BAYSIDE POWER STATION PSD PERMIT REVISION UNIT 3 AIR CONSTRUCTION PERMIT APPLICATION

Prepared for:

TAMPA ELECTRIC
Tampa, Florida

Prepared by:

Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 030698-0100

July 2003

TAMPA ELECTRIC

RECEIVED
JUL 22 2003
BUREAU OF AIR REGULATION

July 21, 2003

Ms. Trina Vielhauer
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via Fedex
Airbill No. 7922 9054 9260

Re: Bayside Power Station Units 3A and 3B Air Construction Permit Application

Dear Ms. Vielhauer:

Please find enclosed four signed and sealed copies of the Bayside Power Station Units 3A and 3B Air Construction Permit Application. Please find enclosed the Responsible Official Signature in Attachment A and the Air Construction Application in Attachment B. If you have questions please contact Dru Latchman or me at (813) 641-5358.

Sincerely,

Dru Latchman
for

Laura R. Crouch
Manager- Air Programs
Environmental Affairs

EA\gm\DNL182

Enclosures

c/enc: Mr. Jerry Kissel - FDEP SW
Ms. Alice Harman - EPCHC

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111

AN EQUAL OPPORTUNITY COMPANY
HTTP://WWW.TAMPAELECTRIC.COM

CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

BAYSIDE POWER STATION PSD PERMIT REVISION UNIT 3 AIR CONSTRUCTION PERMIT APPLICATION

Prepared for:

TAMPA ELECTRIC
Tampa, Florida

Prepared by:

ECT
Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 030698-0100

July 2003

RECEIVED
JUL 22 2003
BUREAU OF AIR REGULATION

TABLE OF CONTENTS

RECEIVED
JUL 22 2003
BUREAU OF AIR REGULATION

TABLE OF CONTENTS
(Continued, Page 2 of 2)

LIST OF TABLES

LIST OF TABLES
(Continued, Page 2 of 2)

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

RECEIVED
JUL 22 2003
BUREAU OF AIR REGULATION

1.1 INTRODUCTION

The existing Tampa Electric Company (TEC) F.J. Gannon Station (Gannon) consists of six steam boilers (Units 1 through 6), six steam turbines, one simple-cycle combustion turbine (SCCT) (CT-1), a once-through cooling water system, storage and handling of solid fuels, fluxing material, fly ash, slag, fuel oil storage tanks, and ancillary support equipment. Gannon is located on Port Sutton Road in Tampa, Hillsborough County, Florida. Units 1 and 2 each have a nominal generation capacity of 125 megawatts (MW). Units 3, 4, 5, and 6 each have a nominal generation capacity of 180, 188, 239, and 414 MW, respectively. CT-1 has a nominal generation capacity of 14 MW. Units 1 through 6 are all fired with solid fuels; CT-1 is fired with No. 2 distillate fuel oil. Gannon Units 1 through 6 are scheduled to be retired no later than December 31, 2004, per the U.S. Environmental Protection Agency (EPA)/TEC Consent Decree signed in February 2000.

The TEC Bayside Power Station (Bayside) is currently being constructed at the existing Gannon site. Upon completion, Bayside will consist of 11 combined-cycle combustion turbines (CCCTs). Bayside Unit 1 includes three CCCTs (designated as Bayside Units 1A, 1B, and 1C) and will be used to repower existing F.J. Gannon Station Unit 5. Bayside Unit 2 includes four CCCTs (designated as Bayside Units 2A, 2B, 2C, and 2D) and will be used to repower existing F.J. Gannon Station Unit 6. Bayside Units 3 and 4 each include two CCCTs (designated as Bayside Units 3A, 3B, 4A, and 4B) and will be used to repower existing F.J. Gannon Station Units 3 and 4, respectively.

TEC submitted air construction permit applications to the Florida Department of Environmental Protection (FDEP) for Bayside Units 1 and 2 in September 2000 and for Bayside Units 3 and 4 in June 2001. In response, FDEP issued Air Permit No. PSD-FL-301 addressing the construction and initial operation of Units 1 and 2 on March 30, 2001. This permit was subsequently revised to include all 11 Bayside CCCTs (i.e., Units 1 through 4) and reissued as Air Permit No. PSD-FL-301A.

As presently authorized by Air Permit No. PSD-FL-301A, each Bayside CCCT is comprised of a natural gas-fired General Electric (GE) 7FA combustion turbine (CT) equipped with an unfired heat recovery steam generator (HRSG) for operating in combined-cycle (CC) mode. Based on projected future demands for electricity, TEC requests the addition of dual fuel, simple-cycle (SC) mode operation to Bayside Units 3A and 3B as an alternative operating scenario to the presently authorized natural gas CC operating mode.

TEC plans to initially construct and operate Bayside Units 3A and 3B in dual-fuel SC mode operation. Each SCCT will be equipped with an inlet air evaporative cooling system and fired primarily with pipeline-quality natural gas. Low-sulfur (containing no more than 0.05 weight percent sulfur) distillate fuel oil will serve as a secondary fuel source. Bayside SC Units 3A and 3B will operate at an annual capacity factor of up to 100 percent. At baseload operation, this annual capacity factor is equivalent to 8,760-hours-per-year (hr/yr) operation. TEC proposes to limit the use of distillate fuel oil in Bayside SC Units 3A and 3B to no more than an 8-percent capacity factor (i.e., no more than 700 hr/yr at baseload). In the future, TEC plans to convert Bayside SC Units 3A and 3B to CC mode by adding HRSGs as currently authorized by Air Permit No. PSD-FL-301A. The timing of this future conversion will depend on market conditions.

Condition No. 26 of the EPA/TEC Consent Decree requires the repowering of no less than 200 MW of Gannon coal-fired generating capacity Units by May 1, 2003, and a total of 550 MW by December 31, 2004. Bayside CC Units 1 and 2 will satisfy this repowering requirement. Accordingly, the provisions of the EPA/TEC Consent Decree are not applicable to Bayside SC Units 3A and 3B.

This submittal provides a complete air permit application to incorporate the proposed addition of dual fuel, SC mode operation to Bayside Units 3A and 3BConstruction of Bayside SC Units 3A and 3B is scheduled to begin in October 2004 and May 2005, respectively. Construction is expected to take 1 year for each Unit resulting in construction completion of Bayside SC Units 3A and 3B in October 2005 and May 2006, respectively.

Before the commercial operation of Bayside SC Units 3A and 3B, the existing coal fired operation at Gannon will permanently cease operation. With the exception of carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM) and particulate matter less than or equal to 10 microns in aerodynamic diameter (PM_{10}), there will be a substantial net reduction in emissions of other pollutants subject to review under the Prevention of Significant Deterioration (PSD) New Source Review (NSR) permitting program due to the elimination of emissions from Gannon Units 3 through 6. The net increases in CO, VOC, and PM/PM_{10} emissions due to the netting of Gannon Units 3 through 6 with Bayside Units 1 through 4 (including SC Units 3A and 3B) will exceed the PSD significant emission rates for these pollutants. Accordingly, Bayside SC Units 3A and 3B are subject to the PSD NSR requirements of Section 62-212.400, Florida Administrative Code (F.A.C.) for CO, VOC, and PM/PM_{10} emissions.

Since operation of the proposed Bayside SC Units 3A and 3B will result in airborne emissions, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), F.A.C. This report, including the required permit application forms and supporting documentation contained in the appendices, constitutes TEC's application for authorization to commence construction in accordance with (FDEP permitting rules contained in Chapter 62-212, F.A.C.

Bayside SC Units 3A and 3B will be located in an attainment area and will have net CO, VOC, and PM/PM_{10} emissions increases in excess of 100, 40, and 15 tons per year (tpy), respectively. Consequently, Bayside SC Units 3A and 3B qualify as major modifications to an existing major facility and are subject to the PSD NSR requirements of Rule 62-212.400, F.A.C., for CO, VOC, and PM/PM_{10}. 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 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 provides an analysis of best available control technology (BACT) for CO, VOC, and PM/PM_{10}.
- Sections 5.0 (Dispersion Modeling Methodology) and 6.0 (Dispersion Modeling Results) address ambient air quality impacts.

Appendix A contains the FDEP Application for Air Permit—Long Form, and the regulatory applicability tables. The emission rate calculations are shown in Appendix B. All dispersion modeling input and output files for the ambient impact analysis is provided in Appendix C.

1.2 SUMMARY

Bayside SC Unit 3 will consist of two simple-cycle CT units. The CTs will be dual-fired with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf), and distillate fuel oil containing no more than 0.05-weight percent sulfur.

The planned construction start dates for Bayside SC Units 3A and 3B are October 2004 and May 2005, respectively. The planned construction completion dates for Bayside SC Units 3A and 3B are October 2005 and May 2006, respectively.

Based on an evaluation of the anticipated worst-case annual operating scenario, Bayside SC Unit 3 will have the potential to emit 781.2 tpy of nitrogen oxides (NO_x), 293.9 tpy of CO, 168.9 tpy of PM/PM_{10}, 142.9 tpy of sulfur dioxide (SO_2), 29.8 tpy of VOCs, and 0.3 tpy of lead. Regarding noncriteria pollutants, Bayside SC Unit 3 will potentially emit 17.0 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of metals and organic compounds.

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

- The net increase in emissions following the cessation of operation of Gannon Units 3 through 6 with Bayside Units 1 through 4 (including SC Units 3A and 3B) will be below the Table 212.400-2, F.A.C., significant emission rates for all regulated air pollutants, with the exception of CO, VOC, PM/PM_{10}. Accordingly, Bayside SC Unit 3 is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for CO, VOC, and PM/PM_{10} only. Based on actual historical emission rates adjusted for the retroactive application of NO_x, SO_2, and PM BACT, the elimination of Gannon Units 3 through 6 and addition of Bayside Units 1 through 4 will result in a net decrease of 2,029.6 tpy of SO_2, 1,021.8 tpy of NO_x, 33.3 tpy of H_2SO_4 mist, 0.5 tpy of lead, and a net increase of 816.0 tpy of CO, 62.1 tpy of VOC, and 92.0 tpy of PM/PM_{10}. Actual emission rate decreases (i.e., without the retroactive BACT adjustments) will be considerably greater.
- Emissions of PM/PM_{10}, SO_2, and H_2SO_4 mist will be controlled by the use of pipeline-quality natural gas and low-ash and low-sulfur distillate fuel oil.
- NO_x emissions will be controlled by the use of dry low-NO_x (DLN) combustors (natural gas firing) and water injection (distillate oil firing). The NO_x SCCT exhaust concentration will be 10.5 parts per million by dry volume (ppmvd) corrected to 15-percent oxygen for natural gas firing, and 42 ppmvd at 15-percent oxygen for distillate fuel oil firing.
- Advanced burner design and good operating practices to minimize incomplete combustion will be employed to control CO emissions. Maximum short-term CO SCCT exhaust concentration will be 7.8 ppmvd at 15-percent oxygen for natural gas firing and 30.3 ppmvd at 15-percent oxygen for distillate fuel oil firing. Cost effectiveness of a CO oxidation catalyst control system was determined to be \$5,626 per ton of CO. Due to the high control costs, installation of a CO oxidation catalyst control system is considered to be economically infeasible.

- Advanced burner design and good operating practices to minimize incomplete combustion will be employed to control VOC emissions. The maximum SCCT VOC exhaust concentration is projected to be 1.2 ppmvd at 15-percent oxygen for natural gas firing and 3.0 ppmvd for distillate fuel oil firing at 15-percent oxygen. Cost effectiveness of a VOC oxidation catalyst control system was determined to be $99,878 per ton of VOC. Due to the high control costs, installation of a VOC oxidation catalyst control system is considered to be economically infeasible.
- Bayside Units 1 through 4 will have potential emissions of hazardous air pollutants (HAPs) less than the major source thresholds of 10 tpy for any individual HAP and 25 tpy for total HAPs. Bayside is therefore not subject to the case-by-case maximum achievable control technology (MACT) requirements of Section 112(g)(2)(B) of the 1990 Clean Air Act Amendments (CAAA).

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

Bayside SC Unit 3 will be located at the existing TEC Gannon station. Gannon is situated on Port Sutton Road in Tampa, Hillsborough County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the Gannon site location and nearby prominent geographical features.

Bayside SC Unit 3 will consist of two, simple-cycle GE PG7241 (FA) CTs. Each SCCT will be capable of producing a nominal 165 MW of electricity. The two Bayside Unit 3 SCCTs are designated as Units 3A and 3B. The SCCTs will be fired with pipeline quality natural gas. Low sulfur distillate fuel oil will serve as a back-up fuel source.

Bayside Unit 3 will operate at an annual capacity factor of up to 92 and 8 percent for natural gas and distillate fuel oil firing, respectively. Capacity factor is defined as the ratio of the SCCT's actual annual electric output (in Units of megawatts electrical per hour [MWe-hr]) to the unit's nameplate capacity times 8,760 hours. At baseload operation, these annual capacity factors are equivalent to 8,060 hr/yr for natural gas firing and 700 hr/yr for distillate fuel oil firing. The SCCTs will normally operate between 50- and 100-percent load.

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

Figure 2-2 provides a plot plan of the Bayside Power Station showing the Bayside SC Unit 3 layout, major process equipment and structures, and the new SCCT emission points. Figure 2-3 provides a profile view. Primary access to the Bayside Power Station

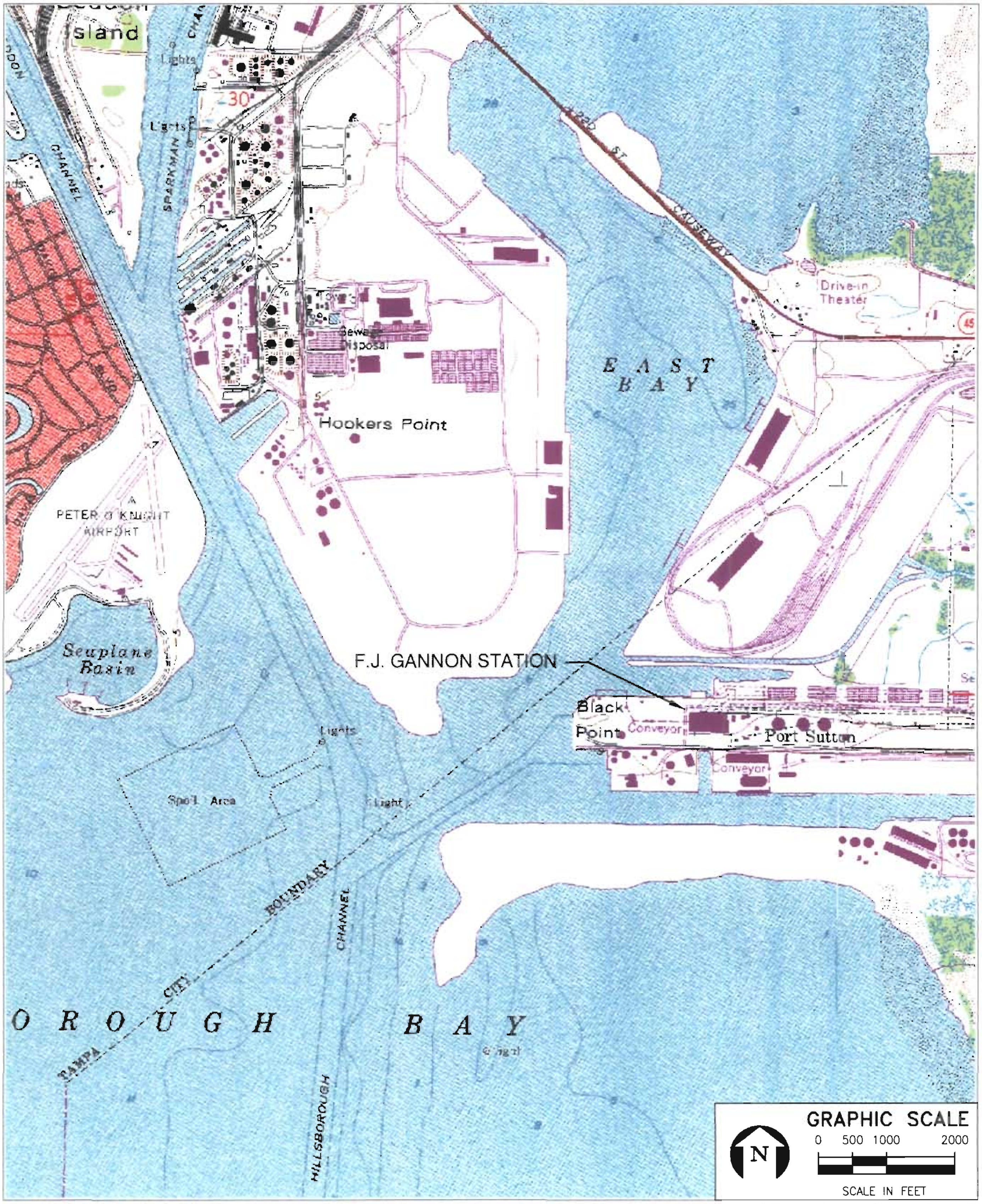
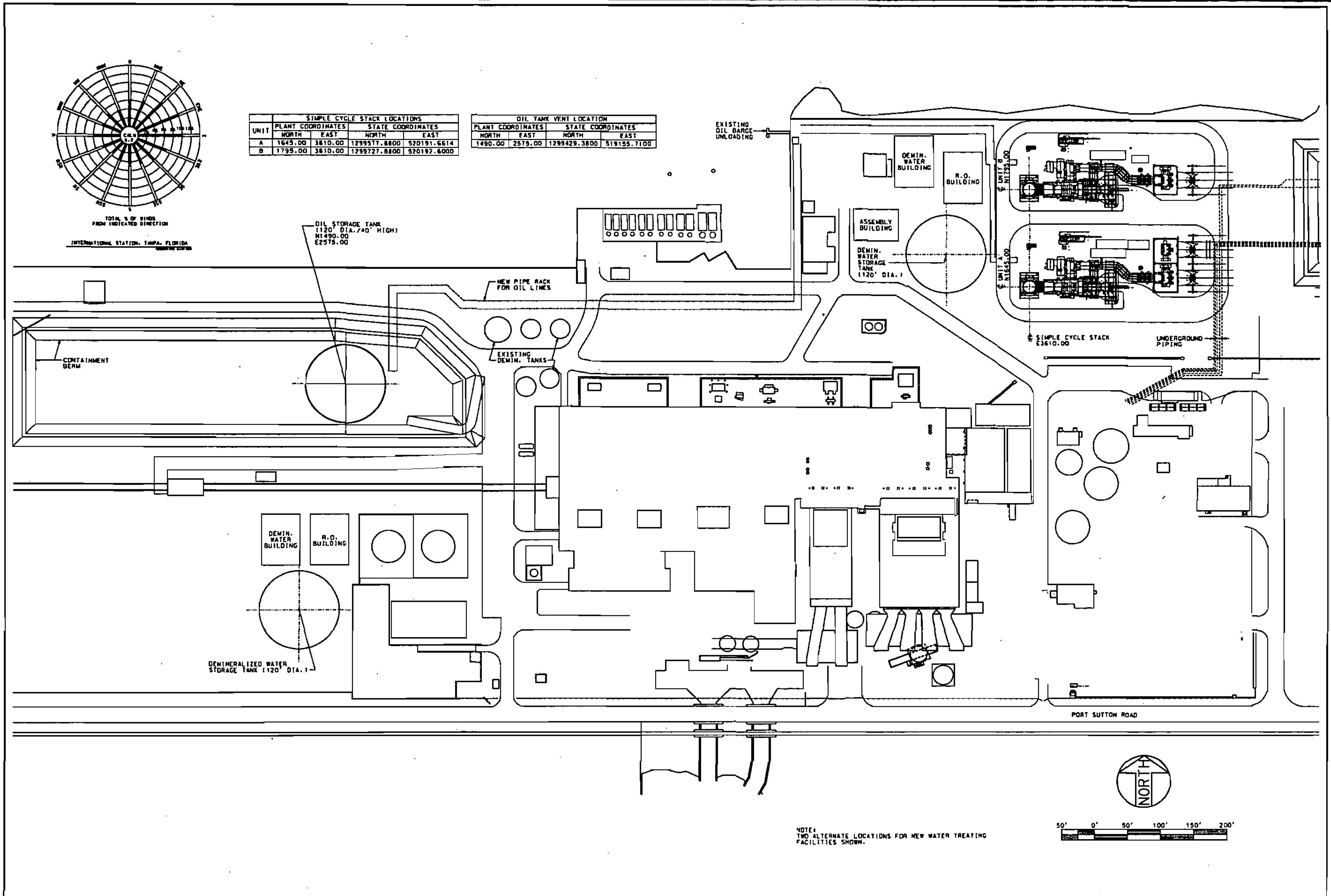


FIGURE 2-1.

F.J. GANNON STATION LOCATION AND SURROUNDINGS

Source: USGS Quad: TAMPA, 1981; ECT, 2003.

TECO
TAMPA ELECTRIC



UNIT	SIMPLE CYCLE STACK LOCATIONS			
	PLANT COORDINATES		STATE COORDINATES	
	NORTH	EAST	NORTH	EAST
A	1645.00	3610.00	1299577.6800	520191.6614
B	1795.00	3610.00	1299727.8800	520192.6000

OIL TANK VENT LOCATION			
PLANT COORDINATES		STATE COORDINATES	
NORTH	EAST	NORTH	EAST
1490.00	2575.00	1299429.3800	519155.7100

FIGURE 2-2.

BAYSIDE UNIT 3 PLOT PLAN

Source: TEC, 2003.

TECO
TAMPA ELECTRIC

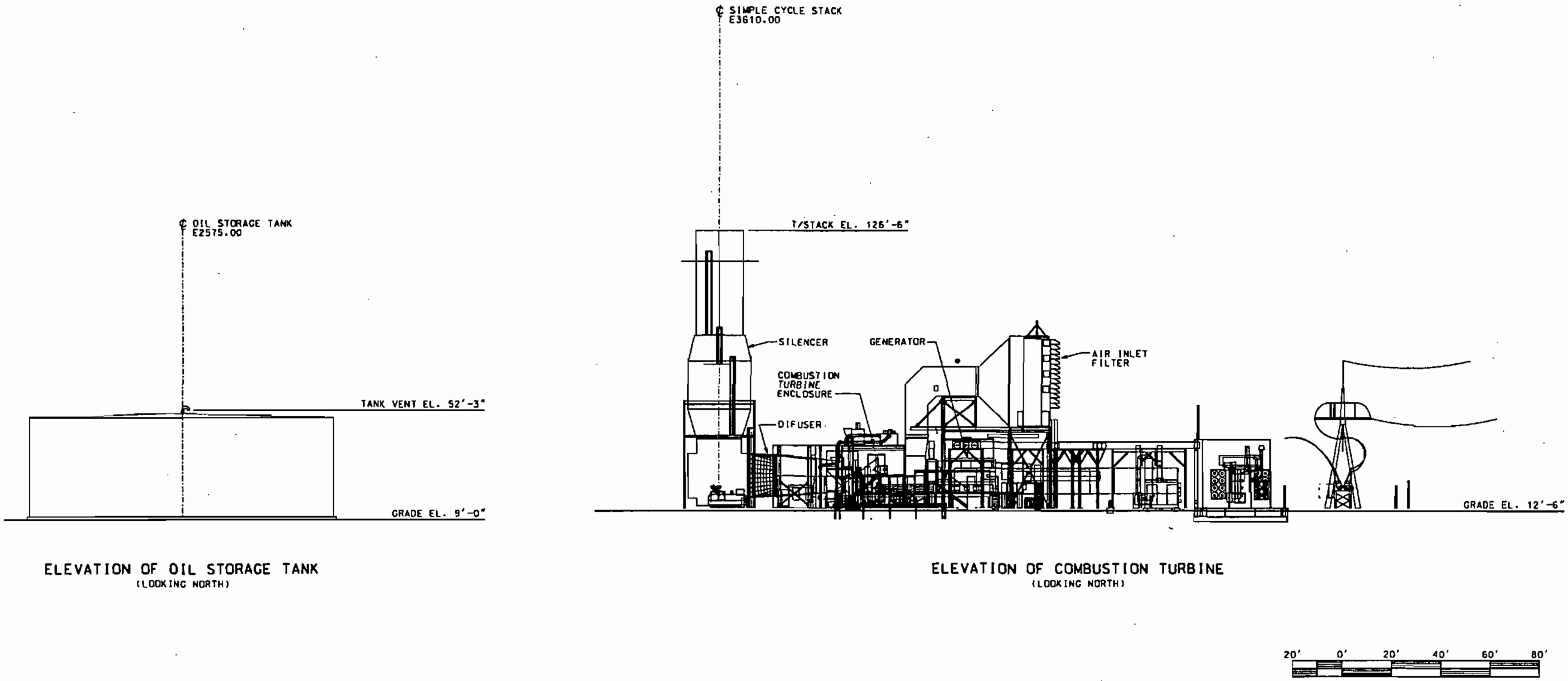


FIGURE 2-3.

BAYSIDE UNIT 3 PROFILE

Source: TEC, 2003.

TECO
TAMPA ELECTRIC

will be from Port Sutton Road on the south side of the site. The Bayside Power Station entrance will have security to control site access.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

Bayside Unit 3 will include two nominal 165-MW CTs operating in simple-cycle mode. Figure 2-4 presents a process flow diagram for Bayside Unit 3.

CTs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTs deliver mechanical output by means of a rotating shaft used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CT compressor. On warm days, the CT inlet air may be conditioned by the use of evaporative coolers. The CT compressor increases the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with natural gas fuel and burned in the CT's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CT to produce rotary shaft power, which is used to drive an electric generator as well as the CT combustion air compressor.

Normal operation is expected to consist of the Bayside Unit 3 SCCTs firing natural gas or fuel oil at baseload. Alternate operating modes include reduced load (i.e., between 50 and 100-percent of baseload), and SCCT inlet air evaporative cooling. SCCT CO and VOC exhaust concentrations are expected to remain essentially constant from 50- to 100-percent load. However, it is possible that CO and VOC exhaust concentrations will also remain essentially unchanged at lower loads (e.g., 45-percent load). For this reason, TEC requests the same permit condition authorizing lower load operations for Bayside SC Unit 3 as specified in Section III, Condition 17.b. of Department Air Permit No. PSD-FL-301A, Project No. 0570040-015-AC, recently issued for Bayside Units 1 through 4. As noted previously, the simple-cycle CTs may operate at an annual capacity factor of up to 100 percent.

Vendor information indicates that the Bayside Unit 3 7FA SCCTs will have a heat input of 1,772 and 1,947 million British thermal Units power hour (MMBtu/hr), higher heating

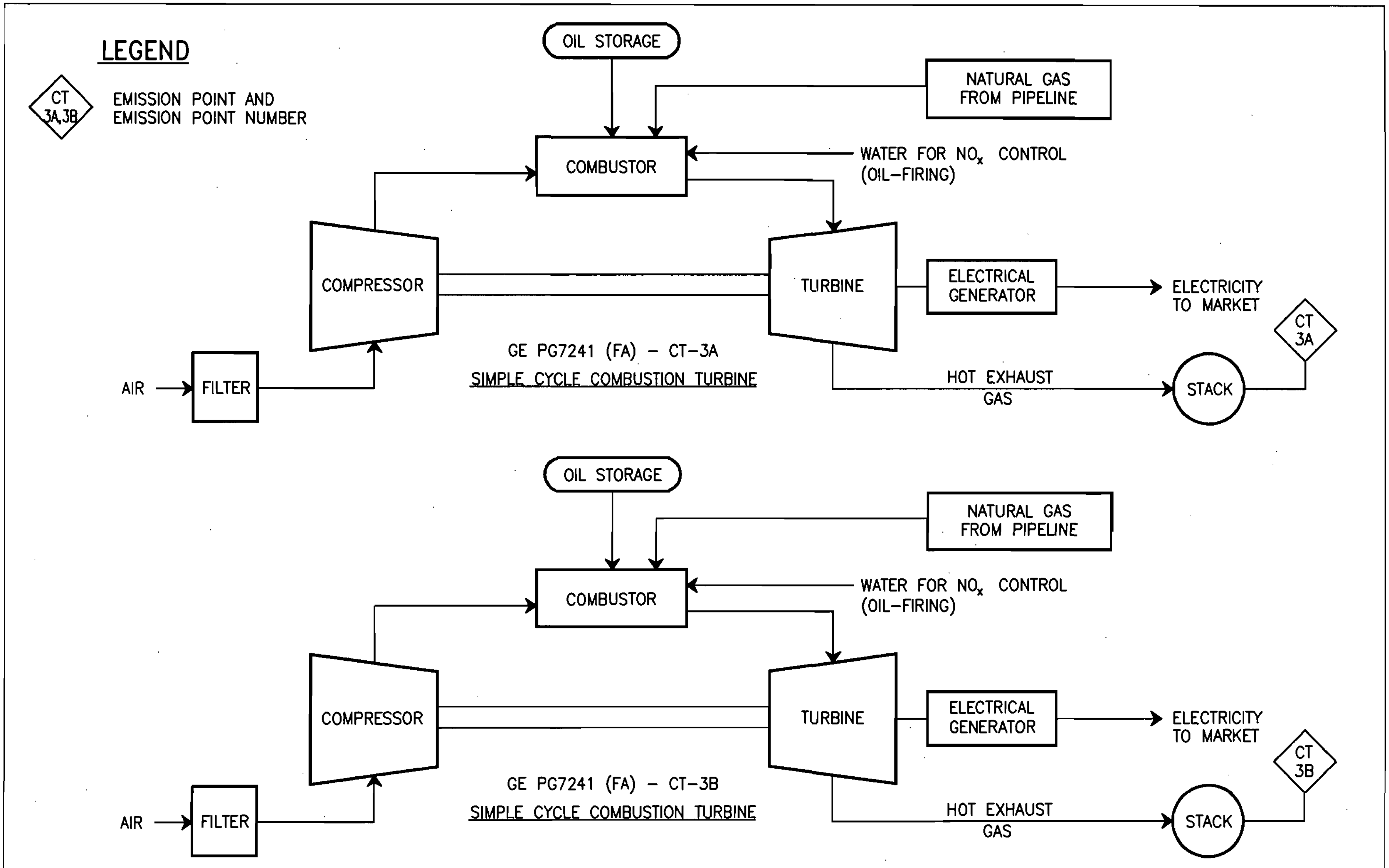


FIGURE 2-4.

BAYSIDE UNIT 3: SCCT PROCESS FLOW DIAGRAM

Source: ECT, 2003.

TECO
TAMPA ELECTRIC

value (HHV) at baseload and 59 degrees Fahrenheit (°F) ambient temperature for natural gas and distillate fuel oil firing, respectively. However, CT vendors typically include a margin in guaranteed heat rates, and, therefore, actual heat inputs could be somewhat higher than provided on the vendor expected performance data sheets. In addition, CT heat rates will gradually increase over time due to routine CT operation and degradation. TEC has therefore estimated heat input rates based on a 3.5-percent margin to allow for heat rate degradation over time consistent with the approach taken for Bayside Units 1 and 2.

The SCCTs will use DLN combustion technology (natural gas firing) and water injection (distillate fuel oil firing) to control NO_x air emissions. The exclusive use of low-sulfur natural gas and low-ash/low-sulfur fuel oil in the SCCTs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant emission rates (per SCCT unit) for natural gas and distillate fuel oil firing, respectively. Table 2-3 summarizes maximum hourly H_2SO_4 mist emission rates. Maximum hourly noncriteria pollutant rates are provided in Tables 2-4 and 2-5 for natural gas and distillate fuel oil firing, respectively. 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 SCCT.

Maximum hourly emission rates for all pollutants, in Units of pounds per hour (lb/hr), are projected to occur for SCCT operations at baseload and low ambient temperature (i.e., 20°F). Appendix B provides the basis for these emission rates.

Table 2-6 presents projected maximum annual criteria and noncriteria emissions for Bayside SC Unit 3. The maximum annualized rates were conservatively estimated assuming baseload operation for 8,060 hr/yr (gas firing), 700 hr/yr (oil firing), and an ambient temperature of 59°F. As noted previously, coal fired operation at existing Gannon Units 3

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (per SCCT)—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	18.0	2.27	10.2	1.28	73.8	9.30	30.5	3.84	3.0	0.38	Neg.	Neg.
	59	18.0	2.27	9.5	1.20	69.1	8.71	30.5	3.84	3.0	0.38	Neg.	Neg.
	90†	18.0	2.27	8.8	1.10	63.0	7.94	30.0	3.79	3.0	0.38	Neg.	Neg.
75	20	18.0	2.27	8.2	1.03	58.6	7.38	30.0	3.79	2.6	0.33	Neg.	Neg.
	59	18.0	2.27	7.7	0.97	55.1	6.94	30.5	3.84	2.6	0.33	Neg.	Neg.
	90†	18.0	2.27	7.2	0.91	51.5	6.49	30.9	3.89	2.8	0.35	Neg.	Neg.
50	20	18.0	2.27	6.5	0.82	45.7	5.76	31.3	3.95	2.8	0.35	Neg.	Neg.
	59	18.0	2.27	6.2	0.78	43.3	5.46	32.2	4.05	2.8	0.35	Neg.	Neg.
	90†	18.0	2.27	5.8	0.73	41.0	5.17	33.0	4.16	2.8	0.35	Neg.	Neg.

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

*Excludes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 2003.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (per SCCT)—Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	34.0	4.28	107.8	13.58	339.4	42.76	69.7	8.79	7.7	0.97	0.104	0.013
	59	34.0	4.28	101.5	12.79	320.3	40.35	69.1	8.70	7.7	0.97	0.098	0.012
	90†	34.0	4.28	92.3	11.63	291.2	36.69	68.6	8.64	7.5	0.95	0.093	0.012
75	20	34.0	4.28	87.4	11.02	273.1	34.41	87.5	11.02	8.0	1.00	0.084	0.011
	59	34.0	4.28	82.5	10.40	258.0	32.51	82.9	10.44	7.8	0.99	0.079	0.010
	90†	34.0	4.28	75.6	9.53	235.9	29.73	82.0	10.33	7.7	0.97	0.073	0.009
50	20	34.0	4.28	68.2	8.59	210.8	26.57	116.4	14.66	7.7	0.97	0.067	0.008
	59	34.0	4.28	64.9	8.18	200.8	25.30	114.9	14.47	7.7	0.97	0.063	0.008
	90†	34.0	4.28	59.8	7.54	184.7	23.28	136.4	17.19	7.5	0.95	0.058	0.007

Note: Neg. = negligible

*Excludes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 2003.

Table 2-3. Maximum H_2SO_4 Mist Pollutant Emission Rates (per SCCT)

Unit Load (%)	Ambient Temperature (°F)	Natural Gas H_2SO_4 Mist lb/hr	Natural Gas H_2SO_4 Mist g/s	Distillate Fuel Oil H_2SO_4 Mist lb/hr	Distillate Fuel Oil H_2SO_4 Mist g/s
100	20	1.2	0.15	12.4	1.56
	59	1.1	0.14	11.7	1.47
	90*	1.0	0.13	10.6	1.34
75	20	0.9	0.12	10.0	1.27
	59	0.9	0.11	9.5	1.19
	90*	0.8	0.10	8.7	1.09
50	20	0.7	0.09	7.8	0.99
	59	0.7	0.09	7.5	0.94
	90*	0.7	0.08	6.9	0.87

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

Sources: GE, 1998.
ECT, 2003.

Table 2-4. Maximum Noncriteria Pollutant Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Natural Gas

Unit Load (%)	Ambient Temperatire (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	8.43E-05	1.06E-05	7.84E-03	9.88E-04	1.25E-03	1.58E-04	2.35E-03	2.964E-04	6.27E-03	7.90E-04	1.27E-01	1.60E-02
	59	7.89E-05	9.94E-06	7.34E-03	9.24E-04	1.17E-03	1.48E-04	2.20E-03	2.77E-04	5.87E-03	7.39E-04	1.19E-01	1.50E-02
	90*	7.26E-05	9.15E-06	6.75E-03	8.51E-04	1.08E-03	1.36E-04	2.03E-03	2.55E-04	5.40E-03	6.81E-04	1.10E-01	1.38E-02

Unit Load (%)	Ambient Temperatire (°F)	Naphthalene		Polycyclic Organic Matter		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.55E-04	3.21E-05	4.31E-04	5.43E-05	5.68E-03	7.16E-04	2.55E-02	3.21E-03	1.25E-02	1.58E-03
	59	2.38E-04	3.00E-05	4.03E-04	5.08E-05	5.32E-03	6.70E-04	2.38E-02	3.00E-03	1.17E-02	1.48E-03
	90*	2.19E-04	2.77E-05	3.71E-04	4.68E-05	4.90E-03	6.17E-04	2.19E-02	2.77E-03	1.08E-02	1.36E-03

Note: Neg. = negligible

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

Source: ECT, 2003.

Table 2-5. Maximum Noncriteria Pollutant Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Distillate Fuel Oil

Unit Load (%)	Ambient Temperatire (°F)	1,3-Butadiene		Arsenic		Benzene		Beryllium		Cadmium		Chromium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	3.42E-02	4.31E-03	2.35E-02	2.96E-03	1.18E-01	1.48E-02	6.63E-04	8.35E-05	1.03E-02	1.29E-03	2.35E-02	2.96E-03
	59	3.22E-02	4.06E-03	2.22E-02	2.79E-03	1.11E-01	1.40E-02	6.25E-04	7.87E-05	9.67E-03	1.22E-03	2.22E-02	2.79E-03
	90*	2.93E-02	3.69E-03	2.02E-02	2.54E-03	1.01E-01	1.27E-02	5.68E-04	7.16E-05	8.80E-03	1.11E-03	2.02E-02	2.54E-03

Unit Load (%)	Ambient Temperatire (°F)	Formaldehyde		Lead		Manganese		Mercury		Naphthalene		Nickel	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	5.99E-01	7.54E-02	2.99E-02	3.77E-03	1.69E+00	2.13E-01	2.57E-03	3.23E-04	7.49E-02	9.43E-03	9.84E-03	1.24E-03
	59	5.64E-01	7.11E-02	2.82E-02	3.55E-03	1.59E+00	2.01E-01	2.42E-03	3.05E-04	7.05E-02	8.89E-03	9.27E-03	1.17E-03
	90*	5.13E-01	6.46E-02	2.57E-02	3.23E-03	1.45E+00	1.82E-01	2.20E-03	2.77E-04	6.41E-02	8.08E-03	8.43E-03	1.06E-03

Unit Load (%)	Ambient Temperatire (°F)	PAH		Selenium	
		lb/hr	g/s	lb/hr	g/s
100	20	8.55E-02	1.08E-02	5.35E-02	6.74E-03
	59	8.06E-02	1.02E-02	5.04E-02	6.35E-03
	90*	7.33E-02	9.24E-03	4.58E-02	5.77E-03

Note: Neg. = negligible

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

Source: ECT, 2003.

Table 2-6. Maximum Annualized Emission Rates for Bayside SC Unit 3 (tpy)

Pollutant	Annualized Emission Rates CT-3A and CT-3B		
	Natural Gas	Distillate Fuel Oil	Total Facility
NO_x	557.0	224.2	781.2
CO	245.6	48.3	293.9
PM/PM_{10}*	145.1	23.8	168.9
SO_2	74.2	68.8	142.9
VOC	24.4	5.4	29.8
H_2SO_4	8.5	7.9	16.4
HAPs			
1,3 Butadiene	6.36E-04	2.26E-02	2.32E-02
Acetaldehyde	5.92E-02		5.92E-02
Acrolein	8.74E-03		8.74E-03
Arsenic		1.55E-02	1.55E-02
Benzene	1.77E-02	7.76E-02	9.53E-02
Beryllium		4.38E-04	4.38E-04
Cadmium		6.78E-03	6.78E-03
Chromium	1.55E-02	1.55E-02	
Ethylbenzene	4.74E-02		4.74E-02
Formaldehyde	9.60E-01	3.94E-01	1.35E+00
Lead		1.97E-02	1.97E-02
Manganese	1.11E+00	1.11E+00	
Mercury	0.00E+00	1.69E-03	1.69E-03
Naphthalene	1.92E-03	4.94E-02	5.13E-02
Nickel		6.48E-03	6.48E-03
PAH	3.26E-03	5.64E-02	5.97E-02
Propylene Oxide	4.28E-02		4.28E-02
Selenium		3.52E-02	3.52E-02
Toluene	1.92E-01		1.92E-01
Xylenes			
Total HAPs	1.33E+00	1.82E+00	3.15E+00

*Excludes H_2SO_4 mist.

Sources: TEC, 2003.
GE, 1998.
ECT, 2003.

through 6 will cease before commercial operation of Bayside SC Unit 3 begins. The net annual change in emissions associated with the elimination of Gannon Units 3 through 6 and the addition of the Bayside Units 1 through 4 (including SC Units 3A and 3B) are shown in Table 2-7.

The exhaust gases from each SCCT will be vented to the atmosphere through separate stacks. Stack parameters for the SCCT Units are provided in Tables 2-8 and 2-9 for natural gas and distillate fuel oil firing, respectively.

Table 2-7. Net Annual Change in Emission Rates (tpy)

Pollutant	F.J. Gannon Units 3 through 6 Net Emissions	Bayside Unit 3 Originally Permitted Emissions	Bayside Unit 3 Currently Proposed Emissions	Bayside Unit 3 Difference in Emissions	Net Change in Emissions	PSD Significant Emission Levels
NO_x	-2,713.7	202.4	781.2	578.9	-1,021.8	40
CO	-609.3	251.4	293.9	42.5	816.0	100
SO_2	-2,573.6	90.4	147.9	57.5	-2,029.6	40
H_2SO_4 mist	-123.1	16.6	17.0	0.4	-33.3	7
PM/PM_{10}	-271.4	88.9	84.4	-4.5	92.0	15
Lead	-1.9	0.25	0.30	0.05	-0.5	0.6
VOC	-78.1	24.5	29.8	5.3	62.1	40

Source: ECT, 2003.

Table 2-8. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	114.0	34.7	1,081	856	151.0	46.0	18.8	5.72
	59	114.0	34.7	1,117	876	144.5	44.0	18.8	5.72
	90	114.0	34.7	1,141	889	137.6	41.9	18.8	5.72
75	20	114.0	34.7	1,111	873	122.7	37.4	18.8	5.72
	59	114.0	34.7	1,139	888	119.7	36.5	18.8	5.72
	90	114.0	34.7	1,166	903	115.4	35.2	18.8	5.72
50	20	114.0	34.7	1,160	900	103.9	31.7	18.8	5.72
	59	114.0	34.7	1,184	913	102.0	31.1	18.8	5.72
	90	114.0	34.7	1,200	922	98.8	30.1	18.8	5.72

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

Sources: GE, 1998.
ECT, 2003.

Table 2-9. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	114.0	34.7	1,067	848	154.8	47.2	18.8	5.72
	59	114.0	34.7	1,098	865	149.0	45.4	18.8	5.72
	90	114.0	34.7	1,130	883	141.1	43.0	18.8	5.72
75	20	114.0	34.7	1,184	913	124.8	38.0	18.8	5.72
	59	114.0	34.7	1,195	919	121.5	37.0	18.8	5.72
	90	114.0	34.7	1,200	922	117.4	35.8	18.8	5.72
50	20	114.0	34.7	1,200	922	104.7	31.9	18.8	5.72
	59	114.0	34.7	1,200	922	103.3	31.5	18.8	5.72
	90	114.0	34.7	1,200	922	100.6	30.7	18.8	5.72

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

Sources: GE, 1998.
ECT, 2003.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the CAAA, EPA has enacted primary and secondary national ambient air quality standards (NAAQS) for six air pollutants (Chapter 40, Part 50, Code of Federal Regulations [CFR]). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also enacted ambient air quality standards (AAQS) (reference Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of NAAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. Bayside is located south of downtown Tampa in Hillsborough County. Hillsborough County is presently designated in 40 CFR 81.310 as unclassifiable (for total suspended particulates [TSPs]; that portion of Hillsborough County which falls within the area of a circle having a centerpoint at the intersection of U.S. Highway 41 South and State Road 60 and a radius of 12 kilometers [km] for SO_2 and for lead; the area encompassed within a radius of 5 km centered on universal transverse mercator [UTM] coordinates: 364.0 km east, 3093.5 km north, zone 17, in the city of Tampa), unclassifiable/attainment (for CO), and unclassifiable or better than national standards (for nitrogen dioxide [NO_2]). EPA had previously revoked the 1-hour ozone standard for all areas of Florida in June 1998 due to adoption of a new 8-hour ozone standard. However, due to litigation involving the new 8-hour ozone standard, on July 5, 2000, EPA reinstated the 1-hour ozone standard for all counties in Florida. Presently, 40 CFR 81.310 designates all counties in Florida, including Hillsborough County, as unclassifiable/attainment with respect to the 1-hour ozone standard.

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [$\mu g/m^3$] unless otherwise stated)

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

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

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

Hillsborough County is designated attainment (for ozone, CO, and NO_2) and unclassifiable (for SO_2, PM_{10}, and lead) by Section 62-204.340, F.A.C. Hillsborough County is also classified as an air quality maintenance area for ozone (entire county), for PM (that portion of Hillsborough County which falls within the area of a circle having a center-point at the intersection of U.S. Highway 41 South and State Road 60 and a radius of 12 km), and for lead (the area encompassed within a radius of 5 km centered on UTM coordinates: 364.0 km east, 3093.5 km north, zone 17) by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

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

3.3 PSD NSR APPLICABILITY

The existing F.J. Gannon Station is classified as a major facility. A modification to a major facility that has potential net emissions equal to or exceeding the significant emission rates indicated in Section 62-212.400, Table 212.400-2, F.A.C., is subject to PSD NSR.

Net emission rates considering the addition of Bayside Units 1 through 4, and the cessation of operations of Gannon Units 3 through 6, will be below the significant emission rate thresholds, with the exception of CO, VOC, and PM/PM_{10}. Table 3-2 provides comparisons of estimated net emissions in relation to PSD significant emission rate thresholds. As shown in this table, potential emissions of all regulated PSD pollutants, with the exception of CO, VOC, and PM/PM_{10}, are projected to be below the applicable PSD significant emission rate levels. Therefore, Bayside SC Unit 3 qualifies as a major modification to a major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for CO, VOC, and PM/PM_{10} only.

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

Pollutant	Project Net Emissions Change* (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	-1,021.8	40	No
CO	816.0	100	Yes
PM	92.0	25	Yes
PM_{10}	92.0	15	Yes
SO_2	-2,029.6	40	No
Ozone/VOC	62.1	40	Yes
Lead	-0.5	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	-33.3	7	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No

*Gannon Units 3 through 6 and Bayside Units 1 through 4.

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2003.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

4.1 METHODOLOGY

The CO, VOC, and PM/PM_{10} BACT analyses were performed in accordance with the EPA top-down method. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information that were used to identify control alternatives include:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar projects.

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

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Air Pollution Control Cost Manual, Sixth Edition* (EPA, 2002). Tables 4-1 and 4-2 summarize specific factors used in estimating capital and annual operating costs, respectively.

Table 4-1. Capital Investment Cost Factors

Cost Item	Factor
Direct Capital Costs (DCC)	
Instrumentation	0.10 × equipment cost
Sales tax	0.06 × 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 Installation 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

Source: EPA, 2002.

Table 4-2. Annual Operating Cost Factors

Cost Item	Factor
Total Direct Costs (TDC)	
Maintenance labor and materials	0.015 × TCI
Catalyst replacement	Catalyst replacement cost × future worth factor
Energy penalty	0.2 to 1.0 percent 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

Source: EPA, 2002.

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

As indicated in Section 3.3, Table 3-2, projected annual emission rates of CO, VOC, and PM/PM_{10} for Bayside SC Unit 3 exceed the PSD significance rates for these pollutants and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 4.3 and 4.4 for PM/PM_{10} and products of incomplete combustion (CO and VOC), respectively.

4.2 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 new source performance standards (NSPS) (40 CFR 60), National Emission Standard for Hazardous Air Pollutants (NESHAPs) (40 CFR 61 and 63), or 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 lower heating value (LHV) of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a manufacturer's rated baseload at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. Bayside SC Units 3A and 3B 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. However, NSPS Subpart GG does not include any emission limitations for PM/PM_{10}, CO, or VOC.

FDEP emission standards for stationary sources are contained in Chapters 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 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7), F.A.C., incorporates the federal NSPS by reference, including Subpart GG.

Emission standards applicable to sources located in ozone nonattainment and maintenance areas are contained in Section 62-296.500, F.A.C. As mentioned in Section 3.0 of this report, all of Hillsborough County is classified as an air quality maintenance area for ozone. However, Section 62-296.500, F.A.C., does not include any emission limitations for PM/PM_{10} or CO.

Bayside will be located at the existing F.J. Gannon Station south of downtown Tampa in Hillsborough County and, therefore, is situated within the Hillsborough County PM air quality maintenance area. Sections 62-296.701 through 62-296.712, F.A.C., specify PM emission standards for 12 categories of sources; none of these categories are applicable to CTs. In addition, these PM emission standards are not applicable to new PM-emitting sources, such as Bayside SC Unit 3, which will be subject to 40 CFR 52.21 (i.e., PSD NSR). Accordingly, there are no PM air quality maintenance area emission limits that are applicable to Bayside SC Unit 3.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAPs, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside SC Unit 3. However, Subpart GG does not contain any PM/PM_{10} or CO emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state PM/PM_{10} or CO emission limitations applicable to Bayside SC Unit 3.

4.3 BACT ANALYSIS FOR PM/PM_{10}

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

4.3.1 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 CTs, none of the previously described control equipment has been applied to CTs because exhaust gas PM/PM_{10} concentrations are inherently low. CTs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The Bayside Units 3 CTs will be fired with natural gas and distillate fuel oil and will generate low PM/PM_{10} emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM/PM_{10} emissions, coupled with a large volume of exhaust gas, produce extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentrations for Bayside SC Units 3A and 3B at baseload and 59°F are approximately 0.003 and 0.005 grains per dry standard cubic foot (gr/dscf) while firing natural gas and distillate fuel oil, respectively. 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.

4.3.2 PROPOSED BACT EMISSION LIMITATIONS

Recent Florida BACT determinations for natural gas-fired CTs are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for SCCTs, the use of good combustion practices and clean fuels is considered to be BACT. Bayside Units 3A and 3B will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The SCCTs will be fired with pipeline-quality natural gas and distillate fuel oil. 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 SCCTs, the use of clean fuels (e.g., pipeline-quality natural gas and distillate fuel oil) and efficient combustion design and operation is proposed as BACT for PM/PM_{10}. Tables 4-3 and 4-4 illustrate some recent FDEP PM BACT determinations for natural gas- and fuel oil-fired CTs, respectively. As an indicator of the use of a clean fuel and efficient combustion design and operation, a visible emissions limit of 10-percent opacity is proposed. Table 4-5 summarizes the PM/PM_{10} BACT proposed for Bayside SC Units 3A and 3B.

4.4 <u>BACT ANALYSIS FOR CO AND VOC</u>

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.

Table 4-3. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size MW	Turbine Size MMBtu/hr	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	857	9.0	0.01	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,214	10.5	0.0134	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	367	(9.0)	0.0245	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	869	7.0	0.0100	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,615	9.0	(0.0056)	Combustion design and clean fuels
09/28/93	Florida Gas Transmission	N/A	32	0.64	N/A	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,755	17.0	0.013	Combustion design and clean fuels
03/07/95	Orange Cogeneration, L.P.	39	388	5.0	(0.013)	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	403	5.0	0.0065	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	971	7.0	(0.0072)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		7.0		Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,468	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,174	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
08/98	Santa Rosa Energy Center	167	1,600	(8.2)	0.0051	Combustion design and clean fuels
08/98	FP&L Ft. Myers Plant Repowering	170	1,600	—	—	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-4. Florida BACT PM Emission Limitation Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size MW	Turbine Size MMBtu/hr	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Control Technology
08/17/92	Florida Power Corp. Intercession City	93	1,144	15.0	(0.0131)	Combustion design and clean fuels
		186	2,032	17.0	(0.0084)	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,170	36.8	0.0472	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	371	10.0	0.0323	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	928	15.0	0.0162	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,850	17.0	(0.0092)	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,765	17.0	0.009	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	406	20.0	0.026	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	991	15.0	(0.0151)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		—	—	Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,660	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,236	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,846	44.8	(0.0243)	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-5. Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA) (per SCCT unit)	Exclusive use of clean fuels (i.e., natural gas and distillate fuel oil) Efficient combustion design and operation 10.0-percent opacity (Indicator of efficient combustion design and operation)

Sources: TEC, 2003.
ECT, 2003.

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 are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO emissions). Accordingly, CT vendors have had to consider the competing factors involved in NO_x and CO/VOC formation to develop Units that achieve acceptable emission levels for those pollutants.

4.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOC from SCCTs: combustion process design and oxidation catalysts.

Combustion Process Design

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

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOC to carbon dioxide (CO_2) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. Recently, high temperature oxidation catalysts have been developed that can tolerate higher temperatures (i.e., greater than 1,200°F). Typically, the oxidation catalyst is located within the HRSG where temperatures range from 450 to 1,100°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO and VOC up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F; higher temperatures on the order of 900°F are needed to oxidize VOC. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time that 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 CT 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 VOC control efficiency using oxidation catalyst is 50 percent.

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

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. The catalyst will further oxidize sulfur compounds that have been oxidized to SO_2 in the combustion process 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

Both SCCT combustor design and oxidation catalyst control systems are considered to be technically feasible for Bayside SC Units 3A and 3B. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO and VOC are provided in the following subsections.

4.4.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing high sulfur contents. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and distillate fuel oil.

Because CO and VOC emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements (i.e., below the defined PSD significant impact levels for CO). The location of Bayside SC Unit 3 (Hillsborough County) is classified attainment for all criteria pollutants, including CO and ozone. As noted in FDEP's 2000 Air Monitoring Report, there have been no exceedances of the CO AAQSs in Florida during the last 13 years. Maximum CO concentrations for all Florida monitoring sites during 2000 were less than 30 percent of the 35-part-per-million (ppm) 1-hour AAQS, and less than 70 percent of the 9-ppm 8-hour AAQS. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of Bayside Units 1 through 4 (including SC Units 3A and 3B) CO emissions indicated that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest, second highest (HSH) 1- and 8-hour average CO impacts were projected to be only 0.7 and 1.7 percent of the Florida and Federal CO AAQS.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CT due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for Bayside SC Units 3A and 3B is projected to have a pressure drop across the catalyst bed of approximately 1.1 inch of water. This pressure drop will result in a 0.26-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 5,261,256 kilowatt-hours (kWh) (17,952 million British thermal Units [MMBtu]) per year at baseload (165 MW) operation and 100-percent capacity factor per SCCT. This energy penalty is equivalent to the use of 35.48 million cubic feet (ft^3)

of natural gas annually based on a natural gas heating value of 1,050 British thermal Units per cubic foot (Btu/ft^3) for both SCCTs. The lost power generation energy penalty, based on a power cost of $0.030/kWh, is $315,675 per year for both SCCTs.

4.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using OAQPS factors and the project-specific economic factors provided in Table 4-6. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-7 and 4-8, respectively.

The base case Bayside SC Unit 3 annual CO emission rate (i.e., for both SCCTs) is 293.9 tpy based on SCCT baseload operation at 59°F for 8,060 hr/yr operation gas firing and 700 hr/yr oil firing. The controlled annual CO emission rate, based on 90-percent control efficiency, is 29.4 tpy. The cost effectiveness of oxidation catalyst for CO emissions was determined to be $5,626 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered economically feasible. The economic analysis is considered to be conservative (i.e., underestimate the actual cost effectiveness) since actual SCCT exhaust CO concentrations are expected to be well below the GE guarantees. Table 4-9 summarizes the results of the oxidation catalyst economic analysis.

The base case Bayside SC Unit 3 annual VOC emission rate (i.e., for both SCCTs) is 29.8 tpy based on CT baseload operation at 59°F for 8,060 hr/yr operation gas firing and 700 hr/yr oil firing. The controlled annual VOC emission rate, based on 50-percent control efficiency, is 14.9 tpy. The cost effectiveness of oxidation catalyst for VOC emissions was determined to be $99,878 per ton of VOC removed. Based on the high control costs, use of oxidation catalyst technology to control VOC emissions is not considered economically feasible. Table 4-10 summarizes the results of the oxidation catalyst economic analysis.

Table 4-6. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
Oxidation catalyst control efficiency	%	90.0*
Electricity cost	$/kWh	0.030*
Labor costs (base rates)	$/hour	
Operator	22.00	
Maintenance	22.00	

*Per FDEP recommendation.

Sources: TEC, 2003.
ECT, 2003.

Table 4-7. Capital Costs for Oxidation Catalyst System (Two SCCTs)

Item	Dollars	EPA Factor
Direct Capital Cost		
Equipment cost	3,215,000	EC
Sales tax	192,900	0.06 × EC
Instrumentation	321,500	0.10 × EC
Freight	160,750	0.05 × EC
Total Purchased Equipment Cost (PEC)	**\$3,890,150**	
Installation cost		
Foundations and supports	311,212	0.08 × PEC
Handling and erection	544,621	0.14 × PEC
Electrical	155,606	0.04 × PEC
Piping	77,803	0.02 × PEC
Insulation for ductwork	38,902	0.01 × PEC
Painting	38,902	0.01 × PEC
Total Installation Cost (TIC)	**\$1,167,046**	
Total Direct Capital Costs (DCC)	**\$5,057,196**	**PEC + TIC**
Indirect Installation Cost		
General facilities	252,860	0.05 × DCC
Engineering and home office fees	505,720	0.10 × DCC
Process contingency	252,860	0.05 × DCC
Total Indirect Installation Cost (IIC)	**\$1,011,440**	
Project Contingency (PC)	910,295	0.15 × (DCC + IIC)
Total Plant Cost (TPC)	**\$6,978,931**	DCC + IIC + PC
Preproduction cost (PPC)	139,579	0.02 × TPC
Total Capital Investment (TCI)	**\$7,118,510**	TPC + PPC

Source: ECT, 2003.

Table 4-8. Annual Operating Costs for Oxidation Catalyst System (Two SCCTs)

Item	Dollars	EPA Factor
Direct Cost		
Maintenance labor and materials (ML&M)	106,778	0.015 × TCI
Catalyst replacement cost		
Replacement (materials and labor)	1,889,112	
Credit for used catalyst	255,000	
Total Catalyst Replacement Cost (CRC)	**$1,634,112**	
Future worth factor (FWF)	0.1739	7.0%, 3 yrs
Annualized Catalyst Cost (ACC)	**$284,157**	CRC × FWF
Energy penalty (EP)		
Turbine backpressure	315,675	0.26% / inch delta P
Total Direct Costs (TDC)	**$706,610**	ML&M + ACC + EP
Indirect Cost		
Capital recovery factor (CRF)	0.1098	7.0%, 15 yrs
Capital recovery	781,574	CRF × TCI
Total Indirect Cost (TINC)	**$781,574**	
Total Annual Cost (TAC)	**$1,488,184**	**TDC + TIC**

Source: ECT, 2003.

Table 4-9. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
	Emission Rates		Emission Reduction	Installed Capital Cost	Total Annualized Cost	Cost Effectiveness Over Baseline	Increase Over Baseline	Toxic Impact	Adverse Environmental Impact
Control Option	lb/hr	tpy	(tpy)	($)	($/yr)	($/ton)	(MMBtu/yr)	(Y/N)	(Y/N)
Oxidation catalyst	6.7	29.4	264.5	7,118,510	1,488,184	5,626	33,340	Y	Y
Baseline	67.1	293.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 8,060 hr/yr gas-fired, 700 hr/yr oil-fired.

Sources: GE, 1998.
ECT, 2003.

Table 4-10. Summary of VOC BACT Analysis

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Environmental Impact (Y/N)
Oxidation catalyst	3.4	14.9	14.9	7,118,510	1,488,184	99,878	33,340	Y	Y
Baseline	6.8	29.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 8,060 hr/yr gas-fired, 700 hr/yr oil-fired.

Sources: GE, 1998.
ECT, 2003.

4.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO or VOC from SCCTs is typically required only for facilities located in CO or ozone nonattainment areas. Recent summaries of FDEP CO BACT determinations for natural gas- and distillate oil-fired CTs are provided in Tables 4-11 and 4-12, respectively. Similar summaries of recent FDEP VOC BACT determinations for natural gas- and distillate oil-fired CTs are provided in Tables 4-13 and 4-14, respectively.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and low-sulfur distillate fuel oil. Because CO and VOC emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality (i.e., well below the defined PSD significant impact levels for CO and VOC).

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion is proposed as BACT for CO. These control techniques have been considered by FDEP to represent BACT for CO and VOC for recent SCCT projects, as shown in Tables 4-11 to 4-14.

Maximum CO exhaust concentrations from Bayside SC Units 3A and 3B will be less than or equal to 7.8 and 30.3 ppmvd for natural gas and distillate fuel oil firing, respectively. These CO exhaust concentrations are consistent with recent FDEP CO BACT determinations for SCCT Units (see Tables 4-11 and 4-12).

Maximum VOC exhaust concentrations from Bayside SC Units 3A and 3B will be less than or equal to 1.2 and 3.0 ppmvd for natural gas and distillate fuel oil firing, respectively. These VOC exhaust concentrations are consistent with recent FDEP VOC BACT determinations for SCCT Units (see Tables 4-13 and 4-14).

Table 4-11. Florida BACT CO Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	30	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
02/21/94	Polk Power Partners	84	25	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	30	Good combustion
06/01/95	Panda-Kathleen	75	25	Good combustion
09/28/95	City of Key West	23	20	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
08/99	Santa Rosa Energy Center	167	9	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-12. Florida BACT CO Summary—Distillate Fuel Oil-Fired CTs

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

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-13. Florida BACT VOC Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit ppmvd	VOC Emission Limit lb/MmBtu	Control Technology
02/21/94	Polk Power Partners	84	25		Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260		0.0017	Good combustion
07/20/94	Pasco Cogen, Limited	42	28		Good combustion
03/07/95	Orange Cogeneration, L.P.	39	10		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4		Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	7		Good combustion
08/99	Santa Rosa Energy Center	167	1.4		Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-14. Florida BACT VOC Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit ppmvd	VOC Emission Limit lb/MmBtu	Control Technology
02/21/94	Polk Power Partners	84	25		Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260		0.0128	Good combustion
07/20/94	Pasco Cogen, Limited	42	28		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	10		Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	10		Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

CO BACT emission limits proposed for Bayside SC Units 3A and 3B are provided in Table 4-15. The CO BACT limits shown in Table 4-15 are consistent with the limits recently approved by FDEP for Bayside Units 1 and 2. VOC BACT emission limits proposed for Bayside SC Units 3A and 3B are provided in Table 4-16.

Table 4-15. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (per SCCT)		
CO (natural gas)	7.8	33.0
CO (distillate fuel oil)	30.3	136.4

*Corrected to 15-percent oxygen.
†CT compressor inlet air temperature of 59°F.

Sources: TEC, 2003.
ECT, 2003.

Table 4-16. Proposed VOC BACT Emission Limits

Emission Source	Proposed VOC BACT Emission Limits ppmvd*	lb/hr†
GE PG7241 (FA) SCCTs (per SCCT)		
VOC (natural gas)	1.2	3.0
VOC (distillate fuel oil)	3.0	8.0

*Corrected to 15-percent oxygen.
†CT compressor inlet air temperature of 59°F.

Sources: TEC, 2003.
ECT, 2003.

5.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

5.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed.

5.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, Bayside SC Units 3A and 3B will have the potential to emit 781.2 tpy of NO_x, 293.9 tpy of CO, 168.9 tpy of PM/PM_{10}, 147.9 tpy of SO_2, 29.8 tpy of VOCs, and 17.0 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates increases for the Gannon/Bayside repowering project. As shown in that table, potential emission increases of all PSD regulated pollutants will be below the applicable PSD significant emission rate levels, with the exception of CO, PM, and PM_{10}. Accordingly, Bayside SC Units 3A and 3B are subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for CO and PM/PM_{10} only. In response to a prior request from FDEP, an air quality impact analysis for Bayside SC Units 3A and 3B was also conducted for NO_2 and SO_2.

5.3 MODEL SELECTION AND USE

For this study, air quality modeling was applied at the refined level. Refined modeling requires more detailed and precise input data than screening modeling, but is presumed to have provided more accurate estimates of source impacts.

The most recent regulatory version of the Industrial Source Complex (ISC3) models (EPA, 2000) is recommended and was used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISC3 short-term (ISCST3) (Version 00101) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

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

5.4 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.

5.5 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. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing, and the other is based on population density. The land use typing method uses the work of Auer (Auer, 1978) and is preferred by EPA and FDEP because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

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

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

5.6 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 centerline (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 centerline, is defined as intermediate terrain.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of Bayside (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as simple terrain. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted (i.e., all receptors were assumed to be at the same elevation as the SCCT stack bases for modeling purposes).

5.7 GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT/BUILDING WAKE EFFECTS

According to EPA regulations (40 CFR 51), GEP stack height is defined as the highest of 65 meters or a height established by applying the formula:

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

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

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While the GEP stack height regulations require that stack heights used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack heights, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for the Bayside SC Units 3A and 3B (126.5 feet [ft]) is less than the *de minimis* GEP height of 65 meters (213 ft) and, therefore, complies with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The 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.

Table 5-1 provides dimensions of the building/structures evaluated for wake effects.

5.8 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."

Table 5-1. Building/Structure Dimensions (meters)

Building/Structure	Dimensions		
	Width	Length	Height
Boiler 1 structure	17.1	21.0	44.8
Boiler 2 structure	15.8	17.1	45.1
Boiler 3 structure	17.1	22.9	45.1
Boiler 4 structure	17.1	21.9	48.8
Boiler 5 structure	17.1	18.9	53.0
Boiler 6 structure	17.1	23.8	62.2
Tripper structure	17.1	185.0	50.3
Steam turbine structure	27.1	191.1	29.0
CT 3A-4B HRSGs	21.3	27.4	28.9
SCCT 3A, 3B inlet air filter	9.9	18.3	21.3

Sources: TEC, 2003.
ECT, 2003.

The entire perimeter of the Gannon/Bayside plant site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

The receptor grids were formulated consistent with GAQM recommendations. Discrete receptors were placed on the restricted area boundaries. Additional discrete receptors were placed at 10-degree (°) increments, beginning at 10° on rings at 250 and 500 meters if the specific polar receptor was an ambient air location. Complete rings with receptors located at 10° increments, beginning at 10°, were located at 250-meter increments from 750 to 7,000 meters and at 8,000; 9,000; 10,000; and 12,000 meters. These receptor grids are consistent with prior Gannon/Bayside dispersion modeling studies submitted to FDEP.

Figure 5-1 illustrates a graphical representation of the receptor grids (out to a distance of 1,500 meters). A depiction of the receptor grids (from 1,500 meters to 12 km) is shown in Figure 5-2.

5.9 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).

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

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

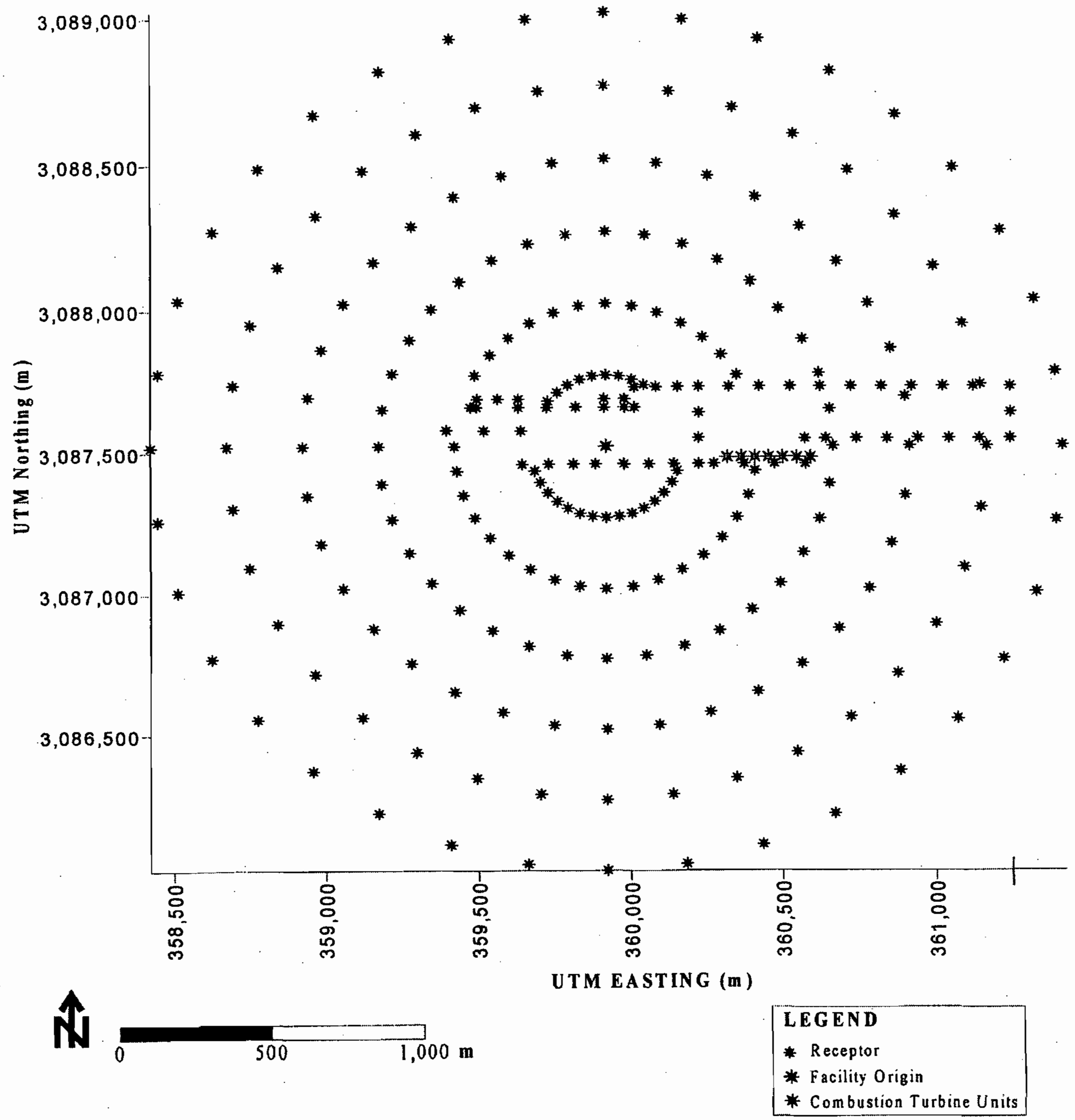


FIGURE 5-1.

RECEPTOR LOCATIONS (WITHIN 1,500 METERS)

Source: ECT, 2003.

TECO
TAMPA ELECTRIC

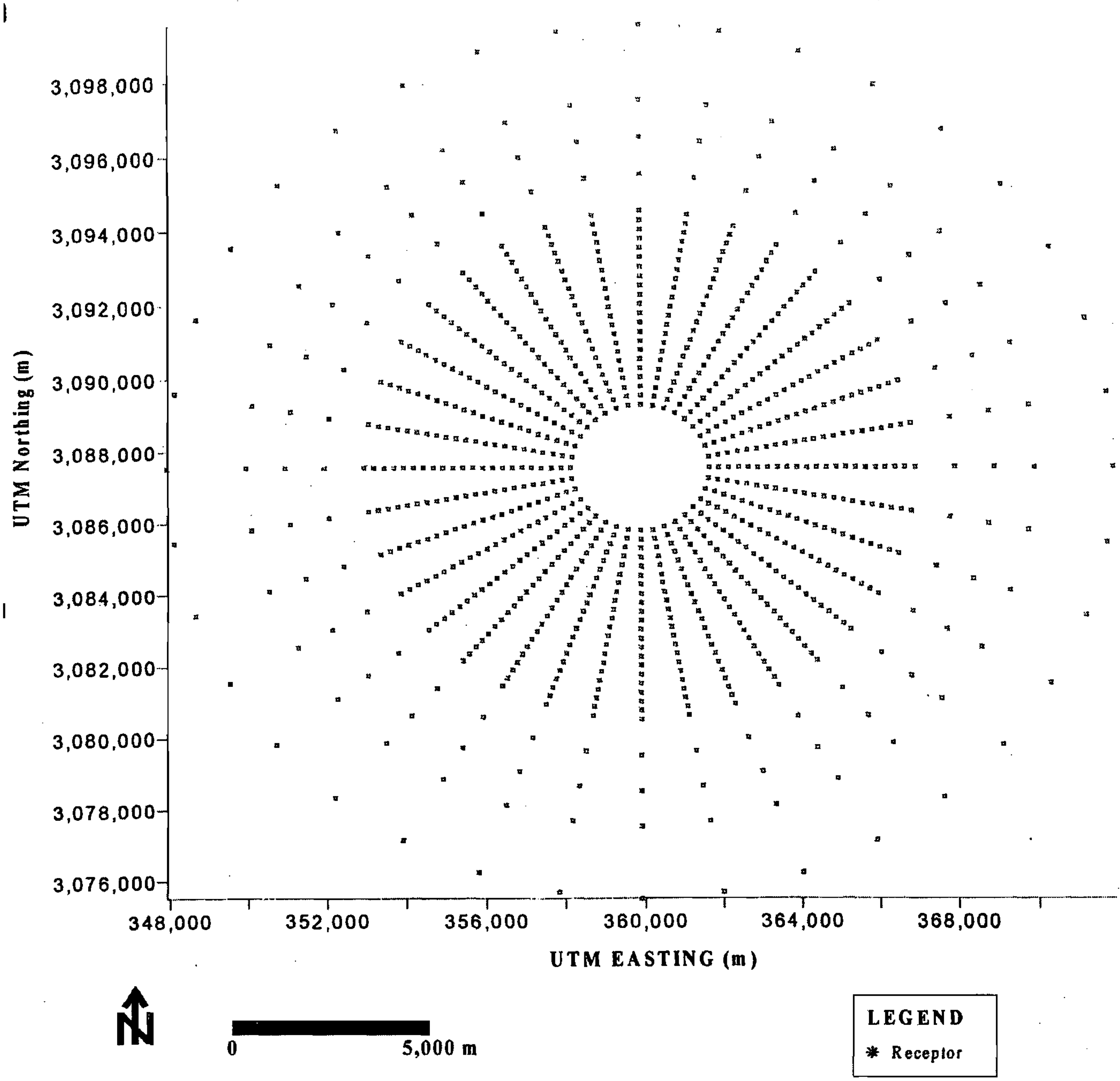


FIGURE 5-2.

RECEPTOR LOCATIONS (FROM 1,500 METERS TO 12 KM)

Source: ECT, 2003.

TECO
TAMPA ELECTRIC

5.10 MODELED EMISSION INVENTORY

As requested by FDEP, the modeled on-property emission sources consisted of the 11 Bayside Units 1 through 4. Refined modeling was conducted for each of the nine operating cases.

Emission rates and stack parameters for the Bayside SC Units 3A and 3B were previously presented in Tables 2-1 and 2-6.

6.0 AMBIENT IMPACT ANALYSIS RESULTS

The refined ISCST3 model was used to model each of the nine Bayside Units 1 through 4 operating scenarios. For SC Units 3A and 3B, short-term (i.e., 1-, 3-, 8-, and 24-hour) and long-term (i.e., annual) impacts were conservatively based on continuous oil firing. These operating scenarios include three loads (50, 75, and 100 percent) and three ambient temperatures (20, 59, and 90°F). Table 6-1 summarizes ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts.

Maximum HSH 3- and 24-hour SO_2 impacts are projected to be 217.1 and 56.4 µg/m^3, respectively. The 3-hour HSH SO_2 impact is 16.7 percent of the Federal and Florida 3-hour average AAQS of 1,300 µg/m^3. The 24-hour HSH SO_2 impact is 15.4 and 21.7 percent of the Federal and Florida 24-hour average AAQS of 365 and 260 µg/m^3, respectively. Maximum annual average SO_2 impact is projected to be 2.5 µg/m^3. This impact is 3.1 and 4.2 percent of the Federal and Florida annual average AAQS of 80 and 60 µg/m^3, respectively.

Maximum annual average NO_2 impact is projected to be 5.1 µg/m^3. This impact is 5.1 percent of the Federal and Florida annual average AAQS of 100 µg/m^3.

Maximum HSH 24-hour PM/PM_{10} impact is projected to be 52.6 µg/m^3. This impact is 35.1 percent of the 24-hour Federal and Florida AAQS of 150 µg/m^3. Maximum annual average PM/PM_{10} impact is projected to be 3.6 µg/m^3. This impact is 7.2 percent of the Federal and Florida annual average AAQS of 50 µg/m^3.

Maximum HSH 1- and 8-hour CO impacts are projected to be 696.6 and 224.8 µg/m^3, respectively. These impacts are 1.7 and 2.2 percent of the Federal and Florida 1- and 8-hour average AAQS of 40,000 and 10,000 µg/m^3, respectively.

Table 6-1. Air Quality Impact Analysis Summary
Bayside Units 1 - 4 (Page 1 of 3)

	Case 1 (100% Load, 18°F Ambient)					Case 2 (75% Load, 18°F Ambient)					Case 3 (50% Load, 18°F Ambient)					Case 4 (100% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
SO_2																				
HSH, 3-Hour ($\mu g/m^3$)	178.2	197.6	179.2	134.4	**217.1**	173.2	167.3	185.5	197.7	215.0	160.8	172.0	154.8	203.6	163.8	169.1	190.3	176.7	146.2	211.5
HSH, 24-Hour ($\mu g/m^3$)	49.0	37.6	43.8	29.5	49.6	50.8	47.4	51.5	44.5	55.8	42.8	47.6	54.1	50.1	**56.4**	45.5	39.0	45.6	32.4	49.4
Annual ($\mu g/m^3$)	1.38	1.38	1.38	1.38	1.38	1.97	1.97	1.97	1.97	1.97	**2.51**	**2.51**	**2.51**	**2.51**	**2.51**	1.50	1.50	1.50	1.50	1.50
NO_2																				
Tier 1 Annual ($\mu g/m^3$)	3.88	3.88	3.88	3.88	3.88	5.40	5.40	5.40	5.40	5.40	**6.86**	**6.86**	**6.86**	**6.86**	**6.86**	4.21	4.21	4.21	4.21	4.21
Tier 2 Annual ($\mu g/m^3$)	2.91	2.91	2.91	2.91	2.91	4.05	4.05	4.05	4.05	4.05	**5.14**	**5.14**	**5.14**	**5.14**	**5.14**	3.16	3.16	3.16	3.16	3.16
PM/PM_{10}																				
HSH, 24-Hour ($\mu g/m^3$)	29.2	27.8	30.6	23.7	0.0	34.8	35.4	41.2	35.7	0.0	48.1	40.7	50.8	45.1	0.0	28.3	30.0	33.2	28.0	0.0
Annual ($\mu g/m^3$)	1.29	1.29	1.29	1.29	1.29	2.33	2.33	2.33	2.33	2.33	3.44	3.44	3.44	3.44	3.44	1.66	1.66	1.66	1.66	1.66
CO																				
HSH, 1-Hour ($\mu g/m^3$)	243.3	268.4	250.7	268.7	270.8	338.3	339.5	321.9	359.5	359.7	545.6	528.2	493.1	580.3	579.8	241.2	262.2	252.6	283.1	271.4
HSH, 8-Hour ($\mu g/m^3$)	113.1	93.2	101.2	77.7	120.9	131.2	125.7	133.4	119.9	154.3	191.8	160.1	176.6	182.7	189.7	99.9	88.2	102.2	85.0	113.1

Table 6-1. Air Quality Impact Analysis Summary
Bayside Units 1 - 4 (Page 2 of 3)

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 90°F Ambient)					Case 8 (75% Load, 90°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
SO_2																				
HSH, 3-Hour ($\mu g/m^3$)	166.8	163.3	178.9	193.6	186.3	155.7	167.5	151.0	196.8	156.3	168.5	178.4	173.1	158.0	200.9	156.7	155.8	168.3	188.8	173.4
HSH, 24-Hour ($\mu g/m^3$)	49.6	46.6	51.2	44.8	54.5	41.1	46.4	50.0	48.6	54.6	45.4	40.0	46.1	34.9	49.7	47.2	45.2	50.1	44.3	51.6
Annual ($\mu g/m^3$)	2.03	2.03	2.03	2.03	2.03	2.42	2.42	2.42	2.42	2.42	1.56	1.56	1.56	1.56	1.56	2.04	2.04	2.04	2.04	2.04
NO_2																				
Annual ($\mu g/m^3$)	5.56	5.56	5.56	5.56	5.56	6.66	6.66	6.66	6.66	6.66	4.39	4.39	4.39	4.39	4.39	5.59	5.59	5.59	5.59	5.59
Tier 2 Annual ($\mu g/m^3$)	4.17	4.17	4.17	4.17	4.17	4.99	4.99	4.99	4.99	4.99	3.29	3.29	3.29	3.29	3.29	4.19	4.19	4.19	4.19	4.19
PM/PM_{10}																				
HSH, 24-Hour ($\mu g/m^3$)	37.4	36.1	41.8	37.9	0.0	48.6	41.2	51.5	45.2	0.0	29.8	31.9	35.4	30.2	0.0	40.0	37.2	44.4	39.5	0.0
Annual ($\mu g/m^3$)	2.52	2.52	2.52	2.52	2.52	3.46	3.46	3.46	3.46	3.46	1.83	1.83	1.83	1.83	1.83	2.69	2.69	2.69	2.69	2.69
CO																				
HSH, 1-Hour ($\mu g/m^3$)	335.6	318.0	315.1	356.8	356.6	544.5	529.5	492.7	579.3	578.8	249.7	263.2	257.3	273.2	276.8	346.3	321.4	319.0	368.4	367.9
HSH, 1-Hour ($\mu g/m^3$)	129.4	124.7	128.8	119.4	149.3	191.3	160.4	187.9	182.5	188.8	102.2	92.0	104.3	89.6	116.1	131.6	124.6	128.2	122.5	149.0

Table 6-1. Air Quality Impact Analysis Summary
Bayside Units 1 - 4 (Page 3 of 3)

	Case 9 (50% Load, 90°F Ambient)					Maximums
	1992	1993	1994	1995	1996	
SO_2						
HSH, 3-Hour ($\mu g/m^3$)	149.1	162.5	146.3	187.4	149.3	**217.1**
HSH, 24-Hour ($\mu g/m^3$)	39.6	44.0	47.4	46.9	52.4	**56.4**
Annual ($\mu g/m^3$)	2.37	2.37	2.37	2.37	2.37	**2.51**
NO_2						
Annual ($\mu g/m^3$)	6.52	6.52	6.52	6.52	6.52	**6.86**
Tier 2 Annual ($\mu g/m^3$)	4.89	4.89	4.89	4.89	4.89	**5.14**
PM/PM_{10}						
HSH, 24-Hour ($\mu g/m^3$)	47.5	43.0	**52.6**	46.5	0.0	**52.6**
Annual ($\mu g/m^3$)	**3.58**	**3.58**	**3.58**	**3.58**	**3.58**	**3.58**
CO						
HSH, 1-Hour ($\mu g/m^3$)	654.3	641.2	592.8	**696.6**	696.0	**696.6**
HSH, 8-Hour ($\mu g/m^3$)	**224.8**	192.5	221.4	218.1	217.1	**224.8**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour ($\mu g/m^3$)	217.1	1	1996	1,300	1,300	16.7	16.7
HSH, 24-Hour ($\mu g/m^3$)	56.4	3	1996	260	365	21.7	15.4
Annual ($\mu g/m^3$)	2.51	3	1996	60	80	4.2	3.1
NO_2							
Annual ($\mu g/m^3$)	5.14	3	1996	100	100	5.1	5.1
PM_{10}							
HSH, 24-Hour ($\mu g/m^3$)	52.6	12	1995	150	150	35.1	35.1
Annual ($\mu g/m^3$)	3.58	12	1996	50	50	7.2	7.2
CO							
HSH, 1-Hour ($\mu g/m^3$)	696.6	9	1995	40,000	40,000	1.7	1.7
HSH, 8-Hour ($\mu g/m^3$)	224.8	9	1992	10,000	10,000	2.2	2.2

Source: ECT, 2003.

APPENDIX A

APPLICATION FOR AIR PERMIT
TITLE V SOURCE

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

RECEIVED
JUL 22 2003
BUREAU OF AIR REGULATION

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: **Tampa Electric Company**	
2. Site Name: **Bayside Power Station**	
3. Facility Identification Number: **0570040**	
4. Facility Location...: Street Address or Other Locator: **Port Sutton Road** City: **Tampa** County: **Hillsborough** Zip Code: **33619**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: **Dru Latchman**
2. Application Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **6499 U.S. Highway 41 North** City: **Apollo Beach** State: **FL** Zip Code: **33572-9200**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5358** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **dlatchman@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	07-22-03
2. Project Number(s):	0570040-019-AC
3. PSD Number (if applicable):	PSD-FL-301B C
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ 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

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
026	Simple Cycle Combustion Turbine Unit 3A	AC1A	$7,500
027	Simple Cycle Combustion Turbine Unit 3B	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name :
   Wade A. Maye, General Manager, F.J. Gannon Station
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: **Tampa Electric Company**
   Street Address: **Port Sutton Road**
   City: **Tampa** State: **FL** Zip Code: **33619**
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(813) 641-5400** ext. Fax: **(813) 641-5418**
4. Owner/Authorized Representative Email Address: **wmaye@tecoenergy.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.

   __________________________ __________________

   Signature Date

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Wade A. Maye, General Manager, F.J. Gannon Station**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(813) 641-5400** ext. Fax: **(813) 641-5351**
4.	Owner/Authorized Representative Email Address: **wamaye@tecoenergy.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.* W Maye — Signature 7/21/03 — Date

APPLICATION INFORMATION

Application Responsible Official Certification

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: **FL** Zip Code: **32606**
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 ☒, 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 — **July 21, 2003**

Signature — 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) **360.00** North (km) **3,087.5**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Dru Latchman, Environmental Coordinator**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5358** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **dlatchman@tecoenergy.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. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

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.	☒	Title V Source	
4.	☒	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.	☒	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:			

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOx	**A**	
CO	**A**	
PM	**A**	
PM10	**A**	
SO2	**A**	
SAM	**A**	
VOC	**A**	
PB	**B**	
HAPs	**B**	

B. EMISSIONS CAPS N/A

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) ☒ Attached, Document ID: **Fig 2-2** ☐ 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) ☒ 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) **N/A** ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 2-1** ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: ☒ Attached, Document ID: **See Section 2.0**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **Appendix A-2**
4. 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)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Sections 5.0, 6.0** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ 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

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

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

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.)

   ☒ 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)

   ☒ 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:
   Simple cycle combustion turbine Unit 3A.

3. Emissions Unit Identification Number: **3A**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
Type C	**October, 2004**	**October 2005**	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241(FA)**

10. Generator Nameplate Rating: **165 MW**

11. Emissions Unit Comment: **Simple cycle combustion turbine**

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **NOx Controls: Dry low_NOx combustors (DLN) and water injection (WI)**	
2. Control Device or Method Code(s): **025 (DLN), 028 (WI)**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **165 MW (per SCCT)**	
2. Maximum Production Rate: **8,760 hours per year**	
3. Maximum Heat Input Rate: **1,834 (gas), 2,015 (oil)** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input is higher heating value (HHV) at 100 percent load, 59 degrees F, and the natural gas firing (i.e., the primary fuel). The maximum heat input for distillate fuel oil firing is 2,015 MMBtu/hr HHV at 59 degrees F. Heat input will vary with load and ambient temperature.**	

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: **Unit 3A**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: V	6. Stack Height: **114.0** feet	7. Exit Diameter: **18.8** feet
8. Exit Temperature: **1,120** °F	9. Actual Volumetric Flow Rate: **2,393,587** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack temperature and flow rate are for 100 percent load, 59 degrees F, and natural gas firing. For the same operating conditions and distillate fuel oil firing,the exhaust temperature is 1,100 degrees F, and the volumetric flow rates would be 2,468,510 acfm at 11.19 percent water vapor, and 742,956 dscfm.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with pipeline quality natural gas (8,760 hours per year).**		
2. Source Classification Code (SCC): **20100202**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.790**	5. Maximum Annual Rate: **15,680**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 grains/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with distillate fuel oil (700 hours per year maximum).**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **13.889**	5. Maximum Annual Rate: **9,722**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05 by weight**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.6**
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

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:		

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
NOX	**025**	**028**	**EL**
CO			**EL**
PM			**EL**
PM10			**EL**
SO2			**EL**
VOC			**EL**

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

(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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
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 _____ of _____

1. Basis for Allowable Emissions Code: **NOX**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.5 ppm (gas), 42 ppm (oil)**	4. Equivalent Allowable Emissions: **69.1** lb/hour **781.2** tons/year
5. Method of Compliance: **EPA Reference Method 7E (initial), NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **CO**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7.8 ppm (gas), 30.3 ppm (oil) max**	4. Equivalent Allowable Emissions: **69.1** lb/hour **293.9** tons/year
5. Method of Compliance: **EPA Reference Method 10 (initial), CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **PM/PM10**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **18.0 lb/hr (gas), 34.0 lb/hr (oil),**	4. Equivalent Allowable Emissions: **34.0** lb/hour **168.9** tons/year
5. Method of Compliance: **Exlusive firing of pipline quality natural gas and distillate fuel oil along with efficient combustion indicated by compliance with CO visible emission standards.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

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 _____ of _____

1. Basis for Allowable Emissions Code: **SO2**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.2 lb/hr (gas), 107.8 lb/hr (oil)**	4. Equivalent Allowable Emissions: **107.8** lb/hour **147.9** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **VOC**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.2 ppm (gas), 3.0 ppm (oil) max**	4. Equivalent Allowable Emissions: **8.0** lb/hour **29.8** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil. Compliance with CO emission limits used as surrogate compliance for VOC**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

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 _____ of _____

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10%** Exceptional Conditions: **20%** Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: EPA Method 9.	
5. Visible Emissions Comment: **Opacity during startup shutdown shall not exceed 10%, except of up to ten 6-minute periods in a calendar day during which the opacity shall not exceed 20%.**	

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 **2**

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
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 **2**

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
7. Continuous Monitor Comment: **Required by 40 CFR Part 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 _____ 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) ☒ 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: **Appendix A-1** ☐ 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: **Section 4.0** ☐ 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 _____ ☒ 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 _____ ☒ 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: _____ _____ ☒ 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: _____ ☐ 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)) ☒ Attached, Document ID: **Section 4.0** ☐ 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.) ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

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

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) ☒ Attached, Document ID: **Fig 2-2** ☐ 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) ☒ 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) **N/A** ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 2-1** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☒ Attached, Document ID: **See Section 2.0**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Appendix A-2**
4.	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)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Sections 5.0, 6.0** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ 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

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

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

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.)

   ☒ 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)

   ☒ 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:
   Simple cycle combustion turbine Unit 3B.

3. Emissions Unit Identification Number: **3B**

4. Emissions Unit Status Code: **Type C**	5. Commence Construction Date: **May, 2005**	6. Initial Startup Date: **May 2006**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? ☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241(FA)**

10. Generator Nameplate Rating: **165 MW**

11. Emissions Unit Comment: **Simple cycle combustion turbine**

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **NOx Controls: Dry low_NOx combustors (DLN) and water injection (WI)**
2. Control Device or Method Code(s): **025 (DLN), 028 (WI)**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **165 MW (per SCCT)**		
2. Maximum Production Rate: **8,760 hours per year**		
3. Maximum Heat Input Rate: **1,834 (gas), 2,015 (oil)** million Btu/hr		
4. Maximum Incineration Rate: pounds/hr	tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day	**7** days/week
	52 weeks/year	**8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input is higher heating value (HHV) at 100 percent load, 59 degrees F, and the natural gas firing (i.e., the primary fuel). The maximum heat input for distillate fuel oil firing is 2,015 MMBtu/hr HHV at 59 degrees F. Heat input will vary with load and ambient temperature.**		

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: **Unit 3B**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: V	6. Stack Height: **114.0** feet	7. Exit Diameter: **18.8** feet
8. Exit Temperature: **1,120** °F	9. Actual Volumetric Flow Rate: **2,393,587** acfm	10. Water Vapor: %

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

15. Emission Point Comment:

Stack temperature and flow rate are for 100 percent load, 59 degrees F, and natural gas firing. For the same operating conditions and distillate fuel oil firing,the exhaust temperature is 1,100 degrees F, and the volumetric flow rates would be 2,468,510 acfm at 11.19 percent water vapor, and 742,956 dscfm.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with pipeline quality natural gas (8,760 hours per year).**		
2. Source Classification Code (SCC): **20100202**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.790**	5. Maximum Annual Rate: **15,680**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 grains/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with distillate fuel oil (700 hours per year maximum).**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **13.889**	5. Maximum Annual Rate: **9,722**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05 by weight**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.6**
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

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:		

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
NOX	**025**	**028**	**EL**
CO			**EL**
PM			**EL**
PM10			**EL**
SO2			**EL**
VOC			**EL**

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

(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:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
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 _____ of _____

1. Basis for Allowable Emissions Code: **NOX**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.5 ppm (gas), 42 ppm (oil)**	4. Equivalent Allowable Emissions: **69.1** lb/hour **781.2** tons/year
5. Method of Compliance: **EPA Reference Method 7E (initial), NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **CO**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7.8 ppm (gas), 30.3 ppm (oil) max**	4. Equivalent Allowable Emissions: **69.1** lb/hour **293.9** tons/year
5. Method of Compliance: **EPA Reference Method 10 (initial), CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **PM/PM10**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **18.0 lb/hr (gas), 34.0 lb/hr (oil),**	4. Equivalent Allowable Emissions: **34.0** lb/hour **168.9** tons/year
5. Method of Compliance: **Exlusive firing of pipline quality natural gas and distillate fuel oil along with efficient combustion indicated by compliance with CO visible emission standards.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

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 _____ of _____

1. Basis for Allowable Emissions Code: **SO2**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.2 lb/hr (gas), 107.8 lb/hr (oil)**	4. Equivalent Allowable Emissions: **107.8** lb/hour **147.9** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **VOC**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.2 ppm (gas), 3.0 ppm (oil) max**	4. Equivalent Allowable Emissions: **8.0** lb/hour **29.8** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil. Compliance with CO emission limits used as surrogate compliance for VOC**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

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 _____ of _____

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10%** Exceptional Conditions: **20%** Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: EPA Method 9.	
5. Visible Emissions Comment: **Opacity during startup shutdown shall not exceed 10%, except of up to ten 6-minute periods in a calendar day during which the opacity shall not exceed 20%.**	

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 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
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 2

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
7. Continuous Monitor Comment: **Required by 40 CFR Part 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 _____ 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) ☒ 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: **Appendix A-1** ☐ 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: **Section 4.0** ☐ 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 _____ ☒ 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 _____ ☒ 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: _____ _____ ☒ 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: _____ ☐ 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)) ☒ Attached, Document ID: **Section 4.0** ☐ 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.) ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

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

APPENDIX A-1

REGULATORY APPLICABILITY ANALYSES

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	§60.7(b) - (h)		CT 3A-3B	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CT 3A-3B	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CT 3A-3B	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CT 3A-3B	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		CT 3A-3B	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CT 3A-3B	General procedures regarding reporting deadlines.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	§60.332(a)(1) and (b), (f), and (i)		CT 3A-3B	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		CT 3A-3B	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Monitoring Requirements	§60.334(a)	X	CT 3A-3B	Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ± 5.0 percent. Applicable to CTs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CT 3A-3B	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CT 3A-3B	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to the Bayside combined cycle CTs.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements which are applicable to the Bayside combined cycle CTs.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, and XXX		X		None of the listed NESHAPS' contain requirements which are applicable to the Bayside combined cycle CTs.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CT 3A-3B	General Acid Rain Program requirements. SO_2 allowance program requirements start January 1, 2000 **(future requirement)**.
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		CT 3A-3B	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CT 3A-3B	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. **(future requirement)**. Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. **(future requirement)**.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Application Shield	§72.32		CT 3A-3B	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CT 3A-3B	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the Bayside combined cycle CTs.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CT 3A-3B	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	§72.82(a) and (c)		CT 3A-3B	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CT 3A-3B	Requirement to submit an annual compliance report. **(future requirement)**

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CT 3A-3B	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CT 3A-3B	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CT 3A-3B	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CT 3A-3B	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CT 3A-3B	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CT 3A-3B	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CT 3A-3B	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CT 3A-3B	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CT 3A-3B	General QA/QC requirements (excluding opacity).

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reference Test Methods	§75.22		CT 3A-3B	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CT 3A-3B	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		CT 3A-3B	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CT 3A-3B	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CT 3A-3B	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CT 3A-3B	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CT 3A-3B	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CT 3A-3B	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CT 3A-3B	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CT 3A-3B	Requirements pertaining to general recordkeeping.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Recordkeeping Provisions	§75.56(b)(1)		CT 3A-3B	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CT 3A-3B	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CT 3A-3B	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CT 3A-3B	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CT 3A-3B	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CT 3A-3B	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CT 3A-3B	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CT 3A-3B	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		The Bayside combined cycle CTs will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Bayside personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 11)

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

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Bayside 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		Bayside 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-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per §64.2(b)(1)(iii) since CTs 1A-2D will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention			Ammonia Storage	Subject to provisions of 40 CFR Part 68 due to anhydrous ammonia storage.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 49, 53, 54, 55, 56, 57, 58, 59, 62, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 600, and 610		X		The listed regulations do not contain any requirements which are applicable to the Bayside combined cycle CTs.

Source: ECT, 2001.

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

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

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Review	62-4.150, F.A.C.	X			Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.	X			Contains no applicable requirements.
Scope of Part II	62-4.2.00, F.A.C.	X			Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits. **(future requirement)**
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting		X			Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

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

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

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

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

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports					
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. **(future requirement)**.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.		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), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration. **Excess emissions for up to 18 hours in a 24 hour period are specifically requested for the Bayside combined cycle CTs. See Section 2.2 of the PSD permit application for details.**
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to the Bayside combined cycle CTs.

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

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

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be 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.			CT 3A-3B	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement).**
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement).**
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.	X			Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Applicability	§62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CT 3A-3B	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation. **(future requirement)**
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CT 3A-3B	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			CT 3A-3B	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	§62-214.370, F.A.C.			CT 3A-3B	Defines revision procedures and automatic amendments **(potential future requirement)**..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CT 3A-3B	Defines permit activation and termination procedures **(potential future requirement)**.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.**[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Project does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to the Bayside combined cycle CTs.
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			Project is not located in an ozone nonattainment area or an ozone air quality maintenance area.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Project is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Project is not located in a lead non-attainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Project is located in a PM air quality maintenance area. However, there are no limits applicable to CTs.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

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

Source: ECT, 2001.

APPENDIX A-2

FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
Other Characteristics	
Heat content	1,022 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5776
Sulfur content (maximum)	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: TEC, 1999.

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Specific gravity @ 60EF (maximum)	0.876
Viscosity, saybolt (SUS) @ 100EF	
Minimum	40.2
Maximum	32.6
Flash point, EF (minimum)	100
Pour point, EF (minimum)	0
Minimum gross heating value, Btu/gal	
LHV	129,811
HHV	137,600
Water and sediment, percent by volume (maximum)	0.05
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015
Trace constituents, ppm (maximum)	
Lead	1.0
Sodium	1.0
Vanadium	0.5

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

Source: TEC, 1992.

APPENDIX B

EMISSION RATE CALCULATIONS

Table B-1. TEC Bayside Power Station, SC Units 3A and 3B CT Operating Scenarios - General Electric 7241FA CT

Case	Ambient Temperature (oF)	Load (%)	Simple Cycle Unit 3A, 3B	Annual Profile (hr/yr)	Evaporative Cooling	Natural Gas Firing	Fuel Oil Firing
1	20	100	X			X	X
2	20	75	X			X	X
3	20	50	X			X	X
4	59	100	X	8,060 (gas), 700 (oil)		X	X
5	59	75	X			X	X
6	59	50	X			X	X
7	90	100	X		X	X	X
8	90	75	X			X	X
9	90	50	X			X	X

Sources: TEC, 2003.
ECT, 2003.

Table B-2. TEC Bayside Power Station, SC Units 3A and 3B
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1] (lb/hr)	PM/PM_{10} [1] (g/sec)	SO_2 [2] (lb/hr)	SO_2 [2] (g/sec)	H_2SO_4 [3] (lb/hr)	H_2SO_4 [3] (g/sec)	Lead [4] (lb/hr)	Lead [4] (g/sec)
20	1	100	18.0	2.27	10.2	1.28	1.2	0.15	0.0306	0.00386
	2	75	18.0	2.27	8.2	1.03	0.9	0.12	0.0245	0.00309
	3	50	18.0	2.27	6.5	0.82	0.7	0.09	0.0196	0.00247
59	4	100	18.0	2.27	9.5	1.20	1.1	0.14	0.0286	0.00361
	5	75	18.0	2.27	7.7	0.97	0.9	0.11	0.0232	0.00292
	6	50	18.0	2.27	6.2	0.78	0.7	0.09	0.0186	0.00235
90	7	100	18.0	2.27	8.8	1.10	1.0	0.13	0.0264	0.00332
	8	75	18.0	2.27	7.2	0.91	0.8	0.10	0.0216	0.00272
	9	50	18.0	2.27	5.8	0.73	0.7	0.08	0.0174	0.00220
		Maximums	**18.0**	**2.27**	**10.2**	**1.28**	**1.2**	**0.15**	**0.0306**	**0.0039**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd) [5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd) [5]	CO (lb/hr)	CO (g/sec)	VOC [6] (ppmvd) [5]	VOC [6] (lb/hr)	VOC [6] (g/sec)
20	1	100	10.5	73.8	9.30	7.2	30.5	3.84	1.2	3.0	0.38
	2	75	10.5	58.6	7.38	7.1	30.0	3.79	1.1	2.6	0.33
	3	50	10.5	45.7	5.76	7.4	31.3	3.95	1.2	2.8	0.35
59	4	100	10.5	69.1	8.71	7.2	30.5	3.84	1.2	3.0	0.38
	5	75	10.5	55.1	6.94	7.2	30.5	3.84	1.1	2.6	0.33
	6	50	10.5	43.3	5.46	7.6	32.2	4.05	1.2	2.8	0.35
90	7	100	10.5	63.3	7.97	7.1	30.0	3.79	1.2	3.0	0.38
	8	75	10.5	51.5	6.49	7.3	30.9	3.89	1.2	2.8	0.35
	9	50	10.5	41.0	5.17	7.8	33.0	4.16	1.2	2.8	0.35
		Maximums	**10.5**	**73.8**	**9.30**	**7.8**	**33.0**	**4.16**	**1.2**	**3.0**	**0.38**

[1] As measured by EPA Reference Methods 201 and 202.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] AP-42, EPA, May 1998 - Draft.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2003.
GE, 1998.

Table B-3. TEC Bayside Power Station, SC Units 3A and 3B
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)	PM/PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1	100	34.0	4.28	107.8	13.58	12.4	1.56	0.104	0.0131
	2	75	34.0	4.28	87.4	11.02	10.0	1.27	0.084	0.0106
	3	50	34.0	4.28	68.2	8.59	7.8	0.99	0.067	0.0084
59	4	100	34.0	4.28	101.5	12.79	11.7	1.47	0.098	0.0123
	5	75	34.0	4.28	82.5	10.40	9.5	1.19	0.079	0.0100
	6	50	34.0	4.28	64.9	8.18	7.5	0.94	0.063	0.0079
90	7	100	34.0	4.28	92.3	11.63	10.6	1.34	0.093	0.0117
	8	75	34.0	4.28	75.6	9.53	8.7	1.09	0.073	0.0092
	9	50	34.0	4.28	59.8	7.54	6.9	0.87	0.058	0.0073
		Maximums	**34.0**	**4.28**	**107.8**	**13.58**	**12.4**	**1.56**	**0.104**	**0.0131**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC[6] (ppmvd)[5]	VOC[6] (lb/hr)	VOC[6] (g/sec)
20	1	100	42.0	339.4	42.76	14.2	69.7	8.79	2.8	7.7	0.97
	2	75	42.0	273.1	34.41	16.5	87.5	11.02	2.7	8.0	1.00
	3	50	42.0	210.8	26.57	24.0	116.4	14.66	2.8	7.7	0.97
59	4	100	42.0	320.3	40.35	14.0	69.1	8.70	2.8	7.7	0.97
	5	75	42.0	258.0	32.51	16.0	82.9	10.44	2.7	7.8	0.99
	6	50	42.0	200.8	25.30	24.5	114.9	14.47	2.9	7.7	0.97
90	7	100	42.0	291.2	36.69	13.9	68.6	8.64	2.8	7.5	0.95
	8	75	42.0	235.9	29.73	16.4	82.0	10.33	2.8	7.7	0.97
	9	50	42.0	184.7	23.28	30.3	136.4	17.19	3.0	7.5	0.95
		Maximums	**42.0**	**339.4**	**42.76**	**30.3**	**136.4**	**17.19**	**3.0**	**8.0**	**1.00**

[1] As measured by EPA Reference Methods 201 and 202.
[2] *Based on fuel oil sulfur content of 0.05 wt percent.*
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Based on 1.0 ppmw lead content of fuel oil, S&L, 2000.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2003.
GE, 1998.

Table B-4a. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants; 20 °F

Maximum Hourly Heat Input: (Case 1)	1,960	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours:	8,060	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	4.30E-08	8.43E-05	1.06E-05	3.18E-04
Acetaldehyde	4.00E-06	7.84E-03	9.88E-04	2.96E-02
Acrolein	6.40E-07	1.25E-03	1.58E-04	4.73E-03
Benzene	1.20E-06	2.35E-03	2.96E-04	8.87E-03
Ethylbenzene	3.20E-06	6.27E-03	7.90E-04	2.37E-02
Formaldehyde	6.49E-05	1.27E-01	1.60E-02	4.80E-01
Naphthalene	1.30E-07	2.55E-04	3.21E-05	9.61E-04
Polycyclic Organic Matter	2.20E-07	4.31E-04	5.43E-05	1.63E-03
Propylene Oxide	2.90E-06	5.68E-03	7.16E-04	2.14E-02
Toluene	1.30E-05	2.55E-02	3.21E-03	9.61E-02
Xylene	6.40E-06	1.25E-02	1.58E-03	4.73E-02

[1] The HAP emission factors for lean premix (LPM) combustion are based on the AP-42 (Section 3.1, April, 2000) diffusion flame emission factors and 90% reduction for LPM combustion.

Source: ECT, 2003.

Table B-4b. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants; 59 °F

Maximum Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours:	8,060	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	4.30E-08	7.89E-05	9.94E-06	3.18E-04
Acetaldehyde	4.00E-06	7.34E-03	9.24E-04	2.96E-02
Acrolein	6.40E-07	1.17E-03	1.48E-04	4.73E-03
Benzene	1.20E-06	2.20E-03	2.77E-04	8.87E-03
Ethylbenzene	3.20E-06	5.87E-03	7.39E-04	2.37E-02
Formaldehyde	6.49E-05	1.19E-01	1.50E-02	4.80E-01
Naphthalene	1.30E-07	2.38E-04	3.00E-05	9.61E-04
Polycyclic Organic Matter	2.20E-07	4.03E-04	5.08E-05	1.63E-03
Propylene Oxide	2.90E-06	5.32E-03	6.70E-04	2.14E-02
Toluene	1.30E-05	2.38E-02	3.00E-03	9.61E-02
Xylene	6.40E-06	1.17E-02	1.48E-03	4.73E-02

[1] The HAP emission factors for lean premix (LPM) combustion are based on the AP-42 (Section 3.1, April, 2000) diffusion flame emission factors and 90% reduction for LPM combustion.

Source: ECT, 2003.

Table B-4c. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants; 90 °F

Maximum Hourly Heat Input: (Case 4)	1,688	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours:	8,060	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	4.30E-08	7.26E-05	9.15E-06	3.18E-04
Acetaldehyde	4.00E-06	6.75E-03	8.51E-04	2.96E-02
Acrolein	6.40E-07	1.08E-03	1.36E-04	4.73E-03
Benzene	1.20E-06	2.03E-03	2.55E-04	8.87E-03
Ethylbenzene	3.20E-06	5.40E-03	6.81E-04	2.37E-02
Formaldehyde	6.49E-05	1.10E-01	1.38E-02	4.80E-01
Naphthalene	1.30E-07	2.19E-04	2.77E-05	9.61E-04
Polycyclic Organic Matter	2.20E-07	3.71E-04	4.68E-05	1.63E-03
Propylene Oxide	2.90E-06	4.90E-03	6.17E-04	2.14E-02
Toluene	1.30E-05	2.19E-02	2.77E-03	9.61E-02
Xylene	6.40E-06	1.08E-02	1.36E-03	4.73E-02

[1] The HAP emission factors for lean premix (LPM) combustion are based on the AP-42 (Section 3.1, April, 2000) diffusion flame emission factors and 90% reduction for LPM combustion.

Source: ECT, 2003.

Table B-5a. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing: Noncriteria Pollutants; 20 °F

Maximum Hourly Heat Input: (Case 1)	2,139	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours:	700	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	1.60E-05	3.42E-02	4.31E-03	1.13E-02
Arsenic	1.10E-05	2.35E-02	2.96E-03	7.76E-03
Benzene	5.50E-05	1.18E-01	1.48E-02	3.88E-02
Beryllium	3.10E-07	6.63E-04	8.35E-05	2.19E-04
Cadmium	4.80E-06	1.03E-02	1.29E-03	3.39E-03
Chromium	1.10E-05	2.35E-02	2.96E-03	7.76E-03
Formaldehyde	2.80E-04	5.99E-01	7.54E-02	1.97E-01
Lead	1.40E-05	2.99E-02	3.77E-03	9.87E-03
Manganese	7.90E-04	1.69E+00	2.13E-01	5.57E-01
Mercury	1.20E-06	2.57E-03	3.23E-04	8.46E-04
Naphthalene	3.50E-05	7.49E-02	9.43E-03	2.47E-02
Nickel	4.60E-06	9.84E-03	1.24E-03	3.24E-03
PAH	4.00E-05	8.55E-02	1.08E-02	2.82E-02
Selenium	2.50E-05	5.35E-02	6.74E-03	1.76E-02

[1] EPA AP-42 HAP Emission Factors, Section 3.1, April, 2000.

ECT, 2003.

Table B-5b. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing: Noncriteria Pollutants; 59 °F

100% Load Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours:	700	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	1.60E-05	3.22E-02	4.06E-03	1.13E-02
Arsenic	1.10E-05	2.22E-02	2.79E-03	7.76E-03
Benzene	5.50E-05	1.11E-01	1.40E-02	3.88E-02
Beryllium	3.10E-07	6.25E-04	7.87E-05	2.19E-04
Cadmium	4.80E-06	9.67E-03	1.22E-03	3.39E-03
Chromium	1.10E-05	2.22E-02	2.79E-03	7.76E-03
Formaldehyde	2.80E-04	5.64E-01	7.11E-02	1.97E-01
Lead	1.40E-05	2.82E-02	3.55E-03	9.87E-03
Manganese	7.90E-04	1.59E+00	2.01E-01	5.57E-01
Mercury	1.20E-06	2.42E-03	3.05E-04	8.46E-04
Naphthalene	3.50E-05	7.05E-02	8.89E-03	2.47E-02
Nickel	4.60E-06	9.27E-03	1.17E-03	3.24E-03
PAH	4.00E-05	8.06E-02	1.02E-02	2.82E-02
Selenium	2.50E-05	5.04E-02	6.35E-03	1.76E-02

[1] EPA AP-42 HAP Emission Factors, Section 3.1, April, 2000.

ECT, 2003.

Table B-5c. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing: Noncriteria Pollutants; 90 °F

100% Load Hourly Heat Input: (Case 7)	1,832	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours:	700	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	1.60E-05	2.93E-02	3.69E-03	1.13E-02
Arsenic	1.10E-05	2.02E-02	2.54E-03	7.76E-03
Benzene	5.50E-05	1.01E-01	1.27E-02	3.88E-02
Beryllium	3.10E-07	5.68E-04	7.16E-05	2.19E-04
Cadmium	4.80E-06	8.80E-03	1.11E-03	3.39E-03
Chromium	1.10E-05	2.02E-02	2.54E-03	7.76E-03
Formaldehyde	2.80E-04	5.13E-01	6.46E-02	1.97E-01
Lead	1.40E-05	2.57E-02	3.23E-03	9.87E-03
Manganese	7.90E-04	1.45E+00	1.82E-01	5.57E-01
Mercury	1.20E-06	2.20E-03	2.77E-04	8.46E-04
Naphthalene	3.50E-05	6.41E-02	8.08E-03	2.47E-02
Nickel	4.60E-06	8.43E-03	1.06E-03	3.24E-03
PAH	4.00E-05	7.33E-02	9.24E-03	2.82E-02
Selenium	2.50E-05	4.58E-02	5.77E-03	1.76E-02

[1] EPA AP-42 HAP Emission Factors, Section 3.1, April, 2000.

ECT, 2003.

Table B-6. TEC Bayside Power Station, SC Units 3A and 3B
CT Annual Emission Rates

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT-3A	4 - NG	8,060	69.1	278.5	30.5	122.8	3.0	12.2
CT-3B	4 - NG	8,060	69.1	278.5	30.5	122.8	3.0	12.2
CT-3A	4 - Oil	700	320.3	112.1	69.1	24.2	7.7	2.7
CT-3B	4 - Oil	700	320.3	112.1	69.1	24.2	7.7	2.7
		Totals	**N/A**	**781.2**	**N/A**	**293.9**	**N/A**	**29.8**

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM_{10}		SO_2		H_2SO_4		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT-3A	4 - NG	8,060	18.0	72.5	9.5	38.4	1.09	4.4	0.029	0.115
CT-3B	4 - NG	8,060	18.0	72.5	9.5	38.4	1.09	4.4	0.029	0.115
CT-3A	4 - Oil	700	34.0	11.9	101.5	35.5	11.66	4.1	0.098	0.034
CT-3B	4 - Oil	700	34.0	11.9	101.5	35.5	11.66	4.1	0.098	0.034
		Totals	**N/A**	**168.9**	**N/A**	**147.9**	**N/A**	**17.0**	**N/A**	**0.299**

1. CT-3A and CT-3B operating with natural gas-firing at a 92% capacity factor; 8,060 hours/year at base load (Case 4).
2. CT-3A and CT-3B operating with fuel oil-firing at a 8% capacity factor; 700 hours/year at base load (Case 4).
3. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
4. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: GE, 1998.
ECT, 2003.
TEC, 2003.

Table B-7. TEC Bayside Power Station, SC Units 3A and 3B
General Electric 7241FA CT
NSPS GG NO_x Limits

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

Sources: ECT, 2003.

Table B-8a. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			75 % Load			50 % Load		
Component	(lb/mole)	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.89	0.87	0.91	0.88	0.87	0.90	0.89	0.86
N_2	28.016	75.06	74.38	72.32	75.07	74.43	72.37	75.18	74.54	72.50
O_2	32.000	12.56	12.38	11.96	12.59	12.52	12.10	12.90	12.85	12.48
CO_2	44.010	3.87	3.87	3.80	3.85	3.80	3.73	3.71	3.65	3.56
H_2O	17.008	7.61	8.49	11.06	7.59	8.37	10.93	7.31	8.07	10.60
SO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.00	100.01	100.01	100.01	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.41	28.30	27.99	28.41	28.31	28.00	28.43	28.33	28.02
Exhaust Flow (lb/sec)		1,053.08	981.13	910.01	839.46	801.53	751.61	689.69	664.87	630.85
Exhaust Temp. (°F)		1,081	1,117	1,141	1,111	1,139	1,166	1,160	1,184	1,200
(K)		856	876	889	873	888	903	900	913	922
Exhaust O_2 (Vol %, Dry)		13.59	13.53	13.45	13.62	13.66	13.58	13.92	13.98	13.96

Sources: ECT, 2003.
GE, 1998.

Table B-8b. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,501,394	2,393,587	2,279,099	2,032,504	1,982,448	1,911,361	1,720,962	1,689,336	1,636,463
Velocity (fps)	151.0	144.5	137.6	122.7	119.7	115.4	103.9	102.0	98.8
Velocity (m/s)	46.0	44.0	41.9	37.4	36.5	35.2	31.7	31.1	30.1
SCFM, Dry[1]	791,825	733,365	668,502	631,260	599,825	552,825	519,904	498,776	465,339
ACFM (15% O_2, Dry)	2,861,380	2,736,637	2,560,494	2,316,258	2,227,959	2,110,800	1,887,869	1,822,012	1,720,949

Sources: ECT, 2003.
GE, 1998.

Table B-8c. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT
Natural Gas-Firing

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

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	8.9	9.0	9.0	8.8	8.8	9.1	8.8	8.9	9.2
CO (15% O_2)	7.2	7.2	7.1	7.1	7.2	7.3	7.4	7.6	7.8
VOC (ppmvw)	1.4	1.4	1.4	1.2	1.2	1.3	1.3	1.3	1.3
VOC (ppmvd)	1.5	1.5	1.6	1.3	1.3	1.5	1.4	1.4	1.5
VOC (15% O_2)	1.2	1.2	1.2	1.1	1.1	1.2	1.2	1.2	1.2

Sources: ECT, 2003.
GE, 1998.

Table B-9a. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			75 % Load			50 % Load		
Component	(lb/mole)	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.87	0.85	0.85	0.85	0.86	0.85	0.87	0.87	0.85
N_2	28.016	71.82	71.31	70.02	71.53	71.26	70.24	72.47	72.21	71.08
O_2	32.000	11.17	11.04	10.85	10.49	10.63	10.77	11.37	11.59	11.69
CO_2	44.010	5.61	5.61	5.50	6.02	5.88	5.59	5.60	5.40	5.12
H_2O	17.008	10.54	11.19	12.79	11.11	11.37	12.56	9.70	9.94	11.27
SO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.01	100.00	100.01	100.00	100.00	100.01	100.01	100.01	100.01
Exhaust MW (lb/mole)		28.30	28.22	28.02	28.28	28.23	28.06	28.40	28.35	28.16
Exhaust Flow (lb/sec)		1,085.99	1,021.29	941.25	811.85	784.24	751.05	677.70	667.94	645.91
Exhaust Temp. (°F)		1,067	1,098	1,130	1,184	1,195	1,200	1,200	1,200	1,200
(K)		848	865	883	913	919	922	922	922	922
Exhaust O_2 (Vol %, Dry)		12.49	12.43	12.44	11.80	11.99	12.32	12.59	12.87	13.17

Sources: ECT, 2003.
GE, 1998.

Table B-9b. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,565,225	2,468,510	2,338,219	2,066,743	2,012,963	1,945,329	1,734,167	1,712,182	1,666,850
Velocity (fps)	154.8	149.0	141.1	124.8	121.5	117.4	104.7	103.3	100.6
Velocity (m/s)	47.2	45.4	43.0	38.0	37.0	35.8	31.9	31.5	30.7
SCFM, Dry[1]	793,504	742,956	677,155	590,027	569,184	541,040	498,086	490,465	470,428
ACFM (15% O_2, Dry)	3,272,679	3,146,844	2,923,523	2,833,193	2,693,164	2,474,511	2,205,243	2,098,885	1,936,533

Sources: ECT, 2003.
GE, 1998.

Table B-9c. TEC Bayside Power Station, SC Unit 3A and 3B CT Exhaust Data - General Electric 7241FA CT Distillate Fuel Oil-Firing

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

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	20.3	20.1	19.9	25.4	24.2	23.9	33.8	33.3	39.7
CO (15% O_2)	14.2	14.0	13.9	16.5	16.0	16.4	24.0	24.5	30.3
VOC (ppmvw)	3.6	3.6	3.5	3.7	3.6	3.6	3.6	3.6	3.5
VOC (ppmvd)	4.0	4.1	4.0	4.2	4.1	4.1	3.9	3.9	3.9
VOC (15% O_2)	2.8	2.8	2.8	2.7	2.7	2.8	2.8	2.9	3.0

Table B-10. TEC Bayside Power Station, SC Unit 3A and 3B CT Fuel Flow Rate Data - General Electric 7241FA CT (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV[1] (MMBtu/hr)	1,960	1,834	1,688	1,572	1,487	1,383	1,255	1,193	1,116
Fuel Rate (lb/hr)	84,521	79,074	72,781	67,796	64,104	59,624	54,119	51,448	48,113
Fuel Rate (10^6 ft^3/hr)	1.913	1.790	1.647	1.534	1.451	1.349	1.225	1.164	1.089
Fuel Rate (lb/sec)	23.478	21.965	20.217	18.832	17.807	16.562	15.033	14.291	13.365

B. Distillate Fuel Oil-Firing

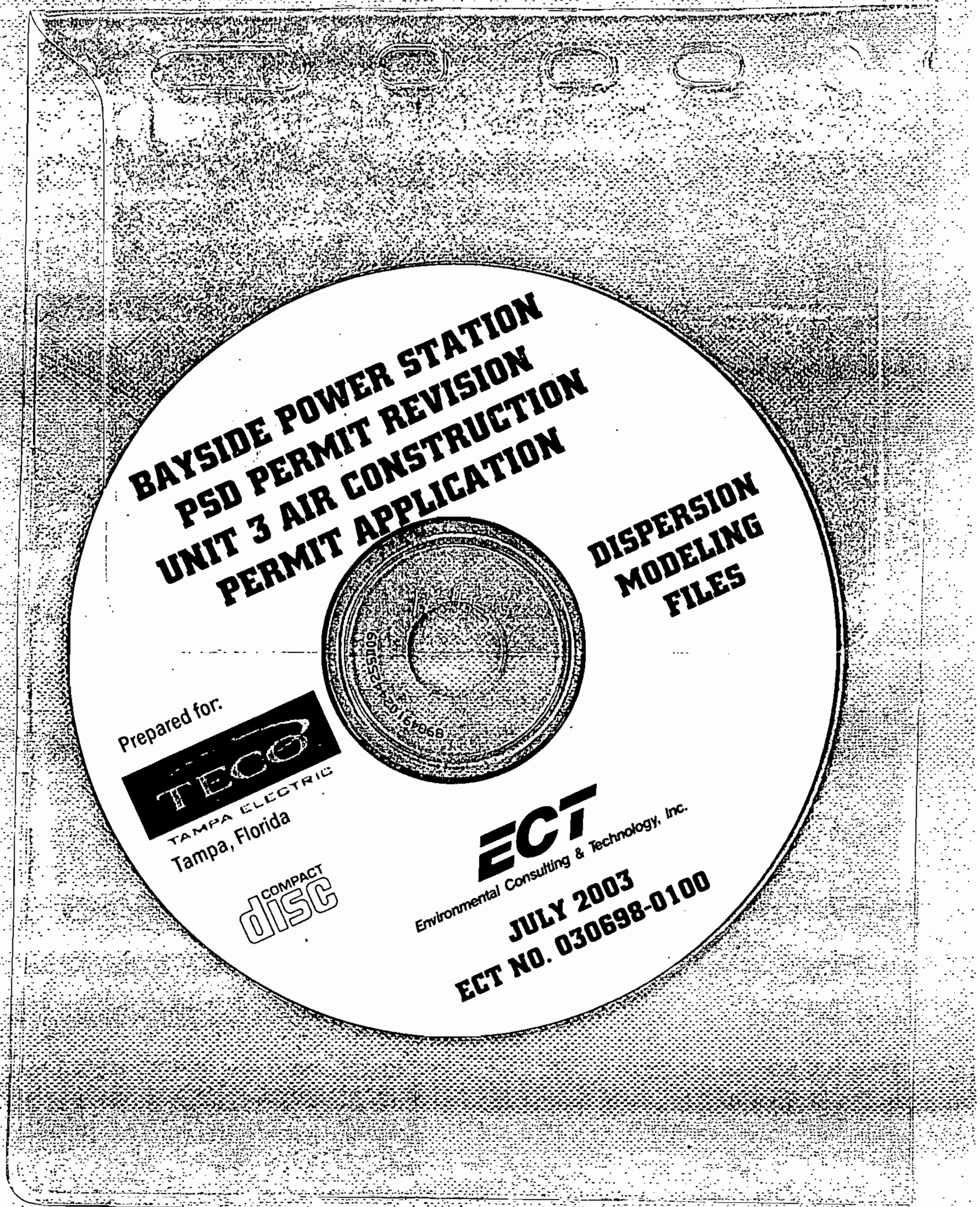
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV[1] (MMBtu/hr)	2,139	2,015	1,832	1,735	1,638	1,501	1,353	1,288	1,187
Fuel Rate (lb/hr)	107,764	101,532	92,336	87,438	82,517	75,612	68,180	64,922	59,832
Fuel Rate (10^3 gal/hr)	14.742	13.889	12.631	11.961	11.288	10.343	9.327	8.881	8.185
Fuel Rate (lb/sec)	29.935	28.203	25.649	24.288	22.921	21.003	18.939	18.034	16.620

[1] Includes a 3.5% margin to account for heat rate degradation over time.

Sources: ECT, 2003.
GE, 1998.

APPENDIX C

DISPERSION MODELING FILES


BAYSIDE POWER STATION
PSD PERMIT REVISION
UNIT 3 AIR CONSTRUCTION
PERMIT APPLICATION
DISPERSION
MODELING
FILES
Prepared for:
TECO
TAMPA ELECTRIC
Tampa, Florida
COMPACT
disc
ECT
Environmental Consulting & Technology, Inc.
JULY 2003
ECT NO. 030698-0100