TECO

TAMPA ELECTRIC

September 10, 2001

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SEP 10 2001

BUREAU OF AIR REGULATION

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7901 5518 4035

Re: Requests for Additional Information
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your requests for additional information dated August 20, 2001 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. The original requests were sent via email to Mr. Tom Davis of ECT. TEC has noted that within the two requests, there are a total of five additional questions or requests by the Florida Department of Environmental Protection (FDEP). For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Issue 1
The application indicates the 1998 AP-42 emission factor as the reference for sulfuric acid mist emissions from the coal-fired units. What is the emission factor? Please note any assumptions.

TEC Response
The emission factor used for sulfuric acid mist for coal fired units varies depending on the sulfur content of the fuel. According to AP-42, in a coal fired unit, one can expect 0.7% of the fuel bound sulfur to be emitted as sulfur trioxide. As shown in Enclosure 1, this factor is used to calculate the sulfur trioxide formation resulting from coal combustion. Then, the stoichiometric relationship between sulfur trioxide, water and sulfuric acid mist is used to calculate the amount of sulfuric acid mist formed as a result of the reaction between sulfur trioxide and water. Finally, as mandated by the EPA Consent Decree, TEC calculated the emissions of sulfuric acid mist from Gannon Station had BACT level controls been applied to Units 3 through 6. These BACT level controls were assumed to be wet limestone flue gas desulfurization systems, which have the ability to remove approximately 35% of incoming sulfuric acid mist.

FDEP Issue 2
Cleve had sent a letter in July regarding the PSD increment for PM. I did not see the response for this item in your last submittal. Please let me know the status of this item.

TEC Response
TEC is currently performing the above referenced analysis, and will provide it to the Department upon completion.

FDEP Issue 3
Please submit the emission factors used to estimate past actual coal-firing emissions.

TEC Response
The requested emission factors are included as Enclosure 2.

FDEP Issue 4
Your most recent submittal indicates a net increase in VOC emissions of 21.5 TPY, which is below the 40 TPY PSD significant emission rate for VOC. However, based on TEC's annual operating reports, I estimate a 64.3 TPY increase. This makes the project subject to PSD for this pollutant, similar to the Bayside Units 1 and 2 project. Therefore, the Department will be making a BACT determination for VOC emissions. Please submit a proposal for BACT controls.

TEC Response
In our August 10, 2001 response to the Department's July 17, 2001 incompleteness letter TEC inadvertently used VOC emission factors applicable to cyclone fired boilers for all four Gannon boilers in the revised PSD netting analysis. Gannon Units 5 and 6 are Riley Stoker turbo, wet bottom fired units, and the VOC emission factor for these units differs from that used for Units 3 and 4. As such, the netting analysis has been adjusted to use the correct VOC emission factor for Gannon Units 5 and 6 as well as only natural gas firing for Bayside Units 1 and 2.

Based on the adjusted netting analysis, TEC calculates a net increase in VOC emissions of 56.8 tons per year. This differs from the values submitted by TEC in annual operating reports because the VOC emission factors for PC- fired, wet bottom boilers changed from 0.07 lb VOC/ton coal to 0.04 lb VOC/ton coal in 1998. TEC believes that it is appropriate to use the most recent emission factors for the purpose of performing this netting analysis.

Since this project results in a net increase of 56.8 tons of VOC emissions per year, TEC has enclosed a BACT analysis for VOC emissions (Enclosure 3). Based on this analysis, TEC has concluded that firing natural gas and good combustion practice is BACT for this project. This is consistent with other recently issued permits for similar facilities by FDEP.

FDEP Issue 5
There were discussions near the end of the last project indicating that TEC may not fire oil at all for this project. The current application for Bayside Units 3 and 4 indicates that these units will fire only natural gas. Please indicate whether or not Bayside Units 1 and 2 will fire distillate oil as a backup fuel.

TEC Response
Although the Bayside Units 1 and 2 were designed with provisions to fire distillate oil as a backup fuel, TEC is requesting to remove the oil firing permit conditions from the Bayside 1 and 2 Air Construction permit. Although these units have been designed to accommodate future oil firing, TEC has elected to fire natural gas as the only fuel. If the decision is made to fire distillate oil in Bayside Units 1 and 2 in the future, TEC will apply for a modification of the appropriate permits at that time.

TEC appreciates the opportunity to provide the additional information contained in this correspondence. If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager-Bayside Power Station
Tampa Electric Company

EP\gm\SKT273

Enclosures

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

Enclosure 1

TECO F.J. Gannon Station
Derivation of H_2SO_4 Emission Rates

Procedure References:

Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-3, Footnote b, 0.7% of fuel sulfur is emitted as SO_3.

No. 2 Oil: Per AP-42 (9/98), Section 1.3, Table 1.3-1, boilers <100 MMBtu/hr (oil-firing), SO_3 emission factor is (2 x %S) lb SO_3 / 1,000 gallons oil.

Retroactive BACT control efficiency for H_2SO_4 = 35%

$SO_3 + H_2O = H_2SO_4$
(one mole of SO_3 and one mole of H_2O react to form one mole of H_2SO_4)

H_2SO_4 Calculation Equations:

Coal:
(lb S / 100 lb coal) x (ton coal / yr) x (2000 lb coal / ton coal) x (0.7 lb SO_3 / 100 lb S)
x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3) x (lb-mole SO_3 /80 lb SO_3)
x (98 lb H_2SO_4 / lb-mole H_2SO_4) x (ton H_2SO_4 / 2000 lb H_2SO_4)
x (1 – (Retroactive BACT Control Efficiency / 100))

Oil:
(2 lb SO_3 / 1,000 gallon oil) x (% S oil) x (gallon oil / yr)
x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3) x (lb-mole SO_3 /80 lb SO_3)
x (98 lb H_2SO_4 / lb-mole H_2SO_4) x (ton H_2SO_4 / 2000 lb H_2SO_4)
x (1 – (Retroactive BACT Control Efficiency / 100))

Example: 1996, Unit 3

Coal Usage: 298,202 ton/yr
Coal Sulfur Content: 1.12 weight percent sulfur
No. 2 Oil Usage: 311,000 gal/yr
No. 2 Oil Sulfur Content: 0.030 weight percent sulfur

Coal:
(1.12 lb S / 100 lb coal) x (298,202 ton coal / yr) x (2000 lb coal / ton coal)
x (0.7 lb SO_3 / 100 lb S) x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3)
x (lb-mole SO_3 /80 lb SO_3) x (98 lb H_2SO_4 / lb-mole H_2SO_4)
x (ton H_2SO_4 / 2000 lb H_2SO_4) x (1 – (35 / 100))
= 18.62 ton/yr H_2SO_4

Oil:
(2 lb SO_3 / 1,000 gallon oil) x (0.030 S oil) x (311,000 gallon oil / yr)
x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3) x (lb-mole SO_3 /80 lb SO_3)
x (98 lb H_2SO_4 / lb-mole H_2SO_4) x (ton H_2SO_4 / 2000 lb H_2SO_4)
x (1 – (35 / 100))
= 0.074 ton/yr H_2SO_4

Total = 18.62 (coal) + 0.074 (oil) = 18.69 ton/yr H_2SO_4

Enclosure 2

Procedure References:

Tampa Electric Company 1996 – 2000 Annual Operating Reports (AORs)

VOC Emission Factors:
Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-19, TNMOC emission factor is 0.11 lb TNMOC / ton coal for cyclone furnaces (Units 3 & 4)
Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-19, TNMOC emission factor is 0.04 lb TNMOC / ton coal for PC-fired, wet bottom furnaces (Units 5 & 6)
No. 2 Oil: Per AP-42 (9/98), Section 1.3, Table 1.3-3, Distillate fuel oil, NMTOC emission factor is 0.2 lb NMTOC / 1,000 gallons oil.

Retroactive BACT emission rate for NO_x = 0.10 lb NO_x / MMBtu

Retroactive BACT emission rate for PM/PM_{10} = 0.010 lb PM/PM_{10} / MMBtu

Retroactive BACT control efficiency SO_2 = 95.0 lb %

NO_x Calculation:

(Annual Heat Input [MMBtu/yr] From AOR) x (0.10 lb NO_x / MMBtu)

Example: 2000, Unit 5

Coal Usage: 418,667 ton/yr
Coal Heat Content: 24 MMBtu/ton
No. 2 Oil Usage: 101,569,000 gal/yr
No. 2 Oil Heat Content: 138,000 Btu/gal

Heat Input Coal:
(418,667 ton coal) x (24 MMBtu / ton coal)
= 10,048,008 MMBtu/yr

Heat Input Oil:
(10,156,900 gallon oil) x (138,000 Btu / gal) x (MMBtu / 1,000,000)
= 1,401,652 MMBtu/hr

Total Annual Heat Input = 10,048,008 (coal) + 1,401,652 (oil) = 11,449,660 MMBtu/yr

NO_x = (11,449,660 MMBtu/yr) x (0.10 lb NO_x / MMBtu) x (1 ton / 2,000 lb)

NO_x = 572.5 ton/yr

TECO F.J. Gannon Station
Derivation of Actual Coal-Firing Emission Rates

PM/PM_{10} Calculations:

(Annual Heat Input [MMBtu/yr] From AOR) x (0.010 lb NO_x / MMBtu)

Example: 1999, Unit 4

Coal Usage: 409,995 ton/yr
Coal Heat Content: 20 MMBtu/ton
No. 2 Oil Usage: 397,000 gal/yr
No. 2 Oil Heat Content: 138,000 Btu/gal

Heat Input Coal:
(409,995 ton coal) x (20 MMBtu / ton coal)
= 8,199,900 MMBtu/yr

Heat Input Oil:
(397,000 gallon oil) x (138,000 Btu / gal) x (MMBtu / 1,000,000)
= 54,786 MMBtu/hr

Total Annual Heat Input = 8,199,900 (coal) + 54,786 (oil) = 8,254,686 MMBtu/yr

PM/PM_{10} = (8,254,686 MMBtu/yr) x (0.010 lb NO_x / MMBtu) x (1 ton / 2,000 lb)

PM/PM_{10} = 41.2 ton/yr

SO_2 Calculation:

(Annual Emissions [ton/yr] From AOR) x (x (1 – (Retroactive BACT Control Efficiency / 100))

Example: 1996, Unit 3

Coal – SO_2: 6,400 ton/yr
Oil – SO_2: 6.5 ton/yr

SO_2 = (6,400 + 6.5 ton/yr SO_2) x (1 – (95 / 100))
SO_2 = (6,406.5 ton/yr SO_2) x (0.05)

SO_2 = 320.3 ton/yr

CO Calculation:

(Annual Emissions [ton/yr] From AOR)

Example: 1997, Unit 4

Coal – CO: 142 ton/yr
Oil – CO: 1 ton/yr

CO = (142 + 1 ton/yr CO)

CO = 143 ton/yr

VOC Calculation:

Coal:
(0.11 lb VOC / ton coal) x (ton coal / yr) x (ton VOC / 2000 lb VOC)

Oil:
(0.2 lb VOC / 1,000 gallon oil) x (gallon oil / yr) x (ton VOC / 2000 lb VOC)

Example: 1998, Unit 4

Coal Usage: 486,831 ton/yr
No. 2 Oil Usage: 598,990 gal/yr

Coal VOC = (486,831 ton/yr) x (0.11 lb VOC / ton coal) x (1 ton / 2,000 lb)
Coal VOC = 26.7 ton/yr

Oil VOC = (598,831 gallon oil/yr) x (0.2 lb VOC / 1,000 gallon oil) x (1 ton / 2,000 lb)
Oil VOC = 0.06 ton/yr

Total VOC = 26.7 (coal) + 0.06 (oil) = 26.8 ton/yr

Enclosure 3

REVISED PSD NETTING ANALYSIS
GANNON UNITS 3 – 6 / BAYSIDE UNITS 1 – 4
(ADJUSTED FOR RETROACTIVE BACT)

Table 3. Bayside Station Units 1, 2, 3 and 4 — Revised 8/23/01

Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

	1996	1997	1998	1999	2000	96 - 00, 5 Yr Avg	98, 99 Avg
Coal Usage (tons)	574,584	450,802	556,487	541,559	418,667	508,420	549,023
Wt % Ash	7.47	8.26	8.15	7.58	6.95	7.68	7.87
Heat Content (10^6 Btu/ton)	24.65	23.96	24.00	24.00	24.00	24.12	24.00
Wt % S	1.19	1.16	1.21	1.17	1.22	1.19	1.19
Oil Usage (10^3 gal)	311.0	600.9	599.0	397.0	10,156.9	2,413.0	498.0
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.276
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.35
Total Heat Input (10^6 Btu/yr)	14,208,885	10,884,135	13,438,679	13,052,202	11,449,660	12,606,712	13,245,440
NO_x [(a)]	710.4	544.2	671.9	652.6	572.5	630.3	662.3
CO AOR	173.0	135.0	140.0	136.4	105.7	138.0	138.2
SO_2 [(b)]	648.4	537.7	685.1	630.1	538.6	608.0	657.6
H_2SO_4 [(c)] AP-42 (1998)	38.2	29.2	37.7	35.4	31.9	34.5	36.6
PM_{10} [(d)]	71.0	54.4	67.2	65.3	57.2	63.0	66.2
PM [(d)]	71.0	54.4	67.2	65.3	57.2	63.0	66.2
Pb AOR	3.8	3.0	3.7	3.6	0.1	2.8	3.4
VOC AP-42 (1998)	11.5	9.1	11.2	10.9	9.4	10.4	10.3

(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 4. Bayside Station Units 1, 2, 3 and 4 Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

Revised 8/23/01

	1996	1997	1998	1999	2000	96 - 00, 5 Yr Avg	97, 98 Avg
Coal Usage (tons)	892,742	920,526	860,597	693,039	391,079	751,597	890,562
Wt % Ash	7.48	8.79	8.41	7.28	7.18	7.83	8.60
Heat Content (10^6 Btu/ton)	24.85	24.28	24.01	24.00	16.00	22.63	24.15
Wt % S	1.19	1.18	1.22	1.13	1.10	1.16	1.20
Oil Usage (10^3 gal)	311.0	639.9	599.0	362.0	6,587.5	1,699.9	619.4
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.270
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.22
Total Heat Input (10^6 Btu/yr)	22,229,515	22,438,664	20,745,925	16,682,892	7,166,339	17,852,667	21,592,294
NO_x [(a)]	1,111.5	1,121.9	1,037.3	834.1	358.3	892.6	1,079.6
CO AOR	269.0	278.0	216.0	174.2	98.5	207.1	247.0
SO_2 [(b)]	1,015.4	1,141.5	1,185.2	801.5	465.5	921.8	1,163.3
H_2SO_4 [(c)] AP-42 (1998)	59.3	60.6	58.7	43.8	26.2	49.7	59.6
PM_{10} [(d)]	111.1	112.2	103.7	83.4	35.8	89.3	108.0
PM [(d)]	111.1	112.2	103.7	83.4	35.8	89.3	108.0
Pb AOR	5.9	6.1	5.7	4.6	0.1	4.5	5.9
VOC AP-42 (1998)	17.9	18.5	17.3	13.9	8.5	15.2	17.9

(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.

5. Bayside Station
Bayside Units 1 - 4/F.J. Gannon Units 3 - 6 Emissions Netting Analysis

	F. J. Gannon Units 3, 4, 5 & 6 (tpy)					Units 3 & 4	Units 5 & 6	Units 3 - 6		Net	PSD	PSD
	1996	1997	1998	1999	2000	2 Yr [a] Avg	2 Yr [b][c] Avg	2 Yr [a][b][c] Avg	CT 1A-4B (tpy)	Change (tpy)	Threshold (tpy)	Review (Y/N)
Coal Usage (tons)	2,252,402	2,348,406	2,345,753	2,074,717	1,746,108	888,241	1,439,585	2,327,825	N/A	N/A	N/A	N/A
Wt % Ash	7.08	7.70	7.54	7.17	7.09	7.01	8.23	15.24	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/ton)	23.79	22.29	21.81	22.25	20.00	20.25	24.07	44.32	N/A	N/A	N/A	N/A
Wt % S	1.15	1.13	1.04	1.05	1.01	0.90	1.20	2.10	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	1,244.0	2,457.5	2,396.0	1,553.0	37,058.2	10,553.9	1,117.4	11,671.3	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	138.273	276.273	N/A	N/A	N/A	N/A
Wt % S	0.30	0.15	0.28	0.41	0.42	0.41	0.28	0.69	N/A	N/A	N/A	N/A
Total Heat Input (10^6 Btu/yr)	54,357,901	53,475,548	52,585,549	47,078,210	40,146,544	19,436,830	34,837,734	54,274,565	N/A	N/A	N/A	N/A
NO_x [d]	2,717.9	2,673.8	2,629.3	2,353.9	2,007.3	971.8	1,741.9	2,713.7	1,113.0	-1,600.8	40.0	N
CO AOR	679.0	709.0	590.0	522.6	440.4	224.1	385.2	609.3	1,382.8	773.5	100.0	Y
SO_2 [e]	2,476.9	2,686.9	2,720.8	2,177.9	1,763.1	752.7	1,820.9	2,573.6	486.5	-2,087.1	40.0	N
H_2SO_4 [f] AP-42 (1998)	145.5	149.7	141.6	123.7	109.4	47.9	96.2	144.1	89.4	-54.7	7.0	N
PM_{10} [g]	271.8	267.4	262.9	235.4	200.7	97.2	174.2	271.4	978.1	706.7	15.0	Y
PM [g]	271.8	267.4	262.9	235.4	200.7	97.2	174.2	271.4	978.1	706.7	25.0	Y
Pb AOR	15.0	15.6	15.6	13.8	0.4	2.9	9.3	12.2	1.4	-10.9	0.6	N
VOC AP-42 (1998)	72.7	81.4	79.7	71.1	71.4	49.9	28.2	78.1	134.9	56.8	40.0	Y

(a) 1999, 2000 average for Units 3 and 4.
(b) 1998, 1999 average for Unit 5.
(c) 1997, 1998 average for Unit 6.
(d) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(e) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(f) Actual emissions reduced by 35% to reflect retroactive BACT.
(g) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

VOC BACT ANALYSIS
BAYSIDE UNITS 3 AND 4

4.0A BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR VOLTILE ORGANIC COMPOUNDS

4.1A METHODOLOGY

The VOC BACT analysis was performed using the methodology previously described in Section 4.1 of the June 2001 Air Construction Permit Application.

4.2A 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 fuel LHV.
- Stationary gas turbines with a manufacturer's rated base load at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines 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 VOC emission limitations.

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.

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 ozone Air Quality Maintenance Area. Sections 62-296.501 through 62-296.516, F.A.C., specify VOC emission standards for 16 categories of sources; none of these categories are applicable to CTs. In addition, these VOC emission standards are not applicable to modified VOC-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 ozone Air Quality Maintenance Area VOC 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 VOC emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state VOC emission limitations applicable to Bayside Units 3 and 4.

4.3A <u>BACT ANALYSIS FOR VOC</u>

VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of VOCs 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 VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in VOC emission rates. Emissions of NO_x and VOC are inversely related; i.e., decreasing NO_x emissions will result in an increase in VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and VOC formation in order to develop units that achieve acceptable emission levels for both pollutants.

4.3.1A POTENTIAL CONTROL TECHNOLOGIES

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

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTs, approximately 99 percent, VOC emissions are inherently low. During normal operations, VOC exhaust concentrations from the Bayside Unit 3 and 4 GE 7FA CTs are projected to be only 1.3 parts per million by volume, dry (ppmvd), corrected to 15-percent oxygen (O_2).

Oxidation Catalysts

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

Efficiency of VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for VOCs up to a temperature of approximately

1,100°F; further temperature increases will have little effect on control efficiency. Temperatures on the order of 900°F are needed to oxidize VOCs. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency range using an oxidation catalyst control system is 30- to 50-percent. However, CTs with low uncontrolled VOC emission rates, such as the GE 7FA units, would be expected to have VOC control efficiencies on the low end of this range.

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 VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist.

Technical Feasibility

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

4.3.2A 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 VOC emissions.

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

Because VOC emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., negligible reductions in ambient VOC/ozone levels. The location of Bayside Units 3 and 4 (Hillsborough County, Florida) is classified attainment for all criteria pollutants.

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 1.2 inch of water (H_2O). This pressure drop will result in a 0.24 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 3,574,080 kilowatt-hours (kwh) (12,195 MMBtu) per year at base load (170-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 46.5 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 $428,890 per year for all four CTs.

4.3.3A ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 4-1 and project-specific economic factors provided in Table 4-2A. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-3A and 4-4A.

The base case Bayside Units 3 and 4 (i.e., for all four CT/HRSG units) annual VOC emission rate is 49.1 tpy. The controlled annual VOC emission rate, based on a 50 percent control efficiency, is 24.5 tpy. Base case and controlled VOC emission rates are summarized in Table 4-5A.

The cost effectiveness of oxidation catalyst for VOC emissions was determined to be $60,378 per ton of VOC removed. Based on the high control costs, use of oxidation catalyst technology to control VOC emissions is not considered to be economically feasible. Results of the oxidation catalyst economic analysis are summarized in Table 4-5A.

4.3.4A PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control VOCs from CTs is typically required only for facilities located in ozone nonattainment areas. BACT VOC limits obtained from the RBLC database for natural gas-fired CTs are provided in Table 4-6A. A summary of recent FDEP VOC BACT determinations for natural gas-fired combustion turbines is provided in Table 4-7A.

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 and low sulfur distillate fuel oil. Because VOC 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., negligible reductions in ambient VOC/ozone levels.

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

Table 4-2A. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
VOC control efficiency	%	50*
Electricity cost	$/kwh	0.030*
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

* Per FDEP request.

Sources: ECT, 2001.
TEC, 2001.

Table 4-3A. Capital Costs for Oxidation Catalyst System, Four CTs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	2,680,000	A
Sales tax	160,800	0.06 x A
Freight	134,000	0.05 x A
Instrumentation	268,000	0.10 x A
Subtotal Purchased Equipment Cost	**3,242,800**	**B**
Installation		
Foundations and supports	259,424	0.08 x B
Handling and erection	453,992	0.14 x B
Electrical	129,712	0.04 x B
Piping	64,856	0.02 x B
Insulation for ductwork	32,428	0.01 x B
Painting	32,428	0.01 x B
Subtotal Installation Cost	**972,840**	
Subtotal Direct Costs	**4,215,640**	
Indirect Costs		
Engineering	324,280	0.10 x B
Construction and field expenses	162,140	0.05 x B
Contractor fees	324,280	0.10 x B
Startup	64,856	0.02 x B
Performance test	32,428	0.01 x B
Contingency	97,284	0.03 x B
Subtotal Indirect Costs	**1,005,268**	
TOTAL CAPITAL INVESTMENT	**5,220,908** (TCI)	

Source: Engelhard, 2001.
ECT, 2001.

Table 4-4A. Annual Operating Costs for Oxidation Catalyst System, Four CTs

Item	Dollars		Basis
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	2,668,224		
Credit for used catalyst	(360,000)		15% credit
Subtotal Catalyst Costs	2,308,224		
Annualized Catalyst Costs	**562,954**		5 yr @ 7.0%
Energy Penalties			
Turbine backpressure	428,890		0.24% penalty
Subtotal Direct Costs	**991,844**	(TDC)	
Indirect Costs			
Administrative charges	104,418		0.02 x TCI
Property taxes	52,209		0.01 x TCI
Insurance	52,209		0.01 x TCI
Capital recovery	280,271		15 yr @ 7.0%
Subtotal Indirect Costs	**489,107**		
TOTAL ANNUAL COST	**1,480,951**		

Sources: Engelhard, 2001.
ECT, 2001.
TEC, 2001.

Table 4-5A. Summary of VOC BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	5.6	24.5	24.5	5,220,908	1,480,951	60,378	48,781	N	Y
Baseline	11.2	49.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

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

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Table 4-6A. RBLC VOC Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0128	ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE	3/16/99	6/23/99	TURBINE, WITH DUCT BURNER	170.0 MW	0.016 LB/MMBTU	EFFICIENT COMBUSTION	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325.0 MMBTU/HR	8 LB/HR	NATURAL GAS AS PRIMARY FUEL	LAER
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, SIMPLE CYCLE LM6000 GAS	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0813	SEPCO	RIO LINDA	10/5/94	8/31/99	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920.0 MMBTU/H	3.7 LB/H	OXIDATION CATALYST	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	8/5/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25.0 MW	3.12 LB/H	OXIDATION CATALYST. VOC IS SHOWN AS CH4.	BACT-OTHER
CA-0855	CROCKETT COGENERATION - C&H SUGAR	CROCKETT	10/5/93	4/19/99	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	240.0 MW	352.6 LB/D	ENGELHARD OXIDATION CATALYST	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	9/28/99	TURBINE, GE, COGENERATION, 48 MW	48.0 MW	0.6 PPMVD @ 15% O2	OXIDATION CATALYST	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246.0 MMBTU/H	16.7 LB/H		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350.0 MMBTU/H	26.7 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385.0 MMBTU/H EACH TURBIN	35.2 T/YR		OTHER
CO-0024	PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	5/1/96	5/19/98	COMBINED CYCLE TURBINES (2), NATURAL	471.0 MW	1.4 PPMVD, SMPL CY	GOOD COMBUSTION CONTROL PRACTICES.	BACT-PSD
CO-0039	FULTON COGENERATION ASSOC., L.P.	BRUSH	8/23/99	12/11/00	ELECTRIC GENERATION, TURBINES, NATURAL GAS	142.0 MW	3 PPMVD @ 15% O2	COMBUSTION CONTROLS	BACT-PSD
CT-0073	PRATT & WHITNEY, UTC	MIDDLETOWN	7/7/89	4/30/90	ENGINE, GAS TURBINE	238.0 MMBTU/H	0.014 LB/MMBTU		BACT-PSD
CT-0139	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24, #1	2.0 MMCF/H	3 LB/H NAT GAS	COMBUSTION CONTROLS	BACT
CT-0140	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24E,#2	2.0 MMCF/H	3 LB/H NAT GAS	COMBUSTION CONTROLS	BACT
FL-0042	ORLANDO UTILITIES COMMISSION	TITUSVILLE	9/1/88	5/14/93	TURBINE, 2 EA	35.0 MW	7 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400.0 MW	9 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	33394	3/24/95	TURBINE, GAS, 4 EACH	400.0 MW	1.6 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWER	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240.0 MW	1 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35.0 MW	7 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	10 PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1,214.0 MMBTU/H	6 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510.0 MMBTU/H	7 PPMVW	GOOD COMBUSTION PRACTICES	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1,032.0 MMBTU/H, NAT GAS	0.003 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0063	MID-GEORGIA COGEN	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116.0 MW	6 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	0.03 LB/MMBTU	VOC EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	0.0055 LB/MMBTU	VOC EMISSION IS BECAUSE OF NO.2 FUEL OIL.	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338.0 MM BTU/HR TURBINE	3.6 LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION	BACT
LA-0118	OCCIDENTAL CHEMICAL CORPORATION	HAHNVILLE	3/19/99	3/19/01	GAS TURBINES (3 UNITS)	170.0 MW	3 LB/H	DLN COMBINATION WITH OTHER TECHNOLOGIES	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1,3[illegible]7.0 MMBTU/H	5.1 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528.0 MW TOTAL	0.4 PPM @ 15% O2		BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175.0 MW	3 LB/H GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170.0 MW [illegible]CH	1 PPM	LOW NOX BURNER	BACT-PSD
MI-0245	SOUTHERN ENERGY, INC.	ZEELAND	3/16/00	8/22/00	COMBINED CYCLE TURBINE	9,000.0 GIGA[illegible]LES	0.008 [illegible]MMBTU	PER CT. GOOD COMBUSTION PRACTICE	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313.0 MM BT[illegible]	2 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190.0 MMBTU/[illegible]CH)	0.0046 LB/MMBTU	TURBINE DESIGN	OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617.0 MMBTU/HR [illegible]	4 PPMDV	TURBINE DESIGN	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257.0 HP	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0 SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0		BACT-PSD
NY-0036	ONEIDA COGENERATION FACILITY	ONEIDA	2/26/90	5/18/90	TURBINE, GE FRAME 6	417.0 MMBTU/H	0.013 LB/MMBTU	COMBUSTION CONTROL	OTHER
NY-0038	EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	5/2/89	5/18/90	TURBINE, GR FRAME 6, 3 EA	416.0 MMBTU/H	0.012 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
NY-0039	FULTON COGENERATION ASSOCIATES	FULTON	1/29/90	5/18/90	TURBINE, GE LM5000, GAS FIRED	500.0 MMBTU/H	5 LB/H	COMBUSTION CONTROL	BACT-PSD
NY-0040	JMC SELKIRK, INC.	SELKIRK	11/21/89	5/18/90	TURBINE, GE FRAME 7, GAS FIRED	80.0 MW	7 PPM	COMBUSTION CONTROL	BACT-PSD
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123.0 MMBT[illegible]R (EACH)	0.0045 LB/MMBTU	OXIDATION CATALYST	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON CRT HSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500.0 HP (EACH)	0.1 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	105 PPM @ 15% O2	OXIDATION CATALYST	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360.0 MMBTU/HR	4.4 LB/HR	GOOD COMBUSTION PRACTICES	BACT-OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153.0 MW	4 PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0 MW	25 PPMV@15%O2	GOOD COMBUSTION	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461.0 MW	5 PPMDV	COMBUSTION CONTROLS.	BACT-PSD
RI-0008	PAWTUCKET POWER	PAWTUCKET	1/30/89	3/31/91	TURBINE/DUCT BURNER	533.0 MMBTU/H	19 PPM @ 15% O2, GAS		BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1,360.0 MMBTU/H EACH	5 PPM @ 15% O2		BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	33450	5/31/92	TURBINE, GAS, 2	49.0 MMBTU/H	0.016 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-OTHER
RI-0018	TIVERTON POWER ASSOCIATES	TIVERTON	2/13/98	2/8/99	COMBUSTION TURBINE, NATURAL GAS	265.0 MW	2 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	77.86 LBS/DAY		LAER
TN-0077	TN VALLEY AUTHORITY LAGOON CREEK COMBUS TURB	BROWNSVILLE	4/26/00	8/16/00	COMBUSTION TURBINE	194,400.0 MMBTU/H	1.4 PPM @ 15% O2	ANNUAL PRODUCTION LIMITS	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	38 TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-0163	VIRGINIA POWER		9/7/89	4/30/90	TURBINE, GAS	1,308.0 MMBTU/H	2 LB/H/UNIT NAT GAS FI		BACT-PSD
VA-0177	DOSWELL LIMITED PARTNERSHIP		5/4/90	3/24/95	TURBINE, COMBUSTION	1,261.0 MMBTU/H	4.4 LB/H	COMBUSTOR DESIGN & OPERATION, GAS	OTHER
VA-0180	COMMONWEALTH GAS PIPELINE CORPORATION	GOOCHLAND	9/30/90	3/24/95	TURBINES, GAS FIRED, SINGLE CYCLE, 5	14.5 MMBTU/H EACH	0	EQUIPMENT DESIGN & OPERATION	BACT-PSD
VA-0184	BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	3/3/92	5/7/97	TURBINE, COMBUSTION	1,175.0 MMBTU/H NAT. GAS	2.3 LB/H/UNIT	FURNACE DESIGN	BACT-PSD
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6,000.0 HRS/YR	38.9 TPY	GOOD COMBUSTION OPERATING PRACTICES	BACT/NSPS

Source: RBLC 2001.

MAXIMUM	105.0 PPM @ 15% O2
MINIMUM	0.4 PPM @ 15% O2
MEDIAN	5.0 PPM @ 15% O2

Table 4-7A. Florida BACT VOC Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit (ppmvd @ 15% O_2)	Control Technology
03/07/95	Orange Cogeneration, L.P.	39	10.0	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4.0	Good combustion
09/29/98	Florida Power Corporation Hines Energy Complex	165	7.0	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	1.4	Good combustion
12/04/98	Santa Rosa Energy, LLC	167	1.4	Good combustion
10/8/99	Tampa Electric Company – Polk Power Station	165	1.4	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	5.0	Good combustion
9/20/99	Lake Worth Generating	170	1.4	Good combustion
10/18/99	Vandolah Power Project	170	1.4	Good combustion
12/28/99	Osceola Power Project	170	3.7	Good combustion
1/13/00	Shady Hills Generating Station	170	1.4	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3	167	1.4	Good combustion
2/22/00	Reliant Energy Osceola	170	1.5	Good combustion
2/24/00	Gainesville Regional Utilities	83	1.4	Good combustion
7/31/00	Gulf Power – Smith Unit 3	170	4.0	Good combustion
2/6/01 (Draft)	Calpine Blue Heron	170	1.2	Good combustion
3/30/01	Tampa Electric Company – Bayside Units 1 & 2	170	1.3	Good combustion
7/5/01	Calpine Osprey	170	2.3	Good combustion
8/15/01	Ft. Pierce Re-Powering	180	2.2	Good combustion

Source: FDEP, 2001.

within the past 5 years. Maximum natural gas-firing VOC exhaust concentrations from the CT/HRSG units will be less than or equal to 1.3 ppmvd at 15 percent oxygen. This VOC exhaust concentration is consistent with recent FDEP VOC BACT determinations for CT/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5. VOC BACT emission limits proposed for Bayside Units 3 and 4 are provided in Table 4-8A.

Table 4-8A. Proposed VOC BACT Emission Limits

Emission Source	Proposed VOC BACT Emission Limits ppmvd at 15 percent oxygen	lb/hr
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)		
VOC (Natural Gas)	1.3	3.0

Sources: ECT, 2001.
TEC, 2001.