06/07/2001	10	SIP Approved*	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NOx.; CatOx - $2,130/ton CO
FL	Florida Power & Light - Fort Myers	340	08/14/2000		12-00	4	SIP Approved*	2	0	GE 7FA (170 MW)	NG; FO	SC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		netting out of NOx, CO, PM10 and SO2 review (subject to VOC reveiw)
FL	CPV - Gulfcoast	250	08/11/2000		2-01	6	SIP Approved*	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
FL	TECO Gannon/Bayside	1,728	09/27/2000		3-01	6	SIP Approved*	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NOx, CO, PM10 and SO2 review (subject to VOC reveiw)
FL	Duke Energy - Ft. Pierce	640	10/11/2000		06/18/2001	8	SIP Approved*	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 1,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI	3-hr rolling	25 ppm NG; 20 ppm FO	GCP	3-hr test	SCR - $50,602/ton NOx; CatOx - $21,832/ton CO&VOC
FL	Pompano Beach Energy Center, LLC	510	10/24/2000		draft permit		SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		Hot SCR - $20,400/ton NOX; CatOx- $31,800/ton CO
FL	Midway Development Center	510	11/17/2000		2-01	3	SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG (9 ppm on startup); 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		Hot SCR - $20,700/ton NOX; CatOx- $31,800/ton CO
FL	South Pond Energy Park	600	11/21/2000		draft permit		SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm /2.5 ppm NG; 36/10 ppm FO	DLN/SCR; WI	3-hr	9 ppm NG; 20 ppm FO	GCP	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
FL	North Pond Energy Park	430	11/21/2000		applic. under review		SIP Approved*	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
FL	Duke Energy Lake	640	12/05/2000		07/18/2001	7	SIP Approved*	8	0	GE 7EA (80 MW)	NG	SC	2,500	12 ppm (9 ppm initial test)	DLN; WI	3-hr rolling	20 ppm (25 ppm first year)	GCP	3-hr test	SCR - $15,000/ton NOx; CatOx - $5,563/ton CO
FL	Calpine Blue Heron Energy Center	1,080	12/01/2000		draft permit		SIP Approved*	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NOx; CatOx - $1,553/ton CO
FL	Jacksonville Electric Authority - Brandy Branch (revision)	200	12/22/2000		03/29/2002	15	SIP Approved*	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR	3-hr	14 ppm	GCP	24-hr	Conversion of 2 SC units to 2 CC units
FL	CPV - Atlantic Power	250	01/11/2001		05/03/2001	4	SIP Approved*	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation
FL	Orlando Utilities - Curtis H Stanton Energy Center	633	01/24/2001		09/26/2001	9	SIP Approved*	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
FL	Deerfield Beach Energy Center	510	01/26/2001		draft permit		SIP Approved*	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1000 FO	9 ppm NG; 42 ppm FO	DLN; WI	24-hr	9 ppm NG; 20 ppm FO	GCP		
FL	Broward Energy Center	775	04/03/2001		05/15/2002		SIP Approved*	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	8 ppm (SC & CC); 12 ppm (CC w/PA)	GCP	3-hr	SC; PA = Power
FL	Belle Glade Energy Center	600	04/03/2001		01/28/2002	10	SIP Approved*	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	(SC); 14 ppm (CC	GCP	3-hr	SC; PA = Power
FL	Manatee Energy Center	600	04/03/2001		01/17/2002	9	SIP Approved*	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	2.5 ppm/8 ppm; 4 ppm (CC w/PA)	GCP	3-hr	SC; PA = Power
FL	CPV Pierce Power Generation Facility	250	04/20/2001		08/17/2001	4	SIP Approved*	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
FL	Fort Pierce Repowering Project	180	04/25/2001		08/15/2001	4	SIP Approved*	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
FL	TECO Bayside Power Station (repowering)	1,032	06/25/2001		01/09/2002	7	SIP Approved*	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	9 ppm (7.8 ppm test avg.)	GCP	24-hr	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)
FL	CPV Cana Power Generation Facility	245	09/07/2001		01/17/2002	4	SIP Approved*	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	GCP	24-hr	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FL	FPL Martin	1,150	02/05/2002		04/16/2003	14	SIP Approved*	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	2.5 ppm NG; 10 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI	24-hr	10 ppm NG/8 ppm NG (12 ppm w/PA); 15 ppm FO	GCP	24-hr	PA = Power Augmentation

State	Facility	# of New MW	Application Date	App. Comp. Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
FL	FPL Manatee	1,150	03/04/2002		04/15/2003	13	SIP Approved*	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	2.5 ppm CC/9-15 ppm SC	SCR/DLN	24-hr	10 ppm NG/8 ppm NG (12 ppm w/PA)	GCP	24-hr	PA = Power Augmentation
FL	FPC - Hines Energy Complex	530	09/17/2002		09/19/2003	12	SIP Approved*	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG/10 ppm FO	SCR	24-hr	10 ppm NG/20 ppm FO	GCP	24-hr	SCONOx - $8,597/ton NOx;
FL	FPL Turkey Point	1,150	11/19/2003		draft permit		SIP Approved*	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	2.0 ppm NG/8.0 ppm FO	SCR	24-hr	4.1 ppm NG/7.6 ppm NG w/DB/8 ppm NG w/PA&DB/14ppm w/PK&DB; 8.0 ppm FO	GCP	24-hr	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx
GA	Tenaska Georgia Partners, L.P.	960	05/01/1998		12-98	7	SIP Approved	6	0	GE 7FA (160 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
GA	West Georgia Generating; Thomaston	680	03/15/1999		6-99	3	SIP Approved	4	0	GE 7FA (170 MW)	NG; FO	SC	4,760; 1,687 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
GA	Heard County Power	510	04/06/1999		10-99	6	SIP Approved	3	0	SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN		25 ppm	GCP		
GA	Georgia Power, Jackson County	1,216	02/11/1999		8-99	6	SIP Approved	16	0	GE 7EA (76 MW)	NG; FO	SC	4,000; 1,000 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		0.101 lb/MMBtu NG; 0.046 lb/MMBtu FO	GCP		
GA	Georgia Power - Wansley (Oglethorpe Power)	2,280	12/02/1999		07/28/2000	7	SIP Approved	8	6	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	29.5 ppm/0.066 lb/MMBtu	GCP		
GA	Duke Energy Murray, LLC	1,240	05/25/2000		2-01	9	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	6,760	3.0 ppm*	DLN/SCR		12 ppm*	GCP		NOx and CO BACT limits were lowered from 3.5 ppm and 22 ppm after the permit was issued in response to a settlement with an Environmental Group
GA	Duke Energy Buffalo Creek, LLC	620	10/25/2000		applic. under review		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		21.9 ppm	GCP		SCONOx - $19,948/ton NOx; CatOx - $2,469/ton CO
GA	Duke Energy Sandersville, LLC	640	10/25/2000		11/09/2001	13	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	10 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		Hot SCR - $36,520/ton NOx; CatOx - $8,330/ton CO
GA	Augusta Energy LLC	750	10/26/2000		09/28/2001	11	SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		2 ppm NG; 2 ppm FO	CatOx		SCONOx - $17,490/ton NOx; CatOx - $1,828/ton CO
GA	Oglethorpe Power Corp. - Talbot	648	11/07/2000		08/09/2001	9	SIP Approved	6	0	SW V84.2 (108 MW)	NG; FO	SC	8,760; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		15 ppm	GCP		Hot SCR - $9,381/ton NOx; CatOx - $3,980/ton CO
GA	Oglethorpe Power Corp.- Wansley	521	12/09/2000		01/15/2002	13	SIP Approved	2	2	SW V84.3a2 (167 MW)	NG	CC	6,760	3.0 ppm	SCR		2.0 ppm	CatOx		
GA	GenPower Rincon	528	12/27/2000		03/24/2003		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm	SCR		2.0 ppm	CatOx		
GA	Effingham Power Co.	525	12/27/2000		12/27/2001		SIP Approved	2	0	GE 7FA (170 MW)	NG	SC/CC	6,760	12/3.5 ppm	DLN/SCR		9 ppm	GCP		Initially SC, but later converting to CC
GA	Peace Valley Generation Co., LLC	1,550	02/20/2001		draft permit		SIP Approved	6	4	GE 7FA (170 MW)	NG	CC/SC	8,760/2,500	2.5/9.0 ppm	SCR/DLN	3-hr	2.0 ppm/8.0 ppm	CatOx/GCP	3-hr	
GA	MEA of Georgia - W. R. Clayton	500	08/07/2001		draft permit		SIP Approved	3	0	GE 7FA (170 MW)	NG; FO	SC	8,760; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI	24-hr	13.1 ppm NG; 32.40 ppm FO	GCP	24-hr	Hot SCR - $14,100/ton NOx; CatOx - $15,000/ton CO
GA	Savannah Electric and Power - Plant McIntosh	1,260	11/20/2001		04/17/2003		SIP Approved	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.5 ppm NG; 6 ppm FO	SCR		2.0 ppm	CatOx		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
GA	Live Oak Co., LLC	600	02/22/2002		applic. under review		SIP Approved	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	SCR		10 ppm (17 ppm w/DB or PA)	GCP		
GA	Big River Power, LLC	855	04/04/2002		applic. under review		SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	6,760; 500 FO	3.0 ppm NG; 6.0 ppm FO	SCR/DLN; WI		19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.0 ppm FO	GCP		SCR - $5,075/ton NOx; CatOx - $4,712/ton CO
KY	Kentucky Pioneer Energy	540	01/31/2000		06/08/2001	16	SIP Approved	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	15/20 ppm	GCP	3-hr	
KY	Duke Energy - Marshall Co.	640	02/08/2000		draft permit		SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr/an	20 ppm NG; 25 ppm FO	GCP		
KY	Duke Energy Metcalfe	640	09/01/2000		draft permit		SIP Approved	8	0	GE 7EA (80 MW)	NG	SC	2,500	12/9 ppm	DLN	1-hr/an	25 ppm	GCP	1-hr	
KY	East Kentucky Power Cooperative, Inc.	240	03/01/2000		07/27/2001	17	SIP Approved	3	0	GE 7EA (80 MW)	NG; FO	SC	8760; 8,760 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		CatOx - $8,000/ton CO
KY	Louisville Gas & Electric - Trimble	960	05/01/2001		06/26/2001	2	SIP Approved	6	0	GE 7FA (160 MW)	NG	SC	8,760	12/9 ppm	DLN	1-hr/an	9 ppm	GCP	3-hr	

EPA REGION 4 CT LIST - JUL:Y 2004 UPDATE

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
KY	Westlake Energy Corp.	520	06/13/2001		draft permit		SIP Approved	2	2	"F" Class (180 MW)	NG	SC	8,760	4.5 ppm	SCR		17.2 ppm	GCP		
KY	Duke Energy Trimble	1,240	01/31/2002		applic. under review		SIP Approved	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm	SCR		9/13.9/20 ppm	GCP		
KY	Summer Shade Development Co.	680	01/14/2002		applic. under review		SIP Approved	4	0	GE 7FA (170 MW)	NG	SC	4,000	9 ppm	DLN		9 ppm	GCP		
MS	LS Power, LP (Batesville)	1,100	05/05/1997		11/07/1999	6	SIP Approved	3	3	SW 501G (281 MW)	NG; FO	CC	8,760 (10% FO)	9 ppm NG; 42 ppm FO	DLN; WI		30.3 ppm NG; 36 ppm FO	GCP		
MS	Mississippi Power Corp., Plant Daniel	1,000	08/26/1998		12-98	6	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.018 lb/MMBtu	DLN/SCR		0.057 lb/MMBtu	GCP		
MS	Duke Energy Hinds, L.L.C.	520	06/30/1999		01/07/2000	7	SIP Approved	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		20 ppm	GCP		
MS	Duke Energy Attala, L.L.C.	520	11/02/1999		4-00	5.5	SIP Approved	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		20 ppm	GCP		
MS	Cogentrix Energy, Southaven Power Project	800	06/09/1999		04/25/2000		SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/ DB)	DLN/SCR		9 ppm, 18 ppm w/ DB	GCP		
MS	Cogentrix Energy, Caledonia Power Project	800	09/22/1999		3-01	18	SIP Approved	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		9 ppm	GCP		revised application to add SCR
MS	Duke Energy Southaven	640	12/17/1999		8-00	8	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	GenPower - McAdams LLC	528	02/21/2000		08/16/2000		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
MS	Warren Power LLC (revision)	320	03/23/2001		05/30/2001		SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	2,000	12 ppm (9 ppm annual)	DLN	24-hr	25 ppm	GCP	24-hr	revised to include startup/shutdown emissions in PTE and modeling analysis
MS	Lone Oak Energy Center	800	04/28/2000		11/13/2001		SIP Approved	3	3	F' Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
MS	Lee Power Partners	1,000	05/15/2000		03/09/2001		SIP Approved	4	4	F' Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		25 ppm	GCP		
MS	Duke Energy Enterprise	160	05/30/2000		05/10/2001		SIP Approved	2	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	LSP-Pike Energy LLC	1,100	08/08/2000		11/14/2000	3	SIP Approved	4	4	F' Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		33.1 ppm (0.15 lb/mmBTU)	GCP		
MS	Magnolia Energy	900	09/29/2000		05/31/2001		SIP Approved	3	3	F' Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		25 ppm	GCP		
MS	MEP Clarksdale Power	320	10/16/2000		04/19/2001		SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		Hot SCR - $26,567/ton NOx; CatOx - $5,593/ton CO
MS	TVA - Kemper CT Plant	440	01/25/2001		07/30/2001		SIP Approved	4	0	GE 7EA (110 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; Hot SCR - $13,668/ton NOx; CatOx - $8,036/ton CO
MS	Reliant Energy - Choctaw Co., LLC	844	02/26/2001		06/13/2001		SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	18.36 ppm	GCP		SCONOx - $48,663/ton NOx; CatOx - $3,550/ton CO
MS	Crossroads Energy Center	580	03/26/2001		06/24/2002		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		10.4 ppm	GCP		SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO
MS	Choctaw Gas Generation, LLC	700	04/18/2001		12/13/2001		SIP Approved	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		23 ppm	GCP		
MS	LSP Energy (Granite Power)	300	07/09/2001		11/13/2001	4	SIP Approved	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR	3-hr	25 ppm	GCP	3-hr	
MS	South Mississippi Electric Power Association	250	11/16/2001		05/29/2002		SIP Approved	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN	24-hr	25 ppm	GCP	3-hr	
MS	Panada Black Prairie LP	1,040	02/07/2002		applic. under review		SIP Approved	4	4	F' Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	7.8 ppm or 80 ppm	GCP		GE7FA or SW501F
NC	CP&L Lee Plant - Wayne County	680	10/03/1997		7/98	10	SIP Approved	4		GE 7241 (2) GE 7231 (2) 170 MW (180 mm btu/hr) each	NG	SC	2000 each ?	12 to 42 ppm depending on control, cell cell comments	DLN, WI	?	not given	not given		This was a permit that was reissued since source failed to meet 18 month begin construction deadline.
NC	Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	2,040	05/14/2001		applic. under review		SIP Approved	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
NC	Carolina Power & Light, Rowan Co.	850	03/26/1999		11/99	8	SIP Approved	5	0	GE 7FA (170 MW)	NG; FO	SC	2,000; 1,000 FO	9 ppm NG at startup/10.5 ppm long-term; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NC	Carolina Power & Light, Rowan Co. (revision)	1,110	05/26/2000		draft permit		SIP Approved	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
NC	Rockingham Power (Dynegy)	780	03/31/1999		6/99	3	SIP Approved	5	0	SW 501F (156 MW)	NG; FO	SC	3,000; 1,000 FO	25 ppm NG until 4/01, 20 ppm until 4/02, 15 ppm after; 42 ppm FO	DLN; WI		25 ppm NG; 50 ppm FO	GCP		
NC	Fayetteville Generation	500	04/03/2000		01/10/2002	20	SIP Approved	2	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1000 FO	2.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI		9 ppm NG; 20-41 ppm FO	GCP		CO level for FO depends on Load
NC	Duke Energy - Buck Steam Station	640	11/16/2000		11/20/2001	12	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 1000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI	24-hr	20 ppm NG; 25 ppm FO	GCP	3-hr	CatOx - $11,976/ton CO
NC	Entergy Power - Rowan Generating Facility	930	01/29/2001		01/25/2002	12	SIP Approved	6	0	GE 7FA (155 MW)	NG; FO	SC	4,400; 1,000 FO	10.5 ppm (9 ppm initially) NG; 42 ppm FO	DLN; WI	24-hr	9 ppm NG; 20 ppm FO	GCP		Hot SCR - $13,049/ton NOx; CatOx - $8,204/ton CO
NC	GenPower Earleys, LLC	528	03/28/2001		01/14/2002	10	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR		9 ppm (14 ppm w/DB)	GCP		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246ton CO
NC	Mirant Gastonia	1,200	10/31/2001		05/28/2002	7	SIP Approved	4	4	"F" Class (175 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR	24-hr block	15 or 30 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
NC	Carolina Plant	1,300	11/15/2001		applic. under review		SIP Approved	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	2.5/3.5 ppm; 13/18 ppm	SCR	24-hr block	47 or 50 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
NC	Mountain Creek - Granville Energy Center	911	01/09/2002		applic. under review		SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		9 ppm (24.3 ppm w/DB)	GCP		SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO
NC	Dominion Person, Inc.	1,100	05/22/2002		applic. under review		SIP Approved	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm; 15 ppm FO	SCR		9 ppm NG (20 ppm w/DB) 20 ppm FO	GCP		
NC	Forsyth Energy Projects	812	12/20/2002		01/23/2004		SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	2.5/3.5 ppm NG; 13/18 ppm FO	SCR	24-hr block	11.6 ppm NG (25.9 ppm w/DB); 15.7 ppm FO (25.1 ppm w/DB)	GCP	3-hr	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels
SC	Santee Cooper, Rainey Generating Station	870	06/14/1999		4-00	10	SIP Approved	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		
SC	Broad River Energy (SkyGen)	513	06/25/1999		12-99	6	SIP Approved	3	0	GE 7FA (171 MW)	NG, FO	SC	3,000; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
SC	SC Electric & Gas - Urquhart	444	05/12/2000		9-00	4	SIP Approved	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		12 ppm NG; 20 ppm FO	GCP		Netted out of NOx, SO2 and PM10 PSD Review
SC	Broad River Energy (SkyGen)	342	07/13/2000		12-00	5	SIP Approved	2	0	GE 7FA (171 MW)	NG	SC	3,000	9 ppm (12 ppm w/SI)	DLN		9 ppm (15 ppm w/SI)	GCP		Steam Injection (SI)
SC	Columbia Energy	515	10/30/2000		4-01	6	SIP Approved	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		17.4 ppm NG; 37 pm FO	GCP		SCONOx - no analysis; CatOx - $1,611/ton CO
SC	GenPower Anderson	640	01/05/2001		07/03/2001	6	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		11.7 ppm	GCP		
SC	Duke Power - Mill Creek (f/k/a RIPP)	654	02/28/2001		11/08/2001	9	SIP Approved	8	0	GE 7EA (80 MW)	NG, FO	SC	2,400; 1,000 FO	10.5 (9 initially) ppm NG; 42 ppm FO	DLN; WI	24-hr	25 ppm NG; 20 ppm FO	GCP	24-hr	
SC	Greenville Generating	930	05/04/2001		draft prmit		SIP Approved	6	0	GE 7FA (155 MW)	NG, FO	SC	3,400; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 36 ppm FO	GCP		Hot SCR - $13,909/ton NOx; CatOx - $8,204/ton CO
SC	Greenville Power Project	810	10/03/2001		applic. under review		SIP Approved	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 20 ppm FO	SCR		12.3 ppm NG; 16.5 ppm FO	GCP		SCONOx - $18,300/ton NOx; CatOx - $5,800/ton CO; DB < 5,120 hr/yr
SC	Jasper County Generating Facility	1,260	10/03/2001		05/28/2002	7	SIP Approved	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	2.5 ppm NG; 7.5 ppm FO	SCR	24-hr	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)	GCP		SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO
SC	Cherokee Falls Combined-Cycle Facility	1,260	10/12/2001		applic. under review		SIP Approved	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		0.063 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		SCONOx - $22,434/ton NOx; CatOx - $2,500/ton CO
SC	Fork Shoals Energy, LLC	1,150	03/01/2002		applic. under review		SIP Approved	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	14 ppm (GE7FA/16 ppm (SW501F)	GCP	24-hr	
SC	Broad River Energy Center (f/k/a Cherokee Falls)	340	03/01/2002		05/22/2003		SIP Approved	2	0	GE 7FA (170 MW)	NG, FO	SC	3,000	9 ppm (12 ppm w/PA); 42 ppm FO	DLN		9 ppm (15 ppm w/PA); 20 ppm FO	GCP		Hot SCR - $22,800/ton NOx; CatOx - $10,500/ton CO

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
SC	GenPower Anderson - revision	340	03/01/2002		applic. under review		SIP Approved	2	0	GE 7FA (170 MW)	NG	SC	2,928	9 ppm	DLN		9 ppm**	GCP		Temporary 4 month operating period - **Not Subject to PSD Review for CO, VOC or SO2
SC	Palmetto Energy Center	970	03/01/2002		applic. under review		SIP Approved	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		15 ppm (31 ppm w/DB)	GCP		SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO
SC	Santee Cooper Rainey Generating Station	251	06/14/2002		05/08/2003		SIP Approved	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		Hot SCR - $15,550/ton NOx; CatOx - $1,717/ton CO
TN	TVA, Johnsonville Fossil Plant	340	12/08/1998		7-99	7	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Gallatin Fossil Plant	340	12/02/1998		7-99	7	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Lagoon Creek Plant	1,760	11/30/1999		4-00	5	SIP Approved	16	0	GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI	30/15 day	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
TN	Vanderbilt University	10	12/13/1999		5-00	5	SIP Approved	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		25 ppm	GCP		
TN	Memphis Generation LLC	1,050	06/13/2000		04/09/2001		SIP Approved	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
TN	Haywood Energy Center (Calpine)	900	12/21/2000		02/01/2002		SIP Approved	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TN	TVA - Franklin	610	6/21/01		draft permit		SIP Approved	2	2	GE 7FA (195 MW)	NG	CC	8,760	3.5 ppm	SCR		25 ppm	GCP		
TN	Southern Power Co.	1,940	12/05/2001		applic. under review		SIP Approved	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3.5/9 ppm NG; 12/42 ppm FO	SCR/DLN; SCR/WI		0.035 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		
Region 5	160	115,207						572	214											
IL	ABB Energy Ventures - Bartlett	558	09/16/1999		09/05/2000	12	Delegated	2	?	2 at 279 MW	NG; FO	CC	8,760	?	SCR	?	?			
IL	Constellation Power - Holland Energy - Beecher City	336	10/07/1999		04/06/2000	6	Delegated	2	?	168 MW each	NG; FO	CC	8,760	?	SCR					
IL	Coastal Power - Fox River Peaking Sta.	345	11/19/1999		final review		Delegated	3	?	115 MW each	NG	SC	?	?	DLN					
IL	Peoples Gas, McDonnell Energy	2,500	06/21/1998		12/21/1998	6	Delegated	10	0	250 MW each	NG, ethane	CC	8,760	4.5 ppm	LNC, SCR	1-hr	15 ppm, 0.031 lb/mmBtu	GCP		BACT; Ox Cat rejected at $3043/ton
IL	Peoples Gas, McDonell Energy	680	06/21/1998		12/21/1998	8	Delegated	4	?	170 MW each	NG, ethane	SC	1,500	15 ppm	DLN	1-hr	15 ppm, 0.031 lb/mmBtu	GCP		BACT; operational
IL	Peoples Gas, McDonell Energy	960	01/27/2000		10/17/2000	10	Delegated	5	?	172 MW each	NG	SC	?	?	DLN					
IL	Peoples Energy - Calumet Power LLC, Chicago	266	10/07/1999		12/13/1999	3	Delegated	2	?	133 MW each	NG	SC	?	?	WI					
IL	Calumet Energy LLC - Chicago	305	11/24/1999		05/18/2000	6	Delegated	2	?	152.5 MW each	NG; FO	SC	?		DLN					
IL	Illinois Power Tilton	176	?		01/01/1999		Delegated	4		44 MW	NG	SC	2,352	0.1 MMBtu	WI					Synth Minor; operating
IL	Indeck Pleasant Valley	?	?		01/28/1999		Delegated	2		150 MW	NG	SC	1,500	15 ppm	DLN					Synth Minor; rejected by county
IL	Indeck - Rockford	300	11/24/1999		02/16/2000	4	Delegated	2	?	150 MW each	NG	SC	?	?	DLN					
IL	Dynegy, Rock Rd. Power	277	12/04/1998		02/04/1999	2	Delegated	3		2 at121 MW & 1 at 35 MW	NG	SC	1,300	2 at 25 ppm and one at 42 ppm	2 on DLN and one withWI					Synth Minor; operational
IL	Dynegy, Rock Rd. Power	121	5/99		10/27/1999	6	Delegated	1		121 MW	NG	SC	1,450	15 ppm	DLN					Synth Minor
IL	Indeck Libertyville	300	?		02/25/1999		Delegated	2		150 MW each	NG	SC	2,000	15 ppm	DLN					Synth Minor; awaiting city approval
IL	Soyland Power Alsey	105	12/06/1998		03/24/1999	4	Delegated	2		30 MW (2) & 22.5 MW (2)	NG; FO	SC	475							Synth Minor; under construction
IL	Soyland Power Alsey	45	12/09/1999		07/07/2000	7	Delegated	1		25 MW	NG; FO	SC	460		WI					Synth Minor; under construction

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IL	LS Power, Kendall Energy	1,000	11/05/1998		06/02/1999	8	Delegated	4	4	250 MW each	NG; FO	CC	8,760	4.5 NG ppm/16 FO ppm	DLN, SCR	1-hr	33.1 ppm NG/49.6 ppm FO, 0.0626 w/DB, 0.0511no DB; >75% load	GCP		BACT; Ox Cat rejected at $4083/ton
IL	Union Electric, Gibson City Power	170	02/19/1999		06/16/1999	4	Delegated	2		135 MW each	NG; FO	SC	1,500	25 ppm NG; 42 ppm FO	DLN					Synth Minor; under construction
IL	Union Electric, Kinmundy Power	170	02/04/1999		06/28/1999	5	Delegated	2		135 MW ech	NG; FO	SC	1,500	9 ppm NG; 42 ppm FO	DLN					Synth Minor; under construction
IL	Reliant Energy (Houston Industries), Cardinal Woods Rivery Refinery	633	09/21/1998		07/14/1999	10	Delegated	3	3	211 MW each	NG, RFG	CC	8760, 1300 hrs w/DB, more if load < 100%.	3.5 ppm NG; 4.5 ppm RFG	SCR	8 hr/1 hr	0.0472 lb/mmBtu	GCP		BACT & LAER (NOx); Co-located with refinery, separate source; Ox Cat rejected at $1993/ton
IL	Reliant Energy Shelby Energy Center	328	09/30/1999		02/01/2000	4	Delegated	8	?	8 at 41 MW each	NG	SC	?	?	WI					
IL	Reliant Energy Williamson Energy Center	328	09/30/1999		02/23/2000	5	Delegated	8	?	8 at 41 MW each	NG	SC	?	?	WI					
IL	Reliant Energy - DuPage County LP	935	11/03/1999		05/20/2000	7	Delegated	10	?	6 at 45 MW & 4 at 170 MW	NG	SC	?	?	6 wiith WI and 4 with DLN					
IL	Mid America, Cordova Energy Center	500	02/26/1999		09/02/1999	6	Delegated	2	0	250 MW each	NG	CC	6,760	4.5 ppm	SCR	1-hr	.0547 lb/mmBtu: loads > 75%, after 9/2001	GCP		BACT; Ox Cat rejected at $1307/ton
IL	Enron, Des Plaines Green Land	664	02/03/1999		09/28/1999	7	Delegated	8	0	83 MW each	NG	SC	3,250	9/12/15 ppm	DLN	an/mo /hr	0.054 lb/mmBtu (>45F), .089 lb/mmBtu (<45F)	GCP		BACT; Ox Cat rejected at $6800/ton
IL	Enron, Des Plaines Green Land	167	04/03/2000		Pending		Delgated	1	?	167 MW	NG	SC	?	?	?	?	?	?		
IL	Reliant Energy, McHenry County Plant	510	05/26/1999		12/09/1999	5	Delegated	3		170 MW each	NG	SC	2,000 max (800 [illegible]	9 ppm	DLN					Synth Minor
IL	Enron, Kendall New Century	664	02/03/1999		01/14/2000	12	Delegated	6	0	83 MW each	NG	SC	3,300	9/12/15 ppm	DLN	an/mo /hr	0.054 lb/mmBtu (>45F), .089 lb/mmBtu (<45F)	GCP		BACT; Ox Cat rejected at $6700/ton
IL	CILCO - Medinia CoGen - Mossville	43	10/29/1999		05/30/2000	7	Delegated	3		3 at 14.2 MW each	NG	CC	?	?	DLN					
IL	Dominion Energy Lincoln Generation - Kincaid	688	2//3/00		in review		Delegated	4	?	4 at 172 MW each	NG	SC	?	?	DLN					
IL	LS Power, Nelson Project	1,000	-		-	-	Delegated	4		220 MW each	NG; FO	SC	8,760	25/15	DLN	1-hr				Synth Minor; minor until test under 15 ppm
IL	LS Power, Nelson Project	1,000	08/11/1998		01/28/2000	6	Delegated	4	4	250 MW each	NG; FO	CC	8,760	4.5 ppm NG; 16 ppm FO	SCR	1-hr	0.0626 w/DB, 0.0511no DB; >75% load	GCP		BACT; Ox Cat rejected at $3100/ton
IL	Ameren CIPS	600	08/30/1999		02/25/2000	6	Delegated	2	2	300 MW each	NG	CC	8,760	-	DLN, future SCR	-	0.06 lb/mmBtu	GCP	3 hr	BACT for CO and VOC only - netting out of NOx, PM and SO2 review; replacing coal boilers; Ox Cat rejected at $3400/ton
IL	Electric Energy - Midwest Electric Power - Mossville	318	10/18/1999		03/29/2000	6	Delegated	5	?	3 at 72 MW each & 2 at 51 MW each	NG	SC	?	?	DLN					
IL	Holland Energy	680			draft permit		Delegated	2	2	680 MW	NG; FO	CC	8,760	4.5 ppm NG (3.5 ppm); 16 ppm FO (10 ppm)	SCR	1 hr (24 hr)	0.02, 0.04 FO, 0.12 NG w/DB	GCP	1-hr	BACT; SCR cost $8,900/ton; Ox Cat rejected at $10,600/ton
IL	Duke Energy - Lee Generating	864	09/13/1999		03/31/2000	7	Delegated	8	0	83 MW each	NG; FO	SC	2,000; 500 FO	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.) ; 1 hr		GCP	1-hr	BACT; SCR rejected at $27,689/ton; Ox. Cat rejected at $6,931/ton
IL	Duke Energy - Kankakee	620	04/10/2000		draft permit		Delegated	2	?	620 MW	NG	CC	8,760							
IL	Duke Energy - Cook County	620	04/24/2000		under review		Delegated	2	?	620 MW	NG	CC	8,760							
IL	Constellation Power Univ. Park	175	12/06/1999		05/01/2000	5	Delegated	2	?	175 MW	NG; FO	CC	?	?	SCR	?				BACT
IL	Rolls-Royce Power ventures - Lockport	294	05/01/2000		at notice		Delegated	6	?	6 at 49 MW each	NG	SC	?	?	DLN					
IL	Skygen Services - Zion Energy Center	800	11/12/1999		Final review		Delegated	5	?	160 MW each	NG; FO	SC	?	?	DLN					
IL	Soyland Power Alsey	100	12/06/1998		03/24/1999	4	Delegated	4	?	30 MW (2), 22.5 MW (2)	NG; FO	SC	?	?	2 with WI, other 2 ?	?				
IL	Soyland Power Alsey	25	12/09/1999		07/07/2000	7	Delegated	1	?	25 MW	NG; FO	SC	?	?	Not given	?				Synth Minor
IL	Standard Energy Ventures - DuPage	600	12/01/1999		in review	?	Delegated	?	?	600 MW	NG	SC								

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IL	Spectrum Energy - Logan County Power	135	05/05/2000		09/12/2000	4	Delegated	3	?	3 at 45 MW each	NG	SC	?	?	WI					
IL	Spectrum Energy - Central Ill. Power - St. Elmo	45	06/16/1999		09/08/1999	3	Delegated	1	?	45 MW	NG	SC	?	?	DLN					
IL	Spectrum Energy - Central Ill. Power - St. Peter	45	10/04/1999		02/01/2000	3	Delegated	1	?	45 MW	NG	SC	?	?	?					
IN	(Acadia Bay) Alleghany Energy Supply Company, LLC	630	03/22/2001		12/07/2001		Delegated	4	0	2 Westinghouse 501 F& 2 General Electric LM2000(46MW)	NG	2 CC & 2 SC	8,760	2 CC @ 3.0ppmvd & 2 SC @ 25 ppmvd	DLN, SCR	2 CC = 3 hr block avg.& 2 SC = 24 hr avg.	2 CC @ 6.0ppmvd & 2 SC @ 25-100ppmvd depending on temp.	GCP	2 CC = 3 hr block avg. & 2 SC = 24 hr avg.	BACT
IN	Cogentrix Lawrence County, LLC	820	07/03/2000		10/05/2001		Delegated	3	3	GE 7FA (Model 7241)	NG	CC	8,760	3.0 ppmvd	DLN and SCR	3 hr rolling avg	>=50% load 9.0 ppmvd w/DB and 6 ppm w/o	GCP	24 hr rolling avg	BACT
IN	Duke Energy Knox, LLC	640	08/31/2001		05/29/2001		Delegated	8	0	GE 7EA 8 @ 80MW each	NG; FO	SC	8,760	>=60% load 9.0 ppmvd NG; 42 ppmvd FO	DLN; WI	24 oper hr avg; 1 hr avg	>=60% load 25 ppmvd NG; 25 ppmvd FO	GCP	24 oper hr avg; 1 hr avg	BACT
IN	Duke Energy Vermillion, LLC	640			07/01/1999		Delegated	8	0	GE 7EA 8 @ 80MW each	NG; FO	SC	8,760	15 ppmvd NG; 42 ppmvd FO	DLN; WI	1 hr avg NG; FO	>=50% load; 25 ppmvd NG; 20 ppmvd FO	GCP	1 hr avg NG; FO	BACT
IN	Duke Energy Vigo, LLC	620	07/12/2000		06/06/2001		Delegated	2	2	GE 7FA 2@ 160MW each	NG	CC	8,760	>=50% load 3.0 ppmvd with and without DB	DLN,SCL, GCP	3 hr avg	>=50% load; 9.0 ppmvd w/DB and 6 ppm w/o	GCP	24 hr avg	BACT
IN	Skygen Mt. Vernon Energy, LLC	265	10/01/2000		draft permit		Delegated	1	0	GE 7FA (7241) 265MW	NG	CC	8,760	>=50% load 3.0 ppmvd with and without DB	DLN, SCR, GCP	3 hr block avg	>=50% load 5.6 with and w/o DB	GCP, CO CatOx if limits aren't met	24 hr avg	BACT
IN	PSEG Lawrenceberg Energy Company	1,130	07/24/2000		06/07/2001		Delegated	4	4	GE 7FA (7241)	NG	CC	8,760	>=50% load 3.0 ppmvd with and without DB	DLN, SCR, GCP	3 hr avg	>=50% load 6 ppmvd w/o DB (9 ppmvd w/DB)	GCP	24 hr avg	BACT
IN	Whiting Clean Energy	332	08/02/1999		07/20/2000		Delegated	2	2	GE 7FA (7241) 2@ 166 MW	NG	CC	8,760	>=50% load 3.0 ppmvd with and without DB	DLN, SCR, GCP	3 hr rolling avg	>=50% load 0.010 lbs/MMBtu w/o DB (0.037 lbs/MMBtu w/DB)	GCP	NA	LAER
IN	SIGECO - A.B. Brown (Southern Indiana Gas and Electric Company) permit# 12029	109 (max)	03/13/2001		11/29/2001		Delegated	1	0	GE 7EA @ 80-109 MW	NG/2 distillate oil	SC	8,760	NG < 9ppmvd NG; #2oil <=42ppmvd	DLN, SI	24hr avg	NG & #2 oil ,<= 25 ppmvd	GCP	24hr avg	BACT
IN	SIGECO - A.B. Brown (Southern Indiana Gas and Electric Company) permit# 14021	80 (max)	03/05/2001		11/16/2001		Delegated	1	0	GE PG7121EA, frame 7EA type MS7100	NG	SC	8,760	< 9ppmvd NG	DLN	24hr avg	<25ppmvd NG	GCP	24hr avg	BACT
IN	Southern Energy, Inc. (Mirant Sugar Creek, LLC)	1,008	04/24/2000		05/09/2001		Delegated	4	4	GE 7FA (7241): 4 @ 252 in CC mode; 4 @ 170 in SC mode	NG	SC or CC	8,760	9 ppmvd (>=50% load)	DLN, GCP	3 hr avg	9 ppmvd (>=50% load)	GCP	24 hr avg	BACT
IN	PSI - Cinergy Fayette Peaking Station	520			12/18/1998		Delegated	4		4@45 or 2@170 MW	NG	SC	peaking	25 ppm	either DLN or WI		15 ppm	GCP		Syn. Minor
IN	PSI-Wabash Peaking Station	169			01/19/1999		Delegated	3		LM 6000 (43 MW)	NG; FO	SC	3,000	25 ppm NG; 28 ppm FO	DLN and WI		42 ppm NG; 6 ppm FO	GCP		Syn. Minor

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IN	Duke Energy Vermillion Generating Station	640	12/18/1998		06/01/2000	7	Delegated	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	annual	25 ppm NG; 20 ppm FO	GEP	1-hr > 50% load	BACT; Usage limit of 20,336 MMCF NG-12 consec. months. Also 2 Emergency Generators; 1 Emergency Diesel Fire Pump; 4 Diesel Storage Tanks; SCR @ $19,309/ton (avg.); Ox Cat @ 90% Control, rejected at $8,977/ton
IN	PSI Cinergy Corporation	169			07/15/1999		Delegated	3		GE LM6000 (43 MW)	NG; FO	SC	3,000	25 ppm NG; 28 ppm FO	DLN and WI		42 ppm NG; 6 ppm FO	GCP		Synth Minor
IN	AES, Greenfield	520			07/15/1999		Delegated	4		4@45 or 2@170 MW	NG	SC	peaking	25 ppm	either DLN or WI		15 ppm	GCP		Synth Minor
IN	Indianapolis Power and Light	191			08/17/1999		Delegated	1		GE 7121EA (95.7 MW)	NG; FO	SC	peaking	25 ppm NG; 42 ppm FO	WI					Synth Minor
IN	Indianapolis Power and Light	265			09/17/1999		Delegated	3		GE (88.4 MW each)	NG	SC	peaking	25 ppm NG; 42 ppm FO	DLN	an/hr	25 ppm NG; 20 ppm FO	GCP		Synth Minor
IN	Duke Energy DeSoto	?			withdrawn 2/18/02		Delegated	8		GE 7EA (80 MW each)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.) ; 1 hr	25 ppm NG; 20 ppm FO	GCP		BACT
IN	Enron West Fork Land Development	540			withdrawn 4/18/01		Delegated	4		SW 501D5A (135 MW)	NG	SC	966	25	WI		12 ppm	GCP		Synth Minor
IN	Parke County	?			no appl.(10-99)		Delegated	2		225 MW?	NG; FO	CC	8,760	3.5ppm, ?? FO	DLN and SCR	an/hr	*unknown*			BACT
IN	LSP Columbus Energy	?			withdrawn 4 /18/01		Delegated	4		200 MW?	NG; FO	EITHER	8,760	3.5 ppm; 4.5 w/DB, 16 FO	DLN/WI and SCR		33.1 ppm - 234.3 (50% load); 49.6 ppm - 168 ppm (50% load) FO	GCP		BACT
MI	Wyandotte Energy	500	application rececived 8/98		02/08/1999	2	Delegated	2	2	GE 7FA	NG	CC	8,760	4.5 ppm(33 lb/hr) NG/18 ppm FO	SCR	1 hr	3 ppm (LAER)	Cat Ox	1 hr	LAER; SCR cost $5600/ton * Time frame required by Michigan Law
MI	Southern Energy	1,000	application received 7/98		03/16/2000	2	Delegated	4	4	GE 7FA	NG	CC	8,760	3.5 ppm, 0.013 lb/mm btu	SCR	1 hr	0.042 lb/mm btu	GCP	1 hr	BACT
MI	KM Power Co	550	application received 3/00		08/26/2000	2	Delegated	7	7	1GE 7EA and 6 GE LM 6000	NG	CC	7380 and 4780	9 ppm and 22 ppm	DLN	30 day	79 lb/hr and 132 lb/hr	GCP	1 hr	BACT
MI	Covert Generating Co	1,200	application received 9/00		01/12/2001	2	Delegated	3	3	Mitsubishi 501 G	NG	CC	8,760	2.5	SCR	24 hr	33.7 lb/hr	Cat Ox	24 hr	BACT
MI	Indec Niles Energy Center	1076	application received 2/00		application under review		Delegated	4	4	Siemens V84.3A	NG	CC								
MI	Midland Cogeneration Venture	510	application received 1/00		application under review		Delegated	2	0	ABBK 24-1	NG	CC								
MI	Detroit Edison Co	250	application received 7/00		application under review		Delegated	3		GE PG7121(EA)										
MN	LSP-Cottage Grove	245	09/15/1995		11/10/1998	38	Delegated	1	1	Westinghouse 501F (245 MW)	NG; FO	CC	7,060 NG; 1,700 FO	4.5 ppm NG; 18 ppm FO	SCR	1-hr	1200 lb/hr, 1200 lb/hr FO	Cat Ox	1-hr	BACT
MN	Lakefield Junction	552			draft permit		Delegated	6		GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	25 ppm NG; 20 ppm FO	GCP	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
MN	Pleasant Valley	444			draft permit		Delegated	3		SW V.64.3A & 501D5A (155 MW & 134 MW)	NG; FO		8,760	35 ppm NG; 42 ppm FO	DLN, WI		35 ppm NG; 35 ppm FO	GCP		PSD
MN	Xcel Energy (formerly NSP-Black Dog)	290	07/31/2000		01/12/2001	5.5	Delegated	1	1	Westinghouse 501F (290 MW)	NG	CC	8760; 1500 hr/yr for duct burners	4.5 ppm	DLN, SCR	3-hr	18 ppm; 25 ppm when duct burners operating; 400 tpy	GCP	3-hr	BACT/PSD

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
OH	Duke Energy Madison LLC	640	12/21/1998		07/01/1999	6	Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,500 NG; 500 FO	15 ppm (12 ppm) NG; 42 ppm FO	DLN	1 hr (ann.)	25 NG; 20 FO	GCP	hr/an	BACT; SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton
OH	Duke Energy Washington, LLC	340	?		01/01/2001		Delegated	2	2	GE 7EA (170 MW)	NG	CC	4260 W/O DB; 4500 W/DB	3.5 ppm	SCR	1 hr (ann.)	10 ppm w/o DB; 114 w/ DB	GCP	hr/an	PSD
OH	Duke Energy Madison II, LLC	640	?		-		Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,000 NG; 500 FO							PSD
OH	PS&G Waterford Energy	340	?		-		Delegated	2		GE 7EA (170 MW)		CC		3.5 ppm	SCR					
OH	Dresden Energy	340	?		-		Delegated	2		GE 7EA (170 MW)		CC		3.5 ppm	SCR					
OH	Rolling Hills Generating	1,045	?		-		Delegated	5		(209 MW)		SC		15 ppm	DLN					
OH	Jackson Generating	640	?		-		Delegated	4		GE 7EA (160 MW)	NG	SC		9 ppm	DLN					
OH	DP&L Tait Generating	?	?		-		Delegated					SC		9 ppm	DLN					
OH	Jackson Co. Power	640	?		-		Delegated	4		GE 7EA (160 MW)	NG	CC		5 ppm	SCR					
OH	Duke Energy - Hanging Rock, LLC	1,270	?	?	12/13/2001	?	Delegated	4	4	GE 7FA (172 MW each)	NG	CC	?	3.0ppm w/d.b. and 3.0ppm w/out d.b.	DLN and SCR	3 hrs	9.0ppm w/d.b. and 6.0ppm w/out d.b.	GCP	24 hrs	CatOx rejected at $3,490/ton
OH	University of Cincinnati	55	?	?	08/15/2002	?	Delegated	2	2	13 MW each	NG; FO	CC	8760	24.56lb/hr w/d.b. and 14.71lb/hr w/out/d.b.	DLN		1.97lb/hr	CatOx	3 hrs	SCR rejected at $11,834/ton
WI	RockGen Energy	525	09/01/1998		01/01/1999	4	SIP Approved	3		GE 7FA (175 MW each)	NG; FO	SC	3,800 Total, 800/CT FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst ; 1 hr	*12 ppm* NG; *15 ppm* FO (load>75%) & 24 ppm FO (load<75%)	DLN, GEP	1-hr	BACT; SCR *not chosen*; cost $23,018/ton; Ox Cat rejected at $15 K/ton
WI	Southern Energy	?	?		02/25/1999	?	SIP Approved	2		GE 7FA (180 MW each)	NG; FO	SC	8,760 Total, 699 FO	12/15 ppm NG; 42 ppm FO	DLN, WI	24 hr/inst ; 1 hr	12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%)/ 42 ppm FO	DLN, GEP	24-hr /1-hr FO	BACT; Ox Cat rejected at $14 K/ton
WI	Wisconsin Public Service	360			07/01/1999		SIP Approved	1		GE 7EA (102 MW)	NG; FO	SC	4,000 Total, 2,000 FO	9 ppm NG; 42 ppm FO	DLN	hr, nat gas, FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $13,666/ton; Ox Cat rejected at $6053/ton incremental cost
WI	Wisconsin Electric	65			draft permit		SIP Approved	1		GE 7EA (85 MW)	NG; FO	SC	178,000 MWhrs, 2,000 hrs, 100 hr power aug.	9 ppm NG (20 ppm w/power aug.); 42 ppm FO	*DLN*	24-hr, 1-hr FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	*GEP*	1-hr	BACT; SCR rejected at *$10,257/ton; Ox Cat rejected* at $5984/ton incremental cost
Region 6																				
AR	Jonesboro City Water & Lights	56	?		?		SIP Approved	2		2 - 23 MW		SC								
AR	Jonesboro City Water & Lights	44	?		07/29/2001		SIP Approved	1		1 - 44 MW		CC								
AR	Hot Springs Energy	1,240	05/31/2000		12/29/2000	7	SIP Approved					CC								
AR	AES Cypress	540	12/11/2000		10/15/2001	11	SIP Approved					CC								
AR	Gen Power	640	01/31/2000		08/08/2000	7	SIP Approved					CC								
AR	Hot Springs Power	700	03/12/2001		11/09/2001	8	SIP Approved					CC								
AR	Pine Bluff Energy	220	09/04/1998		05/05/1999	8	SIP Approved	1				CC								
AR	Pine Bluff Energy - Mod	220	02/23/2000		02/27/2001	12	SIP Approved	1				CC								
AR	AR Electric - Fitzhugh Station	170	02/13/2001		02/15/2002	12	SIP Approved	1				CC								
AR	Union Generating Station	260	07/01/1999		08/24/2000	13	SIP Approved	10		260 MW		CC								
AR	Tenaska - KEO	1,800	09/18/2000		10/09/2001	13	SIP Approved					CC								
AR	KN Power	510	?		draft permit		SIP Approved	7		510 MW total		CC								
AR	Duke Energy Newport	620	06/05/2001		draft permit		SIP Approved					CC								

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AR	Paragould Electric	4	?		draft permit		SIP Approved	4		4 MW total		SC								
AR	Arkansas Electric Coop	153	11/19/1999		03/10/2000	4	SIP Approved	1				SC								
AR	Kinder Morgan - Newpot Power	560	07/02/2001		in review		SIP Approved	7	6	6-LM 6000/1-GE7EA; ERR		SC/CC								
AR	Wrightsville Energy Power facility	510	05/03/1999		02/28/2000	10	SIP Approved	7	6		NG	One CC, Six SC	8,760 in CC; 5,250 in SC	9 ppm (DLN), 25ppm (SI)	DLN (CC), SI (SC)	?	50 ppm (DLN), 66 ppm (SI)	GCP	?	
AR	Genova	550	11/14/2001		In review		SIP Approved					CC								
LA PSD-LA-623	Nations Energy	800			voided?		SIP Approved			800 MW total		CC								
LA	Wash. Ph. Energy Center - Bogalusa	800	11/12/1999		06/25/2000	7	SIP Approved			800 MW total		CC								
LA PSD-LA-651	Ouachita Power - Cogentrix Sterlington	800	11/12/1999		06/21/2000	7	SIP Approved			800 MW total	NG	CC		9 ppm	SCR/LNB					
LA	Caddo Parish Energy		06/25/2001		03/14/2002	9	SIP Approved													
LA	Cogentrix - Acadia	300	?		?		SIP Approved			300 MW total		SC								
LA	Calcasieu Power	370	?		10/21/1999		SIP Approved			370 MW total		CC								
LA PSd-LA-652	Entergy - Monroe	130	01/14/2000		06/16/2000	5	SIP Approved			130 MW Total	NG	steam driven	3000 each	0.110 lb/mmbtu	IFGR,RC SFS in boilers		NA	NA	NA	3 steam-driven turbines
La PSD-LA-645	Acadia Power Partners LLC	1,000	10/14/1999		07/13/2000	9	SIP Approved				NG	CC		9 ppm	SCR/LNB					
LA TV-LA-011VO	Entergy Gulf States LA Station2	140	05/24/2000		01/19/2001	8	SIP Approved			140 mw total	NG	steam driven	3000 each	0.100 lbs/mmbtu	?IFGR,RC SFS,BOO S in boilers		NA	NA	NA	3 steam-driven turbines
LA PSD-LA-633	Occidental Chemical - Taft	510	07/22/1998		03/19/1999	8	SIP Approved	3			NG	CC		8/25 ppm (w/waste gas)	SCR/SI					
LA PSD-LA-650	Occidental Chemical - Convent		?		06/08/2000		SIP Approved													
LA PSD-LA-637	PPG Industries		?		12/02/1999		SIP Approved													
LA TV-LA-002V2	Cleco Evangeline LLC		?		06/29/2000		SIP Approved													
LA	Duke Energy - Ruston		08/06/2000		07/10/2001	11	SIP Approved													
LA PSD-LA-638	Carville Energy				12/09/1999		SIP Approved													
LA	Bayou Cove Peaking Plant		04/16/2001		10/25/2001	6	SIP Approved													
La TV-LA-2136V1	Shell Chemical				applic. under review		SIP Approved													
LA	Bayou Verrett		12/22/1999		11/15/2001	11	SIP Approved													
LA	LA Generating - Big Cajun	240	08/11/2000		12/08/2000	4	SIP Approved	2				CC		15 ppm	DLN					
LA	LA Generating - Big Cajun		09/01/2001		in review		SIP Approved					CC								
LA PSD-LA-622	AirLiquid America Co-Gen		10/08/1997		02/13/1998	4	SIP Approved	1	1	966 mm btu/hr	NG	CC	?	9 ppm	LNB, DLN	?	25 ppm	GCP		
LA	Formosa Plastics Corp. - Baton Rouge						SIP Approved					CC		9 ppm	DLN					
NM	El Paso Electric/Rio Grande Power Plant,	261	?		final permit		SIP Approved			261 MW total										
NM	Lordsburg Limited/100 MW Repowering,	100	07/27/1995		06/18/1997	25	SIP Approved	1		WH 501D5A 100MW total	NG; FO	SC	1,440	15 ppm >75% output, 42 ppm <75% output. 42 ppm/60 ppm FO	DLN, WI	?	10 ppm/200 ppm NG & 90 ppm/150 ppm FO per outputs listed for NOx	Clean fuels, CO catalyst	?	

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NM PSD-90-M2	TNP Lordsburg	220	11/03/1997		08/07/1998	9	SIP Approved	2	2	GE LM6000 Sprint aero-derivative	NG; FO	CC	7,360; 1,400 FO	15 ppm	SCR, WI	?	18 ppm	GCP	?	
NM	Lea County/North Lovington,	50			shutdown		SIP Approved			49.5 MW total										
NM	Plains Electric/Escalante Plant	300			final permit		SIP Approved			200-300 MW total										
NM	PNM/San Juan,	1,798			final permit		SIP Approved			1798 MW total										
NM	Southwestern Public Service/Cunningham,	511	08/09/1996		02/15/1997	6	SIP Approved			511 MW total	NG; FO									
NM	Southwestern Public Service/ Maddox	292			final permit		SIP Approved			292 MW total										
NM	Southwestern Public Service/Carlsbad	16			no TV permit required,		SIP Approved			16 MW total										
NM	Williams Field Services/Milagro Cogen,	62			final permit		SIP Approved			62 MW total										
NM	Raton Public Service/Raton Plant,	11			draft permit		SIP Approved			11.25 MW total										
NM	Luna Energy Facility				12/29/2000															
NM	Energy SW - Las Cruces				01/08/2001															
OK	AECI-Chouteau	530	10/06/1998		03/24/1999	6	SIP Approved	2		530 MW total	NG	CC	8,760	12 ppm	DLN, SCR	?	10 ppm	GCP	?	NOx $2,535/ton
OK	Cogentrix -Jenks	800			10/01/1999		SIP Approved	3		800 MW total		CC								
OK	C&SW	320			10/18/1999		SIP Approved	2		320 MW total		CC								
OK	Panda - Coweta	1,000			01/21/2000		SIP Approved	4		1000 MW total		CC								
OK	OG&E-Horsehoe	90			02/03/2000		SIP Approved	2		90 MW total		SC								
OK	Duke-Newcastle	520			01/21/2000		SIP Approved	2		520 MW total		CC								
OK	ONEOK -Edmond	360			05/01/2000		SIP Approved	4		360 total		SC								
OK	Redbud Energy - OK County	825	03/16/2000		08/15/2001	17	SIP Approved	3		825 MW total		CC								
OK	Energetix - Thunderbird	825	06/12/2000		05/17/2001		SIP Approved	3		825 MW total		CC								
OK	Kiowa Power	1,200			05/01/2001		SIP Approved	4		1200 MW total		CC								
OK	Energetix -Lawton	600	06/13/2000		05/29/2002	23	SIP Approved	2		600 MW total		CC								
OK	SmithCoGen - Pocola	1,200	05/07/2000		08/16/2001	15	SIP Approved	4		1,200 MW total		CC								
OK	Energetix - Webbers Falls	825	11/20/2000		10/22/2001	11	SIP Approved					CC								
OK	KM Power - Pittsburg Plant	550	06/12/2000		05/13/2001	11	SIP Approved			6-LM6000/1-GE7EA; ERR		SC								
OK	WFEC - Anadarko	94			06/26/2000		SIP Approved					SC								
OK	Tenasca - Seminole	1200			withdrawn 10/25/01		SIP Approved					CC								
OK	Energetix GR. Plains	900			Pending Facility Action		SIP Approved					CC								
OK	Duke - Stephens	650/620)	07/10/2001		3/17/03(was1 2/10/2001)	20	SIP Approved					CC								
OK	Mustang Power - Harrah	310	05/10/2001		02/13/2002	9	SIP Approved					SC		25 ppm	DLN					
OK	Horseshoe Energy	310	07/03/2001		02/13/2002	7	SIP Approved					SC		25 ppm	DLN		40 ppm	GCP		

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TX	Sweeney Cogen Ltd. Part. - Brazoria	363	02/12/1996		09/09/1996	7	SIP Approved	3	?	3 W501D5A, 121 ME each			?	15/25 ppm	DLN	?	?	GCP	?	
TX	Sweeney Cogen Ltd. Part. - Brazoria	121	12/12/1997		09/30/1998	10	SIP Approved	1		121 MW				15 ppm	DLN					
TX	QUIXX Corp (SPS) - Hutchison	242	03/11/1996		02/05/1997	11	SIP Approved	2	?	2 W501D5A, 121 MW each			?	15 ppm	DLN	?	10 ppm	GCP	?	
TX	GSE&DCE LS Power LLC, Yoakum	550	12/31/1996		07/17/1997	7	SIP Approved	2	2	2 F7FA,, 180 MW each, 550 MW total		CC	?	15 ppm	DLN	?	?	GCP	?	
TX	Occidental Chemical Co.	500	04/18/1997		01/08/1998	9	SIP Approved	2	2	2 F7FA, 170 MW each		CC	?	15 ppm	DLN	?	20 ppm	GCP	?	
TX	Gregory Power Partnership	336	05/09/1997		03/19/1998	10	SIP Approved	2		2 F7FA, 168 MW each		?	?	15 ppm	DLN	?	20 ppm	GCP	?	
TX	Houston Industries Power Gen	110	10/29/1997		04/01/1998	5	SIP Approved	2		2 F6B 44 MW each		CC	8,760	15 ppm	SCR	?	15 ppm	CatOx	?	
TX	BASF	83	12/08/1997		06/26/1998	7	SIP Approved	1		1 F7FA, 83 MW		?	?	9/5 ppm	DLN	?	25 ppm	GCP	?	
TX	Sweeney - Harris	240	04/01/1996		12/04/1996	8	SIP Approved	1		W501F, 160 MW, 240 MW total	NG, ?	CC	8,760	12 ppm	SCR, SI	?	20 ppm	GCP	?	
TX	Sweeney - Harris	121	12/10/1997		09/30/1998	11	SIP Approved	1		W501D5A 121 MW		?	?	15/25 ppm	DLN	?	10 ppm	GCP	?	Ammended to add Co-Gen
TX	Calpine Corp. Harris	500	12/18/1997		09/30/1998	11	SIP Approved	1		W501F, 160 MW		CC	8,760	12/9 ppm	SCR	?	25 ppm	GCP	?	
TX	Edinburg Energy - Hiladgo	815	12/29/1997		08/18/1998	8	SIP Approved	4		4 ABB GT-24, 180 MW each, 815 MW total		CC	?	15 ppm	DLN	?	10 ppm	GCP	?	
TX	Frontera Generating L.P. - Hilalgo	440	02/12/1998		07/31/1998	7	SIP Approved	2		2 F7FA, 165 MW each, 440 MW total		CC	?	15 ppm	DLN	?	?	GCP	?	
TX	Lubbock Power & Light	128	03/19/1998		01/08/1999	9	SIP Approved	2		LM6000 (42 MW each with project total 128 mW)		CC		15 ppm	SCR		25 ppm	GCP		
TX	Midlothian Energy Ltd. (Venus)	1,080	04/13/1998		10/02/1998	6	SIP Approved	4		ABB GT24 (175 MW)		CC		9/5 ppm	SCR		25 ppm	GCP		
TX	City Public Service	500	04/20/1998		10/14/1998	6	SIP Approved	2		GE 7FA (170 MW)		CC		9 ppm	SCR		25 ppm	GCP		
TX	Calpine Magic Valley	700	05/01/1998		12/31/1998	7	SIP Approved	2		SW501G (230 MW)		CC		12/9 ppm	SCR		25 ppm	GCP		
TX	Lamar Power Part. (Panda Paris) (1000 MW total)	680	05/07/1998		10/28/1998	6	SIP Approved	4		GE 7FA (170 MW each)		SC		9 ppm	DLN		18 ppm	GCP		
TX	Union Carbide	39	05/29/1998		10/20/1999	5	SIP Approved	1		F6B (39 MW)				9 ppm	DLN		25 ppm	GCP		
TX	Duke Energy Hidalgo, LP	520	06/15/1998		12/22/1998	6	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm	GCP		
TX	Panda Guadalupe Power (1000 MW total)	1,000	06/24/1998		02/15/1999	8	SIP Approved	4		GE 7FA (170 MW)		SC		9 ppm	DLN		15 ppm	GCP		
TX	Fina/BASF (amend - Substitute) (78 MW total)	78	10/12/1998		04/22/1999	6	SIP Approved	2		F6B (39 MW each)		CC		9 ppm	DLN/SCR		25 ppm	GCP		Cogen for Boiler, N007 (VOC only,Nox 182f)
TX PSD-908	BASF Freeport Co-Gen	83	12/8/97 rev		06/26/1998	7	SIP Approved	1	1	83 MW	NG	CC	8760 turbibe 4380 duct burner	15 ppm duct burner off, 0.1 lb/mm btu duct burner off	DLN	?	25 ppm duct burner off, 0.008 lb/mm btu duct burner on	GCP	?	Revised to add Co-Gen

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TX permit PSD-840	Brownsville Public Utility	?	12/4/97 rev.		01/09/1998	2	SIP Approved	1	1		NG; FO	CC		15.8 ppm NG/ 42 ppm FO See cell comments	Not in permit file	?	15 ppm NG/ 10 ppm FO	not in permit file	?	
TX PSD-857	Sweeny Co-Gen LTD Brazoria	363	05/23/1996		09/09/1996	4	SIP Approved	3	3	121MW each. W501D5A	NG/Refinery fuel	CC	8,760	15 ppm/25 ppm w/DB	?	?	10 ppm	GCP	?	
TX PSD-857	Sweeny Co-Gen LTD Brazoria	121	12/12/1997		09/30/1998	10	SIP Approved	1	1	121 MW W501D5A	NG/Refinery fuel	CC	8,760	15 ppm/25 ppm w/DB	?	?	10 ppm	GCP	?	
TX	Eastex Cogen	468	11/12/1998		11/19/1999	01/12/1900	SIP Approved	2		GE 7FA (168 MW)		CC		9 ppm	DLN		7 ppm			
TX	Tenaska Gateway	880	12/02/1998		05/07/1999	8	SIP Approved	3		GE 7FA (164 MW)		SC		9 ppm	DLN		25 ppm			
TX PSD-897	Ternaska Frontier Shiro (Grimes)	830	01/13/1998		08/07/1998	7	SIP Approved	3	3	830 MW total	NG; FO	?	?	15 ppm NG/ 42 ppm FO	DLN, SI	?	not given	not given	?	
TX	Hays Energy Project	1,080	12/02/1998		06/08/1999	8	SIP Approved	4		GT24 (175		CC		5 ppm	DLN/SCR		5 (25) ppm			
TX	Ennis-Tractabel Power Co., Inc.	350	01/21/1999		12/15/1999	11	SIP Approved	1		SW501G (250 MW)		CC		9 ppm	SCR		20 ppm			
TX	Sabine River Works Cogen LP	440	02/01/1999		06/22/1999	5	SIP Approved	2		GE 7FA (170 MW)		CC		6 ppm	SCR		15 ppm			
TX	SEI - Texas, LLC	650	02/11/1999		03/21/2000	13	SIP Approved	4		2 GE 7FA (170 MW) / 2 GE 7EA (82 MW)		SC		9/9 ppm	DLN		9/25 ppm			
TX	SEI - Texas, LLC	650	02/11/1999		12/20/1999	10	SIP Approved	3		GE 7FA (170 MW)		SC		9 ppm	DLN		9 ppm			
TX	Mobil Oil	740	02/11/1999		03/14/2000	13	SIP Approved	3		SW501F (180 MW)		SC		9/9 ppm	DLN/SCR		10/25 ppm			
TX	Cogen Lyondell (CT #7)	180	03/04/1999		11/05/1999	8	SIP Approved	1		SW501F (180 MW)		SC		25 ppm	DLN		25 ppm			
TX	City of Garland	65	03/09/1999		02/23/2000	11	SIP Approved	1		GE 7EA (85 WM)		SC		9 ppm	DLN		25 ppm			
TX	Rio Nogales Power Project LP	780	03/17/1999		12/03/1999	8	SIP Approved	3		GE 7FA (170 MW)		SC		9 ppm	DLN		7.4 ppm			
TX	Odessa-Ector Power Partners LP	1,000	04/05/1999		11/19/1999	7	SIP Approved	4		GE 7FA (170 MW)		SC		9 ppm	DLN		9 ppm			
TX	Archer Power Partners LP	1,000	04/05/1999		01/13/2000	9	SIP Approved	4		GE 7FA (170 MW)		SC		9 ppm	DLN		9 ppm			
TX	AES Aurora	1,000	04/22/1999		02/07/2000	9	SIP Approved	4		GE 7FA (170 MW) / SW501F (183 MW)		SC		9 ppm	DLN		25 ppm			
TX	Freestone Power Project LP	1,070	04/30/1999		03/28/2000	11	SIP Approved	4		GE 7FA (175 MW)		SC		9 ppm	DLN		20 ppm			
TX	GenTex Power Corp. & Calpine	500	05/21/1999		09/30/1999	4	SIP Approved	2		SW501F (180 MW)		SC		5 ppm	SCR		10/25 ppm			
TX	Duke Ennergy Kaufman	440	05/27/1999		01/27/2000	8	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm			
TX	Corpus Christi Cogeneration LP	708	05/28/1999		02/04/2000	8	SIP Approved	3		GE 7FA (166 MW)		SC		9 ppm	DLN		15 ppm			
TX	Duke Energy Bell LP	520	06/14/1999		02/04/2000	7	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm			
TX	Midlothian Energy (add #5 & #6)	550	07/01/1999		11/24/1999	5	SIP Approved	2		GT24 (175		CC		5 ppm	SCR		25 ppm			
TX	Gateway Power Project, LP	800	07/08/1999		03/20/2000	9	SIP Approved	3		GE 7FA (170 MW)		SC		9 ppm	DLN		7.4 ppm			
TX	Reliant Energy - Channelview	820	07/06/1999		12/09/1999	5	SIP Approved	4		SW501F (183 MW)		CC		3 ppm	DLN/SCR		23 ppm			N017 (NOx and VOC)
TX	Chambers Energy Facility - Harris	2,000	07/12/1999		08/11/2000	13	SIP Approved	8		GT24 (180		CC		3.5 ppm	SCR (LAER)		25 ppm	CatOx (LAER)		N019 (NOx and VOC)
TX	Coastal Power Company	550	07/28/1999		03/22/2000	8	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm			
TX	Cobisa-Forney, LP	1,774	07/29/1999		03/06/2000	7	SIP Approved	6		GE 7FA (170 MW)		SC		9 ppm	DLN		15 ppm			
TX	Calpine Corp. - Chambers	750	08/02/1999		02/11/2000	6	SIP Approved	3		SW501F (180 MW)				3.5 ppm	DLN/SCR		15 ppm			N020 (NOx and VOC)
TX	LG&E Power Inc.	1,600	08/16/1999		08/18/2000	12	SIP Approved	6		GE 7FA (170 MW)		CC		9 ppm	SCR		15 ppm			

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
TX	Duke Power - Jack, LP	520	08/25/1999		03/14/2000	7	SIP Approved	2		GE 7FA (170 MW)				9 ppm	DLN		20 ppm			
TX	Calpine - Harris	740	08/26/1999		03/22/2000	7	SIP Approved	3		SW501F (180 MW)				3.5 ppm	SCR		25 ppm			N021 (NOx and VOC)
TX	Wise County Power Co., LLC	800	11/04/1999		07/14/2000	8	SIP Approved	2		SW501G (350 MW)		CC		5 ppm	SCR		9 ppm	CatOx		
TX	West Texas Energy LP	1,500	11/10/1999		07/28/2000	8	SIP Approved	6		GT24 (180		CC		5 ppm	SCR		5 ppm			N024 VOC (128f for NOx)
TX	Westvaco Texas	85	12/30/1999		12/15/2000	12	SIP Approved	2		LM6000 (42 MW)		CC		5 ppm	SCR		26 ppm			
TX	Cottonwood Energy Co., LP	600	03/30/2000		12/15/2000	9	SIP Approved	4		GE 7FA (170 MW) / SW501F (180 MW)		CC		5 ppm	SCR		17.6 ppm			
TX	Air Products	176	09/30/2000		12/19/2000	3	SIP Approved	4						15 ppm	DLN		25 ppm	GCP		
TX	Channel Energy	180	11/16/2000		In Review		SIP Approved	1				CC		3.5 ppm	SCR		25 ppm			
TX	Calpine Amelia	1,030	10/20/2000		In Review		SIP Approved	3				CC		2.5 ppm	SCR		22 ppm			
TX	Calpine Deer park	1,060	09/05/2000		08/22/2001	13	SIP Approved	4				CC		2.5 ppm	SCR		25 ppm			
TX	Cedar Power Partners	660	04/13/2000		12/21/2000	7	SIP Approved	2				CC		3 ppm	SCR		25 ppm	GCP		
TX	MC Energy Mont. County	310	04/13/2000		06/20/2001	14	SIP Approved	2				CC		3 ppm	SCR		25 ppm	CatOx		
TX	Ridge Energy	538	04/26/2001		05/15/2002	13		4		EA 418		SC	Peakg	9	SCR		25 ppm	GCP		
TX	So. Tx. Elec COOP	180	05/24/2001		01/17/2002	8		3		LM6000	NG	SC		5 ppm	SCR		15 ppm	GCP		
TX	Hartburg Power	800	03/07/2001		07/05/2002	16		3		GE 7FA	NG	SC		5 ppm	SCR		15 ppm	GCP		
TX	TX Petrochem	900	11/13/2000		10/08/2003	11		3		GE 7FA	NG	CC		5 ppm	SCR		15 ppm	GCP		
TX	BP Amoco	550	10/16/2000		07/21/2001	9		3		GE 7FA	NG, FO	CC		3.5 ppm	SCR		25 ppm	GCP		
TX	BP Amoco Chemical	70	10/24/2000		03/24/2003	29		6		SW501F		SC		3.5 ppm	SCR		25 ppm	GCP		
TX	Steag Power, LLC	1400	07/16/2001		Withdrawn	-		4		SW501G				3.5 ppm	SCR		20 ppm	GCP		
TX	Steag (Brazos Valley)	800	11/06/2000		12/31/2002	23		2		Co-gens		CC		3.5 ppm	SCR		25 ppm	GCP		
TX	Dow Chemical	1440	11/02/2000		Voided	-		6		SW501F				3.5 ppm	SCR		25 ppm	GCP		
TX	Texas Bayou Energy	25	11/22/2000		Withdrawn	-		1		LM2500				4.2 ppm	SCR		25 ppm	GCP		
TX	OxyVinyls, LP	87	11/10/2000		12/20/2002	25		1		GE 7FA		SC		4 ppm	SCR		25 ppm	GCP		
TX	Celanse	252	11/21/2000		Voided	-		6		LM 6000				5 ppm	SCR					
TX	City of Austin	500	05/30/2001		04/12/2002	11		4		LM6000/GE 7FA		SC/CC		5.5 ppm	SCR		9/20 ppm			
TX	Steag-Stearne	1000	09/21/2001		12/06/2002	15		3		SW 501F		CC		5	SCR		21			
TX	Duke Energy	620	09/25/2002		07/23/2003	10		2		F7FA		CC		5	SCR		20			
TX	ExxonMobil	170	10/04/2002		06/13/2003	8		1		F7FA		SC		3	SCR		7.4			
TX	CityPublicSrv-San Antonio	180	10/15/2002		06/27/2003	8		4		LM 6000		SC		5	SCR		12	CatOx		
TX	Bayport Energy	80	01/09/2003		10/20/2003	9		2		F6B		SC		3(1.9)	SCR		17.2			
TX	City of Bryan	50	02/04/2003		03/28/2003	1		1		LM6000		SC		5	SCR		32			
TX	Brownsville Public Utility	50	06/26/2003		09/08/2003	3		1		LM6000		SC		5	SCR		32			
TX	Brownsville Public Utility	50	06/26/2003		09/12/2003	3		1		LM6000		SC		5	SCR		32			
Region 7																				
IA	MidAmerican Energy, Des Moines Power Station	610	10/24/2001		04/10/2002	8	SIP Approved	2	2	SW 501FA (170 MW)	NG	CC	8,760	25 ppm (SC); 3 ppm (CC)	DLN (SC); SCR (CC)	24-hour	10 ppm (Phase I); 5 ppm (Phase II)	Oxidation Catalyst	24-hour	Phased project will start in simple cycle mode (without SCR) and move to combined cycle during transition period
IA	Hawkeye Generation, LLC (a division of Entergy)	580	10/01/2001		07/23/2002	9	SIP Approved	2	2	GE 7FA	NG	CC	SC-2000, CC-8760	SC-9 ppm, CC-3 ppm	SC-DLN; CC-SCR	3-hour	SC-9 ppm, CC-5 ppm	Oxidation Catalyst	3-hour	Duct burning limited to 4,500 hours per year
IA	Interstate Power and Light - Exira Station	568	08/14/2002		12/20/2002	4	SIP Approved	2	1	2- GE-7FA,1-HRSG w/aux firing @ 405MMBTU	NG; FO	SC/CC	SC-400 (NG), 50 (oil); CC-8760 (NG), 200 (oil)	SC-9 ppm (NG), 42 ppm (oil); CC-3 ppm (NG), 33 ppm (oil)	SC-DLN, CC-SCR	3-hour	SC-9 ppm (NG), 20 ppm (oil); CC-5 ppm (NG), 7.1 ppm (oil)	Oxidation Catalyst	3-hour	
KS	Western Resources	380	11/20/1998		06/11/1999	6	SIP Approved	3	0	2 - GE-7EA (100 MW each); 1 GE-7FA (180 MW)	NG; FO	SC		15 ppm NG; 42 ppm FO	DLN; WI					NOx limits are for > 70% load. NSPS limits will apply at < 70 % Load

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
KS	Duke Energy (Leavenworth County)	620	06/20/2001		02/07/2002	8	SIP Approved	2	2	2 - GE-7FA (310 MW each)	NG	CC	8,760	4.5 ppm	SCR, DLN	24-hour	16.9 ppm	GCP	short-term	
KS	Great Plains Power, Paola	320	06/06/2001		05/28/2002	11	SIP Approved	4	0	4 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN	30-day rolling	25 ppm	GCP		
KS	Great Plains Power, Gardner	640	06/06/2001		05/28/2002	11	SIP Approved	8	0	8 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN	30-day rolling	25 ppm	GCP		
KS	Entergy	530	12/2001		Withdrawn		SIP Approved	2	1	GE 7FA	NG	CC	6,760	3-5 ppm	SCR, DLN		TBD	TBD		
KS	Board of Public Utilities of Kansas City Kansas, Nearman Creek Station	80	06/04		Currently Under Review	Currently Under Review	SIP Approved	1	0	1 - GE-7EA	NG; FO	SC	8,760	proposed in application: 9 ppm NG; 42 ppm FO	DLN	?	proposed in application: 25 ppm NG; 20 ppm FO	CC	?	
MO	Kansas City Power & Light - Hawthorn Unit 6	200	08/15/1995		01/10/1996	8	SIP Approved	1	0	Seimens V.34A (200 MW)	NG	SC	8,760	25 ppm	DLN	24-hour		GCP		
MO	AECI - Nodaway Units 1 & 2	200	07/27/1998		11/12/1998	4	SIP Approved	2	0	SW 501D (100 MW each)	NG	SC	2,000	25 ppm	DLN		90 ppm	GCP		
MO	AECI - Essex Unit 1 (synthetic minor)	100	Issued		Issued		SIP Approved	1	0	SW 501D	NG	SC								
MO	AECI - St. Francis Unit 1	250	02/04/1997		08/29/1997	7	SIP Approved	1	1	Seimens V.34A (250 MW)	NG; FO	CC	8,760	4.5 ppm NG	SCR, DLN, WI	3-hr	10 ppm NG	GCP		
MO	AECI - St. Francis Unit 2	266	06/04/1999		07/14/1999	8	SIP Approved	1	1	Seimens V84.3A (266 MW)	NG	CC	8,760	4.5 ppm	SCR		10	GCP		NOx $1,165/ton
MO	Empire District - Stateline Unit 2-1	150	07/12/1999		10/08/99	10	SIP Approved	1	1	SW 501F (150 MW)	NG	CC		4 ppm	SCR	30 day	10 ppm	GCP		recommissioned to CC
MO	Empire District - Stateline Unit 2-2	150	07/12/1999		10/08/99	10	SIP Approved	1	1	SW 501F (150 MW)	NG	CC		4 ppm	SCR	30 day	10 ppm	GCP		
MO	Kansas City Power & Light - Hawthorn Unit 6/9 (HRSG	160	2/29/99		08/18/1999	6	SIP Approved	1	1	Seimens V.34A	NG	CC	8,760	5 ppm	SCR		25 ppm	GCP		Retrofit w/ duct burners, waste heat boiler and SCR
MO	Kansas City Power & Light - Hawthorn Units 7 & 8	150	2/29/99		08/18/1999	6	SIP Approved	2	0	GE 7EA (75 MW, each)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		
MO	Duke Energy - Audrain	640	04/11/2000		05/09/2000	6	SIP Approved	8	0	GE 7EA (80 MW, each)	NG; FO	SC	2,500; 500 FO	12 ppm/9 ppm (NG); 42 ppm (FO)	DLN; WI	1-hr/annual	20 ppm NG; 25 ppm FO	GCP		
MO	Duke Energy - Bollinger	640	08/17/2000		09/22/2000	11	SIP Approved	8	0	GE 7EA (80 MW, each)	NG	SC	2,500	12 ppm/9 ppm	DLN	1-hr/annual	20 ppm	GCP		PM-10: 0.01lb/mmBtu; Formaldehyde: <10 TPY. Each turbine limited to 2,500 hours on NG-only (annual rolling), with entire plant limited to 4,000 hours per year
MO	Utilicorp - Aquila Merchant, Pleasant Hill	600	06/04/1999		08/16/1999	8	SIP Approved	2	2	Seimens Westinghouse 501F (300 MW, each)	NG	CC	8,760	4.5 ppm	SCR	30 day	10 ppm (70-100%), 15 ppm (w/PA), 50 ppm (60-70%)	GCP	short-term	NOx - $2,500/ton
MO	Associated Electric Cooperative - Centralia	360	11/27/2000		02/13/2001	3	SIP Approved	3	0	Siemens V84.2 (120 MW, each)	NG; FO	SC	8,760	15 ppm NG/42 ppm FO	DLN	3-hr	35 ppm	GCP	short-term	Each turbine limited to 2,000 hours per year on N.G. and 500 hours on 0.05%S diesel; plant limited to 4,000 hours per year.
MO	Kinder Morgan, LLC	530	Permit Denied, Application Withdrawn on 10/22/02		Permit Denied, Application Withdrawn on 10/22/02	Permit Denied, Application Withdrawn on 10/22/02	SIP Approved	7	7	6 GE-LM6000; 1 GE-7EA, plus 120 MW supplemental duct firing	NG	CC	8,760							

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
MO	Panda Power - Montgomery Generating Station	1290	12/00		08/21/2001	8	SIP Approved	4	4	4 GE-7FA (170 MW), plus 510 Mwe supplemental duct firing	NG	CC	8,760	3.5 ppm	SCR	3-hr	7.3 ppm/13.9 ppm	GCP	24-hr	
MO	AmerenUE - Columbia Energy Center (synthetic minor)	192	Issued		Issued		SIP Approved	4	0	4 GE PG6581 (B)	NG	SC		Less than 91.8 tons Nox determined with CEMS	DLN	annual	17 lb/hr		Hourly	
MO	Utilicorp - Aquila Merchant, Pleasant Hill - Aries II Project	341	10/01/2001		06/18/2002	9	SIP Approved	3	0	SW 501D5A (113 MWa, each)	NG	SC	2,500	15 ppm@15%O2	DLN		Tentative: 25 ppm	GCP		Each turbine limited to 2,500 hours of operation per year; entire plant limited to 4,000 hours per year.
MO	Empire District - Energy Center	110	11/01		07/25/2002	8	SIP Approved	4	0	2 Pratt & Whitney FT8 Twinpacs, 27.5 MWe each	NG	SC	3,300	'NOx: 25 ppm (15%O2) N.G., 3-hour; NOx: 42 ppm (15%O2) oil, 3-hour	WI	3-hr	CO: <100 ton per year	oxidation catalyst	ann.	BACT analysis based on limitation of 3,300 hours of operation per year
MO	Aquila - Camp Branch Energy Center	371	04/01/2004		Currently Under Review	Currently Under Review	SIP Approved	3	0	113.8 MWe SW 501D5A	NG	SC	2,500 each	'NOx: 15 ppm (15%O2) N.G.	DLN	?	NOx: 25 ppm (15%O2) N.G.	CC	?	BACT analysis based on limit of 2,500 hours of operation/year
NE	Omaha Public Power - Sarpy Units 1, 2, 3, and 4	100	02/09/1999		07/29/1999	5	SIP Approved	4	0	Pratt & Whitney FT-8 (25 MW, each)	NG; FO	SC	2,000 each	25 ppm NG; 42 ppm FO	WI		69 lb/hr NG; 34 lb/hr FO	GCP		
NE	Lincoln Electric System Rokeby Unit 3	90	06/03/1999		11/22/1999	6	SIP Approved	1	0		NG; FO	SC	3,504	25 ppm NG; 42 ppm FO	DLN; WI/SI		not given	GCP		Fuel use limit on gas % oil.
NE	Omaha Public Power, Cass County Station	346	09/06/2000		11/15/2001	14	SIP Approved	2	0	SW 501F (173 MW, each)	NG	SC	2,500 each	20 ppm	DLN		15 ppm	GCP		BACT based on limitation of 2,500 hours per year of operation
NE	Lincoln Electric System, Salt Valley Station	153	06/01/2001		04/04/2002	10	SIP Approved	3		1-SC (45 MW) & 2-CC (54MW)		SC, CC								
NE	City of Grand Island, Burdick Station	80	07/01/2002		01/08/2002	6	SIP Approved	2	0	2 GE PG6581(B), 40 MW each	NG; FO	SC	5,000	15ppm NG/65 ppm FO						BACT based on limit of 5,000 hrs/yr on NG and 240 hrs/yr on FO
NE	Nebraska Public Power District	220	07/24/2002		05/29/2003	10	SIP Approved	2		2 on 1 CC with 2 GE 7E CTs		CC		3.5 ppm	SCR	3-hr	10.8 lb/hr	CatOx	Stack	
Region 8																				
CO	Colorado Energy Management (mod. to CO Power Partners/Brush Cogen) (+ 50 MW)	50	10/21/1998		05/25/1999	7	SIP Approved	2	none	1969 Westinghouse 251AA	NG		4,000 (both CTs)	30 ppm for first 24 months, then 25 ppm	custom low-NOx burners, WI	1-hr	60 ppm	GCP	1-hr	permit action also required NOx emission reductions on 2 other identical units from permitted 42 ppm immediately to 30 ppm and further to 25 ppm in 24 months.
CO	Colorado Springs Utilities/Nixon (66 MW)	66	11/12/1998	11/98	04/19/1999	5	SIP Approved	2	none	GE PG6541(B) 33 MW each	NG	SC	8,660 (both CTs)	15 ppm	DLN	1-hr	?	Pollution prevention built into equip.		NOTE: this project was permitted 3 times - first in 4/95, then 7/98, and finally 4/99. Each time, the applicant modified and/or extended the project due to avalability of equipment, etc. It is our understanding that the 4/99 configuration is being/has been installed.
CO	Fulton Cogeneration/Manchief (284 MW)	284	06/07/1999 (note: original app. under different ownership 4/99)	7/99	8/99	2	SIP Approved	2	none	SW V84.3A1, 142 MW rach	NG	SC	8,760	15 ppm	DLN	1-hr	10 ppm	GCP	1-hr	

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CO	KN Energy/Front Range Energy Associates - Ft. Lupton (160 MW)	160	11/99		on hold		SIP Approved	4	none	GE LM6000	NG	SC	**	25 ppm (proposed)	WI					project originally PSD application; State drafted syn minor permit w/ operating hours restrictions in 7/99; EPA commented to State concerning single source issue w/ adjacent PSCo facility; PSCo appealed to US 10th circuit court - currently
CO	Platte River Power Authority/Rawhide (82 MW)	82	3/00		12/00	9	SIP Approved	1	none	GE Frame 7EA	NG	SC	8,760	9 ppm	DLN					plan startup 5/2002; CO PTE below significance level so didn't do BACT; characterized as peaking plant, but not restricted in operating hours
CO	Public Service Co. of Colo./Ft. St. Vrain Unit 4 (242 MW)	240	01/00		06/19/2000	6	SIP Approved	1	1	GE PG7241 (FA)	NG	SC/CC	8,760	4 ppm (CC); 9 ppm (SC)	DLN+SCR (CC); DLN (SC)	24-hr	9 ppm (CC & SC), 20 ppm (CC w/ DB)	GCP	1-hr	plan startup 6/2001;
CO	Front Range Power Project/Ray Nixon Sta., Fountain, CO (480 MW)	480	11/99, updated application 5/00		11/00	6	SIP Approved	2	2	GE Frame 7	NG	SC/CC	6,760	9 ppm/16 ppm w/ DB	DLN		25 ppm	GCP	1-hr	plan to begin construction 1/01, operation 7/02; PSD mod to existing Colo Springs Utils/Nixon coal-fired power plant; revising application to net out of PSD for NOx using reductions at coal-fired unit; applicant calculated PTE using 95% ca
CO	TriState Generation & Transmission/Limon Station (164 MW)	164	7/00		1/01	6	SIP Approved	2	none	GEF7EA, or equiv	NG, FO (1000 hr, each turbine, limit on FO)	SC	8,760	9 ppm (42 ppm on FO)	DLN (plus WI on FO)	1-hr	25 ppm	GCP		
CO	West Plains Energy, Pueblo (304 MW)	304	5/00		12/00	7	SIP Approved	1	1	(TBD - APPEARS TO BE GE FRAME 7 EQUIVALENT)	NG	CC	8,760	4 ppm	SCR	daily				Company first obtained permit from State in 8/95; subsequently modified project and repermitted in 6/96; modified permit again to change location of project in 8/98; this most recent revision again changed equipment configuration - State reevaluated BACT and other PSD requirements with the 12/00 permit.
CO	North Amer. Power Group/Kiowa Creek (1000MW)	1,000	05/00		01/01	8	SIP Approved	4	4	GE7FA or equivalent	NG	CC	8,760	4 ppm (proposed)	SCR		23.2 ppm	GCP	1-hr	plan to begin construction spring 2001, operation spring 2004; proposed project may trigger 112(g)
CO	Rocky Mountain Energy Center	630	05/02/2002	05/27/2002	07/15/2002	2	SIP Approved	2	2	West 501FD	NG	CC	8,760	3 ppm (normal)/300 ppm SU/SD	SCR	1-hr	9 ppm (normally 1,000 ppm SU/SD	OxCat	1-hr	PM/PM10 - 0.00653 lb/mmBTU; VOC - 0.0026 lb/mmBTU (BACT)
CO	Platte River Power Authority/Rawhide (82 MW)	82	07/08/2003	07/08/2003	10/03/2003	3	SIP Approved	1	none	GE Frame 7EA	NG	SC	8,760	9 ppm/100 ppm SU/SD	DLN	daily	<100 tpy	GCP	N/A	Unit "D" CO PTE below significance level to avoid BACT; characterized as peaking plant, but not restricted in operating hours
CO	North American Power Group - Kiowa Creek	1,000	05/06/2004	tbd	tbd	tbd	SIP Approved	4	4	GE Frame 7FA	NG	CC	8,760	3 ppm (prop)	SCR	12-hr	3 ppm (prop)	Oxid Cat	3-hr	This project was permitted 01/01. This application is to relocate the project - new BACT analysis.
SD	Black Hills Power & Light/Lange CT Facility (80 MW)	80	12/02/1999	08/13/2000	10/10/2000	2	Delegated	2		GE LM6000PD - 40 MW each	NG	SC	8,760	25ppm	DLN	24-hr	25 ppm	GCP		Characterized as peaking plant, but not restricted in operating hours. EPA commented negatively on the NOx BACT.

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UT	Pacificorp - West Valley City	218	03/16/2001		06/15/2001	91 days	SIP Approved	5	0	GE LM6000 PC Sprint	NG	SC	8,760	5 ppm	WI & SCR	30 DRA	10 ppm	Oxid Cat	30 DRA	New power plant in mod PM10 N/A area. NOx limit for turbines is PSD BACT as well as LAER.
UT	Pacificorp - Gadsby	131	01/15/2002		04/03/2002	77 days	SIP Approved	3	0	GE LM6000 PC Sprint	NG	SC	8,760	5 ppm	WI & SCR	30 DRA	10 ppm	Oxid Cat	8-HR BLOCK; ERR	Turbines are at existing power plant consisting of three NG boilers in mod PM10 N/A area. NOx limit is PSD BACT and LAER.
UT	Pacificorp - Currant Creek Power Project	1,050	08/01/2003	02/03/2004	05/17/2004	3 mos.	SIP Approved	2	2	GE 7FA	NG	CC or SC	8,760	9.0 ppm SC 2.25 ppm CC	DLN - SC SCR - CC	18-HR SC; 3-hr CC; ERR	7.8 ppm SC 3.0 ppm CC	Oxid Cat	24-HR SC; 3-hr CC; ERR	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.
UT	Calpine Corp - Vineyard Energy Center LLC	978	11/01/2003	N/A	N/A	N/A	SIP Approved	3	3	Siemens - Westing. 501F	NG	CC	8,361	2.0 ppm (prop) - LAER	DLN + SCR	3-HR; ERR	4.0 ppm (prop)	Oxid Cat.	3-HR; ERR	Will be located in moderate PM10 N/A area. LEAR for NOx & PM10.
WY	Black Hills Power & Light/Niel Simpson II (80 MW)	80	09/15/1999		final 3/00	5.5	SIP Approved	2		GE LM6000PD	NG	SC	8,760	25 ppm	DLN	24-hr	25 ppm	GCP	1-hr	Region provided written comment disagreeing w/ NOx BACT determination; characterized as peaking plant, but not restricted in operating hours.
WY	Two Elk Generation Partners (33 MW turbine)	33	10/31/1996		02/27/1998	26	SIP Approved	1		GE LM5000	NG	SC	8,760	25 ppm	DLN	1-hr	25 ppm	GCP	1-hr	Facility is 250 MW coal-fired steam electric plus 33 MW NG CT; characterized as peaking plant, but not restricted in operating hours
Region 9																				
AZ	Calpine - South Point Generating Station	500	06/15/1998	?	5/24/99 (EPA)	13	Delegated	2		500 MW total	NG; FO	CC		3 ppm	SCR	3-hr	10 ppm NG; 35 ppm FO	oxy.cat		
AZ	Griffith Energy, LLC	850	10/26/1998		7/99	9	Delegated	2	2	650 MW total	NG; FO	CC	8,760	3 ppm	SCR, LNB	?	20 ppm	CTG	?	$1,555/ton NOx
AZ	Reliant Energy - Desert Basin Generating Project	580					Delegated	?	?	580 MW total	NG, ?	CC	8,760	3 ppm	SCR	24-hr	24 ppm		3-hr	
CA # SG-98-01	LaPalemoa generating Co. LLC	1,048	7/16/98		7/27/99 EPA permit	12	Delegated & SIP approved by District	4	?	172 MW each, 262 with HRSG & STG each, ABB turbines		CC	8,760	2.5 ppm	see cell comments	1-hr	10 ppm	oxy.cat		
CA	AES Antelope Valley	1,000	?		?		Delegated & SIP approved by District			1000 MW total										
CA	Blythe Energy	520	05/05/2000	06/13/2000	?		Delegated & SIP approved by District			520 MW total		CC		2.5 ppm	SCR	1 hr	10 ppm >80%; 20 ppm @ 70-80%	?	3-hr	Delayed tue to section 7 ESA consultation & resource constraints
CA	Delta Energy Center -Calpine and Bechtel	880	?		10/21/1999		Delegated & SIP approved by District			880 MW total		CC	8,760	2.5 ppm	SCR	1-hr	10 ppm	Cat.Ox	3-hr	Pollutant Trading - 1:1 VOC for NOx (nonattainment), 4:1 SO2 for PM10 (attainment)
CA	Sempra/OXY - Elk Hills	720	?		?		Delegated & SIP approved by District			680-720 MW total										
CA	OXY & Sempra Energy; Elk Hills Power LLC (joint venture)	500	01/09/1999		08/23/1999	7.5	Delegated & SIP approved by District			500 MW total		CC	8,760	2.5 ppm	SCR;	3-hr	4 ppm	CatOx	24-hr	Pollutant Trading - NOx for PM10; PSD Permit must be issued by EPA
CA	Elk Hills Power project		09/13/1999	10/05/1999	Est. early 2001															
CA	Pastoria Power project		12/10/1999	01/10/2000	2/01	13														

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
CA	High Desert Power Project LLC	700	01/30/1998	03/12/1998	draft 7/99		Delegated & SIP approved by District			700 MW total		CC	8,760	2.5 ppm	SCR	1-hr	4 ppm	CatOx	24-hr	
CA	US Generating - La Paloma	1,048	07/10/1998	07/30/1998	7/27/99 (EPA)	11	Delegated & SIP approved by District	4		ABB (262 MW)		CC	8,760	2.5 ppm	SCR or SCONOx	1-hr				
CA	Long Beach District Energy Facility (ENRON)	500	?		?		Delegated & SIP approved by District			500 MW total										
CA	Calpine and Bechtel - Metcalf Energy	600	?		?		Delegated & SIP approved by District	2		600 MW total, 2 @ 200 MW + HRSG										
CA	Midway Sunset Cogeneration Co.	500	02/22/2000	04/17/2000	Est. early 2001		Delegated & SIP approved by District			500 MW total							6 ppm	CatOx	3-hr	Trading NOx for PM @ 2.2/1
CA	Duke Energy - Moss Landing	1,206	?		05/12/2000		Delegated & SIP approved by District	2		2 @ 530 MW, 2 @ 15 MW (1260 MW total)	NG	CC		2.5 ppm	SCR/DLN	1-hr	9 ppm	GCP	3-hr	AFC submitted to CEC on 5/7/99; Monterey Bay unified APCD to issue ATC early 2000; 2 x 15 MW upgrade SteamTurbine rotor when SCR is added
CA	Duke Energy - Morro Bay	530	11/03/2000		?		Delegated & SIP approved by District			530 MW total										
CA	Calpine and Bechtel - Newark Energy Center	600	?		?		Delegated & SIP approved by District			600 MW total										
CA	PG&E Generating - Otay Mesa	510	?		6/00		Delegated & SIP approved by District			510 MW total		CC		2 ppm	SCONOx/ SCR backup					Pollutant Trading - VOC reduc. for NOx inc.; District plans to issue PDOC in March 2000
CA	Pastoria Power Project	750	?		5/15/00 ?		Delegated & SIP approved by District			750 MW total		CC		2.5 ppm	XONON/SCR Backup	1-hr	6 ppm	CatOx		Pollutant Trading - NOx in lieu of PM10
CA	Pittsburg District Energy Facility (ENRON)	500	?		06/10/1999		Delegated & SIP approved by District			500 MW total		CC		2.5 ppm	SCR	1-hr	6 ppm	CatOx	3-hr	
CA	AES South City	550	?		?		Delegated & SIP approved by District			550 MW total		SC/CC								
CA	Sunlaw Cogen Partners	800	?		?		Delegated & SIP approved by District			800 MW total		CC		1 -2 ppm	SCONOx	1-hr	1 -2 ppm			
CA	Texaco Global - Sunrise Cogeneration	320	?		pending		Delegated & SIP approved by District			320 MW total		CC		2.5 ppm	SCR	1-hr	6 ppm			
CA	Calpine - Sutter Power	500	01/22/1998	03/03/1998	12/02/1999	9.0	Delegated & SIP approved by District			500 MW total		CC		2.5 ppm	SCR	1-hr	4 ppm		1 hr	EPA PSD permit: - permit delayed due to applicant changes, citizen appeal to EAB.
CA	Campbell Cogen	?	?		?		Delegated & SIP approved by District													
CA	Ogden Pacific Power - Three Mountain Power	500	01/01/1999		applic. under review		Delegated & SIP approved by District			500 MW total		CC		2.5 ppm	SCR	1-hr	4 ppm	CatOx	3-hr	Sinificant ESA problems

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NV	Nevada Power Co.	475	?		?		Delegated & SIP approved by District	2		2 @ 235.5 each		CC	8,760	3.5 ppm	SCR	1-hr	2.6 ppm	CatOx		
NV permit # ?	El Dorado Energy	346	03/13/1997		08/21/1997	5	Delegated	2	2	165 MW each turbine, 173 MW each duct burner	NG; FO	CC	8760 4000 FO	3.5 ppm	SCR with ammonia injection (LAER)	?	2.6 ppm	oxy.cat. (LAER)	?	
HI	Ecogen	46	12/19/1994		06/09/1998	42	Delegated	2	?	46 MW total	Naphta, LSFO, gaoline	SC/CC		15 ppm	WI, SCR	?	57.5 ppm	?		
HI	Maui Electric	40	8/8/94		01/06/1998	43	Delegated	2	?	40 MW total	FO	SC		42 ppm	WI	?	44 ppm	?		
Region 10																				
ID, Permit 055-00040	Rathdrum Project (Avista - formerly Washington Water Power)	180	01/11/1993	05/09/1993	08/06/1993	7	Minor NSR	2	0	GE 7EA	NG	SC	16,848 combined	235.5 TPY	DLN		240 TPY	GCP		Operating as peaking unit. Start-up 01/01/95. No minor NSR BACT. IDEQ. Rathdrum, ID. ORIS 7456.
ID, Permit 055-00045	Rathdrum Power (Avista / Cogenerix)	270	04/02/1999	05/03/1999	10/29/1999	6	Minor NSR	1	1	GE 7FA	NG	CC	8000 - CT, 2000 - DB	4.5 ppmdv w/ DB, 3.4 ppmdv w/o DB @ 15% O2	DLN, SCR	24-hr	92.3 TPY	CatOx		Operating as a peaker due to low energy demand. Startup 09/01. www.avista.com. www.cogentrix.com. No minor NSR BACT. IDEQ. Rathdrum, ID. ORIS 55179.
ID, Permit 039-00024	Evander Andrews Complex (Idaho Power Company)	90	03/20/2001	06/08/2001	09/14/2001	6	Minor NSR	2	0	SW 251B12A	NG	SC	10,332 combined	30 ppmdv @ 15%O2, 248 TPY	DLN	24-hr	30 ppmdv @ 15%O2, 159 TPY	GCP	1-hr	Operating as a peaker. Startup 09/01. No minor NSR BACT. Mountain Home, ID. ORIS 7953.
ID, Permit 027-00081	Garnet Energy (Ida-West Energy)	535	06/19/2000	07/20/2000	10/19/2001	16	SIP Approved PSD	2	2	SW 501F	NG;FO	CC	8760	3 / 2.5 ppmdv @15% O2 - gas, 6 ppmdv @ 15% O2 - oil	DLN, SCR	24-hr / 12-month for gas, 24-hr for oil	5 / 2 ppmdv @ 15% O2 gas, 6 ppmdv @ 15% O2 - oil	CatOx	1-hr / 12-month for gas, 1 hr for oil	Permit expired. Permit will expire on 10/19/03 if construction has not commenced. www.ida-west.com/garnet.htm. IDEQ. Middleton, ID.
ID, Permit 039-00025	Mountain View Power, LLC	80	03/05/2001		09/09/2002	18	Minor NSR	2	0	GE LM6000	NG;FO	SC	8760	25 ppmdv @ 15% O2 - gas, 42 ppmdv @ 15% O2 - oil	WI	24-hr	10 ppmdv @ 15% O2 - gas, 6 ppmdv @ 15% O2 - oil	CatOx	24-hr	Not yet constructing. No minor source BACT. IDEQ. Mountain Home, ID.
OR	Beaver Units 1 - 6 (Portland General Electric)	534			01/01/1977		Grandfathered	6	?	GE 7001-B	NG	CC	8760	-	WI	-	-	-	-	Operating. Constructed 1974 in CC mode. HRSGs constructed along with one steam turbine in 1977.
OR, Permit 25-0031	Coyote Springs 1 (Portland General Electric / Avista)	250	01/19/1993		04/04/1994	14	SIP Approved PSD	1	0	GE 7FA	NG;FO	CC	8760	4.5 / 15 ppmdv gas / oil @15% O2	DLN, SCR	24-hr	15 / 20 ppmdv gas / oil 15% O2	GCP	8-hr	Operating. 03/12/97 permit revision. ODEQ - Eastern Region. Boardman, OR. ORIS 7350.
OR, Permit 25-0031	Coyote Springs 2 (Portland General Electric / Avista / Mirant)	280	01/19/1993		04/04/1994	14	SIP Approved PSD	1	0	GE 7FA	NG;FO	CC	8760	4.5 / 15 ppmdv gas / oil @15% O2	DLN, SCR	24-hr	15 / 20 ppmdv gas / oil 15% O2	GCP	8-hr	Operating. Startup 06/03/03. www.avista.com. 03/12/97 permit revision. ODEQ - Eastern Region. Boardman, OR.
OR, Permit 30-0113	Hermiston Generating Plant (US Generating - PG&E Generating)	474	05/27/1993		07/07/1994	13	SIP Approved PSD	2	0	GE 7FA	NG	CC	6760	4.5 ppmdv @ 15%O2	DLN, SCR	24-hr	15 ppmdv @15% O2	GCP	8-hr	Operating. Startup July 1996. www.gen.pge.com. ODEQ - Eastern Region. Hermiston, OR. ORIS 54761.
OR, Permit 30-0118	Hermiston Power Partnership (Calpine)	546	08/10/1994		08/28/1995	12	SIP Approved PSD	2	2	SW501FD2	NG	CC	8760	4.5 ppmdv @ 15% O2	DLN, SCR	24-hr	15 ppmdv 15% O2	GCP	8-hr	Operating. Startup 04/02. 04/13/99 permit revision. www.calpine.com. Compliance test submitted 10/02. ODEQ - Eastern Region. Hermiston, OR. ORIS 55328.

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State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
OR, Permit 18-0003	Klamath Energy Cogeneration Project (Pacificorp Power Marketing)	484	03/01/1996		01/27/1998	23	SIP Approved PSD	2	2	SW501F	NG	CC	8760	4.5 ppmdv @ 15% O2	DLN, SCR	24-hr	15 ppmdv 15% O2	GCP	8-hr	Operating. Startup 07/01. www.klamathcogen.com, Power Magazine's Plant of the Year. 12/29/00 ACDP permit update. Title V permit soon to be issued. ODEQ - Eastern Region. Klamath Falls, OR. ORIS 55103.
OR, Permit 18-0024	Klamath Expansion Project (PacifiCorp Power Marketing)	100	04/30/2001		06/22/2001	2	SIP Approved PSD	4	0	2 Pratt & Whitney FT-8 (Twin Pac)	NG	SC	8760	25 ppmdv @ 15% O2	WI	24-hr	16 ppmdv @15% O2	GCP	8-hr	Operating. Permit expires 24 months after startup. ODEQ - Eastern Region. Klamath Falls, OR. ORIS 55544.
OR, Permit 05-0011	Clatskanie People's Utility District	11	07/19/2001		11/01/2001	4	Minor NSR	1	0	GE/Nuevo Pigone 10B	NG	SC	6000	-	DLN	-	-	GCP	-	Operating. Synthetic minor. ODEQ - Northwest Region. Clatskanie, OR.
OR, Permit 05-0008	Port Westward (Portland General Electric)	650	05/14/2001		01/16/2002	8	SIP Approved PSD	2	2	GE 7FB or SW 501S	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	8-hr	4.9 ppmdv @ 15% O2	CatOx	8-hr	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.
OR, Permit 30-0007	Umatilla Generating (PG&E)	580	04/17/2001		01/18/2002	9	SIP Approved PSD	2	2	GE 7FB	NG	CC	8760	2.0 ppmdv @ 15% O2	DLN, SCR	3-hr	6.0 ppmdv @ 15% O2	CatOx	24-hr	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region. Hermiston, OR.
OR, Permit 05-0012	Summit Westward (Westward Energy LLC)	540	07/02/2001		07/03/2002	12	SIP Approved PSD	2	2	SW V84.3A2	NG	CC	8,760	2.5 ppmdv @ 15% O2	DLN, SCR	3-hr	4 / 7 ppmdv @ 15% O2	GCP	3-hr	Not yet constructing. 4 ppm CO @ loads > 80% w/o duct firing. 7 ppm CO @ loads < 80% w/ duct firing. Serving Golendale Aluminium at The Dalles, OR. ODEQ - Northwest Region. Clatskanie, OR.
OR, Permit 05-2520	Beaver Unit 8 (Portland General Electric)	24	04/24/2001		09/05/2002	5	SIP Approved PSD	1	0	Alstom Power GT 10B	NG	SC	8760	17 ppmdv @ 15% O2	DLN, WI	8-hr	5 ppmdv @ 15% O2	CatOx	8-hr	Operating. Clatskanie, OR.
OR, Permit 25-0003	Morrow Power	25			08/13/2001		Minor NSR	1	0		NG	SC	8760	25 ppmdv @ 15% O2	DLN	3-hr		GCP		Operating. Startup October '01. Boardman, OR. ORIS: 55683.
OR	Grizzly Power (Cogentrix)	980	12/03/2001		Application withdrawn		SIP Approved PSD	4	4	GE 7FA	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	24-hr	4.0 ppmdv @ 15% O2	CatOx	8-hr	Application withdrawn. ODEQ - Eastern Region. Madras, OR.
OR	Turner Energy Center (Calpine)	620	09/16/2003		Public comment period - 7/30/04		SIP Approved PSD	2	2	GE 7FA	NG	CC	8760		DLN, SCR			CatOx		Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR.
OR, Permit 18-0029	California Oregon Border (Peoples Energy)	1,150		12/06/2002	12/30/2003	12	SIP Approved PSD	4	4	F-class	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	8-hr	5.0 ppmdv @ 15% O2	CatOx	8-hr	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region. Bonanza, OR.
OR, Permit 18-0026	Klamath Generation LLC (Pacific Power Energy Marketing)	480	07/17/2002		03/14/2003	8	SIP Approved PSD	2	2	Various	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	8-hr	5.0 ppmdv @ 15% O2	CatOx	8-hr	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.
OR, EPA	WANAPA Energy Center (Diamond Wanapa LLC)	1,200	01/23/2003	08/27/03	Drafting		Federal PSD (Indian Country)	4	4	F-class	NG	CC	8760		DLN, SCR			CatOx		Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Umatilla, OR.
OR, LRAPA	West Cascades Energy	900	11/19/2003		Drafting		SIP Approved PSD	2	2	F-class	NG	CC	8760		DLN, SCR					Lane County, OR.
WA, PSD-X80-02	Whitehorn (Puget Sound Energy)	187			12/19/1979		Federal PSD	2	0	GE 7E	NG;FO	SC	8760	NSPS GG	WI			GCP		Operating. NWAPA. Blaine, WA.
WA, PSD-X80-17	Frederickson (Puget Sound Energy)				09/25/1980		Federal PSD	2	0	GE 7E	NG;FO	SC	8760	NSPS GG	WI			GCP		Operating. PSCAA. Frederickson, WA.

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State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
WA, PSD-X82-09	Fredonia (Puget Sound Energy)	228			08/23/1982		Federal PSD	2	0	SW W501D	NG;FO	SC	8760	NSPS GG	WI			GCP		Operating. NWAPA. Mount Vernon, WA.
WA, SCAPCA	Northeast Combustion Turbine (Avista - formerly Washington Water Power)	66	Initial NOC - 1/13/1978, NOC #1065 - 1/19/01, NOC #1092 - 1/25/02		Initial NOC - 1/20/1978, NOC #1065 - 4/24/01, NOC #1092 - pending	7	Minor NSR (BACT)	2	0	2 - Pratt & Whitney FT4C-3F (Twin-Jet Power Pac)	NG;FO	SC	Initial NOC & SCAPCA Order #95-12 - 500, NOC #1065 - none, NOC #1092 - ng (4000), FO (120)	NOC #1092 NG- 75.44 lb/MMft3, FO - 21.3 lb/1000 gal, SCAPCA Order #95-12 (VEL) - 95 ton/yr	DLN		NOC #1092 NG - 45.77 lb/MMft3, FO - 6.93 lb/1000 gal, SCAPCA Order #95-12 (VEL) - 24 ton/yr	CatOx		Operating. Order #95-12, un-numbered, 1065, and 1092. Peaking unit. NOC's #1065 and #1092 are for adding the DLN/CO control equipment to existing equipment in order to allow Avista to operate the units more hours per year and remain a synthetic minor. SCAPCA. Spokane, WA.
WA, NWAPA 475 & 476	March Point Cogeneration	140			10/26/1990		Minor NSR (BACT)	3	3	GE Frame 6	NG; RFG	CC	8760	13 (Units 1 & 2) / 9 (Unit 3) ppmdv @ 15% O2	WI, SCR	24-hr	37 (Units 1 & 2) / 22 (Unite 3) ppmdv @ 15% O2	GCP	1-hr	Operating. Co-located at Equilon refinery. NOx limits noted here are for combustion of natural gas and refinery fuel gas. NWAPA. Anacortes, WA.
WA, NWAPA Order 304	Sumas Cogeneration (Calpine & NESCO)	125			06/25/1991		Minor NSR (BACT)	1	?		NG	CC	8760	6 ppmdv @ 15% O2	SCR		6 ppmdv @ 15% O2			Operating. Startup 1993. http://www.calpine.com/energy_assets_4/calpine_4_2_3.asp?plant=8. Co-located at sawmill. NWAPA. Sumas, WA.
WA, PSD 91-02	Encogen Northwest Limited Partnership Cogeneration	123			07/31/1991		Joint PSD Issuance: EPA & Ecology	3	0	GE Frame 6	NG; FO	CC	8760	7 / 11 ppmdv gas / oil @ 15% O2	WI, SCR	24-hr	10 ppmdv @15% O2	GCP	1-hr	Operating. Co-located at Georgia Pacific pulp mill. Puget Sound Energy is majority shareholder. NWAPA. Bellingham, WA.
WA, PSD 91-04	Tenaska Ferndale Cogeneration	248			05/29/1992		Joint PSD Issuance: EPA & Ecology	2	2	GE 7EA	NG;FO	CC	8760	6.0 / 12 ppmdv gas / oil @15% O2	DLN, SCR	24-hr	20.0 ppmdv @ 15% O2	GCP	1-hr	Operating. www.tenaska.com. 1/19/00 permit revision to allow installation of fogger to increase output 20 MW. Foggers installed 2001 and turbines upgraded 2002. Co-located at ConocoPhillips refinery. Electricity sold to Puget Sound Energy. NWAPA. Ferndale, WA.
WA, SWCAA 95-1800	River Road (Clark County PUD)	248	07/06/1995		10/25/1995	3	Minor NSR (BACT)	1	0	GE 7FA	NG	CC	8760	4.0 / 3.3 ppmdv @ 15% O2 - 24-hr	DLN, SCR	24-hr / annual	6.0 ppmdv @ 15% O2	CatOx	1-hr	Operating. www.clarkpublicutilities.com SWCAA. Vancouver, WA. ORIS 7605.
NWAPA Order 770	Georgia-Pacific West (tissue plant)	11	04/13/2001		05/31/2001	1	Minor NSR (BACT)	1		Solar Mars 100	NG	SC	8760	5 ppmvd @ 15% O2	SCR	3-hr	7 ppmdv @ 15% O2	CatOx	3-hr	Operated during energy crisis; turbines not presently in use.
PSCAA NOC 7016	Everett Delta Generation (FP&L)	248			10/30/1997		Minor NSR (BACT)	1		GE Frame 7FA	NG: FO	CC	8760	3.5 / 3.5 ppmdv gas / oil @15% O2	DLN, SCR	8-hr	3.5 / 3.5 ppmdv gas / oil @15% O2	CatOx	8-hr	Constructing? Cancelled according to BPA.
WA, PSCAA NOC 7968	Frederickson Power (West Coast Energy)	248			03/25/2000		Minor NSR (BACT)	1	0	GE Frame 7FA	NG: FO	CC	8760	3.0 / 13 ppmdv gas / oil @ 15% O2	DLN, SCR	8-hr	7.0 / 7.0 ppmdv @ 15% O2	CatOx	8-hr	Operating. Startup 05/02. www.tenaska.com. Formerly BPA's Tenaska II. Minor NSR BACT. PSCAA. Frederickson, WA.
WA, PSCAA NOC 8695	Frederickson Power II (West Coast Energy)	290	05/03/2002		06/19/2003	13	Minor NSR (BACT)	1	0	GE Frame 7FA	NG: FO	CC	8760	2.5 / 6 ppmdv gas / oil @ 15% O2	DLN, SCR	1-hr	2.0 / 3.0 ppmdv @ 15% O2	CatOx	1-hr	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA.
WA, SWCAA 01-2342R1	Mint Farm Generation (Mirant)	319			12/4/2001 Revision issued 5-6-02		Minor NSR (BACT)	1	1	GE 7FA	NG	CC	8760	3.0 ppmdv/ 2.5 ppmdv @ 15% O2	DLN, SCR	1-hr / annual	6.0 ppmdv/ 2.0 ppmdv @ 15% O2	CatOx	1-hr /ann.	Construction began 10/01. As of 03/03, 50% complete. Construction suspended. Renewel application pending. SWCAA. Longview, WA.
WA, SWCAA 01-2347R2	Longview Energy Development (Continental Energy)	290			5/14/01 Revision issued 2-20-03		Minor NSR (BACT)	1	1	GE 7FA	NG: FO	CC	8760	3.0 ppmdv/ 2.5 ppmdv @ 15% O2: 6 ppmdv on oil	DLN, SCR	1-hr / annual; 1-hr on oil	6.0 ppmdv/ 2.0 ppmdv @ 15% O2: 6 ppmdv on oil	CatOx	1-hr / annual; 1-hr on oil	Not yet constructing. Renewal application pending. SWCAA. Longview, WA.

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
WA, Ecology Order No. 01AQCR-2037	Goldendale Energy Center (Calpine)	249	08/15/2000	36818	02/23/01	6	Minor NSR (BACT)	1	1	GE7FA	NG	CC	8760	2 ppmdv@ 15% O2	DLN, SCR	3-hr	2 ppmdv @ 15% O2	CatOx	1-hr	Startup expected mid August 2004. Minor NSR BACT. Ecology - Central Region. Goldendale, WA. ORIS: 55482.
WA, EFSEC/95 02	Chehalis Power (Tractebel)	520	01/10/2000		04/17/2001	15	Joint PSD Issuance: EPA & EFSEC	2	0	GE 7FA	NG; FO	CC	8760 / 720 FO	3.0 / 14.0 ppmdv gas / oil @ 15% 02	DLN, SCR	1-hr	3.0 / 8.0 ppmdv gas / oil @ 15% O2	CatOx	1-hr	Startup April 28, 2003, based upon March 13, 2003, letter from Tractebel. Chehalis, WA.
WA, PSCAA NOC 8473	Pierce Power	160			07/03/2001		Minor NSR (BACT)	7	0	GE TM2500 (mobile LM2500)	NG	SC	8760	9 ppmdv@ 15% O2	DLN, SCR	24-hr	10 ppmdv @ 15% O2	CatOx	1-hr	Now shutdown and disassembled. Startup 08/01. Minor NSR BACT. Permit expires 04/03. PSCAA. Tacoma, WA.
WA, Ecology Order No. 01AQIS-3151	Cliffs Energy Project (GNA Energy)	300			09/20/2002		Minor NSR (BACT)	1	1	SW V84.3A	NG	CC	8760	2.5 ppmdv@ 15% O2	DLN, SCR	3-hr	4 ppmdv @ 15% O2	CatOx	3-hr	Minor NSR BACT applies. Ecology - Industrial Section. Goldendale, WA. CANCELLED according to BPA.
WA, BCAA No. 2001-0013	Finley Combustion Turbine Project (Benton County PUD)	27			10/26/2001		Minor NSR (BACT)	1	0	Pratt & Whitney FT8-1 (Power Pac)	NG	SC	8760	5.0 ppmdv @ 15% O2	WI, SCR	Inst	10 ppmdv @ 15% O2	CatOx	Inst	Operating. Minor NSR BACT. ORIS 7945.
WA, EFSEC/2001-01	Satsop (Duke Energy & Energy Northwest)	650	04/23/2001		11/02/2001	6	Joint PSD Issuance: EPA & EFSEC	2	2	GE 7FA	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	1-hr	2.0 ppmdv @ 15% O2	CatOx	1-hr	Application for permit extension submitted. Construction began November 1, 2002. Construction currently suspended due to market conditions. HRSG, stacks, and control system are not physically in place. One year worth of construction remaining. EFSEC & EPA. Elma, WA.
WA, BCAA OA 2002-0012	Plymouth Generating Facility	307	04/24/2001		04/20/2003	24	Minor NSR (BACT)	1	1	Siemens Westinghouse Model 501F	NG	CC	8760	2.0 ppmvd @ 15% O2 (proposed)	DLN, SCR	3-hr	2 ppmdv @ 15% O2 and 10 ppmdv @ 15% O2	CatOx	1-hr and @ partial load	Not constructing. Minor NSR BACT. Permit expires 10/25/04. BCAA. Plymouth, WA.
WA, PSD-01-01 Amendment 1 & SWCAA 01-2350R1	TransAlta Centralia Generation - Big Hanaford Project	268	03/26/2001		PSD: 2/22/2002 PSD Amend: 1/30/03	9	Delegated PSD, Minor NSR (BACT)	4	4	GE LM6000	NG	CC	8760	3.0 ppmdv @ 15% O2	DLN, SCR	3-hr	3.0 ppmdv/ 1.5 ppmdv @ 15% O2	CatOx	1-hr/ 8-hr	Constructing. Minor NSR BACT. Startup 08/02. Ecology - TIES. SWCAA. Centralia, WA. ORIS 3845.
WA, PSD-01-04 & minor NSR	Puget Sound Energy - Fredonia	110	10/23/2001		07/16/2003	21	Delegated PSD, Minor NSR (BACT)	2	0	2 - Pratt & Whitney FT8 (Twin Pack)	NG; FO	SC	8760	5.0 ppmdv @ 15% O2	SCR	3-hr	Minor NSR	CatOx		Ecology - TIES. NWAPA. Mt Vernon, WA. ORIS 607.
WA	Sumas Energy 2 (NESCO)	660	06/29/2001		04/17/2003	22	Joint PSD Issuance: EPA & EFSEC	2	2	SW501F	NG	CC	8760	2.0 ppmdv @ 15%O2	DLN, SCR	3-hr	2.0 ppmdv @ 15%O2	CatOx	1-hr	Not constructing. Application for permit extension submitted. EFSEC & EPA. Sumas, WA.
WA	BP Cherry Point Cogen	720	06/10/2002		Public comment period is over.		Joint PSD Issuance: EPA & EFSEC	3	3	GE 7FA	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	annual	2.0 ppmdv @ 15% O2	CatOx	Ann.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA.
WA	Wallula Power (Newport Northwest Generation)	1,300	09/10/2001		03/03/2003	16	Joint PSD Issuance: EPA & EFSEC, Part D NSR (PM10)	4	4	GE 7FA	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	3-hr	2.0 ppmdv @ 15% O2	CatOx	3-hr	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA.
WA	Starbuck Power (Starbuck Power LLC)	1,200	08/27/2002		Review Suspended		Joint PSD Issuance: EPA & EFSEC	4	4	SW501F	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	24-hr	4.7 ppmdv @ 15% O2	CatOx	8-hr	Project Review Suspended March 2002. EFSEC & EPA. Starbuck, WA.

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
WA	Satsop 2 (Duke Energy & Energy Northwest)	650	11/19/2001		Review Suspended		Joint PSD Issuance: EPA & EFSEC	2	2	GE 7FA	NG	CC	8760	2.5 ppmdv @ 15% O2	DLN, SCR	1-hr	2.0 ppmdv @ 15% O2	CatOx	1-hr	Project Review Suspended August 2002. EFSEC & EPA. Elma, WA.
Totals =	769	385,994						1,932	461											

If completeness date not given, then application date used in "Time to Final Permit" calculation.

* Except for power plants

Abbreviations **:**

GE = Genaral Electric
SW = Seimens Westinghouse

NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner

SC = Simple Cycle
CC = Combined Cycle

DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction

CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

www.epa.gov/region4/air/permits

ATTACHMENT E

DISPERSION MODELING FILES

Calpine Blue Heron Energy Center
Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
BHEC Met Data	5	wpbXX.asc	West Palm Beach, FL surface air meteorological data
		XX = 87 - 91	West Palm Beach, FL upper air meteorological data
BHEC GEP	1	bhec.bpi	Building Profile Input Program (BPIP) input file
	1	bhec.bpo	Building Profile Input Program (BPIP) output file - brief
	1	bhec.sum	Building Profile Input Program (BPIP) output file - detailed
Subtotal Files	3		
BHEC ISC	5	coXX.inp	ISC runs; carbon monoxide (CO) input files, 1987-1991
	5	coXX.out	ISC runs; carbon monoxide (CO) output files, 1987-1991
		XX = 87 - 91	
	5	no2XX.inp	ISC runs; nitrogen dioxide (NO_2) input files, 1987-1991
	5	no2XX.out	ISC runs; nitrogen dioxide (NO_2) output files, 1987-1991
		XX = 87 - 91	
	5	pmXX.inp	ISC runs; particulate matter (PM) input files, 1987-1991
	5	pmXX.out	ISC runs; particulate matter (PM) output files, 1987-1991
		XX = 87 - 91	
	5	so2XX.inp	ISC runs; sulfur dioxide (SO_2) input files, 1987-1991
	5	so2XX.out	ISC runs; sulfur dioxide (SO_2) output files, 1987-1991
		XX = 87 - 91	
Subtotal Files	40		
Total Files	48		

Source: ECT, 2004


CALPINE
BLUE HERON
ENERGY CENTER
Dispersion Modeling Files
ECT
Environmental Consulting & Technology, Inc.
ECT No. 040796-0100
October 2000
(Rev. 1 - December 2004)
COMPACT
disc
DIGITAL DATA