BAYSIDE POWER STATION
UNITS 3 AND 4
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. 991060-0100

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) is planning to repower its existing F.J. Gannon Station located on Port Sutton Road in Tampa, Hillsborough Country, Florida.

The TEC F.J. Gannon Station consists of six steam boilers (Units 1 through 6), six steam turbines, one simple-cycle combustion turbine (CT-1), a once-through cooling water system, storage and handling of solid fuels, fluxing material, fly ash, and slag, fuel oil storage tanks and ancillary support equipment. 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.

TEC is proposing to repower Units 3 and 4 at the F.J. Gannon Station by installing four General Electric (GE) 7FA CT/heat recovery steam generator (HRSG) units that will operate in conjunction with the existing Units 3 and 4 steam turbines (STs). The four new CT/HRSG units will be grouped into two units designated as Bayside Power Station (Bayside) Units 3 and 4. Bayside Units 3 and 4 will repower F.J. Gannon Station Units 3 and 4, respectively. Bayside Unit 3 will include two CT/HRSGs designated as CT-3A and CT-3B. Bayside Unit 4 will include two CT/HRSGs designated as CT-4A and CT-4B.

The HRSGs included with each CT will be unfired (i.e., the HRSGs will not include provisions for supplemental duct burner firing). The CT/HRSG units will not include HRSG by-pass stacks. Each CT will be equipped with an inlet air evaporative cooling system and will be fired exclusively with pipeline-quality natural gas. Ancillary equipment associated with Bayside Units 3 and 4 include cooling towers. The anhydrous ammonia required for the Bayside Units 3 and 4 selective catalytic reduction (SCR) control systems will be provided by either new storage tanks or the ammonia storage tanks planned for Bayside Units 1 and 2.

Bayside Units 3 and 4 will operate at an annual capacity factor of up to 100-percent. At base load operation, this annual capacity factor is equivalent to 8,760 hours per year (hr/yr) operation.

Following installation and commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease. Following installation and commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease. All Bayside Units 3 and 4 CT/HRSG units will be equipped with selective catalytic reduction (SCR) technology to control emissions of nitrogen oxides (NO_x). With the exception of carbon monoxide (CO) and particulate matter (PM/PM_{10}), there will be a substantial net reduction in emissions of all pollutants subject to review under the Prevention of Significant Deterioration (PSD) New Source Review (NSR) permitting program due to the repowering of F.J. Gannon Station Units 3 and 4 with Bayside Units 3 and 4. The net increases in CO, PM, and PM_{10} emissions due to the repowering of F.J. Gannon Station Units 3 and 4 with Bayside Units 3 and 4 will exceed the PSD significant emission rate for these pollutants. Accordingly, Bayside Units 3 and 4 are subject to the PSD NSR requirements of Section 62-212.400, Florida Administrative Code (F.A.C.) for CO, PM, and PM_{10} emissions.

Operation of the proposed Bayside Units 3 and 4 will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the attachments, constitutes TEC's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, F.A.C.

Bayside Units 3 and 4 will be located in an attainment area and will have net CO, PM, and PM_{10} emissions increases in excess of 100, 25, and 15 tons per year (tpy), respectively. Consequently, Bayside Units 3 and 4 qualify as a major modification to an existing major facility and are subject to the PSD NSR requirements of Rule 62-212.400, F.A.C. for CO, PM, and 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, PM, and PM_{10}.
- Sections 5.0 (Dispersion Modeling Methodology) and 6.0 (Dispersion Modeling Results) address ambient air quality impacts.

Attachments A through D provide the FDEP Application for Air Permit—Long Form, NO_x control system descriptions, emission rate calculations, and PSD netting analysis, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in Attachment E.

1.2 SUMMARY

Bayside Units 3 and 4 will consist of four combined-cycle CT/HRSG units. The CTs will be fired exclusively with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf).

The planned construction start date for Bayside Units 3 and 4 is May 2002. The planned construction completion date for Bayside Units 3 and 4 is May 2004.

Based on an evaluation of the anticipated worst-case annual operating scenario, Bayside Units 3 and 4 will have the potential to emit 404.7 tpy of nitrogen oxides (NO_x), 502.8 tpy of carbon monoxide (CO), 355.7 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM/PM_{10}), 180.8 tpy of sulfur dioxide (SO_2), 49.1 tpy of volatile organic compounds (VOCs), and 0.51 tpy of lead. Regarding noncriteria pollutants, Bayside Units 3 and 4 will potentially emit 33.2 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of 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 repowering of F.J. Gannon Station Units 3 and 4 with Bayside Units 3 and 4 will be below the Table212.400-2, F.A.C. Significant Emission Rates for all regulated air pollutants, with the exception of CO, PM, and PM_{10}. Accordingly, Bayside Units 3 and 4 are subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for CO, PM, and PM_{10} only. Based on actual historical emission rates adjusted for the retroactive application of NO_x, SO_2, and PM BACT, the repowering of F.J. Gannon Station Unit 3 and 4 with new Bayside Units 3 and 4 will result in a net decrease of 567.1 tpy of nitrogen oxides (NO_x), 571.9 tpy of sulfur dioxide (SO_2) 2.4 tpy of lead (Pb), and a net increase of 278.7 tpy of CO and 258.5 tpy of PM_{10} and PM. 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 will be controlled by the exclusive use of pipeline quality natural gas.
- NO_x emissions will be controlled by the use of dry low-NO_x (DLN) combustors and the use of SCR control technology. The controlled NO_x CT/HRSG exhaust concentration will be 3.5 parts per million by volume corrected to 15-percent oxygen (ppmvd at 15-percent O_2).
- Advanced burner design and good operating practices to minimize incomplete combustion will be employed to control CO emissions. Maximum short-term CO CT/HRSG exhaust concentration will be 7.8 ppmvd at 15-percent O_2. Cost effectiveness of a CO oxidation catalyst control system was determined to be $3,302 per ton of CO. Due to the high control costs, in-

stallation 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 CT/HRSG VOC exhaust concentration is projected to be 1.3 ppmvd at 15-percent O_2.
- Bayside Units 3 and 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 Units 3 and 4 are 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).
- Analysis of the ambient air quality impacts due to operation of Bayside Units 3 and 4, together with the emissions associated with Bayside Units 1 and 2, demonstrates that maximum impacts will be well below all state and federal ambient air quality standards.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

Bayside Units 3 and 4 will be located at the existing Tampa Electric Company F.J. Gannon Station. The F.J. Gannon Station 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 F.J. Gannon Station site location and nearby prominent geographical features.

Bayside Units 3 and 4 will consist of four, combined-cycle GE PG7241 (FA) CTs. Each CT will be capable of producing a nominal 170 MW of electricity. The two Bayside Unit 3 combined-cycle CTs (designated as CT-3A and CT-3B) will repower F.J. Gannon Unit 3. Bayside Unit 3, including the repowered F.J. Gannon Station Unit 3 steam turbine (ST), will have a nominal generation capacity of 512 MW. The two Bayside Unit 4 combined-cycle CTs (designated as CT-4A and CT-4B) will repower F.J. Gannon Unit 4. Bayside Unit 4, including the repowered F.J. Gannon Station Unit 4 ST, will have a nominal generation capacity of 520 MW. The CTs will be fired exclusively with pipeline quality natural gas.

Bayside Units 3 and 4 will operate at an annual capacity factor of up to 100-percent. Capacity factor is defined as the ratio of the CT'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, this annual capacity factor is equivalent to 8,760 hours per year (hr/yr). The CTs will normally operate between 50- and 100-percent load.

Combustion of natural gas in the CTs 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 combined-cycle CTs include the use of DLN combustors and SCR control technology for abatement of NO_x; good combustion practices for control of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

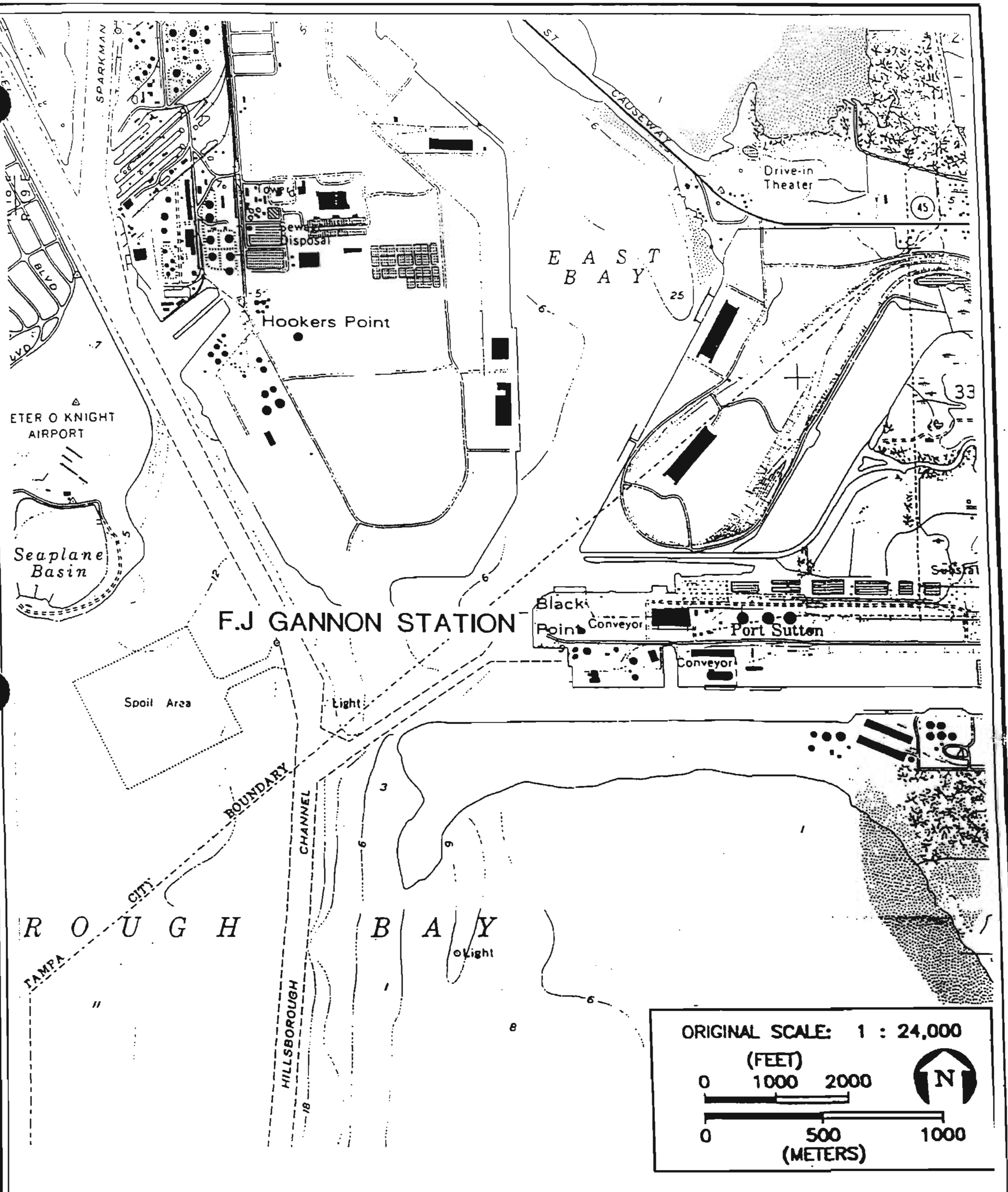

FIGURE 2-1.

F.J. GANNON STATION LOCATION AND SURROUNDINGS

3/4

Source: ECT, 2000.

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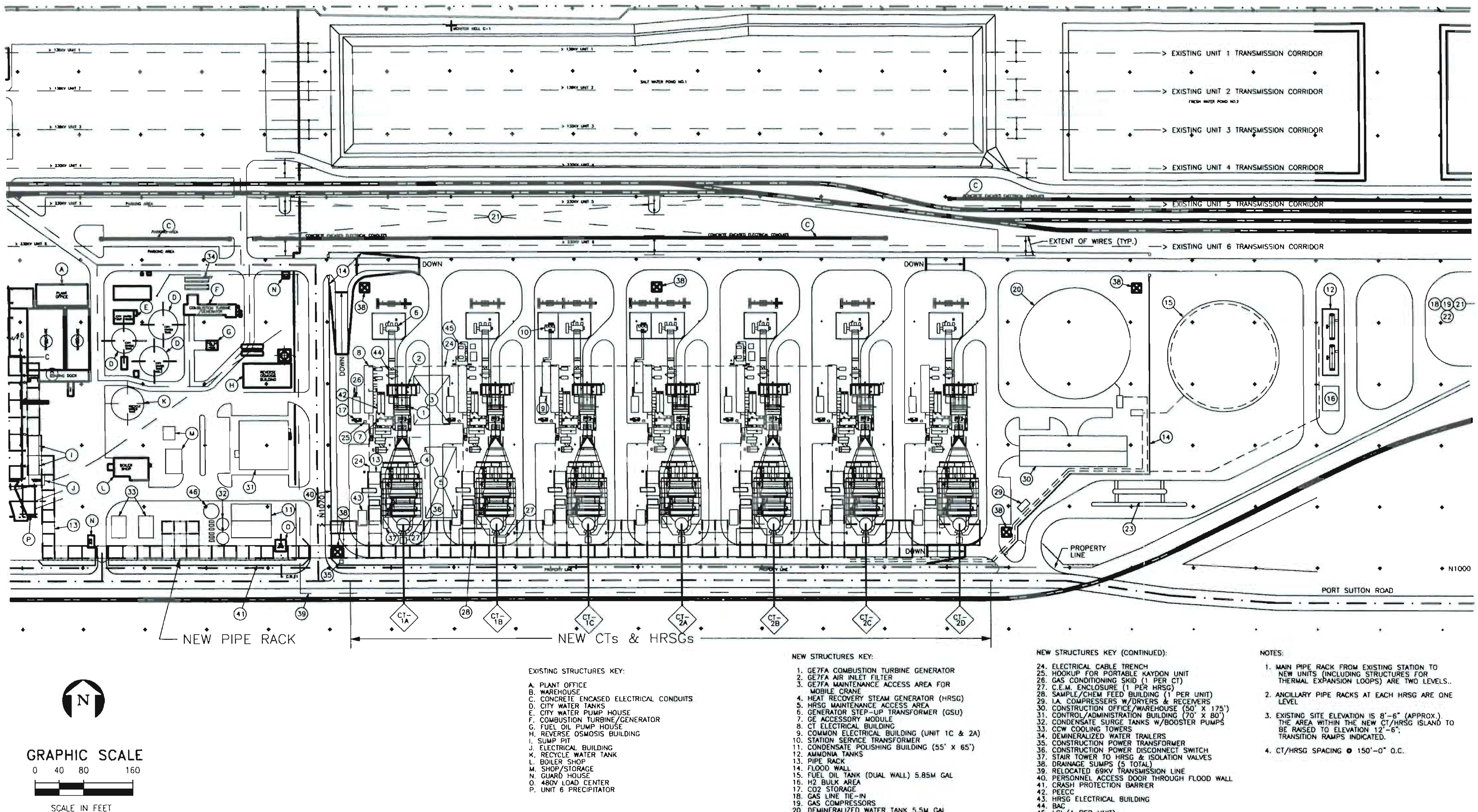
Figure 2-2 provides a plot plan of the Bayside Power Station showing the Bayside Units 3 and 4 layout, major process equipment and structures, and the new CT/HRSG emission points. A profile view of Bayside Units 3 and 4 is provided on Figure 2-3. Primary access to the Bayside Power Station will be from 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 Units 3 and 4 will include four nominal 170-MW CTs operating in combined-cycle mode. Figures 2-4 and 2-5 present process flow diagrams for Bayside Units 3 and 4, respectively.

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's turbine to produce rotary shaft power, which is used to drive an electric generator as well as the CT combustion air compressor.

The exhaust gases from each CT will then flow to a HRSG for the production of low-, intermediate-, and high-pressure steam. Steam produced by the two Bayside Unit 3 CT/HRSG units will be used to repower the existing F.J. Gannon Station Unit 3 ST. The Unit 3 ST, in turn, will drive an existing electric generator having a nominal generation capacity of 180 MW. Steam produced by the two Bayside Unit 4 CT/HRSG units will be used to repower the existing F.J. Gannon Station Unit 4 ST. The Unit 4 ST will drive an existing electric generator having a nominal generation capacity of 188 MW. The HRSGs will be unfired; i.e., the units will not include the capability of supplement duct burner



EXISTING STRUCTURES KEY:

A. PLANT OFFICE
B. WAREHOUSE
C. CONCRETE ENCASED ELECTRICAL CONDUITS
D. CITY WATER TANKS
E. CITY WATER PUMP HOUSE
F. COMBUSTION TURBINE/GENERATOR
G. FUEL OIL PUMP HOUSE
H. REVERSE OSMOSIS BUILDING
I. SUMP PIT
J. ELECTRICAL BUILDING
K. RECYCLE WATER TANK
L. BOILER SHOP
M. SHOP/STORAGE
N. GUARD HOUSE
O. 480V LOAD CENTER
P. UNIT 6 PRECIPITATOR

NEW STRUCTURES KEY:

1. GE7FA COMBUSTION TURBINE GENERATOR
2. GE7FA AIR INLET FILTER
3. GE7FA MAINTENANCE ACCESS AREA FOR MOBILE CRANE
4. HEAT RECOVERY STEAM GENERATOR (HRSG)
5. HRSG MAINTENANCE ACCESS AREA
6. GENERATOR STEP-UP TRANSFORMER (GSU)
7. GE ACCESSORY MODULE
8. CT ELECTRICAL BUILDING
9. COMMON ELECTRICAL BUILDING (UNIT 1C & 2A)
10. STATION SERVICE TRANSFORMER
11. CONDENSATE POLISHING BUILDING (55' X 65')
12. AMMONIA TANKS
13. PIPE RACK
14. FLOOD WALL
15. FUEL OIL TANK (DUAL WALL) 5.85M GAL
16. H2 BULK AREA
17. CO2 STORAGE
18. GAS LINE TIE-IN
19. GAS COMPRESSORS
20. DEMINERALIZED WATER TANK 5.5M GAL
21. CONSTRUCTION LAYDOWN
22. CONSTRUCTION PARKING

NEW STRUCTURES KEY (CONTINUED):

24. ELECTRICAL CABLE TRENCH
25. HOOKUP FOR PORTABLE KAYDON UNIT
26. GAS CONDITIONING SKID (1 PER CT)
27. C.E.M. ENCLOSURE (1 PER HRSG)
28. SAMPLE/CHEM FEED BUILDING (1 PER UNIT)
29. I.A. COMPRESSERS W/DRYERS & RECEIVERS
30. CONSTRUCTION OFFICE/WAREHOUSE (50' X 175')
31. CONTROL/ADMINISTRATION BUILDING (70' X 80')
32. CONDENSATE SURGE TANKS W/BOOSTER PUMPS
33. CCW COOLING TOWERS
34. DEMINERALIZED WATER TRAILERS
35. CONSTRUCTION POWER TRANSFORMER
36. CONSTRUCTION POWER DISCONNECT SWITCH
37. STAIR TOWER TO HRSG & ISOLATION VALVES
38. DRAINAGE SUMPS (5 TOTAL)
39. RELOCATED 69KV TRANSMISSION LINE
40. PERSONNEL ACCESS DOOR THROUGH FLOOD WALL
41. CRASH PROTECTION BARRIER
42. PEECC
43. HRSG ELECTRICAL BUILDING
44. BAC
45. LCI (1 PER UNIT)
46. POLISHER WASTE WATER TANK

NOTES:

1. MAIN PIPE RACK FROM EXISTING STATION TO NEW UNITS (INCLUDING STRUCTURES FOR THERMAL EXPANSION LOOPS) ARE TWO LEVELS..
2. ANCILLARY PIPE RACKS AT EACH HRSG ARE ONE LEVEL
3. EXISTING SITE ELEVATION IS 8'-6" (APPROX.). THE AREA WITHIN THE NEW CT/HRSG ISLAND TO BE RAISED TO ELEVATION 12'-6"; TRANSITION RAMPS INDICATED.
4. CT/HRSG SPACING @ 150'-0" O.C.

FIGURE 2-2.
BAYSIDE UNITS 1 AND 2 PLOT PLAN

Source: Sargent & Lundy, 2000.

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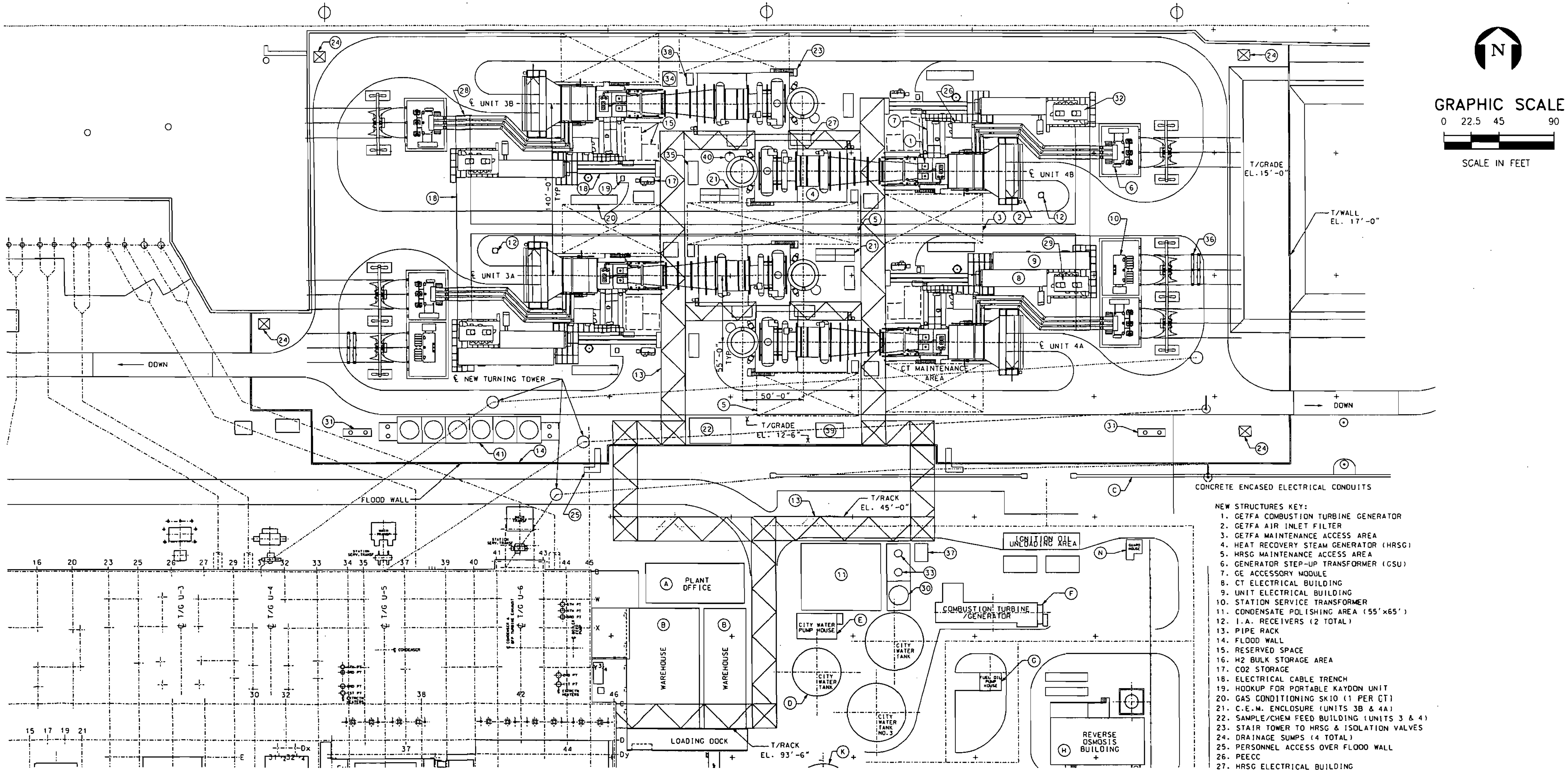

NEW STRUCTURES KEY:
1. GE7FA COMBUSTION TURBINE GENERATOR
2. GE7FA AIR INLET FILTER
3. GE7FA MAINTENANCE ACCESS AREA
4. HEAT RECOVERY STEAM GENERATOR (HRSG)
5. HRSG MAINTENANCE ACCESS AREA
6. GENERATOR STEP-UP TRANSFORMER (GSU)
7. GE ACCESSORY MODULE
8. CT ELECTRICAL BUILDING
9. UNIT ELECTRICAL BUILDING
10. STATION SERVICE TRANSFORMER
11. CONDENSATE POLISHING AREA (55'x65')
12. I.A. RECEIVERS (2 TOTAL)
13. PIPE RACK
14. FLOOD WALL
15. RESERVED SPACE
16. H2 BULK STORAGE AREA
17. CO2 STORAGE
18. ELECTRICAL CABLE TRENCH
19. HOOKUP FOR PORTABLE KAYDON UNIT
20. GAS CONDITIONING SKID (1 PER CT)
21. C.E.M. ENCLOSURE (UNITS 3B & 4A)
22. SAMPLE/CHEM FEED BUILDING (UNITS 3 & 4)
23. STAIR TOWER TO HRSG & ISOLATION VALVES
24. DRAINAGE SUMPS (4 TOTAL)
25. PERSONNEL ACCESS OVER FLOOD WALL
26. PEECC
27. HRSG ELECTRICAL BUILDING
28. BAC
29. LCI & EX2100 (UNITS 3B & 4B)
30. POLISHER WASTE WATER TANK
31. OIL/WATER SEPRATORS (2 TOTAL)
32. EX2100 (UNITS 3A & 4A)
33. ACID & CAUSTIC TANKS
34. METAL CLEANING SUMP
35. FEEDWATER PUMP
36. TRANSMISSION CCVT (UNITS 3B & 4B)
37. AMINE SKIDS
38. SCR SKID
39. WATER WASH SKID (UNITS 3A & 4B)
40. BLOWDOWN TANK
41. CCW COOLING TOWERS

FOR INITIAL REVIEW

PLANT ARRANGEMENT STILL UNDER DEVELOPMENT

HRSG STACK LOCATIONS

UNIT.	PLANT COORDINATES		STATE COORDINATES	
	NORTH	EAST	NORTH	EAST
3A	1700	3660	1299632.5650	520242.0058
3B	1840	3660	1299772.5622	520242.8847
4A	1645	3610	1299577.8800	520191.6614
4B	1785	3610	1299717.8772	520192.5404

EXISTING STRUCTURES KEY:
A. PLANT OFFICE
B. WAREHOUSE
C. COVERED CABLE CONCRETE TRENCH
D. CITY WATER TANKS
E. CITY WATER PUMP HOUSE
F. COMBUSTION TURBINE/GENERATOR
G. FUEL OIL PUMP HOUSE
H. REVERSE OSMOSIS BUILDING
I. NOT USED
J. NOT USED
K. RECYCLE WATER TANK
L. BOILER SHOP
M. NOT USED
N. GUARD HOUSE
O. NOT USED
P. NOT USED
R. NOT USED
S. NOT USED

FIGURE 2-2.
BAYSIDE UNITS 3 AND 4 PLOT PLAN

SOURCE: Sargent & Lundy, 2001.

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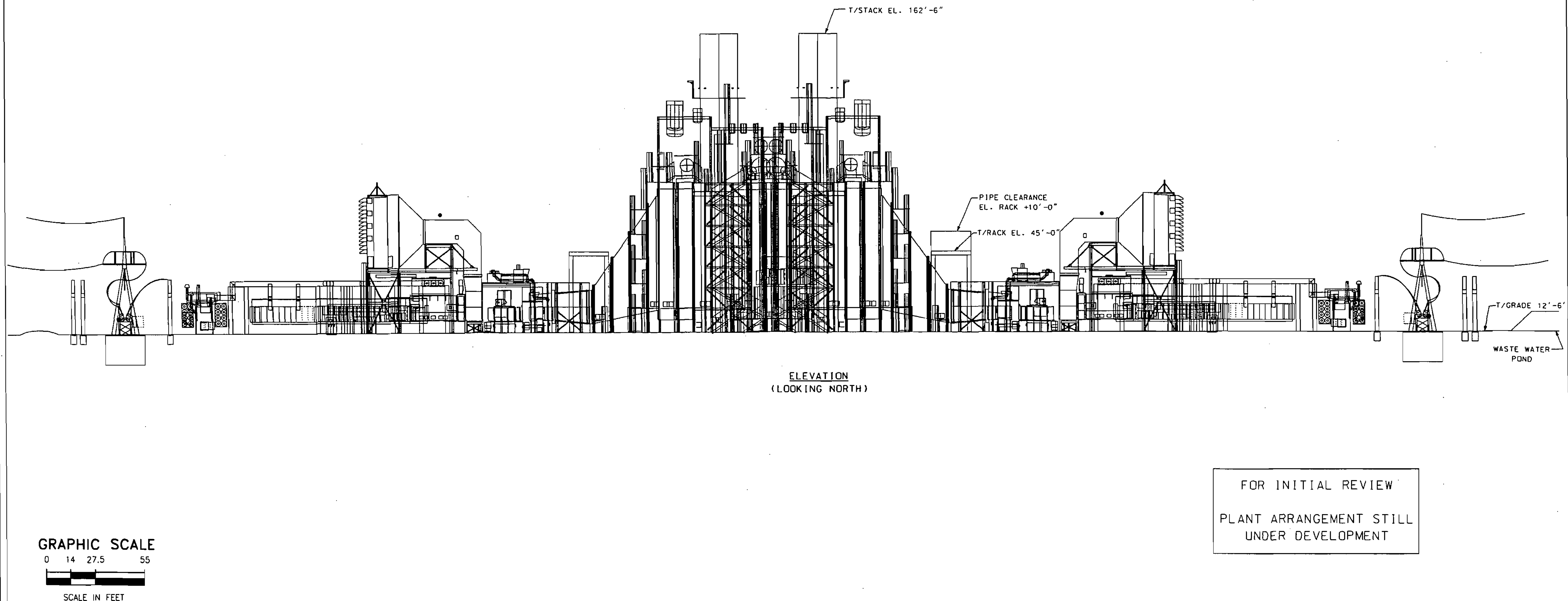

FIGURE 2-3.
BAYSIDE UNITS 3 AND 4 PROFILE

SOURCE: Sargent & Lundy, 2001.

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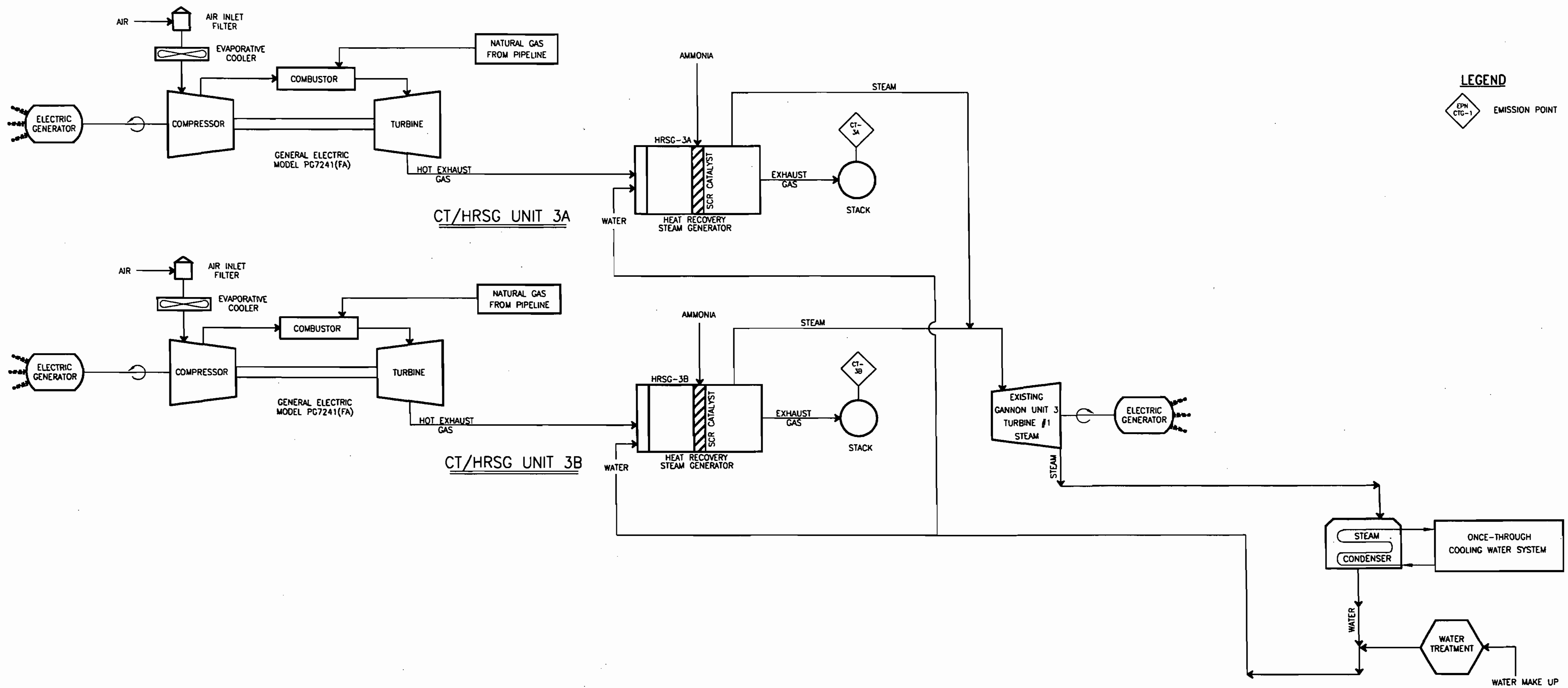

FIGURE 2-4.
PROCESS FLOW DIAGRAM - BAYSIDE UNIT 3

Source: TEC, 2001; ECT, 2001.

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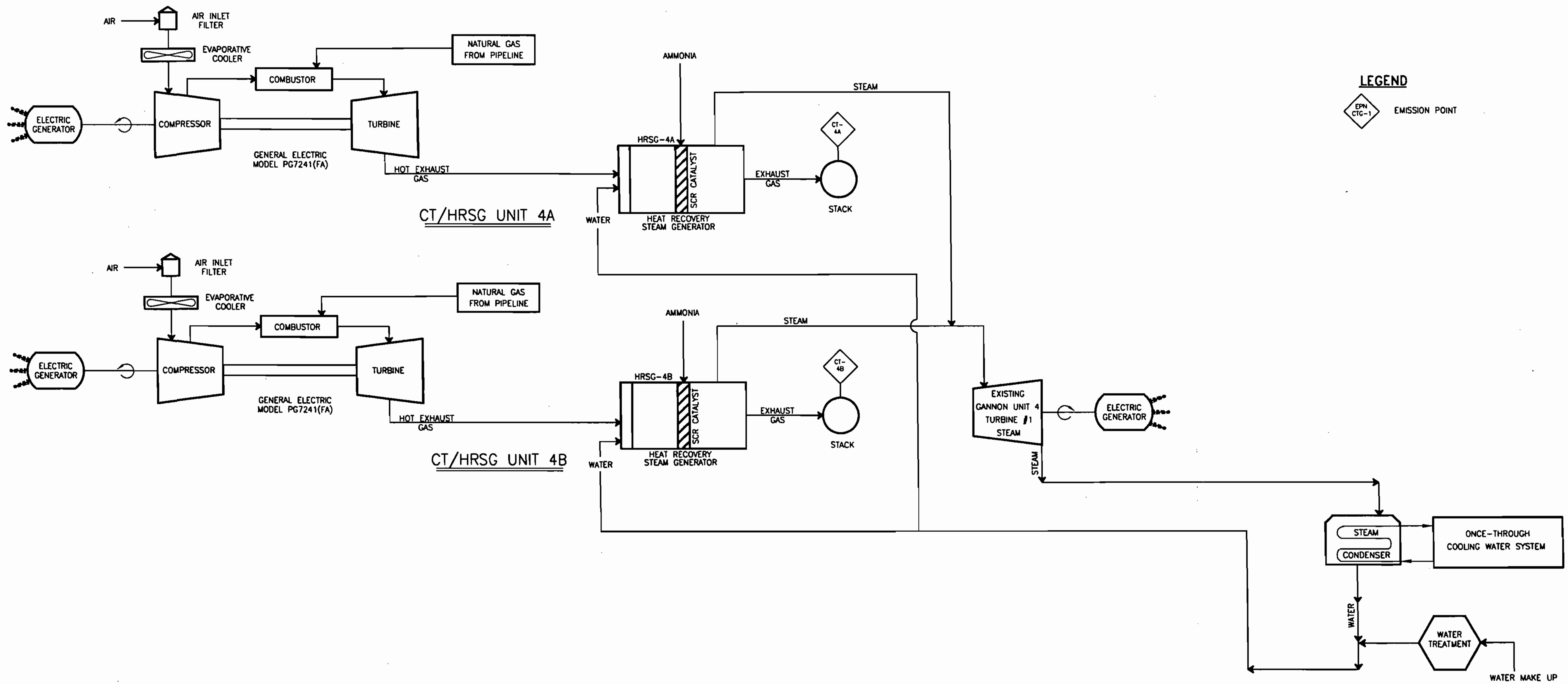

FIGURE 2-5.
PROCESS FLOW DIAGRAM - BAYSIDE UNIT 4

Source: TEC, 2001; ECT, 2001.

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firing. Following reuse of the CTs exhaust waste heat by the HRSGs, the exhaust gases are vented to the atmosphere.

Normal operation is expected to consist of all Bayside Units 3 and 4 CT/HRSGs firing natural gas at base load. Alternate operating modes include reduced load (i.e., between 50 and 100-percent of baseload) operation for one or more of the CT/HRSG units depending on power demands and CT inlet air evaporative cooling. CT/HRSG 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 Units 3 and 4 as specified in Section III., Condition 18.b. of Department Air Permit No. PSD-FL-301, Project No. 0570040-013-AC, recently issued for Bayside Units 1 and 2. As noted previously, the combined-cycle CT/HRSGs may operate at an annual capacity factor of up to 100-percent.

Vendor information indicates that the Bayside Unit 3 and 4 7FA CTs will have a heat input of 1,842 million British thermal units power hour (MMBtu/hr), higher heating value (HHV) at base load and 59°F ambient temperature. 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.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to start-up, shut-down, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CT/HRSG warm and cold start periods will last for 180 and 240 minutes, respectively, excess emissions for up to 4 hours in any 24-hour period are requested for the new CT/HRSGs. Excess emissions may also occur during a steam turbine cold startup. TEC therefore requests the same excess emission provisions for Bayside Units 3 and 4 as specified in Section III., Condition Nos. 18 and

25 of Department Air Permit No. PSD-FL-301, Project No. 0570040-013-AC, recently issued for Bayside Units 1 and 2.

The CTs will utilize DLN combustion technology and SCR to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTs 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

Table 2-1 provides maximum hourly criteria pollutant CT/HRSG emission rates (per CT/HRSG unit). Maximum hourly H_2SO_4 emission rates are summarized in Table 2-2. Maximum hourly noncriteria pollutant rates are provided in Table 2-3. 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 CT/HRSG.

Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for CT/HRSG operations at base load and low ambient temperature (i.e., 18°F). The bases for these emission rates are provided in Attachment C.

Table 2-4 presents projected maximum annual criteria and noncriteria emissions for Bayside Units 3 and 4. The maximum annualized rates were conservatively estimated assuming base load operation for 8,760 hr/yr and an ambient temperature of 59°F. As noted previously, coal fired operation at existing F.J. Gannon Station Units 3 and 4 will cease following commercial operation of Bayside Units 3 and 4. The net annual change in emissions associated with the F.J. Gannon Station repowering project are shown in Table 2-5. Stack parameters for the CT/HRSG units are provided in Table 2-6.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Four Temperatures (Per CT/HRGS)

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	18	20.5	2.58	11.1	1.39	24.7	3.11	31.1	3.92	3.0	0.38	0.031	0.0039
	59	20.3	2.56	10.3	1.30	23.1	2.91	28.7	3.62	2.8	0.35	0.029	0.0036
	72	20.3	2.56	10.1	1.27	22.6	2.85	27.8	3.50	2.7	0.34	0.028	0.0036
	93	20.2	2.55	9.8	1.23	21.9	2.76	26.9	3.39	2.7	0.34	0.027	0.0035
75	18	20.0	2.52	9.0	1.13	19.9	2.51	24.6	3.10	2.4	0.03	0.025	0.0032
	59	19.9	2.51	8.4	1.06	18.7	2.36	23.5	2.96	2.3	0.29	0.024	0.0030
	72	19.8	2.49	8.2	1.03	18.2	2.29	22.8	2.87	2.2	0.28	0.023	0.0029
	93	19.7	2.48	7.8	0.98	17.2	2.17	21.9	2.76	2.2	0.28	0.022	0.0028
50	18	19.6	2.47	7.2	0.91	15.8	1.99	20.4	2.57	2.0	0.25	0.020	0.0025
	59	19.5	2.46	6.8	0.85	14.8	1.86	19.5	2.46	1.9	0.24	0.019	0.0024
	72	19.5	2.46	6.6	0.83	14.4	1.81	19.1	2.41	1.8	0.23	0.018	0.0023
	93	19.4	2.44	6.2	0.79	13.7	1.73	18.6	2.34	1.8	0.23	0.018	0.0022

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

*As measured by EPA Reference Methods 201 and 202.

Sources: ECT, 2001.
S&L, 2001.

Table 2-2. Maximum H_2SO_4 Pollutant Emission Rates for Three Loads and Four Ambient Temperatures (Per CT/HRSG)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4	
		lb/hr	g/s
100	18	2.0	0.26
	59	1.9	0.24
	72	1.9	0.23
	93	1.8	0.23
75	18	1.6	0.21
	59	1.5	0.20
	72	1.5	0.19
	93	1.4	0.18
50	18	1.3	0.17
	59	1.2	0.16
	72	1.2	0.15
	93	1.1	0.14

Sources: ECT, 2001.
S&L, 2001.

Table 2-3. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load and Three Temperatures (Per CT/HRSG)

Unit Load (%)	Ambient Temp. (°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	18	0.00012	1.51E-05	0.085	1.07E-02	0.011	1.39E-03	0.036	4.54E-03	0.045	5.67E-03	0.225	2.84E-02
	59	0.00011	1.39E-05	0.079	9.95E-03	0.010	1.26E-03	0.034	4.28E-03	0.042	5.29E-03	0.210	2.65E-02
	93	0.00011	1.39E-05	0.075	9.45E-03	0.010	1.26E-03	0.032	4.03E-03	0.040	5.04E-03	0.199	2.51E-02

Unit Load (%)	Ambient Temp. (°F)	Mercury		Naphthalene		Polycyclic Aromatic Hydrocarbons		Propylene Oxide		Toluene		Xylene	
		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	18	1.5E-06	1.89E-07	0.0012	1.51E-04	0.0009	1.13E-04	0.056	7.09E-03	0.134	1.70E-02	0.128	1.62E-02
	59	1.4E-06	1.76E-07	0.0012	1.51E-04	0.0009	1.13E-04	0.053	6.71E-03	0.125	1.58E-02	0.120	1.52E-02
	93	1.4E-06	1.76E-07	0.0011	1.39E-04	0.0008	1.01E-04	0.050	6.33E-03	0.119	1.51E-02	0.114	1.44E-02

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

Source: ECT, 2001.

Table 2-4. Maximum Annual Emission Rates (tpy)

Pollutant	Bayside Units 3 and 4 (Both Units)
NO_x	404.7
CO	502.8
PM/PM_{10}*	355.7
SO_2	180.8
VOC	49.1
H_2SO_4 mist	33.2
1,3-Butadiene	0.002
Acetaldehyde	1.391
Acrolein	0.181
Benzene	0.590
Ethylbenzene	0.736
Formaldehyde	3.678
Lead	0.51
Mercury	0.000025
Naphthalene	0.020
Polycyclic Aromatic Hydrocarbons	0.015
Propylene Oxide	0.923
Toluene	2.194
Xylene	2.101

*As measured by EPA Reference Methods 201 and 202.

Sources: ECT, 2001.
TEC, 2001.
S&L, 2001.

Table 2-5. Net Annual Change in Emission Rates (tpy)

Pollutant	F.J. Gannon Station Units 3 & 4 Repowering Project
NO_x	-567.1
CO	278.7
PM/PM_{10}	258.5
SO_2	-571.9
VOC	-0.9
H_2SO_4 mist	-14.7
Pb	-2.4

Sources: ECT, 2001.
TEC, 2001.
S&L, 2000.

Table 2-6 Stack Parameters for Three Unit Loads and Four Ambient Temperatures (Per CT/HRSG)

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height meters	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter meters
100	18	150	45.7	233	385	66.3	20.2	19.0	5.8
	59	150	45.7	212	373	59.9	18.3	19.0	5.8
	72	150	45.7	215	375	59.0	18.0	19.0	5.8
	93	150	45.7	216	375	57.6	17.6	19.0	5.8
75	18	150	45.7	215	375	51.1	15.6	19.0	5.8
	59	150	45.7	212	373	49.0	14.9	19.0	5.8
	72	150	45.7	214	374	48.2	14.7	19.0	5.8
	93	150	45.7	215	375	46.5	14.2	19.0	5.8
50	18	150	45.7	201	367	41.5	12.6	19.0	5.8
	59	150	45.7	211	373	40.5	12.3	19.0	5.8
	72	150	45.7	213	374	40.1	12.2	19.0	5.8
	93	150	45.7	213	374	39.2	12.0	19.0	5.8

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

Sources: ECT, 2001.
S&L, 2001.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

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

Areas of the country in violation of NAAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The F.J. Gannon Station 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. 41 South and State Road 60 and a radius of 12 km, for SO_2, and for lead; the area encompassed within a radius of five km centered on 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 eight-hour ozone standard. However, due to litigation involving the new eight-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[10,11]	0.08	0.08	
NO_2 (ppmv)	Annual[2]	0.053	0.053	0.05
NO_2	Annual[2]			100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

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

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

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. 41 South and State Road 60 and a radius of 12 km), and for lead (the area encompassed within a radius of five 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

The Bayside Power Station will be located in Hillsborough County. As noted above, Hillsborough County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, Bayside Units 3 and 4 are 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 which 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 for the F.J. Gannon Station Units 3 and 4 repowering project will be below the significant emission rate thresholds, with the exception of CO, PM, and PM_{10}. Comparisons of estimated potential annual emission rates for the F.J. Gannon Units 3 and 4 repowering project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of all regulated PSD pollutants, with the exception of CO, PM, and PM_{10}, are projected to be below the applicable PSD significant emission rate levels. Therefore, Bayside Units 3 and 4 qualify as a major modification to a major facility and are subject to the PSD NSR requirements of Section 62-212.400, F.A.C. for CO, PM, and PM_{10} only. Attachment D provides a detailed PSD netting analysis for the repowering project.

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

Pollutant	Repowering Project Net Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	-567.1	40	No
CO	278.7	100	Yes
PM	258.5	25	Yes
PM_{10}	258.5	15	Yes
SO_2	-571.9	40	No
Ozone/VOC	-0.9	40	No
Lead	-2.4	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	-14.7	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

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2001.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

4.1 METHODOLOGY

The CO, PM, and 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 which were used to identify control alternatives include:

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

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

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA, 1996). Specific factors used in estimating capital and annual operating costs are summarized in Table 4-1.

Table 4-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 x control system cost
Freight	0.05 x control system cost
Instrumentation	0.10 x control system cost
Foundations and supports	0.08 x purchased equipment cost
Handling and erection	0.14 x purchased equipment cost
Electrical	0.04 x purchased equipment cost
Piping	0.02 x purchased equipment cost
Insulation	0.01 x purchased equipment cost
Painting	0.01 x purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 x purchased equipment cost
Construction and field expenses	0.05 x purchased equipment cost
Contractor fees	0.10 x purchased equipment cost
Start-up	0.02 x purchased equipment cost
Performance testing	0.01 x purchased equipment cost
Contingencies	0.03 x purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 x total operator labor cost
Maintenance labor	1.10 x operator labor direct wage
Maintenance materials	1.00 x total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 x total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 x total capital investment
Property taxes	0.01 x total capital investment
Insurance	0.01 x total capital investment

Source: ECT, 2001.
EPA, 1996.

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

As indicated in Section 3.3, Table 3-2, projected annual emission rates of CO, PM, and PM_{10} for Bayside Units 3 and 4 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 combustion products (PM/PM_{10}) and products of incomplete combustion (CO), 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 NSPS (40 CFR Part 60), NESHAP (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

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

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

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The Bayside Units 3 and 4 CTs 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} or CO.

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.

The Bayside Power Station 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 Units 3 and 4, 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 Units 3 and 4.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside Unit 3 and 4 CTs. 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 Units 3 and 4.

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 this fuel. Due to its low ash and sulfur contents, natural gas 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 have 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 and 4 CTs will be fired exclusively with natural gas. Combustion of natural gas will generate low PM/PM_{10} emissions in comparison to other fuels due to its low ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentration for the Bayside Units 3 and 4 CTs at baseload and 59°F is approximately 0.003 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

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 CTs, the use of good combustion practices and clean fuels is considered to be BACT. The Bayside Units 3 and 4 CTs 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 CTs will be fired exclusively with pipeline quality natural gas. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTs, the exclusive use of pipeline quality natural gas and efficient combustion design and operation is proposed as BACT for PM/PM_{10}. 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 4-2 summarizes the PM/PM_{10} BACT proposed for the Bayside Unit 3 and 4 CTs.

4.4 BACT ANALYSIS FOR CO

CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO 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 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 emissions.

An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO 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, combustion turbine vendors have had to con-

Table 4-2. Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)	Exclusive Use of Natural Gas Efficient Combustion Design and Operation 10.0 % Opacity [Indicator of Efficient Combustion Design and Operation]

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

sider the competing factors involved in NO_x and CO formation in order to develop units that achieve acceptable emission levels for both pollutants.

4.4.1 POTENTIAL CONTROL TECHNOLOGIES

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

Combustion Process Design

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

Oxidation Catalysts

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

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO 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. The catalyst inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a CO control efficiency of 80 to 90 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. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility

Both CT combustor design and oxidation catalyst control systems are considered to be technically feasible for the Bayside Units 3 and 4. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO is provided in the following sections.

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 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 CTs fired with natural gas.

Because CO emission rates from CTs 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 Units 3 and 4 (Hillsborough County) is classified attainment for all criteria pollutants, including CO. As noted in the Department's 1999 Air Monitoring Report, there have been no exceedances of the CO ambient air quality standards (AAQSs) in Florida during the last twelve years. Maximum CO concentrations for all Florida monitoring sites during 1999 were less than 30 percent of the 35 ppm one-hour AAQS, and less than 65 percent of the 9 ppm eight-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 3 and 4 CO emissions indicate that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest, second highest 1- and 8-hour average CO impacts during natural gas-firing (the exclusive fuel for the Bayside Units 3 and 4) are projected to be only 0.3 and 0.5 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 the Bayside Units 3 and 4 CTs is projected to have a pressure drop across the catalyst bed of approximately 1.1 inch of water (H_2O). This pressure drop will result in a 0.22 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 3,276,240 kilowatt-hours (kwh) (11,179 MMBtu) per year at baseload (170-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 42.6 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3) for all four CTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $393,149 per year for all four CTs.

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 4-3. Specific capital

Table 4-3. 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: ECT, 2001.
TEC, 2001.

and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-4 and 4-5, respectively.

The base case Bayside Units 3 and 4 annual CO emission rate (i.e., for all four CT /HRSG units) is 502.8 tpy based on CT baseload operation at 59°F for 8,760 hr/yr operation. The controlled annual CO emission rate, based on 90 percent control efficiency, is 50.3 tpy. Base case and controlled CO emission rates are summarized in Table 4-6.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $3,302 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible. For example, the California San Joaquin Valley Unified Air Pollution Control District's BACT policy considers CO control costs of less than $300 per ton to be cost effective; i.e., CO control costs equal to or greater than $300 per ton are not considered cost effective. Results of the oxidation catalyst economic analysis are summarized in Table 4-6.

4.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from CTs is typically required only for facilities located in CO nonattainment areas. A summary of recent FDEP CO BACT determinations for natural gas-fired combustion turbines is provided in Table 4-7.

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 CTs fired with natural gas. Because CO emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality, i.e., well below the defined PSD significant impact levels for CO.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion is proposed as BACT for CO. These control techniques have been considered by FDEP to represent BACT for CO for recent CT projects.

Table 4-4. Capital Costs for Oxidation Catalyst System, Four CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	2,812,000	A
Sales tax	168,720	0.06 x A
Instrumentation	281,200	0.10 x A
Freight	140,600	0.05 x A
Subtotal Purchased Equipment	**3,402,520**	**B**
Installation		
Foundations and supports	272,202	0.08 x B
Handling and erection	476,353	0.14 x B
Electrical	136,101	0.04 x B
Piping	68,050	0.02 x B
Insulation for ductwork	34,025	0.01 x B
Painting	34,025	0.01 x B
Subtotal Installation Cost	**1,020,756**	
Total Direct Costs (TDC)	**4,423,276**	
Indirect Costs		
Engineering	340,252	0.10 x B
Construction and field expenses	170,126	0.05 x B
Contractor fees	340,252	0.10 x B
Startup	68,050	0.02 x B
Performance test	34,025	0.01 x B
Contingency	102,076	0.03 x B
Total Indirect Costs (TIC)	**1,054,781**	
TOTAL CAPITAL INVESTMENT (TCI)	**5,478,057**	TDC + TIC

Source: ECT, 2001

Table 4-5. Annual Operating Costs for Oxidation Catalyst System, Four CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	2,774,784	
Credit for used catalyst	(374,400)	15% credit
Annualized Catalyst Costs	**585,431**	
Energy Penalties		
Turbine backpressure	393,149	0.2% penalty
Total Direct Costs (TDC)	**978,580**	
Indirect Costs		
Administrative charges	109,561	0.02 x TCI
Property taxes	54,781	0.01 x TCI
Insurance	54,781	0.01 x TCI
Capital recovery	296,805	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**515,927**	
TOTAL ANNUAL COST (TAC)	**1,494,507**	TDC + TIC

Sources: ECT, 2001
TEC, 2001

Table 4-6. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
Control Option	Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	11.5	50.3	452.5	5,478,057	1,494,507	3,302	44,716	N	Y
Baseline	114.8	502.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Four GE PG7241 (FA) CTs, 100-percent load for 8,760 hr/yr.

Sources: ECT, 2001.
GE, 2001.
TEC, 2001.

Table 4-7 Florida BACT CO Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
9/28/95	City of Key West	23	20	Good combustion
5/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
9/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB Off)	167	9	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB On)	167	24	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	20	Good combustion
10/8/99	Tampa Electric Company – Polk Power Station	165	15	Good combustion
10/8/99	TECO Power Services – Hardee Power Station	75	25	Good combustion
10/18/99	Vandolah Power Project	170	12	Good combustion
12/28/99	Reliant Energy Osceola	170	10.5	Good combustion
1/13/00	Shady Hills Generating Station	170	12	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB Off)	167	12	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB On)	167	20	Good combustion
2/24/00	Gainesville Regional Utilities	83	25	Good combustion
5/11/00	Calpine Osprey (Draft – DB Off)	170	10	Good combustion
5/11/00	Calpine Osprey (Draft – DB On)	170	17	Good combustion
7/31/00	Gulf Power – Smith Unit 3 (DB On)	170	16	Good combustion
1/29/01	CPV Gulfcoast, Ltd. (Power Augmentation Off)	170	9	Good combustion
1/29/01	CPV Gulfcoast, Ltd. (Power Augmentation On)	170	15	Good combustion
3/30/01	Tampa Electric Company – Bayside Units 1 & 2	170	9	Good combustion

Source: FDEP, 2001.

Maximum CO exhaust concentrations from the CT/HRSG units will be less than or equal to 9.0 ppmvd, respectively. This CO exhaust concentration is consistent with recent FDEP CO BACT determinations for CT/HRSG units. CO BACT emission limits proposed for Bayside Units 3 and 4 are provided in Table 4-8. The CO BACT limits shown in Table 4-8 are consistent with the limits recently approved by the Department for Bayside Units 1 and 2.

Table 4-8. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)		
CO (Natural Gas)	7.8‡ (9.0**)	28.7

* Corrected to 15 percent oxygen.
† CT compressor inlet air temperature of 59°F.
‡ 3-run test average determined by EPA Method 10.
** 24-hour block average using CO CEMS.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

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 Units 3 and 4 will have the potential to emit 404.7 tpy of NO_x, 502.8 tpy of CO, 355.7 tpy of PM/PM_{10}, 180.8 tpy of SO_2, 49.1 tpy of VOCs, and 33.2 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates increases for the F.J. Gannon Units 3 and 4 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 Units 3 and 4 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 request from the FDEP, an air quality impact analysis for Bayside Units 3 and 4 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 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 center line (for screening modeling, complex terrain is terrain above the height of the stack top). Terrain above the height of the stack top, but below the height of the plume center line, is defined as intermediate terrain.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the Bayside Power Station (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, assign-

Table 5-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
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

Sources: ECT, 2001.
TEC, 2001.

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." The entire perimeter of the F.J. Gannon Station/Bayside Power Station 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 dispersion modeling studies of the F.J. Gannon Station submitted to the 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.

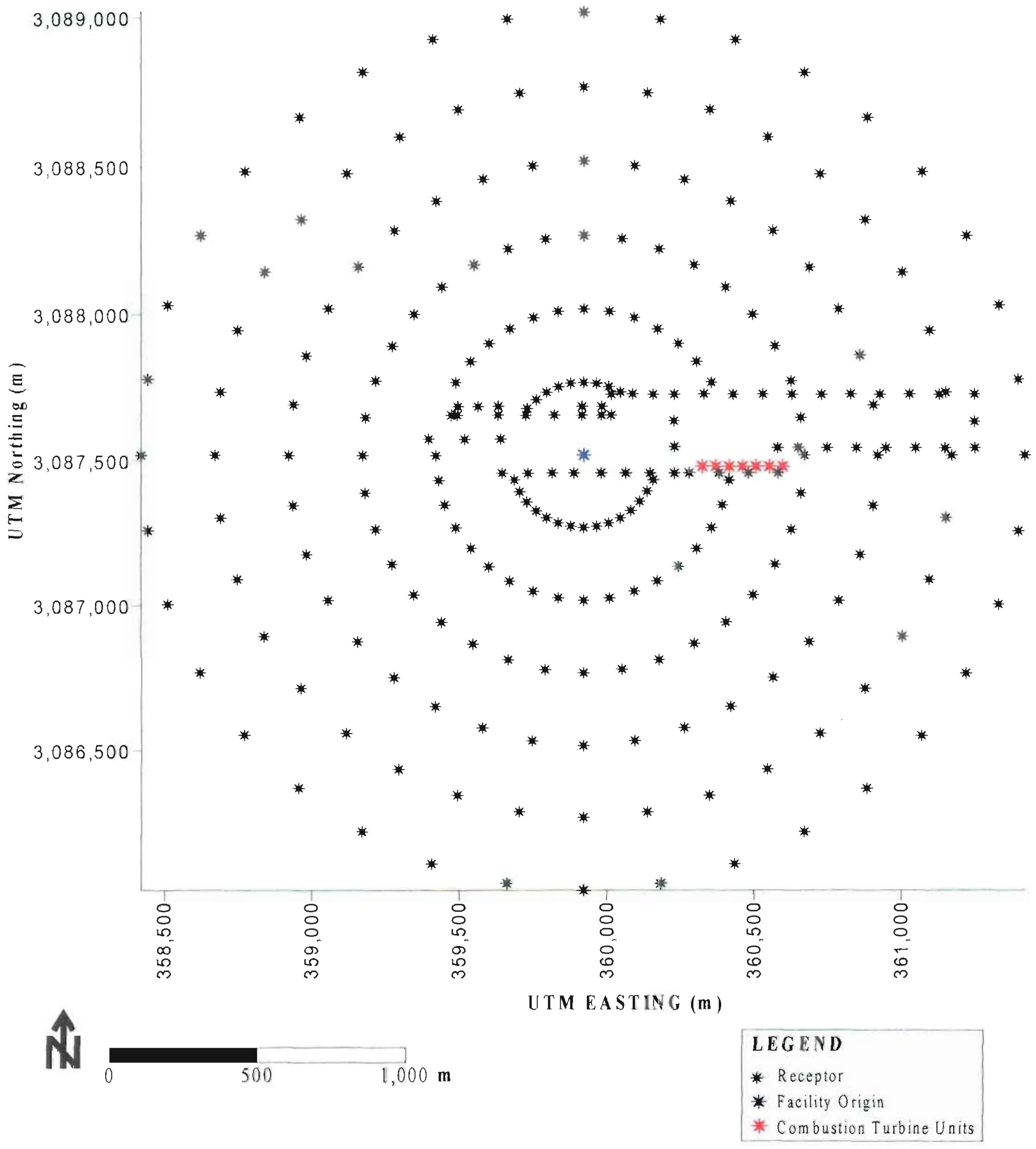

FIGURE 5-1.
RECEPTOR LOCATIONS (WITHIN 1,500 m)

ECT
Environmental Consulting & Technology, Inc.

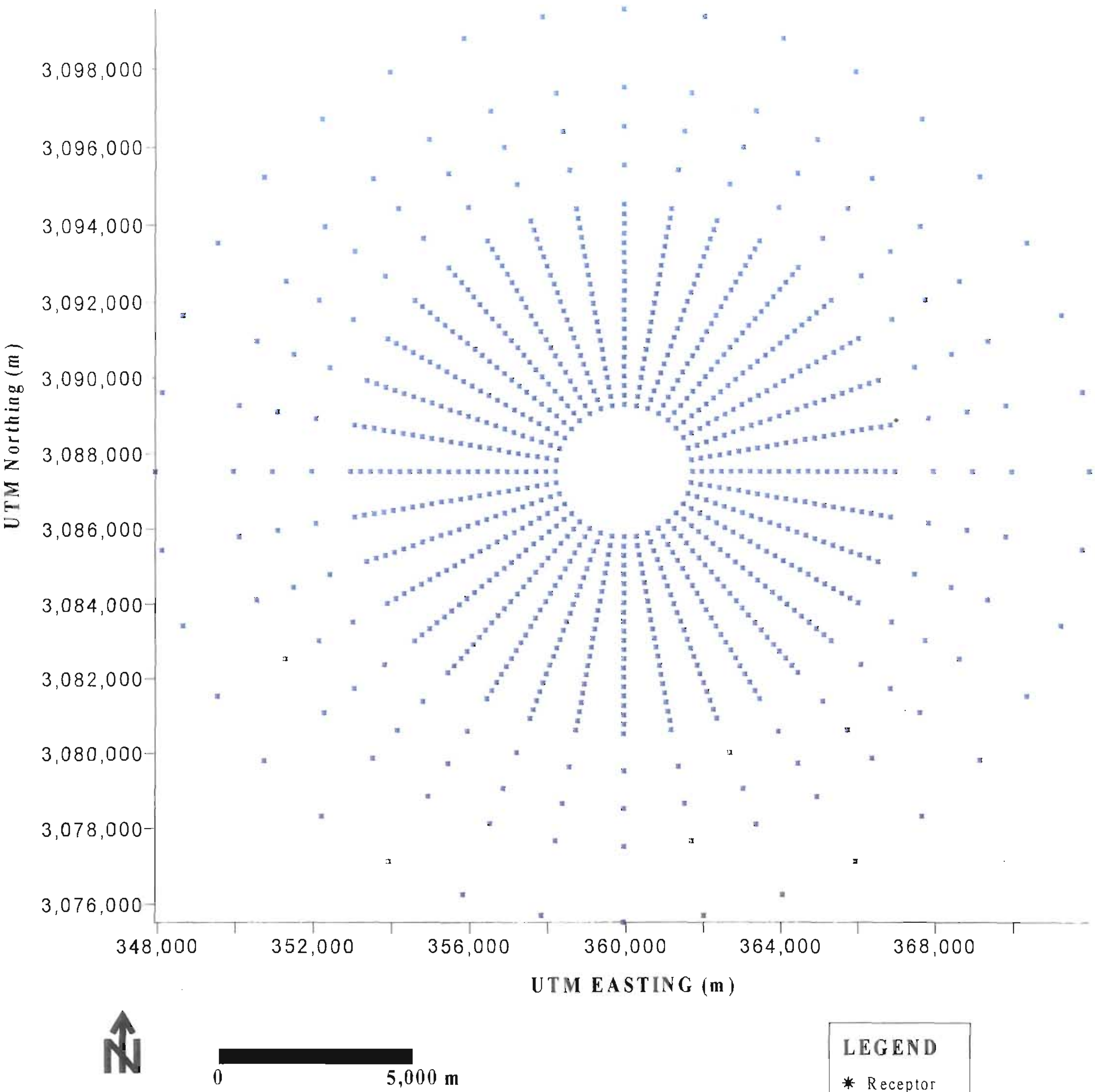

FIGURE 5-2.

RECEPTOR LOCATIONS (From 1,500m to 12 km)

ECT

Environmental Consulting & Technology, Inc.

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.

5.10 MODELED EMISSION INVENTORY

As requested by the Department, the modeled on-property emission sources consisted of the eleven Bayside Units 1 through 4 combined-cycle CT/HRSGs. Refined modeling was conducted for each of the 12 operating cases.

Emission rates and stack parameters for the Bayside Units 3 and 4 CT/HRSGs 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 12 Bayside Units 1 through 4 operating scenarios during natural gas-firing. These operating scenarios include three loads (50, 75, and 100 percent) and four ambient temperatures (18, 59, 72, and 93°F). ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts are summarized on Table 6-1.

Maximum highest, second highest (HSH) 3- and 24-hour SO_2 impacts are projected to be 91.3 and 22.9 $\mu g/m^3$, respectively. The 3-hour HSH SO_2 impact is 7.0 percent of the Federal and Florida 3-hour average Ambient Air Quality Standard (AAQS) of 1,300 $\mu g/m^3$. The 24-hour HSH SO_2 impact is 6.3 and 8.8 percent of the Federal and Florida 24-hour average AAQS of 365 and 260 $\mu g/m^3$, respectively. Maximum annual average SO_2 impact is projected to be 2.0 $\mu g/m^3$. This impact is 2.5 and 3.3 percent of the Federal and Florida annual average AAQS of 80 and 60 $\mu g/m^3$, respectively.

Maximum annual average NO_2 impact is projected to be 3.3 $\mu g/m^3$. This impact is 3.3 percent of the Federal and Florida annual average AAQS of 100 $\mu g/m^3$.

Maximum highest, second highest (HSH) 24-hour PM/PM_{10} impact is projected to be 58.9 $\mu g/m^3$. This impact is 39.3 percent of the 24-hour Federal and Florida AAQS of 150 $\mu g/m^3$. Maximum annual average PM/PM_{10} impact is projected to be 5.5 $\mu g/m^3$. This impact is 11.1 percent of the Federal and Florida annual average AAQS of 50 $\mu g/m^3$.

Maximum highest, second highest (HSH) 1- and 8-hour CO impacts are projected to be 261.5 and 174.8 $\mu g/m^3$, respectively. These impacts are 0.7 and 1.7 percent of the Federal and Florida 1- and 8-hour average AAQS of 40,000 and 10,000 $\mu g/m^3$, respectively.

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (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
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	621.3	625.4	632.3	613.1	615.7	739.9	743.9	735.2	747.8	732.4	1,017.5	953.4	966.4	1,003.4	939.3	675.8	680.6	676.7	670.1	658.9
HSH, 3-Hour ($\mu g/m^3$)	411.7	463.2	419.9	450.2	431.8	526.1	575.2	481.0	521.9	510.0	559.5	622.9	610.1	599.3	596.0	466.2	498.5	472.4	496.3	478.0
HSH, 8-Hour ($\mu g/m^3$)	227.7	251.6	264.5	275.8	267.6	258.7	275.5	322.6	336.6	325.3	284.4	292.7	375.8	358.7	325.8	234.2	252.8	282.0	309.7	295.7
HSH, 24-Hour ($\mu g/m^3$)	125.5	109.8	121.1	151.0	136.2	169.8	158.9	159.3	201.9	191.5	186.4	180.9	199.2	236.6	227.9	150.0	132.3	133.5	168.5	158.3
Annual ($\mu g/m^3$)	7.0	5.2	8.2	7.7	9.6	11.5	9.3	12.7	12.3	16.1	16.6	13.2	16.7	16.7	22.0	8.7	6.9	10.2	9.7	12.4
SO_2																				
Emission Rate (g/s)	1.39	1.39	1.39	1.39	1.39	1.13	1.13	1.13	1.13	1.13	0.91	0.91	0.91	0.91	0.91	1.30	1.30	1.30	1.30	1.30
HSH, 3-Hour ($\mu g/m^3$)	57.2	64.4	58.4	62.6	60.0	59.4	65.0	54.3	84.5	57.6	50.9	56.7	55.5	**91.3**	54.2	60.6	64.8	61.4	64.5	62.1
HSH, 24-Hour ($\mu g/m^3$)	17.5	15.3	16.8	21.0	18.9	19.2	18.0	18.0	22.8	21.6	17.0	16.5	18.1	21.5	20.7	19.5	17.2	17.4	21.9	20.6
Annual ($\mu g/m^3$)	1.0	0.7	1.1	1.1	1.3	1.3	1.0	1.4	1.4	1.8	1.5	1.2	1.5	1.5	**2.0**	1.1	0.9	1.3	1.3	1.6
NO_2																				
Emission Rate (g/s)	3.11	3.11	3.11	3.11	3.11	2.51	2.51	2.51	2.51	2.51	1.99	1.99	1.99	1.99	1.99	2.91	2.91	2.91	2.91	2.91
Tier 2 Annual ($\mu g/m^3$)	1.6	1.2	1.9	1.8	2.2	2.2	1.7	2.4	2.3	3.0	2.5	2.0	2.5	2.5	3.3	1.9	1.5	2.2	2.1	2.7
PM/PM_{10}																				
Emission Rate (g/s)	2.58	2.58	2.58	2.58	2.58	2.52	2.52	2.52	2.52	2.52	2.47	2.47	2.47	2.47	2.47	2.56	2.56	2.56	2.56	2.56
HSH, 24-Hour ($\mu g/m^3$)	32.4	28.3	31.2	39.0	35.1	42.8	40.0	40.1	50.9	48.3	46.0	44.7	49.2	58.4	56.3	38.4	33.9	34.2	43.1	40.5
Annual ($\mu g/m^3$)	1.8	1.4	2.1	2.0	2.5	2.9	2.3	3.2	3.1	4.1	4.1	3.3	4.1	4.1	5.4	2.2	1.8	2.6	2.5	3.2
CO																				
Emission Rate (g/s)	3.92	3.92	3.92	3.92	3.92	3.10	3.10	3.10	3.10	3.10	2.57	2.57	2.57	2.57	2.57	3.62	3.62	3.62	3.62	3.62
HSH, 1-Hour ($\mu g/m^3$)	243.5	245.1	247.9	240.3	241.3	229.4	230.6	227.9	231.8	227.0	**261.5**	245.0	248.4	257.9	241.4	244.6	246.4	245.0	242.6	238.5
HSH, 8-Hour ($\mu g/m^3$)	89.3	98.6	103.7	108.1	104.9	80.2	85.4	100.0	104.3	100.8	73.1	75.2	96.6	92.2	83.7	84.8	91.5	102.1	112.1	107.0

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 2 of 3)

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	807.0	774.2	765.4	792.4	760.9	1,016.6	954.7	966.7	1,003.6	940.7	681.5	685.4	679.6	675.7	662.6	819.4	777.8	772.3	805.1	765.9
HSH, 3-Hour ($\mu g/m^3$)	543.2	570.4	509.4	541.6	534.7	559.3	622.7	610.2	599.4	596.9	470.8	501.0	477.1	499.5	483.7	546.3	572.6	514.8	546.4	541.1
HSH, 8-Hour ($\mu g/m^3$)	272.2	285.1	355.2	358.3	333.4	284.7	294.9	375.4	358.9	326.0	235.4	254.5	285.1	311.3	297.7	273.6	286.2	357.5	360.3	335.0
HSH, 24-Hour ($\mu g/m^3$)	174.7	169.5	164.1	216.3	199.4	187.6	180.6	199.4	236.7	228.4	152.8	134.2	135.5	169.8	160.7	175.8	170.9	165.6	218.0	201.3
Annual ($\mu g/m^3$)	12.4	10.0	13.6	13.2	17.4	16.6	13.2	16.7	16.7	22.1	8.9	7.0	10.4	9.8	12.6	12.6	10.2	13.7	13.4	17.7
SO_2																				
Emission Rate (g/s)	1.06	1.06	1.06	1.06	1.06	0.85	0.85	0.85	0.85	0.85	1.27	1.27	1.27	1.27	1.27	1.03	1.03	1.03	1.03	1.03
HSH, 3-Hour ($\mu g/m^3$)	57.6	60.5	54.0	57.4	56.7	47.5	52.9	51.9	85.3	50.7	59.8	63.6	60.6	85.8	61.4	56.3	59.0	53.0	82.9	55.7
HSH, 24-Hour ($\mu g/m^3$)	18.5	18.0	17.4	**22.9**	21.1	15.9	15.3	17.0	20.1	19.4	19.4	17.0	17.2	21.6	20.4	18.1	17.6	17.1	22.5	20.7
Annual ($\mu g/m^3$)	1.3	1.1	1.4	1.4	1.8	1.4	1.1	1.4	1.4	1.9	1.1	0.9	1.3	1.3	1.6	1.3	1.0	1.4	1.4	1.8
NO_2																				
Emission Rate (g/s)	2.36	2.36	2.36	2.36	2.36	1.86	1.86	1.86	1.86	1.86	2.85	2.85	2.85	2.85	2.85	2.29	2.29	2.29	2.29	2.29
Tier 2 Annual ($\mu g/m^3$)	2.2	1.8	2.4	2.3	3.1	2.3	1.8	2.3	2.3	3.1	1.9	1.5	2.2	2.1	2.7	2.2	1.7	2.4	2.3	3.0
PM/PM_{10}																				
Emission Rate (g/s)	2.51	2.51	2.51	2.51	2.51	2.46	2.46	2.46	2.46	2.46	2.56	2.56	2.56	2.56	2.56	2.49	2.49	2.49	2.49	2.49
HSH, 24-Hour ($\mu g/m^3$)	43.8	42.5	41.2	54.3	50.0	46.1	44.4	49.1	58.2	56.2	39.1	34.4	34.7	43.5	41.1	43.8	42.5	41.2	54.3	50.1
Annual ($\mu g/m^3$)	3.1	2.5	3.4	3.3	4.4	4.1	3.2	4.1	4.1	5.4	2.3	1.8	2.7	2.5	3.2	3.1	2.5	3.4	3.3	4.4
CO																				
Emission Rate (g/s)	2.96	2.96	2.96	2.96	2.96	2.46	2.46	2.46	2.46	2.46	3.50	3.50	3.50	3.50	3.50	2.87	2.87	2.87	2.87	2.87
HSH, 1-Hour ($\mu g/m^3$)	238.9	229.2	226.5	234.6	225.2	250.1	234.8	237.8	246.9	231.4	238.5	239.9	237.9	236.5	231.9	235.2	223.2	221.6	231.1	219.8
HSH, 8-Hour ($\mu g/m^3$)	80.6	84.4	105.2	160.3	98.7	70.0	72.5	92.3	88.3	80.2	82.4	89.1	99.8	**174.8**	104.2	78.5	82.1	102.6	103.4	96.1

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 3 of 3)

	Case 9 (50% Load, 72°F Ambient)					Case 10 (100% Load, 93°F Ambient)					Case 11 (75% Load, 93°F Ambient)					Case 12 (50% Load, 93°F Ambient)					Maximums
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	
Nominal 10 g/s Impacts:																					
HSH, 1-Hour (µg/m^3)	1,020.5	958.9	970.7	1,007.7	944.6	691.0	694.0	685.8	687.5	670.7	856.8	796.4	809.1	842.8	798.4	**1,035.7**	974.2	985.9	1,023.1	958.2	**1,035.7**
HSH, 3-Hour (µg/m^3)	560.1	**623.6**	612.2	600.5	598.0	480.4	506.2	486.1	506.2	494.4	535.8	546.4	527.8	541.1	559.8	563.5	560.3	619.9	604.7	601.8	**623.6**
HSH, 8-Hour (µg/m^3)	285.9	297.6	376.0	359.8	326.3	237.9	258.2	291.0	314.6	302.1	275.2	261.6	347.7	341.0	334.6	290.0	311.8	**378.5**	367.9	310.8	**378.5**
HSH, 24-Hour (µg/m^3)	185.9	181.0	200.4	237.3	229.1	158.7	138.3	139.5	175.5	165.2	178.4	171.2	170.0	222.8	205.6	187.4	184.0	204.4	**241.3**	232.9	**241.3**
Annual (µg/m^3)	16.7	13.3	16.8	16.8	22.2	9.4	7.5	10.7	10.2	13.1	13.3	10.6	14.3	14.0	18.5	17.2	13.6	17.1	17.1	**22.7**	**22.7**
SO_2																					
Emission Rate (g/s)	0.83	0.83	0.83	0.83	0.83	1.23	1.23	1.23	1.23	1.23	0.98	0.98	0.98	0.98	0.98	0.79	0.79	0.79	0.79	0.79	**1.4**
HSH, 3-Hour (µg/m^3)	46.5	51.8	50.8	83.6	49.6	59.1	62.3	59.8	62.3	60.8	52.5	53.6	51.7	82.6	54.9	44.5	44.3	49.0	80.8	47.5	**91.3**
HSH, 24-Hour (µg/m^3)	15.4	15.0	16.6	19.7	19.0	19.5	17.0	17.2	21.6	20.3	17.5	16.8	16.7	21.8	20.1	14.8	14.5	16.1	19.1	18.4	**22.9**
Annual (µg/m^3)	1.4	1.1	1.4	1.4	1.8	1.2	0.9	1.3	1.3	1.6	1.3	1.0	1.4	1.4	1.8	1.4	1.1	1.4	1.4	1.8	**2.0**
NO_2																					
Emission Rate (g/s)	1.81	1.81	1.81	1.81	1.81	2.76	2.76	2.76	2.76	2.76	2.17	2.17	2.17	2.17	2.17	1.73	1.73	1.73	1.73	1.73	**3.1**
Tier 2 Annual (µg/m^3)	2.3	1.8	2.3	2.3	3.0	1.9	1.5	2.2	2.1	2.7	2.2	1.7	2.3	2.3	3.0	2.2	1.8	2.2	2.2	2.9	**3.3**
PM/PM_{10}																					
Emission Rate (g/s)	2.46	2.46	2.46	2.46	2.46	2.55	2.55	2.55	2.55	2.55	2.48	2.48	2.48	2.48	2.48	2.44	2.44	2.44	2.44	2.44	**2.6**
HSH, 24-Hour (µg/m^3)	45.7	44.5	49.3	58.4	56.4	40.5	35.3	35.6	44.8	42.1	44.2	42.4	42.2	55.3	51.0	45.7	44.9	49.9	**58.9**	56.8	**58.9**
Annual (µg/m^3)	4.1	3.3	4.1	4.1	5.5	2.4	1.9	2.7	2.6	3.4	3.3	2.6	3.6	3.5	4.6	4.2	3.3	4.2	4.2	**5.5**	**5.5**
CO																					
Emission Rate (g/s)	2.41	2.41	2.41	2.41	2.41	3.39	3.39	3.39	3.39	3.39	2.76	2.76	2.76	2.76	2.76	2.34	2.34	2.34	2.34	2.34	**3.9**
HSH, 1-Hour (µg/m^3)	245.9	231.1	233.9	242.9	227.6	234.3	235.3	232.5	233.1	227.4	236.5	219.8	223.3	232.6	220.4	242.4	228.0	230.7	239.4	224.2	**261.5**
HSH, 8-Hour (µg/m^3)	68.9	71.7	90.6	86.7	78.6	80.7	87.5	98.6	106.7	102.4	76.0	72.2	96.0	94.1	92.3	67.9	73.0	88.6	86.1	72.7	**174.8**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (µg/m^3)	91.3	3	1995	1,300	1,300	7.0	7.0
HSH, 24-Hour (µg/m^3)	22.9	5	1995	260	365	8.8	6.3
Annual (µg/m^3)	2.0	3	1996	60	80	3.3	2.5
NO_2							
Annual (µg/m^3)	3.3	3	1996	100	100	3.3	3.3
PM_{10}							
HSH, 24-Hour (µg/m^3)	58.9	12	1995	150	150	39.3	39.3
Annual (µg/m^3)	5.5	12	1996	50	50	11.1	11.1
CO							
HSH, 1-Hour (µg/m^3)	261.5	3	1992	40,000	40,000	0.7	0.7
HSH, 8-Hour (µg/m^3)	174.8	7	1995	10,000	10,000	1.7	1.7

Source: ECT, 2001.

APPENDIX A

APPLICATION FOR AIR PERMIT—

TITLE V SOURCE

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **F.J. Gannon/Bayside Power Station**	
3. Facility Identification Number: **0570040**	[ ] Unknown
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 Permitted Facility? [✔] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Patrick Shell** **Manager, Generation Projects**
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 – 5210** Fax: **(813) 641-5081**

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:____________________________________

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

Current construction permit number:____________________________________

Operation permit number to be revised:__________________________________

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

Operation permit number to be revised/corrected:__________________________

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

Operation permit number to be revised:__________________________________

Reason for revision:____

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Karen Sheffield, General Manager – Bayside Station**
2.	Application Contact Mailing Address: Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(813) 641-5400** Fax: **(813) 641-5418**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [✔], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Karen A. Sheffield 6/21/01 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

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

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature: [signature] Date: 6/15/01

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
026	Bayside Combustion Turbine Unit No. 3-A	AC1A	$7,500
027	Bayside Combustion Turbine Unit No. 3-B	AC1A	N/A
028	Bayside Combustion Turbine Unit No. 4-A	AC1A	N/A
029	Bayside Combustion Turbine Unit No. 4-B	AC1A	N/A

Application Processing Fee

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

Note: PSD review fee provided per Rule 62-4.050(4)(a)1., F.A.C.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **TEC is proposing to repower Units 3 and 4 at the F.J. Gannon Station by installing four General Electric (GE) 7FA combustion turbine (CT)/heat recovery steam generator (HRSG) units that will operate in conjunction with the existing Units 3 and 4 steam turbines (STs). The four new CT/HRSG units will be grouped into two units designated as Bayside Power Station (Bayside) Units 3 and 4. Bayside Units 3 and 4 will repower F.J. Gannon Station Units 3 and 4, respectively. Bayside Unit 3 will include two CT/HRSGs designated as CT-3A and CT-3B. Bayside Unit 4 will include two CT/HRSGs designated as CT-4A and CT-4B. The CTs will be fired exclusively with pipeline quality natural gas. The new combined-cycle CT/HRSGs will operate at an annual capacity factor of up to 100 percent.**
2. Projected or Actual Date of Commencement of Construction: **May 2002**
3. Projected Date of Completion of Construction: **May 2004**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **360.00**	North (km): **3,087.50**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):	Longitude (DD/MM/SS):		
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Adriano Alcoz, 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. Facility Contact Telephone Numbers: Telephone: **(813) 228-1111, Ext. 35095** Fax: **(813) 641-5566**

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

Previously submitted – see Title V permit application.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**	**N/A**	**N/A**	**N/A**	
SO2	**A**	**N/A**	**N/A**	**N/A**	
CO	**A**	**N/A**	**N/A**	**N/A**	
PM10	**A**	**N/A**	**N/A**	**N/A**	
PM	**A**	**N/A**	**N/A**	**N/A**	
SAM	**A**	**N/A**	**N/A**	**N/A**	
VOC	**A**	**N/A**	**N/A**	**N/A**	
PB	**B**	**N/A**	**N/A**	**N/A**	
HAPS	**A**	**N/A**	**N/A**	**N/A**	
H106 (HCl)	**A**	**N/A**	**N/A**	**N/A**	
H107 (HF)	**A**	**N/A**	**N/A**	**N/A**	

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
2. Facility Plot Plan: [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
3. Process Flow Diagram(s): [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [ ] Not Applicable [✔] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [✔] Attached, Document ID: [ ] Not Applicable **Air Construction Permit Application**	
7. Supplemental Requirements Comment: **Items 1, 2, 3, 4, and 5 above previously submitted - see F.J. Gannon Station Title V permit application.**	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

Items 8. through 15. above previously submitted – see F.J. Gannon Station Title V permit application.

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

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

4. Emissions Unit Identification Number: [✔] No ID
ID: **026 (CT 3-A)** [ ] ID Unknown

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

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **NO_x Controls** **Dry low-NO_x combustors** **Selective Catalytic Reduction (SCR)**	
2. Control Device or Method Code(s):	**025 (dry low-NO_x combustors)** **065 (catalytic reduction)**

Emissions Unit Details

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,841.7 (HHV)**	mmBtu/hr		
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):				
Maximum heat input is higher heating value (HHV) at 100 percent load, 59°F, operating conditions. Heat input will vary with load and ambient temperature.				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

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

Emission Point Description and Type

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

5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **19.0** feet
8. Exit Temperature: **212** °F	9. Actual Volumetric Flow Rate: **1,018,786** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Stack temperature and flow rate are at 100 percent load and 59°F ambient temperature operating conditions. Stack temperature and flow rate will vary with load and ambient temperature.**	

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.934**	5. Maximum Annual Rate: **16,941.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,025**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents higher heating value (HHV).**		

Segment Description and Rate: Segment ____ of ____

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

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	**025**	**065**	**EL**
2 – CO			**EL**
3 – PM			**EL**
4 – PM10			**EL**
5 – SO2			**EL**
6 – SAM			**EL**
7 – VOC			**EL**

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **24.7** lb/hour	**101.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **24.7 lb/hr** Reference: **Sargent & Lundy**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 23.1 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvd @ 15% O_2, 24-Hour Block Average**	4. Equivalent Allowable Emissions: **23.1** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 7E (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP/EPA Consent Agreement.** **Field 4 (23.1 lb/hr) equivalent allowable emissions is at a CT inlet air temperature of 59° F.** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **31.1** lb/hour **125.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **31.1 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 28.7 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **7.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **28.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Field 4 (28.7 lb/hr) equivalent allowable emissions is at a CT inlet air temperature of 59° F.**	

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9.0 ppmvd, 24-Hour Block Average**	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): **CO CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Field 3 (9.0 ppmvd) is corrected to 15% O_2.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **20.5** lb/hour **88.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **20.5 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 20.3 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **PM emissions data represents "front- and back-half" particulate matter as measured by EPA Reference Methods 201 and 202. PM and PM_{10} emissions are assumed to be equal.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **20.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **20.5** lb/hour **88.9** tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **20.5 lb/hr** Reference: **Sargent & Lundy**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 20.3 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **PM emissions data represents "front- and back-half" particulate matter as measured by EPA Reference Methods 201 and 202. PM and PM_{10} emissions are assumed to be equal.**		

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **20.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.1** lb/hour **45.1** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **11.1 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**

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

(2.0 gr S/100 scf) x (1.934 x 10^6 ft^3/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 11.1 lb/hr SO_2

Annual emissions based on 10.3 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **11.1** lb/hour **N/A** tons/year

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

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

Unit is also subject to less stringent fuel sulfur limits of 40 CFR Part 60, Subpart GG (NSPS).

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.0** lb/hour **8.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **2.0 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 1.9 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **2.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.0** lb/hour **12.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **3.0 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 2.8 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Clean Fuel and Good Operating Practices**	4. Equivalent Allowable Emissions: **3.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **N/A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

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

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

Continuous Monitoring System: Continuous Monitor 1 of 2

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **CO_2**	2. Pollutant(s):
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Specific CEMS information will be provided to FDEP when available.**	

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

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

Above items previously submitted, see F.J. Gannon Station Title V permit application.

NOTE:

EMISSION UNITS CT-3A, CT-3B, CT-4A, AND CT-4B ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 026 (CT-3A) IS ALSO APPLICABLE TO EU 027 (CT-3B), EU 028 (CT-4A), AND EU 029 (CT-4B).

EMISSIONS UNIT INFORMATION SECTIONS 2 THROUGH 7 ARE IDENTICAL TO SECTION 1, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

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-4B	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CT 3A-4B	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CT 3A-4B	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CT 3A-4B	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-4B	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CT 3A-4B	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-4B	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-4B	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-4B	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-4B	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CT 3A-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CT 3A-4B	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-4B	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CT 3A-4B	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CT 3A-4B	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-4B	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-4B	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-4B	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CT 3A-4B	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CT 3A-4B	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CT 3A-4B	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-4B	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-4B	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-4B	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CT 3A-4B	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CT 3A-4B	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CT 3A-4B	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CT 3A-4B	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CT 3A-4B	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CT 3A-4B	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CT 3A-4B	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-4B	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CT 3A-4B	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CT 3A-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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)
<u>Gas Composition</u>	
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
<u>Other Characteristics</u>	
Heat content (HHV)	1,020 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, 2001.

APPENDIX B

NITROGEN OXIDES
CONTROL SYSTEM DESCRIPTION

NITROGEN OXIDES CONTROL SYSTEM DESCRIPTIONS

A. Selective Catalytic Reduction

Selective catalytic reduction (SCR) technology will be used to control NO_x emissions from Bayside Units 3 and 4. SCR reduces NO_x emissions by reacting ammonia (NH_3) with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. NH_3 is injected upstream of the catalyst bed where the following primary reactions take place:

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

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

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

Reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. Due to these temperature constraints, the SCR catalyst modules will be located in the appropriate section of the HRSGs where temperatures are suitable for proper SCR operation.

A NH_3 injection grid will be located in the HRSG downstream of the high pressure steam drum and upstream of the SCR catalyst modules. This injection grid will be utilized to inject anhydrous ammonia into the CT exhaust stream. The NH_3 and NO_x (i.e., NO and NO_2) in the exhaust stream will then be adsorbed on the surface of the SCR catalyst and react catalytically to form N_2 and H_2O per reactions (1) and (2) above. The N_2 and H_2O formed is subsequently desorbed and discharged to the atmosphere with the CT exhaust stream.

The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions. The Bayside Units 3 and 4 SCR control systems are designed to achieve a target ammonia slip rate of no more than 5.0 ppmvd at 15% O_2. If the ammonia slip concentration exceeds 5.0 ppmvd at 15% O_2, additional ammonia slip testing will be taken in accordance with the additional ammonia slip testing requirements specified in Condition No. 24. of FDEP Project No. 0570040-013-AC, Air Permit No. PSD-FL-301 issued for Bayside Units 1 and 2. Corrective action will be taken prior to the ammonia slip exceeding 7.0 ppmvd at 15% O_2 in accordance this permit condition for Bayside Units 1 and 2.

APPENDIX C

EMISSION RATE CALCULATIONS

Table 1. Bayside Station - Units 3 and 4
Operating Scenarios - General Electric PG7241 (FA) CTs

Case	Ambient Temperature (oF)	Load (%)	CT 3A-3B CT 4A-4B Combined Cycle	Annual Profile (hr/yr)	Evaporative Cooling	Natural Gas Firing
1	18	100	X			X
2	18	75	X			X
3	18	50	X			X
4	59	100	X	8,760 (Gas)		X
5	59	75	X			X
6	59	50	X			X
7	72	100	X		X	X
8	72	75	X			X
9	72	50	X			X
10	93	100	X		X	X
11	93	75	X			X
12	93	50	X			X

Sources: TEC, 2001.
ECT, 2001.

Ta[illegible] Bayside Station - Units 3 and 4
Hourly Emission Rates - Natural Gas-Firing
General Electric 7FA CTs (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10} [a] (lb/hr)	PM/PM_{10} [a] (g/sec)	SO_2 [b] (lb/hr)	SO_2 [b] (g/sec)	H_2SO_4 [c] (lb/hr)	H_2SO_4 [c] (g/sec)	Lead [d] (lb/hr)	Lead [d] (g/sec)
18	1	100	20.5	2.58	11.1	1.39	2.0	0.26	0.0310	0.00390
	2	75	20.0	2.52	9.0	1.13	1.6	0.21	0.0251	0.00317
	3	50	19.6	2.47	7.2	0.91	1.3	0.17	0.0202	0.00254
59	4	100	20.3	2.56	10.3	1.30	1.9	0.24	0.0289	0.00364
	5	75	19.9	2.51	8.4	1.06	1.5	0.20	0.0236	0.00298
	6	50	19.5	2.46	6.8	0.85	1.2	0.16	0.0189	0.00239
72	7	100	20.3	2.56	10.1	1.27	1.9	0.23	0.0283	0.00356
	8	75	19.8	2.49	8.2	1.03	1.5	0.19	0.0230	0.00290
	9	50	19.5	2.46	6.6	0.83	1.2	0.15	0.0184	0.00232
93	10	100	20.2	2.55	9.8	1.23	1.8	0.23	0.0274	0.00345
	11	75	19.7	2.48	7.8	0.98	1.4	0.18	0.0218	0.00275
	12	50	19.4	2.44	6.2	0.79	1.1	0.14	0.0175	0.00220
		Maximums	**20.5**	**2.58**	**11.1**	**1.39**	**2.0**	**0.26**	**0.0310**	**0.00390**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd) [e]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd) [e]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd) [e][f]	VOC (lb/hr) [g]	VOC (g/sec)
18	1	100	3.5	24.7	3.11	7.2	31.1	3.92	1.2	3.0	0.38
	2	75	3.5	19.9	2.51	7.1	24.6	3.10	1.2	2.4	0.30
	3	50	3.5	15.8	1.99	7.4	20.4	2.57	1.3	2.0	0.25
59	4	100	3.5	23.1	2.91	7.2	28.7	3.62	1.2	2.8	0.35
	5	75	3.5	18.7	2.36	7.2	23.5	2.96	1.2	2.3	0.29
	6	50	3.5	14.8	1.86	7.6	19.5	2.46	1.3	1.9	0.24
72	7	100	3.5	22.6	2.85	7.1	27.8	3.50	1.2	2.7	0.34
	8	75	3.5	18.2	2.29	7.2	22.8	2.87	1.2	2.2	0.28
	9	50	3.5	14.4	1.81	7.6	19.1	2.41	1.3	1.9	0.24
93	10	100	3.5	21.9	2.76	7.1	26.9	3.39	1.2	2.7	0.34
	11	75	3.5	17.2	2.17	7.3	21.9	2.76	1.3	2.2	0.28
	12	50	3.5	13.7	1.73	7.8	18.6	2.34	1.3	1.8	0.23
		Maximums	**3.5**	**24.7**	**3.11**	**7.8**	**31.1**	**3.92**	**1.3**	**3.0**	**0.38**

[a] As measured by EPA Reference Methods 201 and 202.
[b] *Based on natural gas sulfur content of 2.0 gr/100 ft^3.*
[c] Based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
[d] AP-42, EPA, May 1998 - Draft.
[e] Corrected to 15% O_2.
[f] Non-mathane, non-ethane.
[g] *Expressed as methane.*

Sources: ECT, 2001.
S&L, 2001.

HAZARDOUS AIR POLLUTANT EMISSION FACTORS

Section 3.1 of AP-42, Stationary Gas Turbines, was revised in April 2000 to include natural gas-fired combustion turbine (CT) emission factors for eleven hazardous air pollutants (HAPs), including formaldehyde and toluene. The April 2000 AP-42 formaldehyde and toluene emission factors for natural gas-fired CTs are 7.1×10^{-4} and 1.3×10^{-4} lb/10^6 Btu, respectively.

As stated in the introduction to AP-42, the emission factors in AP-42 are "simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average)". Accordingly, the emission factors in AP-42 are generally appropriate for use in making areawide emission inventories. Because the AP-42 emission factors represent a source category population average, the factors do not necessarily reflect the emission rates for any particular member of that source category population.

In the case of the formaldehyde emission factor for natural gas-fired CTs, the April 2000 AP-42 emission factor is based on the average of 22 CT source tests. The CTs in the 22 source test database include small CTs (9 of the 22 CTs tested, or 40% of all units tested, had a rating of less than 15 MW), aircraft-derivative CTs (5 of the 22 CTs, or 23% of all units tested, were GE LM series aircraft-derivative CTs), and frame-type CTs. The largest CT of the 22 units tested was a GE Frame 7E unit with a rating of 87.8 MW. The average rating of the 22 CTs tested is 30.2 MW. The majority of the CTs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CT test database shows considerable variability in formaldehyde emission factors. The maximum formaldehyde emission factor (5.61×10^{-3} lb/10^6 Btu) is 2,538 times higher than the minimum factor (2.21×10^{-6} lb/10^6 Btu). Six of the 22 test series include runs for which there were no detectable emissions of formaldehyde.

The CTs proposed for Bayside Units 3 and 4 are GE Frame 7FA units each rated at a nominal 170 MW. During natural gas-firing, dry low-NO_x (DLN) combustor and SCR control technology will be employed to control NO_x emissions. Accordingly, the average April 2000 AP-42 formaldehyde emission factor for natural gas-fired CTs is not considered applicable to the GE 7FA CT. The GE 7FA CT is 5.5 times larger (i.e., has a rating of 170 vs. 30.6 MW) than the average CT included in the AP-42 CT database and is equipped with DLN and SCR control technology.

Evaluation of the AP-42 CT formaldehyde source test database shows that six of the units tested were large, frame-type CTs. Emission factors for these six CTs were averaged to develop a formaldehyde emission factor which is considered to be more representative of the GE 7FA units. This average factor for frame-type CTs, 1.14×10^{-4} lb/10^6 Btu, was used to estimate emissions of formaldehyde for Bayside Units 3 and 4.

A similar analysis was conducted with respect to the April 2000 AP-42 toluene emission factor for natural gas-fired CTs. The April 2000 AP-42 toluene emission factor is based on the average of 7 CT source tests. The CTs in the 7 source test database include small CTs (3 of the 7 CTs tested, or 43% of all units tested, had a rating of less than 15 MW), aircraft-derivative CTs (2 of the 7 CTs, or 29% of all units tested, were GE LM series aircraft-derivative CTs), and frame-type CTs. The largest CT of the 7 units tested was a GE Frame 7 unit with a rating of 75 MW. The average rating of the 7 CTs tested is 26.6 MW. The majority of the CTs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CT test database also shows variability in toluene emission factors. The maximum toluene emission factor (7.10×10^{-4} lb/10^6 Btu) is 67.6 times higher than the minimum factor (1.05×10^{-5} lb/10^6 Btu). Two of the 7 test series include runs for which there were no detectable emissions of toluene.

Evaluation of the AP-42 CT toluene source test database shows that two of the units tested were large, frame-type CTs. Emission factors for these two CTs were averaged to develop a toluene emission factor which is considered to be more representative of the GE 7FA units. This average factor for frame-type CTs, 6.80×10^{-5} lb/10^6 Btu, was used to estimate emissions of toluene for Bayside Units 3 and 4.

Average emission factors for frame-type CTs were developed for the remaining listed HAPs for natural gas-fired CTs using the same methodology as described above for formaldehyde and toluene.

Table 3. Bayside Station - Units 3 and 4
Natural Gas-Firing: Hazardous Air Pollutants

Parameter	Units	Case		
		100% - 18 °F	100% - 59 °F	100 % - 93 °F
Maximum Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,973.0	1,841.7	1,747.1
Maximum Annual Hours:	hrs/yr	N/A	8,760	N/A

Pollutant	Emission Factor [a][b] (lb/10^6 Btu)	Emission Rates (Per CT) 18 °F (lb/hr)	59 °F (lb/hr)	93 °F (lb/hr)	Annual (ton/yr)	Unit 3 Annual (ton/yr)	Unit 4 Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.00012	0.00011	0.00011	0.00049	0.0010	0.0010
Acetaldehyde	4.31E-05	0.085	0.079	0.075	0.348	0.70	0.695
Acrolein	5.60E-06	0.011	0.010	0.010	0.045	0.09	0.090
Benzene	1.83E-05	0.036	0.034	0.032	0.148	0.30	0.295
Ethylbenzene	2.28E-05	0.045	0.042	0.040	0.184	0.37	0.368
Formaldehyde	1.14E-04	0.225	0.210	0.199	0.920	1.84	1.839
Mercury	7.80E-10	0.0000015	0.0000014	0.0000014	0.0000063	0.000013	0.000013
Naphthalene	6.33E-07	0.0012	0.0012	0.0011	0.0051	0.010	0.010
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.0009	0.0009	0.0008	0.0038	0.008	0.008
Propylene Oxide	2.86E-05	0.056	0.053	0.050	0.231	0.461	0.461
Toluene	6.80E-05	0.134	0.125	0.119	0.549	1.097	1.097
Xylene	6.51E-05	0.128	0.120	0.114	0.525	1.050	1.050
Maximum Individual HAP		0.225	0.210	0.199	0.920	1.839	1.839
Total HAPs		0.723	0.675	0.641	2.958	5.915	5.915

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

Source: ECT, 2001.

Table 4A. Bayside Station
Annual Emission Rates - Unit 3

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates NO_x (lb/hr)	NO_x (tpy)	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)
2	4	8,760	46.2	202.4	57.4	251.4	5.60	24.5
		Totals	**N/A**	**202.4**	**N/A**	**251.4**	**N/A**	**24.5**

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates PM/PM_{10} (lb/hr)	PM/PM_{10} (tpy)	SO_2 (lb/hr)	SO_2 (tpy)	H_2SO_4 (lb/hr)	H_2SO_4 (tpy)	Lead (lb/hr)	Lead (tpy)
2	4	8,760	40.6	177.8	20.6	90.4	3.8	16.6	0.058	0.25
		Totals	**N/A**	**177.8**	**N/A**	**90.4**	**N/A**	**16.6**	**N/A**	0.25

1. Three CTs operating with natural gas-firing for 8,760 hours/year at base load (Case 4).
2. Natural gas SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
3. Natural gas H_2SO_4 rates based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 4B. Bayside Station
Annual Emission Rates - Unit 4

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
2	4	8,760	46.2	202.4	57.4	251.4	5.60	24.5
		Totals	**N/A**	**202.4**	**N/A**	**251.4**	**N/A**	**24.5**

No. of CTs	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)
2	4	8,760	40.6	177.8	20.6	90.4	3.8	16.6	0.058	0.25
		Totals	**N/A**	**177.8**	**N/A**	**90.4**	**N/A**	**16.6**	**N/A**	**0.25**

1. Four CTs operating with natural gas-firing for 8,760 hours/year at base load (Case 4).
2. Natural gas SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
3. Natural gas H_2SO_4 rates based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 4C. Bayside Station
Annual Emission Rates - Units 3 and 4

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4	4	8,760	92.4	404.7	114.8	502.8	11.20	49.1
		Totals	**N/A**	**404.7**	**N/A**	**502.8**	**N/A**	**49.1**

No. of CTs	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)
4	4	8,760	81.2	355.7	41.3	180.8	7.6	33.2	0.116	0.51
		Totals	**N/A**	**355.7**	**N/A**	**180.8**	**N/A**	33.2	**N/A**	0.51

1. Seven CTs operating with natural gas-firing for 8,760 hours/year at base load (Case 4).
2. Natural gas SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
3. Natural gas H_2SO_4 rates based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 5. Bayside Station - Units 3 and 4
Annual Hazardous Air Pollutants Emission Rates

Pollutant	Unit 3 Emissions (ton/yr)	Unit 4 Emissions (ton/yr)	Units 3 & 4 Emissions (ton/yr)
1,3-Butadiene	0.0010	0.0010	0.0020
Acetaldehyde	0.695	0.695	1.391
Acrolein	0.090	0.090	0.181
Benzene	0.295	0.295	0.590
Ethylbenzene	0.368	0.368	0.736
Formaldehyde	1.839	1.839	3.678
Mercury	0.000013	0.000013	0.000025
Naphthalene	0.010	0.010	0.020
Polycyclic Aromatic Hydrocarbons	0.008	0.008	0.015
Propylene Oxide	0.461	0.461	0.923
Toluene	1.097	1.097	2.194
Xylene	1.050	1.050	2.101
Maximum Individual HAP	1.839	1.839	3.678
Total HAPs	5.915	5.915	11.831

Source: ECT, 2001.

Table 6. Bayside Station - Units 3 and 4
Stack Parameters (Per CT/HRSG)
Natural Gas-Firing

Stack Height: 150.0 ft; 45.7 m

Stack Area: 283.5 ft^2; 26.3 m^2

Stack Diameter: 19.0 ft; 5.8 m

Case	Temperature		Flow Rate (actual)		Velocity	
	(°F)	(K)	(ft^3/min)	(m^3/min)	(ft/sec)	(m/s)
1	233	385	1,128,021	31,942	66.3	20.2
2	215	375	869,018	24,608	51.1	15.6
3	201	367	705,450	19,976	41.5	12.6
4	212	373	1,018,786	28,849	59.9	18.3
5	212	373	832,897	23,585	49.0	14.9
6	211	373	689,171	19,515	40.5	12.3
7	215	375	1,003,134	28,406	59.0	18.0
8	214	374	819,987	23,219	48.2	14.7
9	213	374	682,862	19,337	40.1	12.2
10	216	375	980,050	27,752	57.6	17.6
11	215	375	790,282	22,378	46.5	14.2
12	213	374	667,237	18,894	39.2	12.0

Sources: ECT, 2001.
S&L, 2001.

Table 7. Bayside Station Units 3 and 4
Fuel Flow Data - General Electric PG7241(FA); Per CTG

Natural Gas-Firing

	100 % Load				75 % Load				50 % Load			
	18 °F	59 °F	72 °F	93 °F	18 °F	59 °F	72 °F	93 °F	18 °F	59 °F	72 °F	93 °F
Case	1	4	7	10	2	5	8	11	3	6	9	12
Heat Input - LHV[1] (MMBtu/hr)	1,777.8	1,659.5	1,623.4	1,574.3	1,442.9	1,356.5	1,320.8	1,252.1	1,157.5	1,087.9	1,057.0	1,003.7
Heat Input - HHV (MMBtu/hr)	1,973.0	1,841.7	1,801.6	1,747.1	1,601.3	1,505.4	1,465.7	1,389.6	1,284.6	1,207.3	1,173.1	1,113.9
Fuel Rate[2] (lb/hr)	85,136	79,471	77,741	75,392	69,097	64,959	63,249	59,963	55,433	52,097	50,620	48,067
Fuel Rate[3] (10^6 ft^3/hr)	1.934	1.806	1.766	1.713	1.570	1.476	1.437	1.362	1.260	1.184	1.150	1.092
Fuel Rate (lb/sec)	23.649	22.075	21.595	20.942	19.194	18.044	17.569	16.656	15.398	14.471	14.061	13.352

[1] Includes a 3.5% margin to account for heat rate degradation over time.
[2] Natural gas heat content of 20,882 Btu/lb (LHV).
[3] Natural gas density of 0.0443 lb/ft^3.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 8. Bayside Station Units 3 and 4
General Electric PG7241(FA) CT
NSPS GG NO_x Limit

Fuel	PG7241(FA) Gas Turbine ISO Heat Rate (LHV)		FBN F	NO_x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Natural Gas	9,465	9.986	0.0	108.2

Sources: ECT, 2001.
GE, 2001.

APPENDIX D
PSD NETTING ANALYSIS

Bayside Units 3 and 4 PSD Netting Analysis

The procedures for determining applicability of the PSD NSR permitting program to modifications planned at existing major Florida facilities are specified in Rule 62-212.400(2)(d)4., F.A.C. Because the existing F.J. Gannon Station is a major facility (i.e., has potential emissions of 100 tpy or more of an air pollutant subject to regulation under Chapter 403, Florida Statutes) that would be subject to PSD preconstruction review if it were itself a proposed new facility (i.e., has potential emissions of 100 tpy or more of a pollutant regulated under the Clean Air Act and is located in an attainment area), modifications to the existing F.J. Gannon Station which result in a *significant net emissions increase* of any pollutant regulated under the Clean Air Act are subject to PSD NSR.

The term "significant net emission increase" is defined by Rule 62-212.400(2)(e), F.A.C. For each regulated pollutant, the net emission increase for a modification project is equal to the sum of the increases in emissions associated with the proposed project plus all facility-wide creditable, contemporaneous emission increases minus all facility-wide creditable, contemporaneous emission decreases. If this net emissions increase is equal to or greater than the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates, then the net emission increase is considered to be "significant" and the modification will be subject to PSD NSR for that particular regulated pollutant.

In accordance with Rule 62-212.400(2)(e)3., F.A.C., the "contemporaneous" period for a modification project begins five years prior to the date of submittal of a complete permit application and ends when the new or modified emission units are estimated to begin operation.

In accordance with Rule 62-212.400(2)(e)4., F.A.C., contemporaneous emission increases and decreases are "creditable" if:

(1) the emission increase or decrease will affect PSD increment consumption; i.e., will consume or expand the available increment;

(2) The emission increase or decrease was not previously considered in the issuance of a PSD NSR permit (to avoid "double counting"); and

(3) The FDEP has not relied on the emission increase or decrease in attainment or reasonable further progress demonstrations.

Contemporaneous emission increases and decreases are based on *actual* emission rates. The term "actual emissions" is defined by Rule 62-210.200(12), F.A.C. For new emission units, including new electric utility steam generating units, actual emissions are equal to potential emissions. For changes to existing emission units, actual emissions are generally the actual average emission rates, in tpy, for the two year period preceding the change and which are representative of normal operations. The Department may allow the use of a different time period if it is determined that the other time period is more representative of the normal operation of an emissions unit.

For emission decreases, the old level of actual or allowable emissions (whichever is lower) must be greater than the new level of actual emissions. The actual emission decrease must also take place on or before the date that emissions from the modification project first occur and must be federally enforceable on and after the date the Department issues a construction permit for the modification project.

For Bayside Units 3 and 4, the contemporaneous period is projected to begin in March 1996 and end in June 2005. Creditable emission decreases that will occur within this contemporaneous period consist of the actual emissions associated with the cessation of coal-fired operations of F.J. Gannon Station Units 3 and 4. Creditable emission increases consist of those associated with Bayside Units 3 and 4. Emission decreases and increases associated with the Bayside Units 1 and 2 Repowering Project (i.e., decreases associated with the cessation of coal-fired operations of F.J. Gannon Station Units 5 and 6 and increases associated with Bayside Units 1 and 2) are not creditable because they have been relied on in the issuance of the PSD NSR permit for Bayside Units 1 and 2. There are no other creditable emission increases that have occurred or will occur at the F.J. Gannon Station during the March 1996 through June 2005 contemporaneous period.

Summaries of historical, actual emission rates for F.J. Gannon Station Units 3 and 4 for the 1996 – 2000 five year period are provided on Tables 1 and 2, respectively.

Table 3 provides an analysis of PSD NSR applicability for Bayside Units 3 and 4. Contemporaneous, creditable emission decreases were determined based on the average actual emissions for F.J. Gannon Station Units 3 and 4 for the 1999/2000 two-year period. These actual emission rates reflect the retroactive application of NO_x, SO_2, and PM BACT in accordance with provisions of the EPA/TEC Consent Decree. The net emission rate changes due to the increase in potential emissions for Bayside Units 3 and 4, minus the two-year average actual emissions for F.J. Gannon Station Units 3 and 4 are all below the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates with the exception of CO and PM/PM_{10}. For most regulated pollutants, there will be a substantial reduction in actual emissions; e.g., approximately 570 tpy for SO_2 and NO_x. Accordingly, Bayside Units 3 and 4 are subject to PSD NSR for CO and PM/PM_{10} only.

Table 1. Bayside Station Units 3 and 4
Netting Analysis - F.J. Gannon Station Unit 3 Historical Emissions

	1996	1997	1998	1999	2000	96-00, 5 Yr Avg	99,00 Avg
Coal Usage (tons)	298,202	502,172	441,838	431,164	474,944	429,664	453,054
Wt % Ash	6.60	6.88	6.79	6.87	7.09	6.85	6.98
Heat Content (10^6 Btu/ton)	23.31	20.06	19.19	21.00	20.00	20.71	20.50
Wt % S	1.12	1.15	0.87	0.95	0.85	0.99	0.90
Oil Usage (10^3 gal)	311.0	639.9	599.0	397.0	10,156.9	2,420.7	5,277
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.000
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.42
Total Heat Input (10^6 Btu/yr)	6,994,776	10,161,863	8,561,862	9,109,230	10,900,532	9,145,653	10,004,881
NO_x [a]	349.7	508.1	428.1	455.5	545.0	457.3	500.2
CO AOR	90.0	153.0	111.0	108.8	119.8	116.5	114.3
SO_2 [b]	320.3	488.6	372.9	372.9	367.5	384.4	370.2
H_2SO_4 [c] AP-42 (1998)	18.7	32.3	21.6	23.0	25.9	24.3	24.4
PM_{10} [d]	35.0	50.8	42.8	45.5	54.5	45.7	50.0
PM [d]	35.0	50.8	42.8	45.5	54.5	45.7	50.0
Pb AOR	2.0	3.3	2.9	2.9	0.1	2.2	1.5
VOC AP-42 (1998)	16.4	27.7	24.4	23.8	27.1	23.9	25.4

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 2. Bayside Station Units 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 4 Historical Emissions

	1996	1997	1998	1999	2000	96-00, 5 Yr Avg	99,00 Avg
Coal Usage (tons)	486,874	474,906	486,831	408,955	461,418	463,797	435,187
Wt % Ash	6.75	6.85	6.79	6.95	7.13	6.89	7.04
Heat Content (10^6 Btu/ton)	22.35	20.87	20.04	20.00	20.00	20.65	20.00
Wt % S	1.08	1.04	0.87	0.94	0.86	0.96	0.90
Oil Usage (10^3 gal)	311.0	576.9	599.0	397.0	10,156.9	2,408.1	5,277
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.000
Wt % S	0.30	0.15	0.28	0.41	0.41	0.31	0.41
Total Heat Input (10^6 Btu/yr)	10,924,725	9,990,887	9,839,084	8,233,886	10,630,012	9,923,719	9,431,949
NO_x [(a)]	546.2	499.5	492.0	411.7	531.5	496.2	471.6
CO AOR	147.0	143.0	123.0	103.2	116.4	126.5	109.8
SO_2 [(b)]	492.8	519.2	477.7	373.5	391.6	450.9	382.5
H_2SO_4 [(c)] AP-42 (1998)	29.4	27.6	23.7	21.6	25.4	25.5	23.5
PM_{10} [(d)]	54.6	50.0	49.2	41.2	53.2	49.6	47.2
PM [(d)]	54.6	50.0	49.2	41.2	53.2	49.6	47.2
Pb AOR	3.2	3.2	3.2	2.7	0.1	2.5	1.4
VOC AP-42 (1998)	26.8	26.2	26.8	22.5	26.4	25.7	24.5

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 3. Bayside Station
Bayside Units 3 & 4/F.J. Gannon Units 3 & 4 Emissions Netting Analysis

	Units 3 & 4 (tpy)					Unit 3	Unit 4	Total		Net	PSD	PSD
	1996	1997	1998	1999	2000	2 Yr [a] Avg	2 Yr [a] Avg	2 Yr [a] Avg	CT 3A-4B (tpy)	Change (tpy)	Threshold (tpy)	Review (Y/N)
Coal Usage (tons)	785,076	977,078	928,669	840,119	936,362	453,054	435,187	888,241	N/A	N/A	N/A	N/A
Wt % Ash	6.68	6.87	6.79	6.91	7.11	6.98	7.04	7.01	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/ton)	22.83	20.47	19.62	20.50	20.00	20.50	20.00	20.25	N/A	N/A	N/A	N/A
Wt % S	1.10	1.10	0.87	0.95	0.86	0.90	0.90	0.90	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	622.0	1,216.7	1,198.0	794.0	20,313.8	5,277.0	5,277.0	10,553.9	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.000	138.000	138.000	N/A	N/A	N/A	N/A
Wt % S	0.30	0.15	0.28	0.41	0.42	0.42	0.41	0.41	N/A	N/A	N/A	N/A
Total Heat Input (10^6 Btu/yr)	17,919,501	20,152,750	18,400,946	17,343,116	21,530,544	10,004,881	9,431,949	19,436,830	N/A	N/A	N/A	N/A
NO_x [b]	896.0	1,007.6	920.0	867.2	1,076.5	500.2	471.6	971.8	404.7	-567.1	40.0	N
CO AOR	237.0	296.0	234.0	212.0	236.2	114.3	109.8	224.1	502.8	278.7	100.0	Y
SO_2 [c]	813.1	1,007.8	850.6	746.4	759.0	370.2	382.5	752.7	180.8	-571.9	40.0	N
H_2SO_4 [d] AP-42 (1998)	48.1	59.9	45.3	44.5	51.3	24.4	23.5	47.9	33.2	-14.7	7.0	N
PM_{10} [e]	89.6	100.8	92.0	86.7	107.7	50.0	47.2	97.2	355.7	258.5	15.0	Y
PM [e]	89.6	100.8	92.0	86.7	107.7	50.0	47.2	97.2	355.7	258.5	25.0	Y
Pb AOR	5.2	6.5	6.2	5.6	0.2	1.5	1.4	2.9	0.5	-2.4	0.6	N
VOC AP-42 (1998)	43.2	53.9	51.2	46.3	53.5	25.4	24.5	49.9	49.1	-0.9	40.0	N

(a) Fuel data represents 1999, 2000 average for Units 3 and 4.
(b) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(d) Actual emissions reduced by 35% to reflect retroactive BACT.
(e) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

APPENDIX E

DISPERSION MODELING FILES


BAYSIDE UNITS 3 & 4
AIR DISPERSION
MODELING FILES
ECT No. 991060-0100-1100
JUNE, 2001

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