7099 3400 0000 1449 2471

U.S. Postal Service
CERTIFIED MAIL RECEIPT
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Article Sent To:

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

TEC Bayside

Postmark Here

Name (Please Print Clearly) (to be completed by mailer) Ms. Karen Sheffield, Gen. Mgr

Street, Apt. No.; or PO Box No. Port Sutton Road

City, State, ZIP+4 Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Karen Sheffield, Gen. Mgr.
TEC Bayside Power Station
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 4/2/01

C. Signature
X S/6 John Spearman ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
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PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

THE TAMPA TRIBUNE
Published Daily
Tampa, Hillsborough County, Florida

State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared J. Rosenthal, who on oath says that she is Classified Billing Manager of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

FEBRUARY 10, 2001

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

J Rosenthal

Sworn to and subscribed by me, this 10 day of FEBRUARY, A.D. 20'01

Personally Known ✓ or Produced Identification ______
Type of Identification Produced ______

NOTARY PUBLIC STATE OF FLORIDA
OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
CC639424
MY COMMISSION EXP.
APRIL 16, 2001

Susie Lee Slaton

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
Tampa Electric Company
Bayside Power Station
(Gannon Re-Powering Project)
Project No. 0570040-013-AC
Draft Permit PSD-FL-301

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have an electrical production capacity of approximately 1740 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

In accordance with state and federal settlement agreements, the applicant proposes to re-power the existing Gannon Station with seven new combined cycle General Electric Model PG7241(FA) gas turbines. All existing coal-fired boilers will be shut down before January 1, 2005. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. It is estimated that the Bayside project will reduce actual emissions of nitrogen oxides (NOx) by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required by rule for each pollutant, the proposed permit represents current Best Available Control Technology (BACT) measures for combined cycle gas turbines to control emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfur dioxide (SO2), and volatile organic compounds (VOC). The proposed permit also requires the continuous monitoring of CO and NOx emissions.

The project results in smaller, but significant increases in emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions of PM/PM10. Therefore, the project is subject to review in accordance with Rule 62-212.400, F.A.C., the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, and BACT determinations are required for each significant pollutant. The Department determined BACT controls for the emissions of CO, PM/PM10, and VOC to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (less than 0.05% sulfur by weight) is the backup fuel. Each unit may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired. To reduce emissions of nitrogen oxides (NOx), each combined cycle unit incorporates dry low-NOx combustion technology when firing natural gas and water injection when firing oil. Pursuant to the state and federal settlement agreements, a Selective Catalytic Reduction (SCR) system for each unit is required to further reduce NOx emissions. As agreed to by the applicant, the proposed permit defers the determination of the Maximum Available Control Technology (MACT) for hazardous air pollutants (HAP) until after a unit is tested for HAP emissions.

The applicant performed an air quality analysis in accordance with the Department's PSD requirements in Rule 62-212.400, F.A.C. Significant net increases in actual emissions were predicted for carbon monoxide and volatile organic compounds. The Department reviewed the applicant's analysis and modeling files. The ambient impact analysis predicted that emissions from the project would have an insignificant impact on Class II areas. Except for six national parks and wilderness areas, all of Florida is designated as a Class II area. No Class I significant impact levels have been defined for carbon monoxide or volatile organic compounds (ozone). The analysis also indicated that emissions from the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standard when evaluated independently.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District Office
Air Resources
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Hillsborough County Environmental Protection Commission
Air Management Division
1410 North 21 Street
Tampa, FL 33605
Telephone: 813/272-5530
Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. Key documents may be viewed at www.dep.state.fl.us/air/permitting and clicking on TEC Bayside.

1448 2/10/01

7099 3400 0000 1449 4031

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:
Ms. Karen Sheffield

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Karen Sheffield
General Manager
Tampa Electric Company
Bayside Power Station
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* B. Date of Delivery 2/7

C. Signature
X [signature] ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number (Copy from service label)
7099 3400 0000 1449 4031

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

7099 3400 0000 1453 3198

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:

1453 3198

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

12/15/00

Name (Please Print Clearly) (to be completed by mailer)
Karen Sheffield, TECO
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Karen Sheffield
General Manager
Bayside Power Station
Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 12/18

C. Signature
X
☐ Agent
☐ Addressee

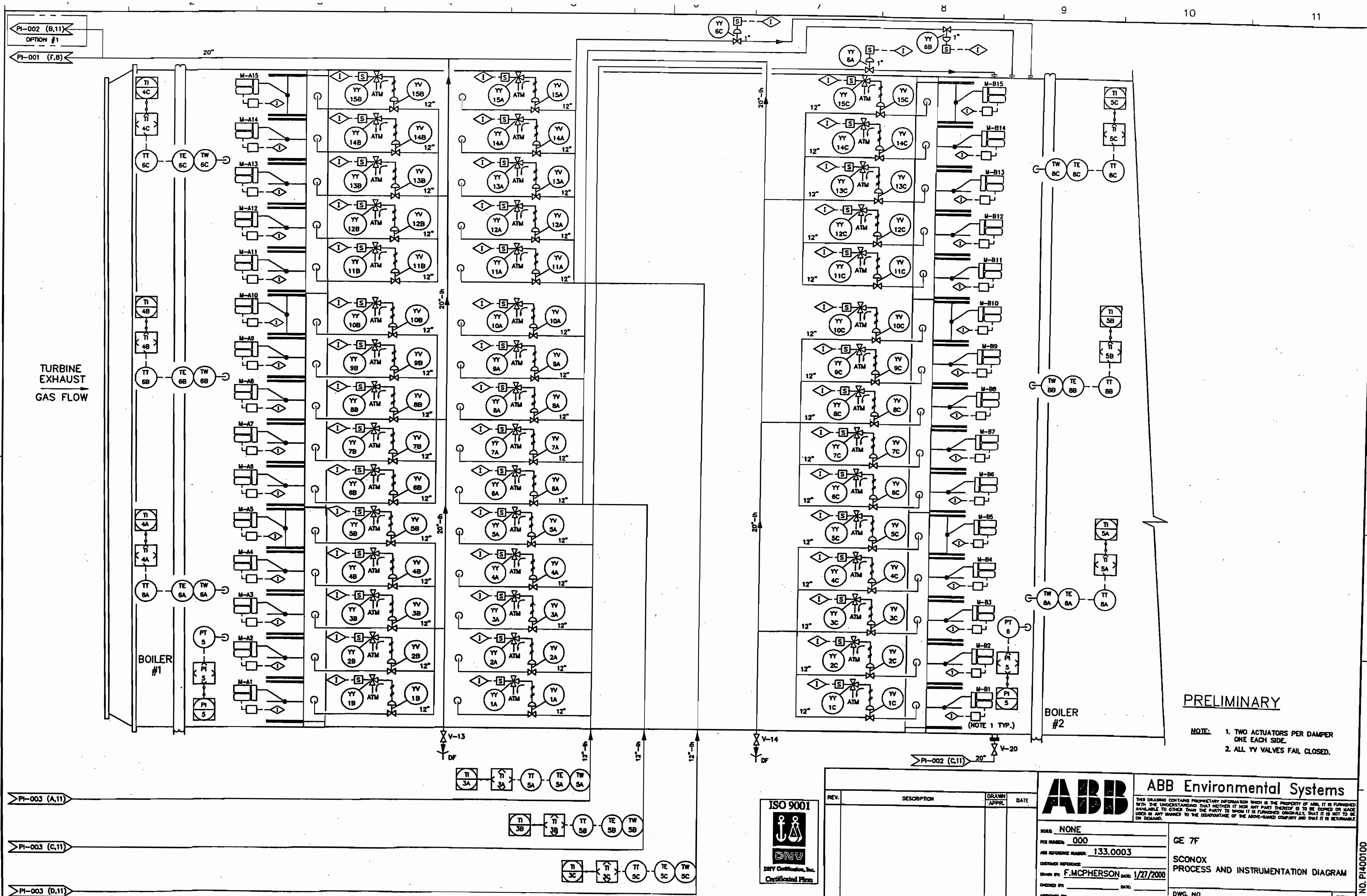
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 3198

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789



PRELIMINARY

NOTE:
1. TWO ACTUATORS PER DAMPER ONE EACH SIDE.
2. ALL YV VALVES FAIL CLOSED.

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm

ABB Environmental Systems

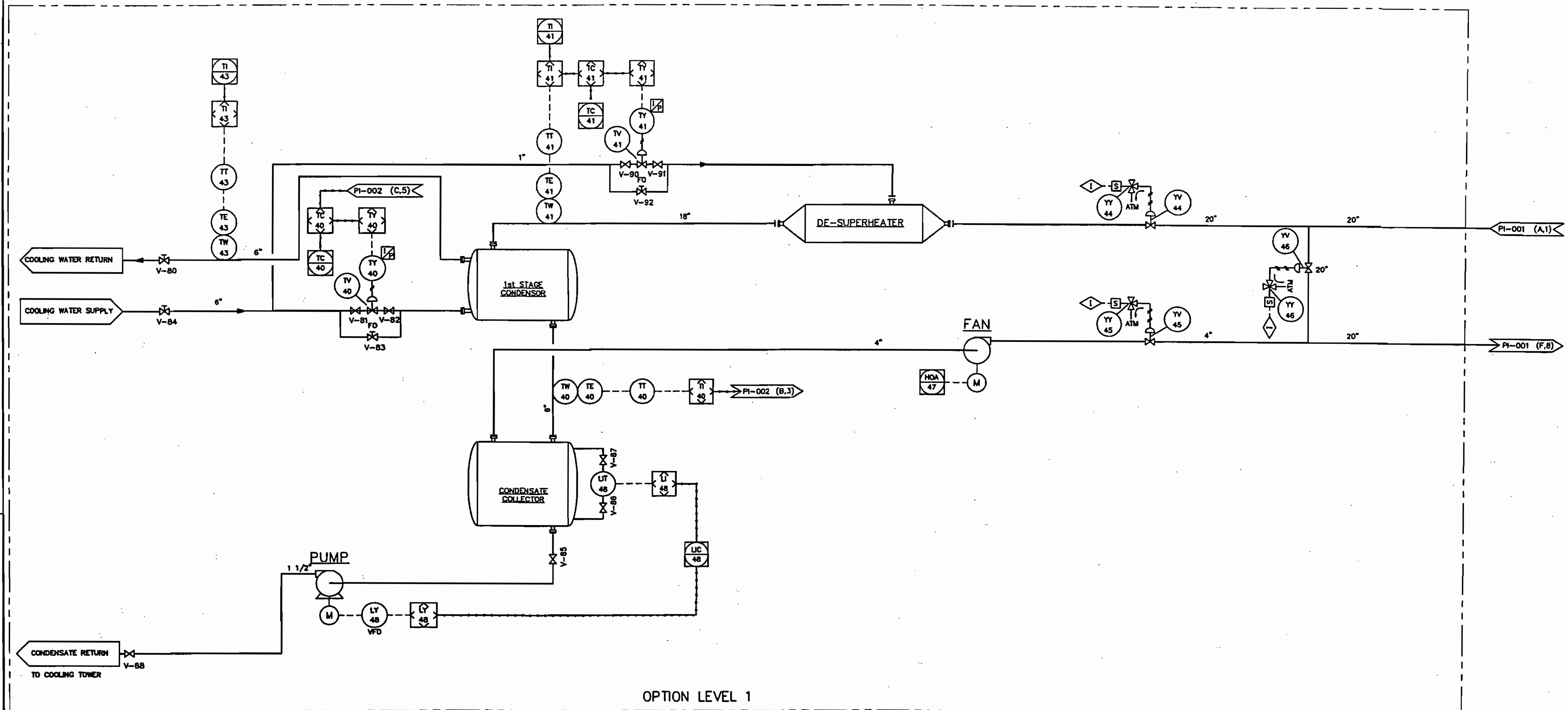
SCALE: NONE
FCS NUMBER: 000
ABB REFERENCE NUMBER: 133.0003
CUSTOMER REFERENCE:
DRAWN BY: F.MCPHERSON DATE: 1/27/2000
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

GE 7F
SCONOX
PROCESS AND INSTRUMENTATION DIAGRAM

DWG. NO. 1330003-PI-000-001
REV. 00

FILE NO. PI40010G

1/10" 1/8"-1/4" 3/8"-3/4" 1/2"-1"



PRELIMINARY

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm

ABB Environmental Systems

THIS DRAWING CONTAINS PROPRIETARY INFORMATION WHICH IS THE PROPERTY OF ABB. IT IS FURNISHED WITH THE UNDERSTANDING THAT NEITHER IT NOR ANY PART THEREOF IS TO BE COPIED OR MADE AVAILABLE TO OTHER THAN THE PARTY TO WHOM IT IS FURNISHED ORIGINALLY, THAT IT IS NOT TO BE USED IN ANY MANNER TO THE DISADVANTAGE OF THE ABOVE-NAMED COMPANY AND THAT IT IS RETURNABLE ON DEMAND.

SCALE: NONE
PCS NUMBER: 000
ABB REFERENCE NUMBER: 133.0003
CUSTOMER REFERENCE:
DRAWN BY: F.MCPHERSON DATE: 1/27/2000
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

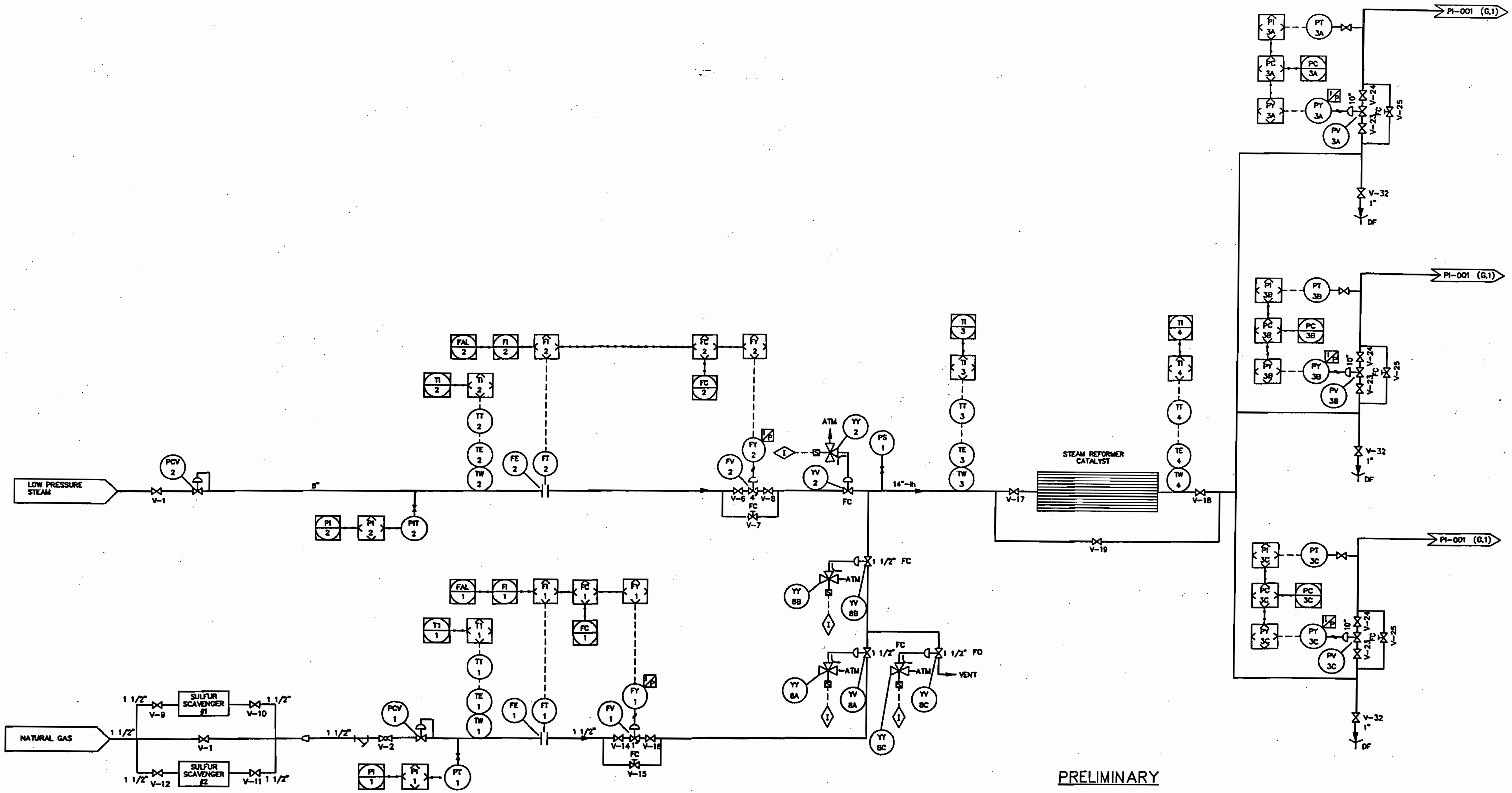
GE 7F

PROCESS AND INSTRUMENTATION DIAGRAM

DWG. NO. 1330003-PI-000-002 REV. 00

FILE NO. PI400202G

1/10" 1/8"-1/4" 3/8"-3/4" 1/2"-1"



PRELIMINARY

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm

ABB Environmental Systems

SCALE: NONE
PCS NUMBER: 000
ABB REFERENCE NUMBER: 133.0003
CUSTOMER REFERENCE:
DRAWN BY: F.MCPHERSON DATE: 1/27/2000
CHECKED BY: DATE:
APPROVED BY: DATE:
APPROVED BY: DATE:

GE 7F

PROCESS AND INSTRUMENTATION DIAGRAM

DWG. NO. 1330003-PI-000-003 REV. 00

FILE NO. PI400300

Table 6-1. Air Quality Impact Analysis Summary
Distillate Fuel Oil-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 ($\mu g/m^3$)	263.5	264.3	289.9	215.4	260.7	323.4	335.9	335.1	297.1	331.1	367.3	375.1	377.1	360.8	369.4	290.4	293.2	305.0	257.4	289.6
HSH, 3-Hour ($\mu g/m^3$)	123.2	114.1	122.3	117.2	130.1	161.4	171.3	157.8	128.1	168.6	207.9	193.0	192.4	141.3	176.4	134.6	134.3	134.0	122.4	149.4
HSH, 8-Hour ($\mu g/m^3$)	77.5	78.5	75.7	47.2	98.5	100.5	100.5	98.4	67.7	115.0	95.3	113.9	111.3	92.9	133.4	88.2	85.0	85.6	52.9	109.2
HSH, 24-Hour ($\mu g/m^3$)	43.8	30.6	43.1	19.1	60.6	63.0	49.6	51.5	30.4	78.4	68.6	57.1	55.4	42.9	88.1	51.7	39.8	46.8	22.2	68.8
Annual ($\mu g/m^3$)	2.0	1.4	1.4	0.8	1.2	3.9	3.2	2.6	1.8	2.3	5.7	4.8	3.6	2.6	3.4	2.6	2.0	1.7	1.1	1.5
SO_2																				
Emission Rate (g/s)	13.17	13.17	13.17	13.17	13.17	10.62	10.62	10.62	10.62	10.62	8.43	8.43	8.43	8.43	8.43	12.38	12.38	12.38	12.38	12.38
HSH, 3-Hour ($\mu g/m^3$)	162.3	150.3	161.0	154.3	171.3	171.4	182.0	167.5	315.5	179.0	175.2	162.7	162.2	304.2	148.7	166.7	166.3	165.9	151.5	184.9
HSH, 24-Hour ($\mu g/m^3$)	57.7	40.3	56.8	25.2	79.8	66.9	52.7	54.7	32.3	83.2	57.9	48.1	46.7	36.2	74.3	64.0	49.3	58.0	27.5	85.1
Annual ($\mu g/m^3$)	2.7	1.9	1.8	1.0	1.6	4.1	3.4	2.8	1.9	2.5	4.8	4.1	3.1	2.2	2.9	3.2	2.4	2.2	1.3	1.9
NO_2																				
Emission Rate (g/s)	16.67	16.67	16.67	16.67	16.67	13.31	13.31	13.31	13.31	13.31	10.47	10.47	10.47	10.47	10.47	15.65	15.65	15.65	15.65	15.65
Tier 2 Annual ($\mu g/m^3$)	2.5	1.8	1.7	1.0	1.5	3.9	3.2	2.6	1.8	2.3	4.5	3.8	2.9	2.1	2.7	3.0	2.3	2.1	1.3	1.8
PM/PM_{10}																				
Emission Rate (g/s)	6.78	6.78	6.78	6.78	6.78	6.30	6.30	6.30	6.30	6.30	5.88	5.88	5.88	5.88	5.88	6.63	6.63	6.63	6.63	6.63
HSH, 24-Hour ($\mu g/m^3$)	29.7	20.7	29.2	13.0	41.1	39.7	31.2	32.5	19.1	49.4	40.4	33.6	32.6	25.2	51.8	34.3	26.4	31.0	14.7	45.6
Annual ($\mu g/m^3$)	1.4	1.0	0.9	0.5	0.8	2.5	2.0	1.6	1.1	1.5	3.4	2.8	2.1	1.5	2.0	1.7	1.3	1.2	0.7	1.0
CO																				
Emission Rate (g/s)	8.82	8.82	8.82	8.82	8.82	8.14	8.14	8.14	8.14	8.14	9.34	9.34	9.34	9.34	9.34	8.13	8.13	8.13	8.13	8.13
HSH, 1-Hour ($\mu g/m^3$)	232.4	233.1	255.7	190.0	229.9	263.3	273.5	272.8	241.8	269.5	343.1	350.3	352.2	337.0	345.0	236.1	238.4	248.0	209.3	235.4
HSH, 8-Hour ($\mu g/m^3$)	68.3	69.3	66.7	41.7	86.9	81.8	81.8	80.1	55.1	93.6	89.0	106.4	104.0	86.8	124.6	71.7	69.1	69.6	43.0	88.8

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:										
HSH, 1-Hour ($\mu g/m^3$)	336.3	350.6	351.8	317.3	344.3	384.6	388.2	392.4	382.1	382.2
HSH, 3-Hour ($\mu g/m^3$)	182.0	185.9	169.4	135.4	174.2	229.0	208.5	203.8	155.0	183.4
HSH, 8-Hour ($\mu g/m^3$)	105.2	114.3	102.8	75.9	120.8	101.3	120.2	116.2	102.5	**139.6**
HSH, 24-Hour ($\mu g/m^3$)	67.4	52.1	56.6	35.2	82.8	73.0	59.9	58.6	45.9	**92.4**
Annual ($\mu g/m^3$)	4.4	3.7	2.9	2.0	2.6	6.5	5.5	4.1	3.0	3.9
SO_2										
Emission Rate (g/s)	10.00	10.00	10.00	10.00	10.00	7.97	7.97	7.97	7.97	7.97
HSH, 3-Hour ($\mu g/m^3$)	182.0	185.9	169.4	135.4	174.2	182.5	166.2	162.5	304.6	146.1
HSH, 24-Hour ($\mu g/m^3$)	67.4	52.1	56.6	35.2	82.8	58.2	47.7	46.7	36.6	73.6
Annual ($\mu g/m^3$)	4.4	3.7	2.9	2.0	2.6	**5.2**	4.4	3.3	2.4	3.1
NO_2										
Emission Rate (g/s)	12.52	12.52	12.52	12.52	12.52	9.9	9.89	9.89	9.89	9.89
Tier 2 Annual ($\mu g/m^3$)	4.2	3.5	2.8	1.9	2.5	**4.8**	4.1	3.1	2.3	2.9
PM/PM_{10}										
Emission Rate (g/s)	6.19	6.19	6.19	6.19	6.19	5.80	5.80	5.80	5.80	5.80
HSH, 24-Hour ($\mu g/m^3$)	41.7	32.3	35.1	21.8	51.3	42.3	34.7	34.0	26.6	**53.6**
Annual ($\mu g/m^3$)	2.7	2.3	1.8	1.2	1.6	3.8	3.2	2.4	1.8	2.2
CO										
Emission Rate (g/s)	7.47	7.47	7.47	7.47	7.47	9.00	9.00	9.00	9.00	9.00
HSH, 1-Hour ($\mu g/m^3$)	251.3	261.9	262.8	237.0	257.2	346.2	349.4	353.1	343.9	344.0
HSH, 8-Hour ($\mu g/m^3$)	78.6	85.4	76.8	101.1	90.3	91.2	108.2	104.6	92.2	125.6

	Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:										
HSH, 1-Hour ($\mu g/m^3$)	294.2	298.1	307.9	264.6	294.5	338.6	352.9	354.5	322.0	346.7
HSH, 3-Hour ($\mu g/m^3$)	136.5	138.0	136.7	123.2	151.3	185.9	170.7	171.9	136.8	175.0
HSH, 8-Hour ($\mu g/m^3$)	89.6	85.8	87.1	53.8	110.9	106.0	116.9	103.6	77.7	121.8
HSH, 24-Hour ($\mu g/m^3$)	53.0	41.7	47.4	22.7	70.1	68.8	52.6	58.5	36.1	83.6
Annual ($\mu g/m^3$)	2.7	2.0	1.8	1.1	1.6	4.6	3.8	3.0	2.1	2.7
SO_2										
Emission Rate (g/s)	12.10	12.10	12.10	12.10	12.10	9.75	9.75	9.75	9.75	9.75
HSH, 3-Hour ($\mu g/m^3$)	165.2	166.9	165.5	**320.2**	183.0	181.2	166.5	167.6	313.9	170.6
HSH, 24-Hour ($\mu g/m^3$)	64.1	50.5	57.3	27.5	84.8	67.1	51.3	57.1	35.2	81.5
Annual ($\mu g/m^3$)	3.2	2.5	2.2	1.3	1.9	4.4	3.7	2.9	2.0	2.6
NO_2										
Emission Rate (g/s)	15.32	15.32	15.32	15.32	15.32	12.21	12.21	12.21	12.21	12.21
Tier 2 Annual ($\mu g/m^3$)	3.1	2.3	2.1	1.3	1.8	4.2	3.5	2.7	1.9	2.5
PM/PM_{10}										
Emission Rate (g/s)	6.58	6.58	6.58	6.58	6.58	6.14	6.14	6.14	6.14	6.14
HSH, 24-Hour ($\mu g/m^3$)	34.8	27.5	31.2	15.0	46.1	42.3	32.3	35.9	22.2	51.3
Annual ($\mu g/m^3$)	1.8	1.3	1.2	0.7	1.0	2.8	2.3	1.8	1.3	1.7
CO										
Emission Rate (g/s)	7.88	7.88	7.88	7.88	7.88	7.32	7.32	7.32	7.32	7.32
HSH, 1-Hour ($\mu g/m^3$)	231.8	234.9	242.6	208.5	232.1	247.9	258.3	259.5	235.7	253.8
HSH, 8-Hour ($\mu g/m^3$)	70.6	67.6	68.6	97.1	87.4	77.6	85.6	75.8	56.9	89.2

	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)	386.1	389.7	394.0	384.3	383.6	300.4	306.0	312.3	272.5	302.5	345.6	358.6	360.2	333.5	352.6	391.3	394.2	**398.9**	390.7	387.9	**398.9**
HSH, 3-Hour (µg/m^3)	230.1	211.7	205.0	156.8	184.1	139.6	146.0	141.4	124.6	154.5	195.6	177.3	178.0	140.2	176.9	**233.4**	215.0	208.4	161.8	186.5	**233.4**
HSH, 8-Hour (µg/m^3)	102.0	120.9	116.8	103.5	128.9	92.0	87.3	89.5	56.4	113.8	108.0	121.9	105.5	82.1	124.4	100.8	122.9	118.5	107.7	130.8	**139.6**
HSH, 24-Hour (µg/m^3)	73.4	60.2	58.9	46.2	89.1	55.1	46.3	48.3	24.0	72.6	70.8	53.9	59.4	38.6	85.6	68.5	61.1	60.5	48.1	86.6	**92.4**
Annual (µg/m^3)	6.6	5.6	4.2	3.1	3.9	3.0	2.4	2.0	1.3	1.8	4.9	4.1	3.2	2.3	2.9	**6.8**	5.8	4.3	3.2	4.0	**6.8**
SO_2																					
Emission Rate (g/s)	7.75	7.75	7.75	7.75	7.75	11.70	11.70	11.70	11.70	11.70	9.25	9.25	9.25	9.25	9.25	7.35	7.35	7.35	7.35	7.35	**13.2**
HSH, 3-Hour (µg/m^3)	178.3	164.1	158.9	297.8	142.7	163.4	170.8	165.4	145.8	180.8	180.9	164.0	164.6	308.5	163.7	171.6	158.0	153.2	287.2	137.1	**320.2**
HSH, 24-Hour (µg/m^3)	56.9	46.7	45.6	35.8	69.0	64.5	54.2	56.5	28.1	84.9	65.5	49.8	55.0	35.7	79.1	50.3	44.9	44.5	35.4	63.7	**85.1**
Annual (µg/m^3)	5.1	4.3	3.2	2.4	3.0	3.5	2.8	2.4	1.5	2.1	4.5	3.8	3.0	2.1	2.7	5.0	4.3	3.2	2.4	3.0	**5.2**
NO_2																					
Emission Rate (g/s)	9.61	9.61	9.61	9.61	9.61	14.82	14.82	14.82	14.82	14.82	11.58	11.58	11.58	11.58	11.58	9.10	9.10	9.10	9.10	9.10	**16.7**
Tier 2 Annual (µg/m^3)	4.8	4.0	3.0	2.2	2.8	3.3	2.6	2.3	1.4	2.0	4.3	3.6	2.8	2.0	2.5	4.7	4.0	2.9	2.2	2.8	**4.8**
PM/PM_{10}																					
Emission Rate (g/s)	5.76	5.76	5.76	5.76	5.76	6.50	6.50	6.50	6.50	6.50	6.04	6.04	6.04	6.04	6.04	5.68	5.68	5.68	5.68	5.68	**6.8**
HSH, 24-Hour (µg/m^3)	42.3	34.7	33.9	26.6	51.3	35.8	30.1	31.4	15.6	47.2	42.8	32.5	35.9	23.3	51.7	38.9	34.7	34.4	27.3	49.2	**53.6**
Annual (µg/m^3)	3.8	3.2	2.4	1.8	2.2	1.9	1.5	1.3	0.8	1.2	3.0	2.5	1.9	1.4	1.8	**3.9**	3.3	2.4	1.8	2.3	**3.9**
CO																					
Emission Rate (g/s)	9.40	9.40	9.40	9.40	9.40	7.61	7.61	7.61	7.61	7.61	7.07	7.07	7.07	7.07	7.07	10.24	10.24	10.24	10.24	10.24	**10.2**
HSH, 1-Hour (µg/m^3)	362.9	366.3	370.4	361.2	360.6	228.6	232.9	237.6	207.4	230.2	244.3	253.6	254.7	235.8	249.3	400.7	403.6	**408.4**	400.1	397.2	**408.4**
HSH, 8-Hour (µg/m^3)	95.9	113.6	109.8	97.2	121.2	70.0	66.4	68.1	42.9	86.6	76.3	86.2	74.6	58.1	87.9	103.2	125.8	121.3	110.3	**134.0**	**134.0**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (µg/m^3)	320.2	7	1995	1,300	1,300	24.6	24.6
HSH, 24-Hour (µg/m^3)	85.1	4	1996	260	365	32.7	23.3
Annual (µg/m^3)	5.2	6	1992	60	80	8.7	6.5
NO_2							
Annual (µg/m^3)	4.8	6	1992	100	100	4.8	4.8
PM_{10}							
HSH, 24-Hour (µg/m^3)	53.6	6	1996	150	150	35.7	35.7
Annual (µg/m^3)	3.9	12	1992	50	50	7.7	7.7
CO							
HSH, 1-Hour (µg/m^3)	408.4	12	1994	40,000	40,000	1.0	1.0
HSH, 8-Hour (µg/m^3)	134.0	12	1996	10,000	10,000	1.3	1.3

Source: ECT, 2000.

Table 6-2. 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 ($\mu g/m^3$)	307.0	313.6	317.9	280.5	309.2	373.3	378.0	384.1	369.7	370.1	448.6	462.3	447.6	440.0	440.7	335.0	349.1	350.8	311.2	340.2
HSH, 3-Hour ($\mu g/m^3$)	143.2	152.4	149.7	127.2	159.4	211.8	201.1	198.0	154.2	186.6	258.7	249.5	226.1	193.5	230.9	174.0	185.5	170.8	128.2	176.3
HSH, 8-Hour ($\mu g/m^3$)	96.3	89.1	92.2	58.8	118.5	116.8	133.5	112.3	98.7	134.6	146.4	139.5	128.9	144.7	147.3	107.3	112.1	102.4	75.4	131.8
HSH, 24-Hour ($\mu g/m^3$)	58.3	48.7	51.0	25.0	75.6	78.6	58.0	61.9	46.9	92.9	84.2	71.4	80.0	59.2	97.5	68.3	51.5	56.6	34.4	85.9
Annual ($\mu g/m^3$)	3.1	2.4	2.1	1.3	1.9	6.0	5.1	3.9	2.8	3.6	9.3	8.1	5.8	4.5	5.6	4.4	3.6	2.9	2.0	2.6
SO_2																				
Emission Rate (g/s)	1.35	1.35	1.35	1.35	1.35	1.09	1.09	1.09	1.09	1.09	0.88	0.88	0.88	0.88	0.88	1.26	1.26	1.26	1.26	1.26
HSH, 3-Hour ($\mu g/m^3$)	19.3	20.6	20.2	17.2	21.5	23.1	21.9	21.6	**40.3**	20.3	22.8	22.0	19.9	38.7	20.3	21.9	23.4	21.5	16.2	22.2
HSH, 24-Hour ($\mu g/m^3$)	7.9	6.6	6.9	3.4	10.2	8.6	6.3	6.7	5.1	10.1	7.4	6.3	7.0	5.2	8.6	8.6	6.5	7.1	4.3	**10.8**
Annual ($\mu g/m^3$)	0.4	0.3	0.3	0.2	0.3	0.7	0.6	0.4	0.3	0.4	**0.8**	0.7	0.5	0.4	0.5	0.5	0.5	0.4	0.2	0.3
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 ($\mu g/m^3$)	0.7	0.6	0.5	0.3	0.4	1.1	1.0	0.7	0.5	0.7	1.4	1.2	0.9	0.7	0.8	0.9	0.8	0.6	0.4	0.6
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 ($\mu g/m^3$)	15.1	12.6	13.2	6.4	19.5	19.8	14.6	15.6	11.8	23.4	20.8	17.6	19.8	14.6	24.1	17.5	13.2	14.5	8.8	22.0
Annual ($\mu g/m^3$)	0.8	0.6	0.5	0.3	0.5	1.5	1.3	1.0	0.7	0.9	2.3	2.0	1.4	1.1	1.4	1.1	0.9	0.7	0.5	0.7
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 ($\mu g/m^3$)	120.3	122.9	124.6	110.0	121.2	115.7	117.2	119.1	114.6	114.7	115.3	118.8	115.0	113.1	113.3	121.3	126.4	**127.0**	112.6	123.1
HSH, 8-Hour ($\mu g/m^3$)	37.8	34.9	36.1	23.0	46.5	36.2	41.4	34.8	30.6	41.7	37.6	35.9	33.1	37.2	37.9	38.8	40.6	37.1	27.3	47.7

Table 6-2. 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)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:										
HSH, 1-Hour ($\mu g/m^3$)	386.3	392.1	394.8	387.1	380.8	448.0	464.2	450.6	440.2	439.7
HSH, 3-Hour ($\mu g/m^3$)	218.6	212.2	216.9	162.4	187.8	259.1	248.8	226.1	192.1	232.3
HSH, 8-Hour ($\mu g/m^3$)	120.9	138.8	116.2	106.4	139.3	146.1	139.4	128.0	144.5	148.9
HSH, 24-Hour ($\mu g/m^3$)	82.2	60.2	64.1	50.4	96.3	84.3	71.3	79.8	59.2	98.0
Annual ($\mu g/m^3$)	6.7	5.7	4.3	3.2	4.0	9.3	8.0	5.8	4.5	5.6
SO_2										
Emission Rate (g/s)	1.03	1.03	1.03	1.03	1.03	0.82	0.82	0.82	0.82	0.82
HSH, 3-Hour ($\mu g/m^3$)	22.5	21.9	22.3	16.7	19.3	21.2	20.4	18.5	36.1	19.0
HSH, 24-Hour ($\mu g/m^3$)	8.5	6.2	6.6	5.2	9.9	6.9	5.8	6.5	4.9	8.0
Annual ($\mu g/m^3$)	0.7	0.6	0.4	0.3	0.4	0.8	0.7	0.5	0.4	0.5
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
Tier 2 Annual ($\mu g/m^3$)	1.2	1.0	0.8	0.6	0.7	1.3	1.1	0.8	0.6	0.8
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
HSH, 24-Hour ($\mu g/m^3$)	20.6	15.1	16.1	12.7	24.2	20.7	17.5	19.6	14.6	24.1
Annual ($\mu g/m^3$)	1.7	1.4	1.1	0.8	1.0	2.3	2.0	1.4	1.1	1.4
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
HSH, 1-Hour ($\mu g/m^3$)	114.3	116.1	116.8	114.6	112.7	110.2	114.2	110.8	108.3	108.2
HSH, 8-Hour ($\mu g/m^3$)	35.8	41.1	34.4	48.1	41.2	35.9	34.3	31.5	35.6	36.6

	Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:										
HSH, 1-Hour ($\mu g/m^3$)	337.1	351.2	353.3	315.6	342.5	388.8	395.1	396.5	390.2	383.0
HSH, 3-Hour ($\mu g/m^3$)	177.9	187.6	171.7	129.1	177.2	219.7	214.1	220.6	163.4	188.4
HSH, 8-Hour ($\mu g/m^3$)	107.8	114.4	103.1	77.0	132.6	121.6	139.7	116.9	107.7	140.1
HSH, 24-Hour ($\mu g/m^3$)	68.8	52.0	56.9	35.2	86.6	82.8	60.7	64.4	50.8	96.9
Annual ($\mu g/m^3$)	4.4	3.7	2.9	2.0	2.6	6.8	5.8	4.4	3.2	4.0
SO_2										
Emission Rate (g/s)	1.23	1.23	1.23	1.23	1.23	1.00	1.00	1.00	1.00	1.00
HSH, 3-Hour ($\mu g/m^3$)	21.9	23.1	21.1	38.8	21.8	22.0	21.4	22.1	39.0	18.8
HSH, 24-Hour ($\mu g/m^3$)	8.5	6.4	7.0	4.3	10.6	8.3	6.1	6.4	5.1	9.7
Annual ($\mu g/m^3$)	0.5	0.5	0.4	0.2	0.3	0.7	0.6	0.4	0.3	0.4
NO_2										
Emission Rate (g/s)	2.85	2.85	2.85	2.85	2.85	2.29	2.29	2.29	2.29	2.29
Tier 2 Annual ($\mu g/m^3$)	0.9	0.8	0.6	0.4	0.6	1.2	1.0	0.7	0.6	0.7
PM/PM_{10}										
Emission Rate (g/s)	2.56	2.56	2.56	2.56	2.56	2.49	2.49	2.49	2.49	2.49
HSH, 24-Hour ($\mu g/m^3$)	17.6	13.3	14.6	9.0	22.2	20.6	15.1	16.0	12.7	24.1
Annual ($\mu g/m^3$)	1.1	0.9	0.7	0.5	0.7	1.7	1.4	1.1	0.8	1.0
CO										
Emission Rate (g/s)	3.50	3.50	3.50	3.50	3.50	2.87	2.87	2.87	2.87	2.87
HSH, 1-Hour ($\mu g/m^3$)	118.0	122.9	123.7	110.5	119.9	111.6	113.4	113.8	112.0	109.9
HSH, 8-Hour ($\mu g/m^3$)	37.7	40.0	36.1	45.2	46.4	34.9	40.1	33.6	30.9	40.2

Table 6-2. 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/m³)	449.2	467.6	454.2	441.4	442.1	341.6	355.8	358.1	324.8	347.3	396.2	404.2	403.4	399.5	389.4	453.7	**479.5**	466.1	445.9	453.0	**479.5**
HSH, 3-Hour (μg/m³)	259.8	235.5	226.8	192.7	234.6	185.5	192.7	174.5	131.8	179.6	224.4	220.1	231.8	169.1	190.3	**262.4**	238.4	229.5	198.8	239.1	**262.4**
HSH, 8-Hour (μg/m³)	146.4	139.8	128.4	143.3	149.3	109.3	119.5	104.6	80.5	134.6	124.0	142.6	119.4	112.6	145.4	147.7	141.2	135.3	145.0	**150.9**	**150.9**
HSH, 24-Hour (μg/m³)	84.9	71.6	80.5	59.6	98.2	70.3	52.9	58.0	37.1	88.1	84.7	62.1	67.0	52.3	**99.6**	87.0	73.1	82.2	61.1	99.2	**99.6**
Annual (μg/m³)	9.3	8.0	5.8	4.5	5.6	4.7	3.9	3.1	2.1	2.8	7.2	6.2	4.6	3.5	4.3	**9.5**	8.3	6.0	4.7	5.7	**9.5**
SO_2																					
Emission Rate (g/s)	0.80	0.80	0.80	0.80	0.80	1.19	1.19	1.19	1.19	1.19	0.95	0.95	0.95	0.95	0.95	0.76	0.76	0.76	0.76	0.76	**1.4**
HSH, 3-Hour (μg/m³)	20.8	18.8	18.1	35.3	18.8	22.1	22.9	20.8	15.7	21.4	21.3	20.9	22.0	38.0	18.1	19.9	18.1	17.4	33.9	18.2	**40.3**
HSH, 24-Hour (μg/m³)	6.8	5.7	6.4	4.8	7.9	8.4	6.3	6.9	4.4	10.5	8.0	5.9	6.4	5.0	9.5	6.6	5.6	6.2	4.6	7.5	**10.8**
Annual (μg/m³)	0.7	0.6	0.5	0.4	0.4	0.6	0.5	0.4	0.3	0.3	0.7	0.6	0.4	0.3	0.4	0.7	0.6	0.5	0.4	0.4	**0.8**
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/m³)	1.3	1.1	0.8	0.6	0.8	1.0	0.8	0.6	0.4	0.6	1.2	1.0	0.8	0.6	0.7	1.2	1.1	0.8	0.6	0.7	**1.4**
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/m³)	20.9	17.6	19.8	14.7	24.2	17.9	13.5	14.8	9.5	22.5	21.0	15.4	16.6	13.0	**24.7**	21.2	17.8	20.1	14.9	24.2	**24.7**
Annual (μg/m³)	2.3	2.0	1.4	1.1	1.4	1.2	1.0	0.8	0.5	0.7	1.8	1.5	1.1	0.9	1.1	**2.3**	2.0	1.5	1.1	1.4	**2.3**
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/m³)	108.3	112.7	109.5	106.4	106.5	115.8	120.6	121.4	110.1	117.7	109.4	111.6	111.3	110.3	107.5	106.2	112.2	109.1	104.3	106.0	**127.0**
HSH, 8-Hour (μg/m³)	35.3	33.7	31.0	34.5	36.0	37.0	40.5	35.5	27.3	45.6	34.2	39.4	33.0	31.1	40.1	34.6	33.0	31.7	33.9	35.3	**48.1**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (μg/m³)	40.3	2	1995	1,300	1,300	3.1	3.1
HSH, 24-Hour (μg/m³)	10.8	4	1996	260	365	4.2	3.0
Annual (μg/m³)	0.8	3	1992	60	80	1.4	1.0
NO_2							
Annual (μg/m³)	1.4	3	1992	100	100	1.4	1.4
PM_{10}							
HSH, 24-Hour (μg/m³)	24.7	11	1996	150	150	16.5	16.5
Annual (μg/m³)	2.3	12	1992	50	50	4.7	4.7
CO							
HSH, 1-Hour (μg/m³)	127.0	4	1994	40,000	40,000	0.3	0.3
HSH, 8-Hour (μg/m³)	48.1	5	1995	10,000	10,000	0.5	0.5

Source: ECT, 2000.

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Karen Sheffield, General Mgr.

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Karen Sheffield, General Mgr.
Bayside Power Station
Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

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Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 27, 2000

Ms. Karen A. Sheffield, P.E.
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111

Re: Second Request for Additional Information
F. J. Gannon Station – Wood Derived Fuel Request for Units 1, 2 and 4
DEP File No.: 0570040-012-AC

Dear Ms. Sheffield:

This letter is being sent as a follow up to our letter dated September 26 and your response dated November 22, 2000. There are still some issues that need clarification in order to continue processing your request.

Item three of our September 26 letter requested information about a possible debottleneck at the facility. Your response indicated that Condition 3.a. of permit No. 0570040-006-AC is clearly a limit on coal fuel heat input only. The Department agrees with this assessment. The concern is that there does not appear to be a limit on the heat input from wood-derived fuel (WDF). The referenced permit does limit the fuel yard throughput of WDF to 362,025 tons per 12-month period. However, this is a processing limit, not a combustion limit. The heat input from WDF is clearly not limited by this permit. Please provide additional information that clearly demonstrates how a debottleneck will not occur.

The Consent Final Judgement, dated December 16, 1999, requires that these units be repowered from coal to natural gas between January 1, 2003 and December 31, 2004. Based on the current application being processed for the repowering project, it appears that these coal-fired boilers will be replaced by natural gas-fired combustion turbines. Since WDF can not be burned in combustion turbines, it appears that your authority to combust WDF will end with the removal of the coal-fired boilers in a very short time. It is our understanding that Unit 3, under its current limitations, can accommodate all of the WDF that is submitted to your facility for combustion. Considering the time it takes to obtain a construction permit, publish the required Public Notice, perform any required compliance demonstrations, then timely apply for and obtain a Title V operation permit revision to allow continued use of this new method of operation, we would like to better understand your need to process this request.

The information contained in your application indicates that you wish to have Units 1, 2 and 4 limited to the same operational conditions as specified for Unit 3 in permit No. 0570040-011-AC. Condition 3.A. of permit No. 0570040-011-AC limits the maximum amount of wood derived fuel (WDF) to 10% of the fuel fired on a weight basis. Condition 3.B. defines WDF to be paper pellets, yard trash, or wood/wood chips. As the result of test burns conducted on March 4 and May 27, 1998, Condition 3.C., further limited WDF to 7% of the total fuel stream, and to paper pellets only. It is not clear from your application if the request is to maintain the amount of WDF authorized for Unit 3 to be combusted proportionately in each of the four units, or if the desire is to allow up to 7% WDF (potentially 10% after successful testing) in each of the four units. An increase in the allowable amount of WDF could cause potential conflicts with the emissions netting activities that are currently underway as part of the repowering project (project number 0570040-013-AC). Please provide additional information that clearly outlines your WDF combustion requirements and your intent for each of the four units.

Item four of our September 26 letter requested a resubmission of the test results to support this specific application (i.e. 7% paper pellets). The test results that were submitted with your November 22 response indicate that the tests conducted on April 18 and 19, 2000, were performed using an actual WDF blend of 4% wood chips and 96% coal. The submitted test results do not support this specific application. Please provide the test results that indicate combusting 7% paper pellets causes no increase in pollutant emissions. Also, please clarify whether you were attempting to expand your combustion capabilities to include another classification of WDF.

If you should you have any questions regarding this matter, please contact Mr. Scott Sheplak at (850) 921-9532, or write to me at the above letterhead address.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/sms/h

cc: Mr. Jamie Hunter, TECO
Mr. Tomas W. Davis, P.E., ECT, Inc.
Mr. Jerry Campbell, EPCHC
Mr. Bill Thomas, DEP - SWD
Mr. Al Linero, DEP – BAR
Mr. Scott Sheplak, DEP – BAR
Mr. Jeffery Koerner, DEP - BAR

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Project No. 0570040-013-AC
Air Permit No. PSD-FL-301
F.J. Gannon Re-Powering Project

Authorized Representative:
Ms. Karen Sheffield, General Manager

Hillsborough County, Florida

Enclosed is Final Air Permit No. PSD-FL-301 (Project No. 0570040-013-AC). This permit authorizes construction of seven new combined cycle gas turbines to re-power the existing F.J. Gannon Station. The existing plant is renamed the "Bayside Power Station" and is located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. As noted in the Final Determination (attached), minor changes to the draft permit were made by the Department, mostly at the request of the applicant. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/30/01 to the person(s) listed:

Ms. Karen Sheffield, TEC Bayside Power Station*
Ms. Cindy Barringer, TEC Bayside Power Station
Mr. Patrick Shell, TEC
Mr. Tom Davis, ECT
Chair, Hillsborough County BCC

Mr. Jerry Campbell, HEPC
Mr. Bill Thomas, SWD
Mr. John Notar, NPS
Mr. Winston Smith, EPA Region 4

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 3/30/01
(Clerk) (Date)

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TEC Bayside Power Station
Port Sutton Road
Tampa, FL 33619

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Bayside Power Station
Re-Powering of the F.J. Gannon Plant
Hillsborough County, Florida

Air Permit No. PSD-FL-301
Project No. 0570040-013-AC

PROJECT DESCRIPTION

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Port Sutton Road in Tampa, Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed on December 7, 1999 and with the EPA/TEC Consent Decree entered on October 5, 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing the steam-electric turbine of Gannon Unit 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power the existing steam-electric turbine of Gannon Unit 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have a nominal electrical production capacity of approximately 1742 MW.

NOTICE, PUBLICATION, AND COMMENTS RECEIVED

The Department distributed an Intent to Issue Permit package on February 5, 2001 that authorizes the construction of the seven new combined cycle gas turbines to re-power the existing F.J. Gannon Station. The applicant published the "Public Notice of Intent to Issue" in The Tampa Tribune on February 10, 2001 and the Department received proof of publication on February 15, 2001. During the 30-day comment period, the Department received comments regarding the proposed draft permit from the following sources:

- In a letter dated March 6, 2001, the Hillsborough Environmental Protection Commission (HEPC) made several comments and suggestions.
- In a letter dated March 9, 2001, the Tampa Electric Company (TEC) made several comments and suggestions.
- In a letter dated March 12, 2001, the EPA Region 4 Office offered no written comments in addition to previous verbal comments made to staff.

On February 23, TEC filed for an extension of time in which to file for an administrative hearing. On March 14, 2001, the Department met with TEC to discuss and resolve their concerns. The meeting resulted in several mutually agreed upon minor changes. On March 16, 2001, the proposed changes were provided to the HEPC and EPA Region 4 office for additional comments with a response deadline of March 23, 2001. No additional comments on the proposed changes were received. The following sections identify the agreed upon changes, summarize other minor changes, and provide responses to other questions and concerns. Actual permit text is included in "quotation marks", deleted text is marked with a ~~strikethrough~~, and revised text is noted with a dotted underline.

RESPONSES AND REVISIONS

PLACARD PAGE (PAGE 1)

Expiration Date: Revised the "Expiration Date" from ~~December 31, 2004~~ to July 1, 2005 to allow a reasonable time to submit the Title V application and make it "complete". Added a requirement to complete physical construction by December 31, 2004 (original expiration date) to Condition 4 in section IIIA.

Statement of Basis: No revision was made. TEC withdrew request regarding rewording of references to the settlement agreements.

SECTION I. FACILITY INFORMATION

Page 2, Facility Description: For clarification, revised first sentence of descriptive text to, "Upon completion of construction by the end of 2004, the new Bayside Power Station will have a nominal electrical production capacity of 1742 MW based on the nominal capacities for Bayside Unit 1 (753 MW), Bayside Unit 2 (975 MW), and existing simple cycle combustion turbine CT-1 (14 MW)." Note: This change provides more detail and clarifies the nominal capacity of the plant in response to comments by both TEC and HEPC.

Page 2, Regulatory Classification, Title III: For clarification, revised second sentence of descriptive text to, "The MACT applicability determination for this project is deferred until ~~one new combined cycle gas turbine is tested for HAP emissions~~ completion of the HAP emissions testing as described in this permit."

Page 3, Regulatory Classification, Title V: For clarification, the first sentence of descriptive text was revised to, "The ~~existing~~ facility is a Title V major source of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year."

Page 3, Relevant Documents: For clarification, revised reference to the EPA/TEC Consent Decree to, "EPA/TEC Consent Decree ~~signed in February of 2000~~ entered on October 5, 2000; and".

SECTION II. STANDARD CONDITIONS

Page 4, Condition 8: Corrected typographical error of rule citation to, "[Rule 62-212.400(6)(b), F.A.C. and 40 CFR ~~52~~51.166(j)(4)]".

Page 5, Condition 12: No revision was made. TEC agrees to submit the Title V revision application for Bayside Unit 1 in accordance with this condition as drafted. However, TEC will specifically note the current schedule for completing Bayside Unit 2 in the application and that the required information will be provided as soon as possible to "complete" the application for a Title V revision. As previously mentioned, the expiration date was extended 6 months to allow additional time to make the application complete. A requirement to complete physical construction by December 31, 2004 (original expiration date) was added to Condition 4 in Section IIIA.

Page 5, Condition 18.a: No revision was made. HEPC suggested changing the minimum visible emissions observation period from 30 minutes to 60 minutes because of the multiple opacity standard in Condition 19.a in Section IIIA. The Department notes that this is an alternative standard specified for periods of startup and shutdown and does not intend the permittee to conduct regularly scheduled visible emissions tests for startup and shutdown in addition to tests for normal operation.

SECTION III. A. COMBINE CYCLE GAS TURBINES

Page 7, Emissions Unit Description: For clarification, revised table format and added descriptive text, "Bayside Unit 1 is designed to produce a nominal 753 MW and Bayside Unit 2 is designed to produce a nominal 975 MW of electrical power" under heading of "Generating Capacity".

Page 7, Condition 1: Deleted unnecessary comma after "particulate matter".

Page 8, Condition 4: As previously discussed, revised condition to:

> "4. Schedule: Bayside Unit 1 is scheduled for completion in ~~March~~ May 2003 and Bayside Unit 2 is scheduled for completion in ~~March~~ May 2004. Physical construction shall be complete by December 31, 2004. The permittee shall inform the Department of any substantial changes to the construction schedule. [Application; Rule 62-212.400, F.A.C.]"

Page 8, Condition 5: For clarification, revised the first sentence of condition to, "The permittee is authorized to install, tune, operate and maintain seven new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 170 MW ~~direct~~ of electrical power."

Page 8, Condition 5: For clarification, revised last sentence of condition to, "The permittee shall submit the final design data ~~upon completion~~ with the Title V application."

Page 8, Condition 8: For clarification, revised condition to:

"8. DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each combined cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the dry low-NOx combustors and automated gas turbine control system shall be tuned to ~~optimize the reduction of CO, NOx, and VOC emissions~~ minimize NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations ~~to minimize these pollutant emissions. The permittee shall provide at least 5 days advance notice prior to any tuning session.~~ For each regularly scheduled tuning session to be performed by the manufacturer, the permittee shall provide at least 5 days advance notice. Such notice is not required for tuning sessions conducted to mitigate an emergency, correct a malfunction, or provide engineering test data. [Design; Rule 62-212.400(BACT), F.A.C.]"

Page 8, Condition No. 9: For clarification, revised last sentence of condition to, "... The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels ~~control NOx emissions to the permitted levels with an ammonia slip no greater than 5 ppmvd corrected to 15% oxygen when firing natural gas and no greater than 9 ppmvd corrected to 15% oxygen when firing distillate oil~~."

Page 8, Condition 10: Revised last sentence of condition to, "The permittee shall submit the final design data ~~upon completion~~ with the Title V application."

Page 9, Condition 11: Moved redundant text "a compressor inlet air temperature of 59° F" from paragraph "a" and paragraph "b" to following unnumbered paragraph.

Page 9, Condition 13: Deleted this entire condition and renumbered accordingly. TEC maintained that the ability to operate the existing Gannon units as necessary until the required shutdown was a motivating factor during the settlement discussions. The Department agreed that the authority to prioritize dispatch of the remaining coal-fired units was not specifically addressed in the settlement agreements.

Page 9, Condition 14.c: No revision was made. TEC withdrew an initial request for a slightly higher oil-firing limit. HEPC requested clarification regarding the oil-firing limit. Each unit is capable of firing approximately 13,460 gallons of oil per hour for 875 hours, which is approximately 11,750,000 gallons per unit per year. The allowable oil-firing rate is based on a 12-month rolling total.

Page 10, Condition 16: Revised specific paragraphs of condition to:

"a. **Ammonia Slip**: ~~Each SCR system shall be designed and operated for a maximum ammonia slip of no more than 5 ppmvd corrected to 15% oxygen when firing natural gas and no more than 9 ppmvd corrected to 15% oxygen when firing distillate oil.~~ Subject to the requirements of Condition No. 25 in this section, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas. When firing distillate oil, the ammonia slip shall not exceed 9 ppmvd corrected to 15% oxygen. [Rule 62-4.070(3), F.A.C.]"

b. No revision was made. TEC's withdrew initial comments regarding CO emissions.

d. Based on EPA Region 4's verbal comments, revised the last sentence before the permitting note to, "Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as ~~surrogate standards for particulate matter~~ indicators of good combustion." HEPC suggested moving the notes regarding "expected maximum" particulate matter emissions from the note to the enforceable part of the condition. The Department did not intend these rates to be enforceable and, as such, did not require any compliance testing for particulate matter. Instead, the "efficient combustion of clean fuels" is the BACT control and compliance with the CO CEMS limit serves as an indicator of good combustion.

g. Based on EPA Region 4's verbal comments, revised the last sentence before the permitting note to, "Compliance with CO standards shall serve as ~~surrogate standards for VOC emissions~~ indicators of good combustion." HEPC suggested moving the notes regarding "expected maximum" VOC emissions from the note to the enforceable part of the condition. The Department has the same response as that for particulate matter above.

Page 10, Condition 19: Revised specific paragraphs of condition to:

"b. ~~Except for startup and shutdown, operation below 50% base load is prohibited.~~ Excluding startup, shutdown, and documented unavoidable malfunction, each gas turbine is allowed up to 3 hours of operation below 50% base load in any 24-hour block period, providing:

(1) The gas turbine is firing natural gas;

(2) The CO and NOx CEM systems are functioning properly during such periods and valid emissions data (within the span range of the monitors) is being monitored and recorded; and

(3) The gas turbine remains in compliance with the CO and NOx emissions standards (24-hour block averages) based on valid CEM system data.

Note: Operation during startup, shutdown, and documented unavoidable malfunction are addressed in Condition No. 27.d."

c. Revised first sentence to, "A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more ~~and~~ or the first stage turbine metal temperature is 250° F or less."

"e. For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of the procedures, and the methods used to minimize emissions during these periods. Within 90 days of completing ~~the~~ eight~~h~~ steam turbine cold startups following commencement of commercial operation or within 90 days after 12 months of commercial operation, whichever occurs first, the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether the period of data exclusion for a steam turbine cold startup defined in Condition 27 of this section shall be ~~*decreased*~~ modified to represent good operational practices. The Department shall also evaluate the operational information and determine whether a separate "warm startup" requirement shall be specified in the Title V operation permit for startup after the steam turbine has been offline for 24 hours or more, but less than 48 hours."

Page 12, Condition 22: Revised third sentence of condition to, "Tests for CO~~,~~ and NOx~~, and VOC~~ shall be conducted concurrently." This was a typographical error as no testing was required for VOC emissions.

Page 13, Condition 23: Replaced last sentence of this condition with, "Within 60 days after submittal of the HAP emissions test report, the permittee shall submit a revised MACT applicability analysis (based on the test data and current EPA guidance) and propose a Maximum Available Control Technology for the units, if required." Note: At this time, the Department is aware of only two viable HAP emissions control options for this project: an oxidation catalyst and the efficient high-temperature combustion of the General Electric Model PG7241(FA) gas turbine.

Page 13, Condition 24: Changed "200" to "400" hours of oil firing as the threshold for conducting compliance tests if oil if fired as a backup fuel. Deleted third sentence of condition to clarify that annual CO and NOx emissions testing (in addition to CEMS monitoring) is not required and added following, "{Permitting Note: Continuous compliance with the CO and NOx standards is demonstrated with certified CEMS system data.}"

Page 13, Condition 25: Completely revised condition to:

"25. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Take corrective actions before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen that lowers the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]"

Note: Ammonia emissions greater than "7" ppmvd corrected to 15% oxygen would be considered a permit violation subject to daily penalties until corrected.

Page 13, Condition 26: Deleted condition and renumbered accordingly. It was considered unnecessary because Condition No. 22 in Section II previously addressed conducting "special compliance tests" in accordance with Rule 62-297.310(7)(b), F.A.C.

Page 13 and 14, Condition 27: This condition was revised to:

27. Continuous Emission Monitoring System: Removed references to an oxygen monitor because TEC will install a CO_2 monitor.

a. *Data Collection.* Replaced seventh sentence with, "~~All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.~~ The CEM system shall be designed and operated to sample, analyze, and record data evenly spaced over the hour."

c. *CO and~~,~~ CO_2~~, and Oxygen~~ Certification.* Removed references to an oxygen monitor because TEC will install a CO_2 monitor.

d. *Data Exclusion*. Revised paragraph (2) to:

"(2) Periods of data excluded for a steam turbine cold startup shall not exceed sixteen hours in any ~~block~~ 24-hour block period. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more ~~and~~ or the first stage turbine metal temperature is 250° F or less. Based on actual operating experience and data, the Department may ~~*decrease*~~ modify this period of data exclusion in the Title V air operating permit without modifying this PSD permit."

Page 16, Condition 30: Revised first sentence of condition to:

"30. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of distillate oil consumption for each gas turbine ~~of each allowable fuel~~ in accordance with the provisions of 40 CFR 75 Appendix D."

SECTION III.C. EXISTING EMISSIONS UNITS

Page 18, Condition 1: Revised last sentence of condition to, "Upon first fire in any combined cycle gas turbine for Bayside Unit 1, the heat input limit on the coal yard (EU-008) is reduced to 56.7 x 10^{+06} mmBTU per calendar year ~~consecutive 12 months~~." Note: The calendar year basis for the coal yard heat-input limit is consistent with the original permit condition.

Page 18, Condition 2: Revised last sentence of condition to, "Upon first fire in any combined cycle gas turbine for Bayside Unit 2, the heat input limit on the coal yard (EU-008) is reduced to 35.3 x 10^{+06} mmBTU per calendar year ~~consecutive 12 months~~." Note: The calendar year basis for the coal yard heat-input limit is consistent with the original permit condition.

SECTION IV. APPENDICES

Appendix B: Minor formatting changes were made to the emissions summary table and additional notes added. Additional details were included in the Final BACT Determinations summary.

Appendix GC, Condition G.2: This condition was not revised because it is directly from Rule 62-4.160, F.A.C.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Page 6, Paragraph 3.7: TEC asserts that available information suggests that substantial increases in CO emissions resulted from their efforts to reduce NOx emissions from the Gannon coal-fired boilers (primarily by reducing the combustion oxygen). TEC believes that the single 3-hour test performed on Gannon Unit 5 confirms this supposition. TEC does not believe that the AP-42 emission factors represent reasonable CO emissions from coal-fired boilers using lean combustion to control NOx emissions. The Department notes the following:

- TEC submitted a supporting document entitled, "Results from the ICCT T-Fired Demonstration Project Including the Effect of Coal Fineness on NOx Emissions and Unburned Carbon Levels (Hardman, Smith, and Tavoulareas)", which was presented at the EPRI/EPA Joint Symposium on Stationary NOx Control in May of 1993.
- The NOx reduction strategies were included as a pollution control project in 1996. At this time, TEC did not identify that any substantial increases in CO emissions would result.
- Through at least 1999, TEC continued to submit CO emissions data in their Annual Operating Reports based on AP-42 emission factors.
- The Department does not believe a 3-hour stack test is sufficient to determine annual emissions.

The Department acknowledges that TEC disagrees with the Department's PSD applicability determination regarding CO emissions.

Page 9, Paragraph 4.2: TEC withdrew initial comments questioning the oil-firing limit.

Page 10, Table 4.1: TEC requested that ammonia slip limits be included for the projects listed in this table. The Department does not have ready access to this information for out-of-state projects. However, the following table summarizes ammonia slip limits for recently permitted projects in Florida.

Facility	Ammonia Slip Limit
Calpine Osprey Energy Center	9 ppmvd @ 15% O2, gas only
Calpine Blue Heron Energy Center	5 ppmvd @ 15% O2, gas only
FPC Hines Power Block II	5 ppmvd @ 15% O2, gas 9 ppmvd @ 15% O2, oil
CPV Gulfcoast	5 ppmvd @ 15% O2, gas and oil
CPV Atlantic	5 ppmvd @ 15% O2, gas and oil
KUA Cane Island Unit 3	5 ppmvd @ 15% O2, gas and oil
Duke New Smyrna Beach Power	5 ppmvd @ 15% O2, gas only

Page 15, Paragraph 4.7: HEPC notes that this paragraph indicates a volume of "5.85" million gallons for the distillate oil tank (EU 027), but that the Draft Permit specifies an "8" million gallons. The Department agrees that this should read "8" million gallons.

Page 16, Paragraph 5: The Department acknowledges that TEC disagrees with the Department's determination regarding MACT applicability. TEC maintains that the three gas turbines serving a single steam turbine comprising Bayside Unit 1 and the four gas turbines serving single steam turbine comprising Bayside Unit 2 are separate "process or production units" as defined by the MACT regulations in Section 112(g) of the Clean Air Act Amendments of 1990. Therefore, the potential HAP emissions must be considered independently when determining MACT applicability. The Department disagrees with this interpretation, as does EPA Region 4.

Pages 19 and 20, Paragraph 7.3: This section discusses an estimated reduction in the operation of existing coal-fired Gannon Units 1 – 4 after the Bayside Units become operational. This information is based on several assumptions made by the Department's reviewing project engineer and is not an enforceable requirement. The Department recognizes that TEC does not necessarily agree with the assumptions or conclusions regarding this point.

CONCLUSION

Other typographical and formatting errors were corrected. The Department considers all revisions to be minor. The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Project No. 0570040-013-AC
Air Permit No. PSD-FL-301
Facility ID No. 0570040
SIC No. 4911
Expires: July 1, 2005

Authorized Representative:
Ms. Karen Sheffield, General Manager

PROJECT AND LOCATION

This permit authorizes construction of seven new combined cycle gas turbines with a nominal electrical production capacity of approximately 1728 MW to re-power the existing Gannon Station. The existing plant is renamed the "Bayside Power Station" and is located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. The UTM coordinates are Zone 17, 360.00 km E, 3087.50 km N.

STATEMENT OF BASIS

The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department. This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. Specifically, this permit is issued pursuant to the Chapter 62-212, F.A.C. requirements for Preconstruction Review of Stationary Sources and the Prevention of Significant Deterioration (PSD) of Air Quality. The conditions of this permit do not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A - Terminology
Appendix B - Final BACT Determinations and Emissions Standards
Appendix E - Summary of Mass Emissions for Given Inlet Temperatures
Appendix GC - General Conditions
Appendix GG - NSPS Subpart GG Requirements for Gas Turbines
Appendix XS - Semi-Annual Continuous Monitor Systems Report

Howard L. Rhodes
Howard L. Rhodes, Director
Division of Air Resources Management

3/30/01
(Date)

FACILITY DESCRIPTION

Upon completion of construction by the end of 2004, the new Bayside Power Station will have a nominal electrical production capacity of 1742 MW based on the nominal capacities for Bayside Unit 1 (753 MW), Bayside Unit 2 (975 MW), and existing simple cycle combustion turbine CT-1 (14 MW). The following table summarizes the emission units and current status upon issuance of this air construction permit.

EU No.	Status [a]	Emission Unit Description
001	A [d]	Gannon Unit 1 – 125 MW coal fired boiler with steam electrical generator
002	A [d]	Gannon Unit 2 – 125 MW coal fired boiler with steam electrical generator
003	A [d]	Gannon Unit 3 – 180 MW coal fired boiler with steam electrical generator
004	A [d]	Gannon Unit 4 – 188 MW coal fired boiler with steam electrical generator
005	A [b, d]	Gannon Unit 5 – 239 MW coal fired boiler with steam electrical generator
006	A [c, d]	Gannon Unit 6 – 414 MW coal fired boiler with steam electrical generator
007	A	Combustion Turbine No. 1 – 14 MW simple cycle gas turbine
008	A	Gannon Station Coal Yard - Serves Gannon Units 1 – 6
009	A	Economizer Ash Silo w/Baghouse – Serves Gannon Unit No. 4
010	A	Fly Ash Silo No. 1 w/Baghouse – Serves Gannon Units 5 and 6
011	A	Fly Ash Silo No. 2 w/Baghouse – Serves Gannon Units 1 – 4
012	A	Pug Mill and Truck Unloading – Serves Gannon Units 5 and 6
013	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 1
014	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 2
015	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 3
016	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 4
017	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 5
018	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 6
019	I	Inactive emission unit
020	C [b]	Bayside Unit 1A – 170 MW combined cycle gas turbine
021	C [b]	Bayside Unit 1B – 170 MW combined cycle gas turbine
022	C [b]	Bayside Unit 1C – 170 MW combined cycle gas turbine
023	C [c]	Bayside Unit 2A – 170 MW combined cycle gas turbine
024	C [c]	Bayside Unit 2B – 170 MW combined cycle gas turbine
025	C [c]	Bayside Unit 2C – 170 MW combined cycle gas turbine
026	C [c]	Bayside Unit 2D – 170 MW combined cycle gas turbine
027	A	Distillate Oil Storage Tank - 8 million gallon capacity serves Bayside Units

Notes:

a. Status: A (Active), I (Inactive), C (Under Construction)

b. EU 005 must be shutdown before operating EUs 020, 021, and 022.

c. EU 006 must be shutdown before operating EU 023, 024, 025, and 026.

d. EUs 001, 002, 003, 004, 005, and 006 must be shut down before January 1, 2005.

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). The MACT applicability determination for this project is deferred until completion of the HAP emissions testing as described in this permit.

Title IV: The facility has several emissions units, including the new combined cycle gas turbines, that are subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PPSC: The existing Gannon Station was constructed prior to the power plant site certification requirements of Chapter 62-17, F.A.C. The re-powering project is not subject to power plant site certification because there will be no expansion of the steam electrical generating capacity.

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the industries listed as one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

NESHAP: The permittee did not identify any emission unit as being subject to a National Emissions Standard for Hazardous Air Pollutants (NESHAP).

NSPS: The new combined cycle gas turbines are subject to the New Source Performance Standards (NSPS) of 40 CFR 60, Subpart GG and the oil storage tank is subject to 40 CFR 60, Subpart Kb.

RELEVANT DOCUMENTS

- DEP/TEC Consent Final Judgment signed on December 7, 1999;
- EPA/TEC Consent Decree entered on October 5, 2000; and
- PSD permit application received on September 21, 2000 and all related correspondence.

ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road - MS #5505, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authorities: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southwest District Office, Florida Department of Environmental Protection, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218. The phone number is 813/744-6100 and the fax number is 813/744-6084. Copies of all such documents shall be submitted to the Air Management Division of the Hillsborough County Environmental Protection Commission, 1410 North 21 Street, Tampa, FL 33605. The phone number is 813/272-5530 and the fax number is 813/272-5605.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.

4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. Such an extension does not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree. [40 CFR 52.21(r)(2)]

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. Such an extension does not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with an extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The

Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least ninety days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation with copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. [Rule 62-210.700(4), F.A.C.]

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

18. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. **Required Sampling Time**. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

b. **Minimum Sample Volume**. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. **Calibration of Sampling Equipment**. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

[Rule 62-297.310(4), F.A.C.]

19. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C.; 40 CFR 60.7 and 60.8]

20. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

21. Determination of Process Variables

a. **Required Equipment**. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

b. **Accuracy of Equipment**. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

22. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

23. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

24. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

25. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

A. COMBINED CYCLE GAS TURBINES

This section of the permit addresses the following new emissions units.

EU ID	Bayside ID	Common Emission Unit Description
020 021 022 023 024 025 026	1A 1B 1C 2A 2B 2C 2D	Combined Cycle Gas Turbines: Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the primary fuel with very low sulfur distillate oil as a limited backup fuel.
Controls: Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas and combined with water injection when firing very low sulfur distillate oil as a backup fuel. **Heat Input**: At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F. At a compressor inlet air temperature of 59° F and firing 1995 mmBTU (HHV) per hour of very low sulfur distillate oil, each unit produces approximately 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,160,000 acfm at 275° F. **Generating Capacity**: Bayside Units 1A, 1B, and 1C supply steam to a single steam electrical generator (formerly serving Gannon Unit 5) with a nameplate rating of 239 MW. Bayside Units 2A, 2B, 2C, and 2D supply steam to a single steam electrical generator (formerly serving Gannon Unit 6) with a nameplate rating of 414 MW of electrical power. Bayside Unit 1 is designed to produce a nominal 753 MW and Bayside Unit 2 is designed to produce a nominal 975 MW of electrical power.		

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). [Rule 62-212.400(BACT), F.A.C.]

2. MACT Determination: The MACT applicability determination for this project is deferred until a combined cycle gas turbine is tested for HAP emissions in accordance with Condition No. 22 of this section. However, the permittee shall plan accordingly for the possibility of future applicable controls. If additional controls are later required, the Department shall allow the permittee a reasonable time to install equipment and conform to new or additional conditions. [Rules 62-4.080 and 62-204.800(10)(d), F.A.C.; Section 112(g), CAAA]

3. NSPS Requirements: Each gas turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. **Subpart A, General Provisions**, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. **Subpart GG, Standards of Performance for Stationary Gas Turbines** as specified in *Appendix GG* of this permit.

EQUIPMENT

4. Schedule: Bayside Unit 1 is scheduled for completion in May of 2003 and Bayside Unit 2 is scheduled for completion in May of 2004. Physical construction shall be complete by December 31, 2004. The permittee shall inform the Department of any substantial changes to the construction schedule. [Application; Rule 62-212.400(BACT), F.A.C.]

5. Combined Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain seven new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 170 MW of electrical power. Each unit shall be designed as a combined cycle system to include an automated gas turbine control system, an inlet air filtration system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter, and associated support equipment. [Applicant Request; Design]

6. Heat Recovery Steam Generators (HRSG): The preliminary design of the HRSGs provides three levels of steam conditions when firing natural gas (high pressure, intermediate pressure, and low pressure) and two levels of steam conditions when firing very low sulfur distillate oil as a backup fuel (high pressure and intermediate pressure). The Bayside 1 Unit HRSGs will be identical and the Bayside 2 Unit HRSGs will be identical. The permittee shall submit the final design data with the Title V application. [Design]

7. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated gas turbine control system for each combined cycle unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. [Design; 62-212.400(BACT), F.A.C.]

8. DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each combined cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the dry low-NOx combustors and automated gas turbine control system shall be tuned to minimize NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. For each regularly scheduled tuning session to be performed by the manufacturer, the permittee shall provide at least 5 days advance notice. Such notice is not required for tuning sessions conducted to mitigate an emergency, correct a malfunction, or provide engineering test data. [Design; Rule 62-212.400(BACT), F.A.C.]

9. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate and maintain an SCR system to control NOx emissions from each combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, anhydrous ammonia storage, monitoring and control system, electrical, piping and other support equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]

10. Evaporative Inlet Air-Cooling System: Each combined cycle gas turbine may have an evaporative cooling system designed to reduce the temperature of the inlet air to the gas turbine compressor. The reduced temperature provides a greater mass flow rate and increase in power production with additional fuel combustion. The preliminary design is for a water distribution system with packed media blocks of corrugated layers of fibrous material. Air passing over the system wicks moisture away from the media to create the cooling effect. The permittee shall submit the final design data with the Title V application. [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

11. Permitted Capacity: The maximum heat input rates to each gas turbine shall not exceed the following:

    a. **Natural Gas Firing**: 1842 mmBTU per hour while producing approximately 170 MW.

    b. **Distillate Oil Firing**: 1995 mmBTU per hour while producing approximately 182 MW.

    The heat input rates are based on a compressor inlet air temperature of 59° F, the higher heating values (HHV) of each fuel and expected performance levels beyond the manufacturer's guarantee. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

12. Allowable Fuels: As the primary fuel, each combined cycle gas turbine shall fire pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet of natural gas. As a backup fuel, each combined cycle gas turbine may be fired with very low sulfur No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight. No other fuels are allowed. [Design; Rules 62-210.200(PTE); DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree]

13. Restricted Operation: The hours of operation for each combined cycle gas turbine are not limited (8760 hours per year). However, very low sulfur distillate oil may only be fired as a backup fuel, provided:

    a. The unit cannot fire natural gas;

    b. The unit fires No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight as the backup fuel;

    c. The unit fires no more than 11,775,000 gallons of very low sulfur distillate oil during any consecutive 12 months (equivalent to 875 hours per year of oil firing);

    d. All air pollution controls are functional and used to the maximum extent possible for the unit; and

    e. The unit is in compliance with the emissions standards of this permit.

    [Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.; EPA/TEC Consent Decree]

14. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combined cycle gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix B of this permit.}

15. Emissions Standards Based on Performance Tests: The following standards apply to each combined cycle gas turbine as determined by emissions performance tests conducted at permitted capacity. The mass emission limits are based a compressor inlet temperature of 59° F. For comparison to the standard, actual measured mass emissions shall be corrected to a compressor inlet temperature of 59° F with manufacturer's data on file with the Department.

a. **Ammonia Slip**: Subject to the requirements of Condition No. 24 in this section, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas. When firing distillate oil, the ammonia slip shall not exceed 9 ppmvd corrected to 15% oxygen. [Rule 62-4.070(3), F.A.C.]

b. **Carbon Monoxide (CO)**: When firing natural gas, CO emissions shall not exceed 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen. When firing distillate oil, CO emissions shall not exceed 64.5 pounds per hour and 15.0 ppmvd corrected to 15% oxygen. Compliance shall be based on a 3-run test average as determined by EPA Method 10. Certified CEM system data may be used to demonstrate compliance with this standard. [Rule 62-212.400(BACT), F.A.C.]

c. **Nitrogen Oxides (NOx)**: When firing natural gas, NOx emissions shall not exceed 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen. When firing distillate oil, NOx emissions shall not exceed 79.2 pounds per hour and 12.0 ppmvd corrected to 15% oxygen. NOx emissions are defined as oxides of nitrogen reported as NO_2. Compliance shall be based on a 3-run test average as determined by EPA Methods 7E. Certified CEM system data may be used to demonstrate compliance with this standard. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree; 40 CFR 60.332]

d. **Particulate Matter (PM/PM_{10})**: The fuel specifications in Condition No. 12 of this section combined with the efficient combustion design and operation of each combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. {Permitting Note: Particulate matter emissions are expected to be less than 12 pounds per hour when firing natural gas and less than 30 pounds per hour when firing distillate oil, as determined by EPA Methods 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]

e. **Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)**: The limits on fuel sulfur specified in Condition No. 12 of this section effectively limit the potential emissions of SO_2 and SAM. Compliance with the fuel sulfur limits shall be demonstrated by the fuel sampling, analysis, record keeping and reporting requirements in Condition No. 27 of this section. [Design; 40 CFR 60.333]

f. **Visible Emissions**: When firing either natural gas or distillate oil, visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition No. 18 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

g. **Volatile Organic Compounds (VOC)**: The efficient combustion of clean fuels and good operating practices for each combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the CO standards shall serve as indicators of good combustion. {Permitting Note: VOC emissions are expected to be less than 3 pounds per hour (1.3 ppmvd corrected to 15% oxygen) when firing natural gas and less than 7.5 pounds per hour (3.0 ppmvd corrected to 15% oxygen) when firing distillate oil, as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-212.400(BACT), F.A.C.]

16. <u>Emissions Standards Based on CEM System Data</u>: The following standards apply to each combined cycle gas turbine based on data collected from required Continuous Emissions Monitoring (CEM) systems.

a. **Carbon Monoxide (CO)**: When firing natural gas, CO emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, CO emissions shall not exceed 20.0 ppmvd corrected to 15% oxygen based on a 24-hour block average.

b. **Nitrogen Oxides (NOx)**: When firing natural gas, NOx emissions shall not exceed 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 24-hour block average.

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the CO and NOx CEM system compliance averages. [Rule 62-210.700(4), F.A.C.]

18. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of each combined cycle gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

    a. During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

    b. Excluding startup, shutdown, and documented unavoidable malfunction, each gas turbine is allowed up to 3 hours of operation below 50% base load in any 24-hour block period, providing:

        (1) The gas turbine is firing natural gas;

        (2) The CO and NOx CEM systems are functioning properly during such periods and valid emissions data (within the span range of the monitors) is being monitored and recorded; and

        (3) The gas turbine remains in compliance with the CO and NOx emissions standards (24-hour block averages) based on valid CEM system data.

    Note: Operation during startup, shutdown, and documented unavoidable malfunction are addressed in Condition No. 25.

    c. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more or the first stage turbine metal temperature is 250° F or less. To minimize emissions, no more than one gas turbine for each Bayside Unit shall be operated during such a startup. The permittee shall notify each Compliance Authority at least 24 hours in advance of a steam turbine cold startup.

    d. In accordance with Condition No. 25 of this section, specific data collected by the CEM systems during startup, shutdown, malfunction, and tuning may be excluded from the CO and NOx compliance averaging periods. If a CEM system reports emissions in excess of a 24-hour block emissions standard, the permittee shall notify the Compliance Authority within one (1) working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    e. For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of the procedures, and the methods used to minimize emissions during these periods. Within

90 days of completing eight steam turbine cold startups following commencement of commercial operation or within 90 days after 12 months of commercial operation, whichever occurs first, the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether the period of data exclusion for a steam turbine cold startup defined in Condition 25 of this section shall be modified to represent good operational practices. The Department shall also evaluate the operational information and determine whether a separate "warm startup" requirement shall be specified in the Title V operation permit for startup after the steam turbine has been offline for 24 hours or more, but less than 48 hours.

[Design; Rules 62-210.700, 62-4.130, and Rule 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

20. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
5	Determination of Particulate Matter Emissions from Stationary Sources • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 dscf per run.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography • EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

21. Initial Compliance Tests: Each combined cycle gas turbine shall be tested when firing each authorized fuel to demonstrate compliance the emission standards for CO, NOx, visible emissions and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. Tests for CO and NOx shall be conducted concurrently. Certified CEM system data may be used to demonstrate compliance with the CO and NOx standards. The test results for ammonia slip shall also report the average NOx emissions during each test run. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

22. Initial HAP Performance Tests: At least one of the Bayside Unit 1 combined cycle gas turbines shall be tested when firing natural gas for total volatile organic compounds and the following hazardous air pollutant (HAP) emissions: acetaldehyde, formaldehyde, toluene, and xylene. EPA Method 25A shall be used to determine the emission rate of total volatile organic compounds and EPA Method 18 shall be used to determine the emission rate of each individual HAP. The tests must be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. Tests shall be conducted at two operating rates: between 65% and 75% of permitted capacity and between 90% to 100% of permitted capacity. For each operating rate, the tests shall consist of at least three 1-hour runs and emissions shall be reported in terms of ppmvd corrected to 15% oxygen, pounds per million BTU, pounds per hour, and pounds per MW-hour. The test report shall include the gas turbine exhaust temperature (prior to the heat recovery steam generator) and the average CO and NOx emissions recorded by the CEM systems. Within 60 days after submittal of the HAP emissions test report, the permittee shall submit a revised MACT applicability analysis (based on the test data and current EPA guidance) and propose a MACT for the units, if required. [Rule 62-4.070(3), F.A.C.]

23. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each combined cycle gas turbine shall be tested when firing natural gas to demonstrate compliance with the emission standards for ammonia slip and visible emissions. Each combined cycle gas turbine that fires more than 400 hours of distillate oil during the federal fiscal year shall also be tested for visible emissions and ammonia slip when firing oil. NOx emissions recorded by the CEM system during the test for ammonia slip shall be reported for each test run. {Permitting Note: Continuous compliance with the CO and NOx standards is demonstrated with certified CEMS system data.} [Rules 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.]

24. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

   a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

   b. Take corrective actions before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen that lowers the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

   c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

   Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. Continuous Emissions Monitoring Systems: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring (CEM) system in the exhaust stack of each emissions unit to measure and record the emissions of NOx and CO from these emissions units in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit. The carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where NOx and CO are monitored to correct the measured NOx and CO emissions rates to 15% oxygen. The oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel being fired. The CEM system shall be used to demonstrate compliance with the CEM emission standards for NOx and CO specified in this permit.

    a. *Data Collection.* Compliance with the CEM emission standards for NOx and CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. Each hourly value shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. The CEM system shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

    b. *NOx Certification.* The NOx monitor shall be certified and operated in accordance with the following requirements. The NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the CEM emission standards of this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

    c. *CO and CO_2 Certification.* The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semi-annually to each Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than

20 ppm, and the span for the upper range shall not be greater than 60 ppm, as corrected to 15% oxygen. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *Data Exclusion.* Emissions data for NOx, CO and CO_2 (or oxygen content) shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NOx and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards as provided in this paragraph.

(1) Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented unavoidable malfunction shall not exceed two hours in any 24-hour block period. Periods of data excluded for such episodes shall not exceed a total of four hours in any 24-hour block period. Gas turbine startup is the commencement of operation of a gas turbine which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion. A documented unavoidable malfunction is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

(2) Periods of data excluded for a steam turbine cold startup shall not exceed sixteen hours in any 24-hour block period. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more or the first stage turbine metal temperature is 250° F or less. Based on actual operating experience and data, the Department may modify this period of data exclusion in the Title V air operating permit without modifying this PSD permit.

(3) If the permittee provides at least five days advance notice prior to a tuning session, data may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards. Periods of data excluded for such episodes shall not exceed a total of three hours in any 24-hour block period. Tuning sessions must be performed in accordance with the manufacturer's recommendations. No more than two such tuning sessions are expected during any year.

All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported semi-annually to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including periods in which no data is excluded or no instances of missing data occur.

f. *Data Conversion.* Upon a Department request, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

g. *Availability.* NOx and CO monitor availability shall not be less than 95% in any calendar quarter.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Ammonia Monitoring Requirements: The permittee shall install, calibrate, maintain and operate, in accordance with the manufacturer's specifications, an ammonia flow meter to measure and record the ammonia injection rate to each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of combustion turbine load conditions allowed by this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS

27. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of distillate oil consumption for each gas turbine in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption and hours of operation for each gas turbine. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

B. STORAGE TANK

This section of the permit addresses the following emissions unit.

EU ID	Emission Unit Description
027	Oil Storage Tank: Existing eight million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to the combined cycle gas turbines (EUs 020 through 026).

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]
2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE REQUIREMENTS

3. Equipment: The existing 8 million gallon tank shall provide storage for the very low sulfur distillate oil used as backup fuel for the combined cycle gas turbines. [Applicant Request]
4. Hours of Operation: Operation for the distillate oil storage tank is not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

RECORDS

5. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual throughput of distillate oil through the storage tank. [Rule 62-210.370(3), F.A.C.]
6. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

C. EXISTING EMISSIONS UNITS

The following conditions supplement all other valid air construction and operation permits for these units.

EU ID	Emission Unit Description
001	Gannon Unit 1 – 125 MW coal fired boiler with steam electrical generator
002	Gannon Unit 2 – 125 MW coal fired boiler with steam electrical generator
003	Gannon Unit 3 – 180 MW coal fired boiler with steam electrical generator
004	Gannon Unit 4 – 188 MW coal fired boiler with steam electrical generator
005	Gannon Unit 5 – 239 MW coal fired boiler with steam electrical generator
006	Gannon Unit 6 – 414 MW coal fired boiler with steam electrical generator
008	Gannon Station Coal Yard - Serves Gannon Units 1 – 6

SHUTDOWN REQUIREMENTS

1. Shutdown of Gannon Unit 5: Gannon Unit 5 (EU 005) shall be shut down and rendered incapable of operation prior to first fire in any combined cycle gas turbine for Bayside Unit 1 (EU 020 – EU 022). Upon first fire in any combined cycle gas turbine for Bayside Unit 1, the heat-input limit on the coal yard (EU 008) is reduced to 56.7 x 10^{+06} mmBTU per calendar year. [Rule 62-212.400(BACT), F.A.C.]

2. Shutdown of Gannon Unit 6: Gannon Unit 6 (EU 006) shall be shut down and rendered incapable of operation prior to first fire in any combined cycle gas turbine for Bayside Unit 2 (EU 023 – EU 026). Upon first fire in any combined cycle gas turbine for Bayside Unit 2, the heat-input limit on the coal yard (EU 008) is reduced to 35.3 x 10^{+06} mmBTU per calendar year. [Rule 62-212.400(BACT), F.A.C.]

3. Shutdown of Gannon Units 1 - 6: The permittee shall shutdown and cease any and all operation of coal-fired Gannon Units 1 - 6 (EU 001 - 006) no later than December 31, 2004. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including wood-derived fuel) nor produce any steam for electricity production, other than through re-powering as specified in this permit. [EPA/TEC Consent Decree]

4. Permanent Bar on Combustion of Coal: Commencing on January 1, 2005, the permittee shall not combust coal in the operation of any unit at this plant. [EPA/TEC Consent Decree]

5. Notification: Before January 1, 2005, the permittee shall notify the Department of plans for the coal storage and handling facilities. Additional permits may be required. [Rule 62-210.300, F.A.C.]

6. Revisions or Extensions: The provisions of this section shall not be extended or revised the without prior written approval of the U.S. EPA. [EPA/TEC Consent Decree]

SECTION IV. APPENDIX A

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

CCGT	-	Combined Cycle Gas Turbine
CEM	-	Continuous Emissions Monitor
DARM	-	Division of Air Resource Management
DEP	-	State of Florida, Department of Environmental Protection
DLN	-	Dry Low-NOx Combustion Technology
EPA	-	United States Environmental Protection Agency
°F	-	Degrees Fahrenheit
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
HRSG	-	Heat Recovery Steam Generator
UTM	-	Universal Transverse Mercator
SCR	-	Selective Catalytic Reduction

FORMATS FOR PERMIT REFERENCES AND RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example: [Rule 62-213.205, F.A.C.]

Where:	62	-	identifies the specific Title of the F.A.C.
	62-213	-	identifies the specific Chapter of the F.A.C.
	62-213.205	-	identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001

Where:	099	-	identifies the specific county location
	0221	-	identifies the specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV

Where:	AC	-	identifies the permit as an Air Construction Permit
	AV	-	identifies the permit as a Title V Major Source Air Operation Permit
	099	-	identifies the specific county that project is located in
	2222	-	identifies the specific facility
	001	-	identifies the specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456

Where:	AC	-	identifies the permit as an Air Construction Permit
	AO	-	identifies the permit as an Air Operation Permit
	123456	-	identifies the specific permit project

TABLE B-1. EMISSIONS STANDARDS SUMMARY FOR BAYSIDE UNITS 1 AND 2
Seven General Electric Model PG7241(FA) Combined Cycle Gas Turbines

Pollutant	Gas Firing	Oil Firing
Standards based on emissions performance tests at permitted capacity and an inlet temperature of 59° F:		
Ammonia	*Standard*: 5 ppmvd @ 15% O_2	*Standard*: 9 ppmvd @ 15% O_2
CO (BACT)	*Control*: Good combustion *Standard*: 7.8 ppmvd @ 15% O_2 *Standard*: 28.7 lb/hour	*Control*: Good combustion *Standard*: 15.0 ppmvd @ 15% O_2 *Standard*: 64.5 lb/hour
Fuel Specification (BACT)	*Standard*: Natural gas with a maximum of 2 grains sulfur per 100 SCF	*Standard*: No. 2 distillate oil containing no more than 0.05% sulfur by weight
NOx	*Controls*: SCR with DLN combustion *Standard*: 3.5 ppmvd @ 15% O_2 *Standard*: 23.1 lb/hour	*Controls*: SCR with wet injection *Standard*: 12.0 ppmvd @ 15% O_2 *Standard*: 79.2 lb/hour
PM/PM_{10} (BACT)	*Controls*: Good combustion and fuel specifications (above) *Standard*: 10% opacity, 6-minute average *Comments*: The CO standard serves as an indicator of good combustion. The estimated maximum emission is 12 lb/hour.	*Controls*: Good combustion and fuel specifications (above) *Standard*: 10% Opacity, 6-minute average *Comments*: The CO standard serves as an indicator of good combustion. The estimated maximum emission is 30 lb/hour.
SAM/SO_2	*Standard*: Fuel specifications (above)	*Standard*: Fuel specifications (above) and oil use limited to an equivalent of 875 hour/year
VOC (BACT)	*Controls*: Good combustion *Comments*: The CO standard serves as an indicator of good combustion. The estimated maximum emission is 3 lb/hour (1.3 ppmvd @ 15% O_2).	*Controls*: Good combustion *Comments*: The CO standard serves as an indicator of good combustion. The estimated maximum emission is 7.5 lb/hour (3 ppmvd @ 15% O_2).
Standards based on CEM systems data:		
CO (BACT)	*Control*: Good combustion *Standard*: 9.0 ppmvd @ 15% O_2, 24-hour block average	*Control*: Good combustion *Standard*: 20.0 ppmvd @ 15% O_2, 24-hour block avg.
NOx	*Controls*: SCR with DLN combustion *Standard*: 3.5 ppmvd @ 15% O_2, 24-hour block average	*Controls*: SCR with wet injection *Standard*: 12.0 ppmvd @ 15% O_2, 24-hour block average

Notes:

- "BACT" means Best Available Control Technology. "SCR" means selective catalytic reduction system. "DLN" means dry low-NOx combustion technology.
- A detailed description of each BACT evaluation is presented in the Technical Evaluation and Preliminary Determination. Any changes are noted in the Department's Final Determination issued simultaneously with the final permit.

FINAL BACT DETERMINATIONS

Actual emissions of NOx and SO_2 from the re-powered plant will decrease due to the shutdown of existing coal-fired units. Therefore, the project nets out of PSD for NOx and SO_2 emissions. However, each gas turbine is required to fire natural gas as the primary fuel and to incorporate an SCR system for NOx and SO_2 emissions reductions as a result of the DEP/TEC Consent Final Judgement and the EPA/TEC Consent Decree. The gas turbines are subject to the acid rain requirements, which require a Continuous Emissions Monitoring (CEM) system for NOx emissions. The NOx CEM system will also be used for compliance with the specified permit limits.

The project did result in significant net actual emissions increases of carbon monoxide (CO) and volatile organic compounds (VOC). The Tampa Electric Company disagrees with the Department's PSD applicability determination regarding CO emissions. Based on an interpretation by EPA Region 4, emissions of particulate matter (PM/PM_{10}) would also be significant if BACT-level controls had previously been installed on existing Gannon Units 5 and 6. For CO, PM/PM_{10}, and VOC emissions, the Department determines that the efficient combustion of clean fuels and good operating practices represent BACT for the combined cycle units. In addition to the control requirements, the CO, PM/PM_{10}, and VOC emissions standards specified in the permit and summarized in Table B-1 represent BACT. A continuous monitoring system is required for CO emissions to demonstrate continuous compliance with the corresponding CO standards and as a continuous indicator of good combustion for PM and VOC emissions. The Department's technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued on February 5, 2001 with the Draft Permit.

Determination By:

Jeffery J. Koerner — 03-29-01

J. F. Koerner, P.E., Project Engineer
New Source Review Section — (Date)

Recommended By:

C H Fancy — 3/29/01

C. H. Fancy, Chief
Bureau of Air Regulation — (Date)

Approved By:

Howard L Rhodes — 3/30/01

Howard L. Rhodes, Director
Division of Air Resources Management — (Date)

Table E-1. Summary of Mass Emissions for Given Compressor Inlet Temperatures

Pollutant	Inlet Temp.	Mass Emission Rate, lb/hour	
		Gas Firing	Oil Firing
CO	18° F	31.1	70.0
	35° F	30.0	68.0
	59° F	28.7	64.5
	72° F	27.8	62.5
	93° F	26.9	60.4
NOx	18° F	24.7	96.8
	35° F	23.8	94.3
	59° F	23.1	90.9
	72° F	22.6	89.0
	93° F	21.9	86.0
PM/PM10	18° F	11.5	29.0
	35° F	11.4	28.6
	59° F	11.3	28.0
	72° F	11.3	27.6
	93° F	11.2	27.1
VOC	18° F	3.0	7.8
	35° F	3.0	7.5
	59° F	2.8	7.3
	72° F	2.7	7.1
	93° F	2.7	6.9

Notes:

- NOx emissions standards for emissions controlled by an SCR system and reported as NO_2.
- PM are based on EPA Method 5 (front-half catch only).

GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by

Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (Yes, for CO, PM/PM_{10}, and VOC);

(b) Determination of Prevention of Significant Deterioration (Yes); and

(c) Compliance with New Source Performance Standards (Yes, with Subparts GG and Kb).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\,e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

<u>Department requirement</u>: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SEMI-ANNUAL CONTINUOUS MONITOR SYSTEMS REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From ________________ to ________________

Company: ________________________________

Emission Limitation: ________________________________

Address: ________________________________

Monitor Manufacturer and Model No.: ________________________________

Date of Latest CMS Certification or Audit: ________________

Process Unit(s) Description: ________________________________

Total source operating time in reporting period [a]: ________________

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months.

I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Title

________________________________ ________________
Signature *Date*

Memorandum

Florida Department of
Environmental Protection

TO: Howard Rhodes 3/29

THRU: Clair Fancy 3/28
Al Linero aal

FROM: Jeff Koerner JK

DATE: March 28, 2001

SUBJECT: Final Air Permit No. PSD-FL-301
Project No. 0570040-013-AC
Tampa Electric Company – Bayside Power Station
Project to Re-Power the F.J. Gannon Station

The Final Permit is attached for your approval and signature that authorizes construction of seven new combined cycle gas turbines to re-power the existing F.J. Gannon Station. The existing plant is renamed the "Bayside Power Station" and is located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida.

The Tampa Electric Company (TEC) published the "Public Notice of Intent to Issue" in The Tampa Tribune on February 10, 2001 and we received proof of publication on February 15, 2001. During the 30-day comment period, we received minor comments from TEC, the Hillsborough Environmental Protection Commission, and the EPA Region 4 office. On February 23, TEC filed for an extension of time in which to file for an administrative hearing. On March 14, 2001, we met with TEC to discuss and resolve their concerns. The meeting resulted in several mutually agreed upon minor changes. On March 16, 2001, the proposed changes were provided to the Hillsborough Environmental Protection Commission and the EPA Region 4 office for additional comments with a response deadline of March 23, 2001. We received no additional comments on the proposed changes. As noted in the attached Final Determination, the Department made minor changes to the draft permit, mostly at the request of the applicant.

The original Day 90 for this project was April 17, 2001. However, the processing time clock remained tolled for 33 days until TEC withdrew their request for an extension of time in which to file for an administrative hearing. Day 90 is now May 20, 2001. I recommend your approval and signature.

Attachments

CHF/AAL/jfk

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED
MAR 14 2001
BUREAU OF AIR REGULATION

MAR 12 2001

4 APT-ARB

A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for TECO Gannon/Bayside Power Station (PSD-FL-301) located in Hillsborough County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for the Tampa Electric Company (TECO) Gannon/Bayside Power Station dated February 5, 2001. The draft PSD permit is for a repowering project involving the shutdown of TECO Gannon's coal-fired units 5 and 6 and the addition of seven combined cycle combustion turbines (CTs) with a total nominal generating capacity of 1728 MW. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CTs would fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 876 hours per year. Total emissions from the revised project are above the thresholds requiring PSD review for carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM/PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we do not have any additional comments beyond those previously discussed with Mr. Jeff Koerner of the Florida Department of Environmental Protection and those previously submitted during our review of the PSD permit application. If you have any questions or concerns, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Koerner
C. Holladay
B. Thomas, SWD
J. Campbell, EPC
A. Linda, TECO
NPS

FAXED 3-13-01
TO: JIM LITTLE, EPA Reg. 4
NEW SOURCE REVIEW
FROM: JEFF KOERNER

TECO

TAMPA ELECTRIC

RECEIVED

MAR 12 2001

BUREAU OF AIR REGULATION

March 9, 2001

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 Facsimile and
FedEx
Airbill No. 7909 1798 5685

Re: Comments on Draft Air Construction Permit
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received the Draft Air Construction Permit addressing the repowering of Gannon Station to Bayside Station. Based on a review by Tampa Electric Company, several comments are presented below. For referencing convenience, the condition or applicable section is in bold text and underlined, followed by the comment underneath.

Section III.A, Condition 13

This Condition requires TEC to dispatch Bayside Units 1 and/or 2 before dispatching any of the existing coal fired generation at Gannon that has not been disabled during the period of time between the initial operation of Bayside Unit 1 and January 1, 2005. The permit references the Consent Final Judgment and the Consent Decree as the basis for this requirement. However, the Consent Final Judgment does not address this type of operation and the Consent Decree does not contain this requirement as applied to Gannon/Bayside Station. The Consent Decree does require TEC to dispatch any unit fully controlled for SO_2 emissions including the natural gas fired combined cycle units at Bayside Station before dispatching an uncontrolled coal fired unit at Big Bend Station. Since this requirement does not apply to the remaining coal fired units at Gannon Station, TEC requests that this condition be removed.

Section III.A, Condition 19.e

Condition 19.e requires TEC to submit a startup plan after eight cold steam turbine startups. In addition, after reviewing the data presented, the Department may decrease the period of allowable data exclusion during a cold steam turbine startup. During the startup and initial operation of each Bayside Unit, several cold steam turbine startups may take place in a short period of time due to unforeseen process upsets that may occur during the "shakedown" period. During the startup and initial operation period, the startup procedures and practices will evolve as operational experience is developed. Because of this ongoing development, it may be possible for TEC to perform eight cold steam turbine startups in a relatively short period of time, without ever establishing what is "typical" or "normal." To alleviate this, TEC requests that the Department modify the condition, in part, to read as follows:

> *"...Within 90 days of completing eight cold steam turbine startups following commercial operation, or within 90 days after 12 months of commercial operation; whichever occurs first, the permittee shall submit a revised plan to the Department based on actual operating data and experience."*

This would allow TEC to work through the "shakedown" period and collect meaningful data regarding the necessary time required to complete a cold steam turbine startup.

In addition to changing the basis of the requirement to submit a startup plan, TEC also requests that FDEP change the reference to "*decreasing* the allowable startup time" to "*modifying* the allowable startup time." This could allow for an increase in startup time in the event that it is not possible to perform a cold steam turbine startup in 16 hours or less due to the mechanical and physical limitations of the process. If additional time is necessary to perform a cold steam turbine startup, TEC could identify the load ranges at which it would operate during such an event to minimize excess emissions. Ultimately, it is in the Company's best interests to minimize startup times so that it can maximize the efficiency of electricity production.

Section III.A, Condition 25

Background
The repowering of the Gannon station provides a significant environmental benefit, particularly in reducing emissions of oxides of nitrogen (NO_x). This repowering will result in the reduction of the overall Tampa Bay nitrogen budget, therefore assisting the Tampa Bay area in meeting goals for ozone maintenance and holding the line on nitrogen input to Tampa Bay. These were all considerations when Tampa Electric Company agreed to the repowering of the Gannon Station and to the installation of Selective Catalytic Reduction (SCR) technology on the units at Gannon that are required to be repowered.

All projects that do not cause a significant increase in the emissions of NO_x are not subject to the requirements of the Prevention of Significant Deterioration (PSD) and therefore are not required to conduct a Best Availability Control Technology (BACT) determination. The Department reviewed and deemed TEC's application complete without a NO_x BACT determination in recognition of the agreement to install SCR and establishing a NO_x emission rate limit of 3.5 ppmvd @ 15% O_2.

In consideration of these facts, it is reasonable for the Department to consider this project in a more favorable light than a greenfield project that adds to the nitrogen budget in the State of Florida. Therefore, TEC holds the position that no unfair precedent is set by proposing a standard for NH_3 different than the standard set on permitted, but not yet constructed greenfield projects.

Condition 25 limits ammonia slip emissions to 5 ppmvd with a trigger to begin quarterly testing if the ammonia slip reaches 4.5 ppmvd. This slip limit and associated testing is not practical, and TEC believes that FDEP's authority to regulate ammonia emissions is limited, since ammonia is not a regulated air pollutant. In addition, the SCRs required for each combustion turbine are not required as a result of a BACT determination, so ammonia slip may not be regulated in accordance with the PSD program.

Nature of SCR operation

The requirement for SCR on low NO_x emitting combined cycle turbines is new in the State of Florida. As such, the Department and TEC have little operational history to rely on in understanding the operational and maintenance issues associated with this NO_x control device. TEC has continued to investigate the expected NH_3 slip characteristics of this device. Recent communication with the SCR vendor, Hitachi, has provided new information that has changed Tampa Electric's position on the testing requirements. Hitachi has estimated that the proposed NH_3 slip limit of 5 ppm is approached at a gradual rate, meaning that the unit may operate in the NH_3 emission concentration range of 4.5 to 5 ppm for approximately 6 months or more prior to triggering the replacement of the catalyst. As the draft permit currently reads this will require the testing of each of the combustion turbines once per quarter for approximately 6 months or more.

Other reasonable assurance

The Department has maintained that an ammonia slip rate of 5 ppm is necessary to ensure the proper operation of the SCR system. However, since catalyst life and operation of the SCR can be easily determined through the examination of the NO_x emission rate and the ammonia injection rate, TEC suggests that the Department will have reasonable assurance that each SCR system is operating at an optimal level through the examination of these parameters. That is, if TEC establishes an ammonia injection rate that controls NO_x at full load upon initial operation, a large increase in that injection rate could signal a problem with the SCR such as degrading catalyst.

Recommendation

Based on the information discussed above, TEC recommends that this condition be changed to read:

> *"If the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen when firing natural gas as determined through annual stack testing, the permittee shall take corrective action, test and comply with the limit of 7 ppmvd corrected to 15% oxygen within 180 days of first detection."*

Section III. A, Condition 27

Based on the assumption that the operation of Bayside Station will result in a significant increase in Carbon Monoxide (CO) emissions, the Department has required TEC to install, calibrate and operate a continuous emissions monitor for CO. CO emissions data will be used to monitor startup operations as well as provide surrogate data for volatile organic compounds (VOC) and Particulate Matter (PM) emissions.

Background

The Department believes that it is appropriate to install and operate a CO continuous emissions monitoring system (CEMs) for each combustion turbine at Bayside Power Station. This requirement stems from the fact that based on calculated past actual CO emissions from Gannon Units 5 and 6, and future potential emissions from Bayside Units 1 and 2, the Department believes that a significant increase in CO emissions will occur as a result of operating Bayside Units 1 and 2. This significant increase would trigger PSD review and a subsequent BACT analysis. TEC performed and submitted this BACT analysis, and although the data demonstrated that adding oxidation catalyst to control CO emissions was infeasible, the Department has included a requirement to operate and maintain CO CEMs for each Bayside Unit in the draft air construction permit to provide 'reasonable assurance' that CO emissions are being minimized.

TEC has attempted to demonstrate to the Department that past actual CO emissions from Gannon Units 5 and 6 were significantly elevated due to efforts to lower NO_x emissions from those units. This demonstration shows that the operation of Bayside Units 1 and 2 will not result in a significant increase in CO emissions, since the baseline used in the netting analysis is significantly higher. The Department was provided with a thorough explanation of why the actual CO emissions from Gannon Units 5 and 6 were substantially higher than was previously estimated through the use of AP-42 emission factors, but has thus far rejected this argument.

Additional assurance

Another method to assure the Department that CO emissions will not significantly increase in conjunction with this project is to demonstrate that actual CO emissions from the seven Bayside combustion turbines are much lower than originally believed. Based on the initial compliance testing of Polk Unit 2, this may be the case. While GE guarantees a CO emission rate of 9 ppmvd @ 15% O_2, the results of the Polk Unit 2 initial compliance test show a CO emission rate that is much lower than the GE guarantee. Although CO emissions from the Bayside units are expected to be lower than the GE guarantee, it is not clear if they will be as low as those observed during the initial compliance test of Polk Unit 2 due to the fact that the Bayside units will operate in combined cycle mode and utilize SCR for NO_x control.

Recommendation

TEC recommends that the Department postpone the requirement for the CO CEMs until TEC has an opportunity to test Bayside Units 1 and 2 for CO emissions. If the CO emissions during the Bayside 1 and 2 initial compliance tests are lower than the emissions guaranteed by GE, then TEC may be able to demonstrate that CO emissions remain unchanged or decrease as a result of the operation of Bayside Units 1 and 2. If this is the case, then TEC may be willing to accept a more stringent CO emission limit, which would result in CO emissions netting out of PSD review. If this proves to be the case, then CO CEMs for Bayside Units 1 and 2 would be unnecessary. If, however, the testing does reveal that CO emissions are significantly increased as a result of the operation of Bayside Units 1 and 2, then TEC will install and operate CO CEMs on each combustion turbine.

TEC will also utilize the period of time prior to the shutdown of Gannon Units 5 and 6 to continue investigating the past actual CO emissions from these units. TEC will keep the Department advised of any testing conducted to support this activity. The results of this testing may provide new information to support TEC's position on the Gannon 5 and 6 CO baseline.

Section III.A, Condition 8

Condition 8 requires TEC to tune the dry-low NO_x combustors to minimize emissions of NO_x, CO and VOC. Since the combustors are designed to minimize NO_x emissions, TEC believes that they should be tuned only to minimize NO_x emissions as specified by General Electric. If the combustors were tuned to minimize CO and VOC emissions, it is unclear how the Department could verify this, it is unclear what the effect of this would be on the dry-low NO_x combustors performance, it is unclear what level of CO and VOC emissions would be considered 'optimal', and it is also unclear what level of NO_x emissions would be associated with these 'optimal' levels.

In addition, because the Department has identified CO as a surrogate for PM and VOC emissions, an annual test of CO emissions will provide reasonable assurance that PM and VOC emission limits are met. Furthermore, a comparison of CO emissions versus unit load graph as provided by General Electric should give the Department reasonable assurance that all CO emissions remain constant between 50% and 100% load. Therefore, TEC requests that the language in Condition 8 require TEC to tune each dry-low NO_x combustor to minimize NO_x emissions only, and that the reference to tuning the combustors to minimize CO and VOC emissions be removed from the permit.

Finally, this condition requires at least five days advanced notice prior to any tuning of the combustors. This requirement is unnecessary and will be difficult to comply with, since, in the event of a malfunction, some tuning sessions may need to be performed with much less than five days notice to return emissions to permitted levels. In fact, some tuning sessions may be able to be performed instantly, while the unit is online. Therefore, TEC requests that the Department remove this portion of Condition 8 from the permit.

Statement of Basis

The sentence: "The conditions of this permit do not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree" in the general introduction to the permit is not standard permit language. This statement can be found in several places throughout the permit. TEC requests that this language be changed to:

> *"The conditions of this permit do not relieve the permittee from any applicable regulation, or agency requirement."*

This language is more general and conveys the same message.

Facility Description, Page 2

The Facility Description indicates that the nominal electrical production of the Bayside Power Station will be 1,742 MW. However, elsewhere in the draft permit, the capacity of the Bayside Power Station is identified as 1,700 MW. Since it is only Bayside Units 1 and 2, and not Bayside Power Station that are being permitted, TEC requests that FDEP strike the reference to "the new Bayside Power Station" and insert "Bayside Units 1 and 2". In addition, although this is not a large difference, TEC requests that the Department make all references to the Bayside Power Station nominal capacity consistent by identifying it as 'nominal net 1,742 MW' throughout the permit.

Section III.A, Condition 19.b

This condition prohibits the operation of any Bayside Station combustion turbine below 50% load except during startup and shutdown operation. TEC understands that the intent of this condition is to minimize excess emissions. However, 62-21.700, F.A.C. allows for excess emissions during startup, shutdown, and malfunction. As such, TEC requests that operation below 50% load be allowed in the event of an unforeseen malfunction. In addition, it may be possible for TEC to operate the combustion turbines below 50% load while maintaining compliance with all applicable emission limits. Therefore, to incorporate both of the above referenced changes, TEC requests that the condition be changed to read:

> *"Except for startup, shutdown, malfunction, and periods during which all applicable emission limits are complied with, operation below 50% base load is prohibited."*

Section III,A, Condition 23

Condition 23 requires a revised MACT applicability determination, and a MACT analysis, if required, to be submitted with the HAP emissions test report. Submittal of a revised MACT applicability determination concurrently with the HAP emission test report submittal is reasonable. However, to allow time to prepare a case-by-case MACT analysis (if required), TEC requests that the deadline for the MACT analysis submittal be no later than 60 days following submittal of the HAP test report.

Section III.A, Condition 26

In this condition, the Department has the option to require additional performance testing after a 'substantial' modification of the dry-low NO_x combustors or other control equipment. TEC believes that any problem following any 'substantial' modification will be revealed by the data collected by the CEMs. As such, this condition seems unnecessary since the Department will have reasonable assurance that any problem with the dry-low NO_x combustors or other control equipment will be evident based on a review of the CEMs data. For these reasons, TEC requests that this condition be removed from the permit.

Section III.A, Condition 24

Condition 24 requires TEC to perform ammonia slip and opacity testing for any combined cycle combustion turbine that fires more than 200 hours of distillate oil during the federal fiscal year. However, according to 62-297.310(7)(a)5., F.A.C., compliance testing for particulate matter is required only when a unit exceeds 400 hours of annual operation. In addition, ammonia slip testing is not mentioned within this regulation. Therefore, TEC requests that FDEP change the trigger for requiring visible emissions testing from 200 hours of operation to 400 hours of operation per calendar year as well as remove the requirement for ammonia slip testing.

Section III.A, Condition 27.c

This condition identifies certification requirements for an oxygen monitor. However, the CEMs included in the Bayside project will not utilize an oxygen monitor to measure diluent flow. Rather, they will utilize a CO_2 monitor to measure diluent flow. As such, TEC requests that FDEP remove all references to the oxygen monitor in the permit.

Section III.A, Condition 27.d(2)

Please see the comment addressing Section III.A, Condition 19.e. In addition, this comment defines a cold steam turbine startup as a "startup after the steam turbine has been offline for 24 hours or more *and* the first stage turbine metal temperature is 250°F or less." (emphasis added) In correspondence dated November 14, 2000, TEC defined a cold steam turbine startup as the following: "A cold startup occurs either (1) when the first stage turbine metal temperature is 250°F or colder *or* (2) when the steam turbine has been offline for 24 hours or longer." (emphasis added) To be consistent with this definition, TEC requests that the Department modify the definition of a cold steam turbine startup to "startup after the steam turbine has been offline for 24 hours or more *or* the first stage turbine metal temperature is 250°F or less." (emphasis added)

Section III.C, Conditions 1 and 2

These conditions require that upon the shutdown of Gannon Units 5 and 6, the heat input limit from the coal yard must be reduced by the representative heat input of each shutdown unit. This condition is not required by either the Consent Decree or the Consent Final Judgment and does not allow for the degradation in heat rate of the remaining coal fired units, increased customer demand or the increased operation of the remaining coal fired units in the event of an unforeseen decrease in generation capacity due to the malfunction of another unit(s) on Tampa Electric Company's generating system. The heat input limit was placed on the coal yard to allow TEC to fire a variety of fuels without triggering PSD, not to limit the availability of the remaining coal fired units in accordance with the repowering project. Finally, compliance with the limits found in the coal yard permit is based on a calendar year. The new heat input limits in the draft Bayside air construction permit impose a new 12 month rolling average. To alleviate the concerns above, TEC requests that the heat input limits be changed as shown in the table below:

Condition	Limit in Draft Permit*	Proposed Limit**
III.C.1 Shutdown of Gannon Unit 5	$56.7 \times 10^{+06}$	$61.0 \times 10^{+06}$
III.C.2 Shutdown of Gannon Unit 6	$35.3 \times 10^{+06}$	$37.0 \times 10^{+06}$

*Units are mmBTU per consecutive 12 months.
**Units are mmBTU per calendar year.

Facility Description, Page 3

Within the Relevant Documents section, the EPA Consent Decree is described as being signed in February 2000. Although this is correct, the conditions contained within the Consent Decree did not take effect until the agreement was entered, which occurred on October 5, 2000. To be consistent with this, TEC requests that any references to the Consent Decree being signed in February 2000 be changed to reflect the fact that the Consent Decree was actually entered on October 5, 2000.

Section III.A, Condition 5

This condition states that each General Electric Model PG7241 (FA) is designed to produce 170 MW of *direct* electrical power. It is unclear why the word direct is emphasized in the condition, and what it is intended to mean. Rather than using the word 'direct', TEC suggests using the word 'nominal' to describe the capacity of the combustion turbines.

Section III.A, Condition 14.c

Condition 14.c limits oil firing in each combustion turbine at Bayside Station to 11,775,000 gallons per consecutive 12 months, and is based on an equivalent 875 hours per year of oil firing. However, at 59°F and 100% load, the fuel oil consumption as presented in the air construction permit application is 13,644 gallons per hour per combustion turbine. Over the course of one calendar year, this would equate to 11,938,500 gallons of fuel oil consumed per combustion turbine. As such, TEC requests that the fuel oil consumption limit be modified to reflect this. In addition, to truly be equivalent, the condition should limit oil firing to 11,938,500 gallons of low sulfur distillate oil per *calendar year*, rather than per *consecutive 12 months*. For consistency, TEC requests that FDEP modify this condition to limit the low sulfur distillate oil firing in any Bayside Station combustion turbine to 11,938,500 gallons per calendar year.

Section III.A, Condition 16.c

Condition 16.c. limits the NO_x exhaust concentration when firing distillate oil to 12 ppmvd corrected to 15% oxygen. However, the permit application indicated that NO_x emissions when firing distillate oil would actually be 16.4 ppmvd corrected to 15% oxygen. The resulting NO_x emission rate at 59°F and 100% load is calculated to be 90.9 lb/hr as opposed to the 79.2 lb/hr value shown in the draft permit. Accordingly, TEC requests that the allowable NO_x emission limit during oil firing be changed from 79.2 lb/hr to 90.9 lb/hr.

Section III.A, Condition 27.a

This condition requires TEC to record CEM data, to the extent practicable, evenly over the course of an hour. This condition is unnecessary so long as TEC complies with the provisions of 40 CFR 75. As such, this language seems to be unnecessary and TEC requests that the Department remove it from the permit.

Section III.A, Condition 30

This condition requires TEC to monitor the fuel consumption rates of all allowable fuels to demonstrate compliance with fuel consumption limits. Since oil is the only fuel that is limited by the permit, TEC requests that this condition specify that natural gas consumption need not be monitored and recorded.

Section IV, Appendix GC, Condition G.2

This condition states, in part: "Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department." This language is vague and should be further defined to specify what constitutes an 'unauthorized deviation from the approved drawings or exhibits, specifications, or conditions'. For example, since the project is currently in the engineering/design phase, there may be deviations from the original drawings, exhibits, specifications, or conditions. However, most of these deviations will be minor and will not affect the operating characteristics of the units. To address this issue, TEC requests that FDEP modify the language by adding the underlined text as shown below:

> *"Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit resulting in a significant increase in actual annual emissions may constitute grounds for revocation and enforcement action by the Department."*

Section II. Condition 12

Condition 12 requires submittal of a Title V operation permit application "at least ninety days prior to the expiration of this permit, but no later than 180 days after commencing operation." Bayside Units 1 and 2 are anticipated to commence operation in May 2003 and May 2004, respectively. To avoid multiple Title V permit revisions, TEC requests that this condition be changed to read:

> *"at least at least ninety days prior to the expiration of this permit, but no later than 180 days after commencing operation of Bayside Unit 2".*

This schedule of Title V permit application submittal is consistent with recent Department guidance provided for Polk Power Station simple-cycle combustion turbines Units 2 and 3.

Technical Evaluation and Preliminary Determination, Paragraph 3.7

This paragraph refutes the claim that efforts to reduce NO_x emissions from Gannon Units 5 and 6 resulted in substantially higher CO emissions. In addition, the Department claims that AP-42 emission factors should be used in the netting analysis to determine past actual CO emissions from Gannon Units 5 and 6. The Department has not provided supporting evidence indicating that: 1) efforts to reduce NO_x emissions through limiting combustion O_2 do not have a substantial effect on CO emissions and 2) AP-42 emission factors reasonably represent CO emissions from a coal fired boiler using lean combustion to control NO_x emissions.

Technical Evaluation and Preliminary Determination, Paragraph 4.2

Please see the comment addressing Section III.A, Condition 14.c

Technical Evaluation and Preliminary Determination, Table 4.1

Table 4.1 identifies several recently permitted natural gas fired combined cycle combustion turbines and provides a detailed description of each including limits for CO, NO_x, PM, Sulfuric Acid Mist, and VOC. However, this list does not include the associated ammonia slip limit for each project. TEC requests that FDEP modify this table to include the ammonia slip limits associated with each project.

Technical Evaluation and Preliminary Determination, Paragraph 5

In Paragraph 5, FDEP refutes TEC's claim that emissions from the combustion turbines serving Bayside Unit 1 and Bayside Unit 2 should be considered separately when determining MACT applicability. Instead, it is the Department's position that emissions from every combustion turbine must be aggregated when determining MACT applicability. In previous correspondence, TEC submitted a detailed legal analysis including rule citations that concluded that when considering MACT applicability, emissions from separate processes or production units must be considered independently. TEC requests that the Department present TEC's argument in the Technical Evaluation and Preliminary Determination.

Technical Evaluation and Preliminary Determination, Paragraph 7.3

This paragraph assumes that future operation of any remaining coal fired generation at Gannon Station will be greatly reduced or ceased in 2003 or 2004. Specifically, the paragraph states, in part: "Because the settlement agreements require the shutdowns and repowering the Gannon plant with natural gas, "normal operations" for Gannon Units 1-4 are expected to be greatly reduced in 2003 with little or no operation in 2004." This is an assumption that, at this time, cannot be made. TEC is required to cease all coal fired operation at Gannon Station by January 1, 2005, and this requirement is established elsewhere in the permit. Paragraph 7.3 makes an unnecessary assumption about the operation of Gannon Station three to four years from now, and TEC requests that this condition be removed from the permit.

TEC appreciates the opportunity to provide the Department with comments on the remaining issues associated with the permitting of Bayside Units 1 and 2, and looks forward to discussing these issues in person on Wednesday, March 14, 2001 at 9:00 a.m. in Tallahassee. If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Gregory M. Nelson

Gregory M. Nelson, P.E.
Director
Environmental Affairs

EP\gm\SKT244

c: Mr. Howard Rhodes, FDEP
Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
C. Holladay
EPA
NPS

TECO

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BUREAU OF AIR REGULATION

February 14, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7904 7198 6300

Re: Tampa Electric Company (TEC) – Bayside Power Station
Air Construction Permit
DEP File No. 0570040-013-AC (PSD-FL-301)

Dear Mr. Sheplak:

Please find enclosed the original Affidavit of Publication from the Tampa Tribune, as required by 62-110.106(5), F.A.C. This public notice was published in the legal section of the Tampa Tribune on Saturday, February 10, 2001. If you have any questions, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Shannon K Todd
for

Patrick L. Shell
Administrator-Air Programs
Environmental Affairs

EP\gm\SKT236

Enclosure

c: Mr. Tom Davis - ECT
Mr. Jerry Campbell, EPCHC
Mr. Buck Oven, FDEP
Mr. Scott Sheplak, FDEP
Mr. Jerry Kissel - FDEP SW
Mr. John Bunyak - NPS
G. Kaerner
C. Holladay
B. Worley, EPA

THE TAMPA TRIBUNE
Published Daily
Tampa, Hillsborough County, Florida

State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared J. Rosenthal, who on oath says that she is Classified Billing Manager of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

FEBRUARY 10, 2001

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

J. Rosenthal

Sworn to and subscribed by me, this 10 day

of FEBRUARY, A.D. 20 '01

Personally Known ✓ or Produced Identification ______
Type of Identification Produced ______

OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
CC639424
MY COMMISSION EXP.
APRIL 16, 2001

Susie Lee Slaton

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Tampa Electric Company
Bayside Power Station
(Gannon Re-Powering Project)
Project No. 0570040-013-AC
Draft Permit PSD-FL-301

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have an electrical production capacity of approximately 1740 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

In accordance with state and federal settlement agreements, the applicant proposes to re-power the existing Gannon Station with seven new combined cycle General Electric Model PG7241(FA) gas turbines. All existing coal-fired boilers will be shut down before January 1, 2005. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. It is estimated that the Bayside project will reduce actual emissions of nitrogen oxides (NOx) by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required by rule for each pollutant, the proposed permit represents current Best Available Control Technology (BACT) measures for combined cycle gas turbines to control emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The proposed permit also requires the continuous monitoring of CO and NOx emissions.

The project results in smaller, but significant increases in emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions of PM/PM10. Therefore, the project is subject to review in accordance with Rule 62-212.400, F.A.C., the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, and BACT determinations are required for each significant pollutant. The Department determined BACT controls for the emissions of CO, PM/PM10, and VOC to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (less than 0.05% sulfur by weight) is the backup fuel. Each unit may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired. To reduce emissions of nitrogen oxides (NOx), each combined cycle unit incorporates dry low-NOx combustion technology when firing natural gas and water injection when firing oil. Pursuant to the state and federal settlement agreements, a Selective Catalytic Reduction (SCR) system for each unit is required to further reduce NOx emissions. As agreed to by the applicant, the proposed permit defers the determination of the Maximum Available Control Technology (MACT) for hazardous air pollutants (HAP) until after a unit is tested for HAP emissions.

The applicant performed an air quality analysis in accordance with the Department's PSD requirements in Rule 62-212.400, F.A.C. Significant net increases in actual emissions were predicted for carbon monoxide and volatile organic compounds. The Department reviewed the applicant's analysis and modeling files. The ambient impact analysis predicted that emissions from the project would have an insignificant impact on Class II areas. Except for six national parks and wilderness areas, all of Florida is designated as a Class II area. No Class I significant impact levels have been defined for carbon monoxide or volatile organic compounds (ozone). The analysis also indicated that emissions from the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standard when evaluated independently.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District Office
Air Resources
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Hillsborough County Environmental Protection Commission
Air Management Division
1410 North 21 Street
Tampa, FL 33605
Telephone: 813/272-5530
Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. Key documents may be viewed at www.dep.state.fl.us/air/permitting and clicking on TEC Bayside.

1448 2/10/01

FLORIDA

Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

February 5, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Karen Sheffield, General Manager
Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Re: Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301
Draft PSD Permit for the Bayside Power Station
(Gannon Re-Powering Project)

Dear Ms. Sheffield:

Enclosed is one copy of the Draft Permit to re-power the existing Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and consist of seven new gas-fired combined cycle gas turbine units. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to the Administrator of the New Source Review Section, A. A. Linero, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

C. H. Fancy, Chief
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

7099 3400 0000 1449 4031

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:
Ms. Karen Sheffield

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: ***COMPLETE THIS SECTION***

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Karen Sheffield
General Manager
Tampa Electric Company
Bayside Power Station
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 2/7

C. Signature
X [signature]
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number (Copy from service label) 7099 3400 0000 1449 4031

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Department of
Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Project No.	0570040-013-AC
Draft Permit No.	PSD-FL-301
Facility ID No.	0570040
SIC No.	4911

PROJECT DESCRIPTION

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Tampa's Port Sutton Road in Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have an electrical production capacity of approximately 1700 MW.

The project will result in significant net increases in actual emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions PM/PM_{10}. The Best Available Control Technology (BACT) for each of these pollutants is determined to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (< 0.05% sulfur by weight) is the backup fuel. Each unit may fire may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired in the unit. The state and federal settlement agreements specified installation of the SCR systems. NOx emissions are controlled by an SCR system combined with dry low-NOx combustion technology when firing natural gas and combined with water injection when firing oil. Each combined cycle unit will have CO and NOx continuous emissions monitoring systems to demonstrate compliance. The CO emissions standards serve as surrogate standards for emissions of PM/PM_{10} and VOC.

After shutdown of the coal-fired units, it is estimated that the Bayside project will reduce *actual* emissions of nitrogen oxides by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required for each pollutant, the emissions standards specified in the Draft Permit for CO, NOx, PM/PM_{10}, SO_2, and VOC represent BACT-level controls. In addition, the CO and NOx emissions monitors will provide a continuous demonstration of compliance with the standards and efficient combustion of each unit.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery F. Koerner

02-01-01

Jeffery F. Koerner, P.E.
Registration Number: 49441

(Date)

DARM/BAR - New Source Review Section
Florida Department of Environmental Protection

In the Matter of an
Application for Air Permit by:

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619
Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301
Bayside Power Station
Hillsborough County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, Tampa Electric Company, applied on September 21, 2000 to the Department for a permit to re-power the existing F.J. Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station. The Draft Permit requires the shutdown of existing coal-fired units and authorizes the construction of seven new combined cycle gas turbine units. The proposed permit includes determinations of the Best Available Control Technology (BACT) for emissions of carbon monoxide, particulate matter, and volatile organic compounds. As agreed to by Tampa Electric Company, the proposed permit defers the determination of the Maximum Available Control Technology (MACT) for hazardous air pollutants (HAP) until after a unit is tested for HAP emissions.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2), F.S. and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/5/01 to the person(s) listed:

Ms. Karen Sheffield, Bayside*
Mr. Patrick Shell, Bayside
Ms. Cindy Barringer, Bayside
Mr. Tom Davis, ECT
Chair, Hillsborough County BCC
Mr. Jerry Campbell, HEPC
Mr. Bill Thomas, SWD
Mr. John Notar, NPS
Mr. Winston Smith, EPA Region 4

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 2/5/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Tampa Electric Company
Bayside Power Station
(Gannon Re-Powering Project)

Project No. 0570040-013-AC
Draft Permit PSD-FL-301

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have an electrical production capacity of approximately 1740 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

In accordance with state and federal settlement agreements, the applicant proposes to re-power the existing Gannon Station with seven new combined cycle General Electric Model PG7241(FA) gas turbines. All existing coal-fired boilers will be shut down before January 1, 2005. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. It is estimated that the Bayside project will reduce actual emissions of nitrogen oxides (NOx) by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required by rule for each pollutant, the proposed permit represents current Best Available Control Technology (BACT) measures for combined cycle gas turbines to control emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The proposed permit also requires the continuous monitoring of CO and NOx emissions.

The project results in smaller, but significant increases in emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions of PM/PM_{10}. Therefore, the project is subject to review in accordance with Rule 62-212.400, F.A.C., the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, and BACT determinations are required for each significant pollutant. The Department determined BACT controls for the emissions of CO, PM/PM_{10}, and VOC to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (less than 0.05% sulfur by weight) is the backup fuel. Each unit may fire may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired. To reduce emissions of nitrogen oxides (NOx), each combined cycle unit incorporates dry low-NOx combustion technology when firing natural gas and water injection when firing oil. Pursuant to the state and federal settlement agreements, a Selective Catalytic Reduction (SCR) system for each unit is required to further reduce NOx emissions. As agreed to by the applicant, the proposed permit defers the determination of the Maximum Available Control Technology (MACT) for hazardous air pollutants (HAP) until after a unit is tested for HAP emissions.

The applicant performed an air quality analysis in accordance with the Department's PSD requirements in Rule 62-212.400, F.A.C. Significant net increases in actual emissions were predicted for carbon monoxide and volatile organic compounds. The Department reviewed the applicant's analysis and modeling files. The ambient impact analysis predicted that emissions from the project would have an insignificant impact on Class II areas. Except for six national parks and wilderness areas, all of Florida is designated as a Class II area. No Class I significant impact levels have been defined for carbon monoxide or volatile organic compounds (ozone). The analysis also indicated that emissions from the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standard when evaluated independently.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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Mediation is not available in this proceeding.

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A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District Office
Air Resources
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Hillsborough County Environmental
Protection Commission
Air Management Division
1410 North 21 Street
Tampa, FL 33605
Telephone: 813/272-5530
Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. Key documents may be viewed at www.dep.state.fl.us/air/permitting and clicking on TEC Bayside.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION
(Including Draft BACT and MACT Determinations)

Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301

Tampa Electric Company

Bayside Power Station

(Gannon Re-powering Project)

ARMS Facility ID No. 0570040
Emissions Units 001 - 027

Hillsborough County

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

February 1, 2001

{Filename: 301d TEPD.DOC}

TABLE OF CONTENTS

This document describes the overall project, rule applicability, draft determinations of Best Available Control Technology, emissions standards, analysis of air quality impacts, and makes a preliminary determination. It is organized in the following sections:

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Tampa Electric Company – Bayside Station
Port Sutton Road
Tampa, FL 33619

Authorized Representative:
Karen Sheffield, General Manager

1.2 Processing Schedule

09/21/00	Department received the application for a PSD air pollution construction permit.
09/27/00	Department mailed copies to EPA Region 4 and the National Park Service.
10/16/00	Meeting with TEC and Department. Department requested additional information (#1).
10/19/00	Department received written comments from Hillsborough EPC.
11/15/00	Department received written comments from Hillsborough EPC.
11/18/00	Department received additional information (#1).
12/13/00	Meeting between TEC and Hillsborough EPC (Department attended by teleconference).
12/15/00	Department requested additional information (#2).
12/15/00	Department received written comments from EPA Region 4 office.
12/26/00	Department received additional information (#2). Application deemed complete.
12/27/00	Teleconference with TEC, EPA Region 4, and Department.
01/11/01	Department received written responses from TEC to Hillsborough EPC's verbal comments made during the 12/13/00 meeting.
01/12/01	Meeting between TEC and Department (Hillsborough EPC attended by teleconference). Department received TEC's revised netting analysis.

01/19/01 Department received TEC's comments on remaining issues.

01/26/01 Department received TEC information regarding CO emissions from coal fired boilers.

1.3 Facility Description and Location

When complete, the new Bayside Station will consist of seven new 170 MW combined cycle gas turbines, an existing 14 MW simple cycle gas turbine, and distillate oil storage. Steam from three new combined cycle units (Bayside Unit 1) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Unit 2) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). All coal-fired boilers (Gannon Units 1-6) will be shut down prior to January 1, 2005. The re-powered plant will have a nominal electrical production capacity of approximately 1742 MW. The new plant will be located within the existing Gannon plant boundaries on Port Sutton Road in Tampa, Florida. The UTM coordinates are Zone 17, 360.00 km E, 3087.50 km N and the map coordinates are Latitude 27° 54' 18", Longitude 82° 25' 21".

1.4 Standard Industrial Classification Code (SIC)

Industry Group No. 49, Electric, Gas, and Sanitary Services
Industry No. 4911, Electric Services

1.5 Regulatory Categories

PSD: The re-powered plant is considered a fossil fuel fired steam electric plant of more than 250 mmBTU per hour of heat input with emissions of at least one regulated pollutant exceeding 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Therefore, the facility is a major source of air pollution with respect to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

Title V: The re-powered plant is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year.

Title IV: Gas turbines at the re-powered plant are subject to the Title IV acid rain provisions.

Title III: Based on available information, the re-powered plant is potentially a major source of hazardous air pollutants (HAPs).

NESHAP: No emissions units at the re-powered plant are identified as being subject to any National Emissions Standards for Hazardous Air Pollutant (NESHAP) in 40 CFR 61 or 40 CFR 63.

NSPS: The gas turbines (Subpart GG) and the distillate oil storage tank (Subpart Kb) at the re-powered plant are subject to the New Source Performance Standards (NSPS) specified in 40 CFR 60.

2. PROPOSED PROJECT

2.1 Project Description

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Port Sutton Road in Tampa, Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have a nominal electrical production capacity of approximately 1742 MW. See Attachment A for an artist's rendering of the new plant.

2.2 Potential Emissions

The applicant estimates that operation of the new gas turbines would result in potential pollutant emissions of the following amounts: 989.7 tons of carbon monoxide per year, 1018.2 tons nitrogen oxides per year, 1.07 tons of lead per year, 721.4 tons particulate matter per year, 96.7 tons of sulfuric acid mist per year, 576.3 tons sulfur dioxide per year, 99.6 tons volatile organic compounds per year, 4 pounds of beryllium per year, and 14 pounds of mercury per year. Emissions decreases from the shutdown of Gannon Units 5 and 6 are discussed later in the netting analysis covered in Section 3.

2.3 Applicant's Proposed Emissions Standards and Controls

The following table summarizes the applicant's requested emissions standards and proposed control equipment for each combined cycle gas turbine.

Table 2.3 Applicant's Proposed Emissions Standards and Controls for Gas Turbines

Pollutant	Control Option	Emission Standards		
		Natural Gas	Distillate Oil	Units
CO	Combustion Design	7.8	30.3	ppmvd @ 15% O_2
NOx	Dry Low-NOx Combustion and Fuel Limitations	3.5	16.4	ppmvd @ 15% O_2
PM/PM_{10}	Combustion Design and Fuel Specifications	10%	10%	opacity
SAM/SO_2	Fuel Specifications	2.0 NA	NA 0.05%	grains/ 100 scf gas sulfur by weight
VOC	Combustion Design	1.3	3.0	ppmvd @ 15% O_2

3. RULE APPLICABILITY AND THE PSD PRECONSTRUCTION REVIEW PROCESS

3.1 State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following state rules and regulations of the Florida Administrative Code.

Citation	Description
Chapter 62-4	Permitting Requirements
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution
Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

{Note: Chapter 62-17, F.A.C., Electrical Power Plant Siting, does not apply to this project because there will be no expansion in steam electric generating capacity. (Memo from the PPS Office dated 10/11/00)}

3.2 Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Citation	Description
40 CFR 51.166	Submittal of Implementation Plans - Prevention of Significant Deterioration of Air Quality
40 CFR 52.21	Approval of Implementation Plans - Prevention of Significant Deterioration of Air Quality
40 CFR 60	New Source Performance Standards (NSPS)
	NSPS - Subpart A, General Provisions for NSPS Sources
	NSPS - Subpart GG, Stationary Gas Turbines
	NSPS - Subpart Kb, Volatile Organic (Including Petroleum) Liquid Storage Vessels
	NSPS - Applicable Appendices
40 CFR 72	Acid Rain - Permits Regulation
40 CFR 73	Acid Rain - Sulfur Dioxide Allowance System
40 CFR 75	Acid Rain - Continuous Emissions Monitoring
40 CFR 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
40 CFR 77	Acid Rain - Excess Emissions

{Permitting Note: Acid rain requirements will be included in the Title V air operation permit.}

3.3 Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

3.4 Description of PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The applicant must satisfactorily demonstrate that potential project emissions will not significantly contribute to or cause a violation of any ambient air quality standards and will have an insignificant impact on Class I and Class II Areas.

The second part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of the PSD Significant Emission Rates. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation must be performed for each emissions unit and pollutant under consideration. BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention. These approaches are consistent with EPA's consideration of environmental impacts and strategies for pollution prevention.

3.5 <u>Description of "Netting"</u>

As described in Rule 62-212.400(2)(e), F.A.C., the PSD regulations allow applicants to avoid preconstruction review through a concept known as "netting". Applicants may obtain enforceable reductions of actual emissions to compensate for emissions from new projects. For example, an applicant could agree to restrict operation, add improved controls, or even shutdown existing units to secure emissions decreases. If the sum of all the creditable increases and decreases in actual emissions from a project are greater than zero, there is a net emissions increase. A BACT determination is only required for each pollutant with a "significant" net emissions increase greater than the applicable PSD significant emission rate listed in Table 212.400-2, F.A.C.

3.6 <u>Project Applicability</u>

The Bayside project is located in Hillsborough County, an area that is currently in attainment (or designated as "maintenance" or "unclassifiable") for each pollutant subject to a National Ambient Air Quality Standard (NAAQS). The re-powered electrical generating plant is considered a fossil fuel fired steam electric plant of more than 250 mmBTU per hour of heat input, which is one of the 28 PSD industries listed in Table 62-212.400-1, F.A.C. Because emissions of at least one regulated pollutant exceed 100 tons per year, this facility is a major source of air pollution with respect to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD).

The initial application identified the project as subject to PSD review with a BACT determination required for VOC emissions only. This was based on an initial netting analysis considering the full emissions decreases from the shutdown of the coal-fired boilers for Gannon Units 5 and 6. Subsequent comments from EPA Region 4 required a revised netting analysis that indicated the project requires BACT determinations for CO, PM/PM_{10}, and VOC emissions. Both analyses are presented below.

3.7 Applicant's Initial Netting Analysis

Re-powering the existing steam-electrical generators with gas turbines requires shutdown of the coal-fired boilers for Gannon Units 5 and 6. The applicant believes that the emissions decreases from the shutdown units can be used in a PSD netting analysis to avoid triggering BACT determinations for several pollutants. The following table summarizes the applicant's initial netting analysis that considered:

- The contemporaneous period begins in September of 1995 and ends in March of 2004.
- The Gannon Unit 5 coal-fired boiler will be shut down prior to operation of Bayside Units 1A, 1B and 1C, which results in emissions decreases.
- Bayside Units 1A, 1B and 1C begin operation in 2003, which results in emissions increases.
- The Gannon Unit 6 coal-fired boiler will be shut down prior to operation of Bayside Units 2A, 2B, 2C and 2D, which results in emissions decreases.
- Bayside Units 2A, 2B, 2C and 2D begin operation in 2004, which results in emissions increases.
- The analysis assumes that there will be no actual emissions increases from Gannon Units 1, 2, 3, and 4 while the project is being completed.
- No other projects have been identified during the contemporaneous periods that would result in emissions increases.

Table 3.7 Summary of Applicant's Initial Netting Analysis

Pollutant	Gannon Unit 5 TPY	Bayside Unit 1 TPY	Gannon Unit 6 TPY	Bayside Unit 2 TPY	Net Emissions TPY	PSD SER* TPY	BACT Required? Yes/No
CO	-2055.5	+424.2	-3334.1	+565.5	-4399.9	100	No
NOx	-4746.5	+436.4	-10,931.5	+581.8	-14,659.8	40	No
Pb	-3.7	+0.5	-5.9	+0.6	-8.5	0.6	No
PM/PM_{10}	-234.9	+309.2	-864.8	+412.2	-378.3	25/15	No
SAM	-56.2	+41.4	-91.7	+55.3	-51.2	7	No
SO_2	-13,151.0	+247.0	-23,266.5	+329.3	-35,841.2	40	No
VOC	**-11.0**	**+42.7**	**-17.9**	**+56.9**	+70.7	**40**	**Yes**

* *PSD Significant Emission Rate (SER) listed in Table 62-212.400-2, F.A.C.*

As shown, the applicant identifies that the project only requires a BACT determination for VOC emissions. However, the past actual annual CO emissions for Gannon Units 5 and 6 are based on emission performance tests conducted on Gannon Unit 5 in April of 2000. TEC maintains that CO emissions have increased as a direct result of NOx control strategies that began in 1996. The Department does not believe this claim has been proven and believes the past actual annual emissions should be based on the annual operating reports for the representative years. Gannon Unit 5 would have past actual CO emissions of 138.2 tons per year and Gannon Unit 6 would have 247.0 tons per year. Therefore, the Department believes that the re-powering project results in a net CO emissions increase of 604.5 tons per year and also requires a BACT determination for this pollutant. Although a revised netting analysis was performed, the initial netting analysis remains important because it reflects the "actual" emissions increases from the project. It is the actual emissions increases that will determine the requirements for performing the Ambient Air Quality Analysis.

3.8 Revised Netting Analysis Considering EPA Region 4 Comments

The Department questioned the appropriateness of netting because the proposed project resulted from an enforcement action concerning alleged violations of the PSD regulations. Previous EPA guidance advises that emissions decreases necessary to comply with regulatory requirements cannot be used in a netting analysis (Page A.48 of EPA's 1990 draft guidance entitled, "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting"). However, the EPA Region 4 Office provided comments on the netting analysis on December 15, 2000. The comments regarding netting issues interpreted the EPA/TEC Consent Decree and are summarized as follows:

- TEC may use actual emissions reductions from the shutdown of the coal-fired boilers for Gannon Units 5 and 6 to net out of PSD review for the Bayside re-powering project.
- TEC should estimate past actual emissions based on the assumption that "present day" Best Available Control Technology (BACT) is installed on existing Gannon Units 5 and 6. (This will reduce the amount of past actual emissions and lower any emissions decreases resulting from the shutdown of the coal-fired boilers.)
- Any remaining emissions reductions that are not used for the Bayside re-powering project could potentially be used by TEC in a future netting analysis.

EPA Region 4 stated that the EPA/TEC Consent Decree would be modified in the near future to reflect this interpretation. These comments were repeated in a December 27, 2000 teleconference between the Department, EPA Region 4 staff, and TEC staff. In response to these comments, the Department reviewed current projects to determine "present day" BACT controls when modifying an existing coal-fired plant. The Department is processing an application to modify existing coal-fired boilers at the Indiantown Cogeneration Limited Partnership plant. Under consideration are the following controls and standards.

Table 3.8a Evaluation of "Present Day" BACT Controls

Pollutant	Emission Rates			Control Efficiency	AP-42 (Range) Control Efficiency
	Past Actual		Present Day BACT		
	lb/ton coal	lb/mmBTU	lb/mmBTU	Percent (%)	Percent (%)
CO	0.5	0.02	0.092, Good Combustion	NA	NI
NOx	31.0	1.25	0.125, SCR	90%	75 to 86%
Pb	4.2 E^{-04}	1.7 E^{-05}	1.6 E^{-05}, ESP or Baghouse	6%	NI
PM/PM_{10}	43.4	1.75	0.015, ESP or Baghouse	99%	99 to 99.9%
SAM	2.85	0.11	0.0035, Lime Spray Dryer	97%	NI
SO_2	57.0	2.30	0.142, Lime Spray Dryer	94%	> 90%
VOC	0.04	0.002	0.003, Good Combustion	NA	NI

Notes:

a. The "past actual" emission factors are based on uncontrolled AP-42 emission factors for wet bottom, wall-fired, coal fired boilers in Section 1.1. As in the application, SAM is assumed to be 0.5% of the SO_2 emission rate.

b. The "present day" BACT emission factors are based on retrofit controls for the proposed modification of coal fired boilers at the Indiantown Cogeneration Limited Partnership plant.

The Department believes that the above evaluation represents "present day" BACT for the modification of existing coal-fired boilers. Based on this information, the following table summarizes the revised netting analysis assuming that the "present day" BACT controls were installed on Gannon Units 5 and 6 during the representative years.

Table 3.8b Summary of Revised Netting Analysis Based on EPA Region 4's Comments

Pollutant	Gannon Units 5 and 6			Bayside Station	Net Emissions Change TPY	PSD SER* TPY	BACT Required? Yes/No
	Uncontrolled	Present Day BACT		Potential Emissions TPY			
	Past Actual TPY	Control Efficiency	Past Actual TPY				
CO[a]	**385.2**	**0%**	**385.2**	**989.7**	**+604.5**	**100**	**Yes**
NOx	15678.0	90%	1567.8	1018.2	-549.6	40	No
Pb	9.6	0%	9.8	1.07	-8.5	0.6	No
PM/PM10[b]	**1099.7**	**84.5%**	**165.0**	**721.4**	**+556.4**	**25/15**	**Yes**
SAM[c]	148.0	35%	96.2	96.7	+0.5	7	No
SO_2	36,417.5	90%	3641.8	576.3	-3065.5	40	No
VOC	**35.4**	**0%**	**35.4**	**99.6**	**+64.2**	**40**	**Yes**

Notes:

a. The past actual annual emissions are based on the annual operating reports submitted by TEC during the representative years. TEC's past actual CO emissions in the initial netting analysis were based on an emission rate developed from a 3-hour performance test conducted on Gannon Unit 5 in April of 2000. TEC explained that the large CO emissions increases resulted from NOx control strategies implemented in 1996. Although such strategies could increase CO emissions, the Department believes the data presented is insufficient to determine the extent of emissions or to estimate annual emissions. Although TEC disagreed with the Department, they did consent to provide a CO BACT determination and control equipment cost estimates for the combined cycle gas turbines.

b. The "84.5%" particulate control efficiency reflects the additional control necessary to achieve an overall 99% efficiency as "present day" BACT control considering the existing ESPs. It was assumed the existing ESPs achieved 94.5% control to meet the particulate matter standard of 0.10 lb per mmBTU of heat input. For example:

   Uncontrolled = 1.75 lb PM per mmBTU, Section 1.1 of AP-42

   W/Existing ESP = (1.75 lb PM per mmBTU) (1 – 0.945) ≈ 0.10 lb PM per mmBTU

   "Present Day BACT" W/ESP = (1.75 lb PM per mmBTU) (1 – 0.945) (1 – 0.845) ≈ 0.015 lb PM per mmBTU

c. TEC provided information suggesting that the control of sulfuric acid mist with a lime sprayer is unclear at low uncontrolled emission levels and probably no greater 35%. The Department notes that BACT for gas turbine projects is typically determined to be the firing of low sulfur fuels.

According to this revised netting analysis, the Bayside re-powering project requires BACT determinations for emissions of CO, PM/PM10, and VOC. Based on discussions with the Department, TEC submitted a revised netting analysis similar to the Department's except as noted for CO emissions.

4. DRAFT BACT AND EMISSIONS STANDARDS

4.1 Available Information

In addition to the information submitted by the applicant, the Department also relied on the following information to make these determinations:

- EPA Region 4 provided comments on 12/15/00 during application processing;
- Hillsborough EPC provided written comments on 10/19/00 and 11/15/00 and verbal comments on 12/13/00;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical documents regarding DLN emissions and the gas turbine control system;

- Equipment cost quotes for a CO oxidation catalyst system;
- Equipment cost quotes provided for SCR and SCONOx™ systems;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- AP-42, Section 1.1 for coal-fired boilers (09/98);
- AP-42, Section 3.1 for gas turbines (04/00);
- Annual Operating Reports for the Gannon Plant;
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;
- Goal Line Environmental Technology Website: http://www.glet.com; and

The Department also reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse. A list of recent determinations regarding similar projects in the United States is provided in Table 4.1 on the following page.

4.2 Authorized Fuels

The DEP/TEC Consent Final Judgment requires re-powering the Gannon Units with natural gas. However, this settlement agreement neither allows nor prohibits backup fuels. The EPA/TEC Consent Decree also requires re-powering with natural gas, but does allow the firing of low sulfur No. 2 distillate fuel oil in the combined cycle units, provided: the unit cannot be fired with natural gas; the unit has not yet been fired with No. 2 fuel oil as a backup fuel for more than 875 full load equivalent hours in the calendar year in which TEC wishes to fire the unit with such oil; the oil to be used in firing the unit has a sulfur content of less than 0.05% sulfur by weight; TEC uses all emission control equipment for that unit when it is fired with such oil to the maximum extent possible; and TEC complies with all applicable permit conditions, including emissions rates for firing No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

The Department recognizes the need for such flexibility for a base-loaded plant and will also establish emissions standards for oil firing. Therefore, the Draft Permit will include the following equivalent fuel specifications and restrictions as applicable permit conditions.

➢ The primary fuel for each combined cycle gas turbine shall be pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 SCF of natural gas.

➢ Each unit may be fired with No. 2 distillate oil (or a superior grade) as a backup fuel, providing: the unit cannot fire natural gas; the unit shall fire no more than 11,775,000 gallons of distillate oil during any consecutive 12 months (equivalent to 875 hours per year of full load oil firing); the distillate oil contains less than 0.05% sulfur by weight; all air pollution control equipment (water injection and SCR systems) are functional and used to the maximum extent possible;.and the unit is in compliance with the emissions standards of this permit.

4.3 Draft CO and VOC BACT Standards

Discussion

Gas turbines emit carbon monoxide (CO) and volatile organic compounds (VOC) due to incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. However, the dry low-NOx combustor design for General Electric's large frame gas turbines has also successfully reduced CO emissions concurrently with NOx emissions. Because the controls or techniques used to lower CO emissions would also lower VOC emissions, the control technologies for these pollutants are reviewed together.

Requested Emissions Standards

The applicant identified two control options that are technically feasible and commercially available for gas turbines: efficient combustion design with good operating practices and an oxidation catalyst. After attaining a lean premix steady-state operation, the dry low-NOx combustion design of the General Electric

Table 4.1 - Brief Summary of Emissions Standards for 170 MW Combined Cycle Gas Turbine Projects

Project Location	Date	CT Model	Unit MW	Control Technologies	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	PM Limit	SAM Limit	VOC Limit ppm
Calpine Sutter, CA (LAER)	11/99	S/W 501FD	170	DLN/SCR/OC	4, gas	2.5, gas	11.5 lb/hr	NI	NI
Tenaska Gen., AL (AL-0132)	11/99	GE 7FA	170	DLN/WI/SCR	20, gas 28, oil	3.5, gas 12, oil	NI	NI	7, gas 12, oil
KUA Cane Island Unit 3, FL	11/99	GE 7FA	170	DLN/SCR	10, gas 30, oil	3.5, gas w/DB	10% opacity Good Combustion	LSF	1.4, gas 10, oil
Lake Worth Generation, FL	11/99	GE 7FA	170	DLN/WI Optional SCR/OC	3.5/9, gas 5.9/20, oil	9/3.5, gas 42/16.4, oil	10% opacity Good Combustion	LSF	1.4, gas 3.5, oil
Hinds Energy, MS (MS-0037)	01/00	GE 7FA?	170	DLN/SCR	20, gas	3.5, gas	NI	NI	NI
Attala Energy, MS MS-0039	02/00	GE 7FA?	170	DLN/SCR	20, gas	3.5, gas	NI	NI	NI
Calpine Delta, CA (LAER)	02/00	GE 7FA or S/W 501FD	170	DLN/SCR	10, gas w/DB (3-hr CEMS avg.)	2.5, gas w/DB	0.25 gr. S/100 SCF of natural gas	NI	2, gas
Calpine Bullhead City,	02/00?	S/W 501FD	170	DLN/SCR	10, gas w/DB (3-hr CEMS avg.)	3.0, gas w/DB	18.3 lb/hr 22.8 lb/hr w/DB, PA	NI	1.5, gas
Mobile Energy, AL (AL-0143)	03/00	GE 7FA	170	DLN/WI/SCR	18, gas w/DB 26, oil w/DB	3.5, gas w/DB 11, oil w/DB	10% opacity Good Combustion	NI	5, gas 6, oil
GPC Boat Rock, AL (AL-0141)	04/00	GE 7FA	170	DLN/SCR	30, gas w/DB	3.5, gas w/DB	NI	NI	8, gas w/DB
Calpine Osprey, FL	05/00	S/W 501FD	170	DLN/SCR	10, gas (24-hr CEMS avg.)	4.0, gas w/DB	10% opacity 24.1 lb/hr w/DB	LSF	2.3, gas 4.6, gas w/DB, PA
CPV Gulfcoast	11/00	GE 7FA	170-	DLN/WI/SCR	9, gas 20, oil	3.5, gas 10, oil	10% opacity 20 lb/hr, gas 53 lb/hr, oil	LSF	1.4, gas 3.6, oil
Hines PB II, FL	01/01	S/W 501FD	170	DLN/SCR	16, gas 30, oil	3.5, gas 12, oil	7.3, gas 64.8, oil	LSF	2, gas 10, oil
TEC Bayside, FL	*Draft*	**GE 7FA**	**170**	**DLN/SCR/WI**	**8, gas 20, oil**	**3.5, gas 12, oil**	**10% opacity 12 lb/hr, gas 36 lb/hr, oil**	**LSF**	**1.3, gas 3, oil**

Abbreviations:

Manufacturer	Controls	Other
GE – General Electric	DLN – Dry Low-NOx	LAER – Lowest Achievable Emission Rate
S/W – Siemens/Westinghouse	SCR - Selective Catalytic Reduction	BACT – Best Available Control Technology
	WI = Water or Steam Injection	CEMS – Continuous Emissions Monitoring System

Notes: All data presented is for combined cycle gas turbine projects with a nominal direct electrical generating capacity of approximately 170 MW. Many of the limits presented are estimates based on assumptions made to present consistent units for comparison. "NI" means no information was available. "LSF" means low sulfur fuels specified.

Model PG7241(FA) gas turbine results in low emissions of CO and VOC while also maintaining low NOx emissions. The Speedtronic™ automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters including, but not limited to, air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. The dry low-NOx combustion design and Speedtronic™ control system are integral to the Model PG7241(FA) gas turbine. "Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustors and controls system. No adverse energy, environmental, or economic impacts were identified for the use of an efficient combustion design and good operating practices.

An oxidation catalyst consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) and VOC (to carbon dioxide and water) at much lower temperatures (650°F to 1150°F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. CO control efficiencies can approach 90%. VOC control efficiencies would likely be in the 30% to 50% range due to the low uncontrolled VOC emissions from the Model PG7241(FA) gas turbine, which should be less than 3.0 ppmvd corrected to 15% oxygen.

The applicant recognized an oxidation catalyst combined with the efficient combustion of the Model PG7241(FA) gas turbine as the top control for CO and VOC emissions, but identified the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst results in a pressure drop across the catalyst bed of approximately 1 inch of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit. The applicant estimates the lost power generation to be $671,822 per year for all seven gas turbines combined.

Environmental Impacts: Although the project proposes natural gas and very low sulfur distillate oil as the only fuels, the oxidation catalyst would oxidize small amounts of fuel sulfur to sulfuric acid mist. Also, due to the inherently low VOC emissions from the Model PG7241(FA) gas turbine, the applicant believes that the addition of an oxidation catalyst would result in negligible ambient air quality impacts. The Bayside project is located in Hillsborough County, an area that is in attainment (or designated as "maintenance" or "unclassifiable") for all criteria pollutants.

Economic Impacts: The applicant estimates that the installation of an oxidation catalyst would result in total capital investment of between $8,716,033 and $9,586,600 for all seven gas turbines combined. The total annualized costs for the oxidation catalyst systems were estimated to be about $2.4 and $2.6 million per year. Assuming 50% control efficiency for VOC emissions, the applicant estimates that the oxidation catalyst system would remove an additional 50 tons of VOC per year. The cost effectiveness would be approximately $48,000 to $52,000 per ton of VOC removed for the oxidation catalyst system. Assuming 90% control efficiency for CO emissions, the applicant estimates that the oxidation catalyst system would remove an additional 891 tons of CO per year. The cost effectiveness would be approximately $2700 to $2900 per ton of CO removed for the oxidation catalyst system.

The applicant rejected the oxidation catalyst system as not cost effective for the Bayside re-powering project as well as not producing any measurable reductions in air quality impacts. The applicant proposed the following CO and VOC emissions standards for each gas turbine based on the efficient combustion design of the Model PG7241(FA) and good operating practices.

- Requested CO Standard: 7.8/30.3 ppmvd corrected to 15% oxygen for gas/oil firing
- Requested VOC Standard: 1.3/3.0 ppmvd corrected to 15% oxygen for gas/oil firing

Draft BACT Determinations

The Department also recognizes an oxidation catalyst system combined with the efficient combustion of the

Model PG7241(FA) gas turbine as the top control for CO and VOC emissions. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

Energy Impacts: The Department agrees that installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst.

Environmental Impacts: Although the oxidation catalysts systems could result in increased sulfuric acid mist emissions, the oxidation process would also result in lower sulfur dioxide emissions. However, the Department believes that such increases and decreases would be minimal due to the very low sulfur contents of the proposed fuels. The Department rejects the applicant's argument that the further reduction of CO and VOC emissions would have negligible ambient impacts. The PSD preconstruction review process was specifically established for areas that were meeting the state ambient air quality standards in order to prevent the deterioration of the current air quality. Ambient impacts are evaluated in the modeling analysis and are not considered in making a determination of the Best Available Control Technology. The Department also notes that an oxidation catalyst would reduce emissions of hazardous air pollutants, such as formaldehyde.

Economic Impacts: The applicant's estimate of the cost effectiveness for an oxidation catalyst system is reasonable when compared to other projects.

Due to the high temperatures and efficient combustion, VOC emissions are already guaranteed at very low rates. Based on recent emissions performance tests for this model, actual CO emissions are expected to be much lower than General Electric's guaranteed emission rates. TEC's Polk Power Station recently tested a General Electric Model PG7241(FA) gas turbine while firing each fuel. The test results indicate CO emission levels of less than 1/2 ppmvd when firing gas/oil. Such low actual CO emissions would drive the cost effectiveness of an oxidation catalyst system even higher.

The Department believes that installation of an oxidation catalyst would not be cost effective given the low emissions characteristics of this particular gas turbine. Therefore, the Department rejects an oxidation catalyst as not cost effective for this project and determines that the efficient combustion design of this model and good operating practices to be the Best Available Control Technology. The following standards are established as the draft BACT standards for performance testing conducted at base load:

- CO Draft BACT: 7.8/15.0 ppmvd corrected to 15% oxygen for gas/oil firing

In addition the Department establishes the following continuous CO emissions standard as draft BACT standards for CO and as surrogate standards for VOC:

- CO Draft BACT: 9.0/20.0 ppmvd corrected to 15% oxygen for gas/oil firing (24-hour block avg.)

Because VOC emissions are expected to be within the minimum detectable levels of the test methods, the continuous CO standards shall also serve as surrogate BACT standards for emissions of VOC. The Department believes the applicant's request for a CO emissions standard of 30.3 ppmvd corrected to 15% oxygen for oil firing is not justified by actual field test data. This level of emissions was based on a relatively high ambient temperature and operation at 50% base load. This set of conditions is not likely to occur for prolonged periods considering this is a base-loaded plant with evaporative cooling. In addition, the Department has emissions performance curves from the manufacturer that do not identify these higher emissions. The Department believes the slightly higher continuous emissions limits provide adequate flexibility for demonstrating compliance with a 24-hour block CEMS average.

4.4 Draft PM/PM_{10} BACT Standards

Discussion

Emissions of particulate matter will result from the combustion of natural gas and low sulfur distillate oil. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. However, natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants.

Requested Emissions Standards

At the estimated uncontrolled emission rates when firing pipeline-quality natural gas and very low sulfur distillate oil, the applicant believes the installation of add-on controls such as baghouses or electrostatic precipitators would be cost prohibitive. In addition to the specifications and restrictions for authorized fuels, the applicant proposed the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standards.

- Visible emissions shall not exceed 10% opacity (6-minute average) when firing either fuel.

Draft BACT Determinations

The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive due to the low uncontrolled emissions rates. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration for this project. Therefore, to the specifications and restrictions for authorized fuels, the following conditions are established as the draft BACT standards for particulate matter.

- The primary fuel for each combined cycle gas turbine shall be pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 SCF of natural gas.
- The backup fuel shall be No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight and subject to the restrictions listed under "authorized fuels".
- Visible emissions shall not exceed 10% opacity (6-minute average) when firing gas or oil.

The continuous CO standards shall serve as surrogate BACT standards for emissions of particulate matter.

4.5 Draft NOx Standards

Zero Ammonia Technology Issue

Due to the emissions decreases resulting from the shutdown of the existing coal-fired Gannon Units 5 and 6, a BACT determination was not required for emissions of nitrogen oxides. However, the DEP/TEC Consent Final Judgment requires installation of selective catalytic reduction (SCR) systems on each combined cycle unit. SCR is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850° F, which is within the range of the exhaust from the heat recovery steam generators. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects and is capable of very low NOx emissions with control efficiencies approaching 90%, depending primarily on the uncontrolled NOx emission rate.

The DEP/TEC Consent Final Judgment also requires an evaluation of a "Zero Ammonia Technology" control system for at least one of the combined cycle gas turbine units. SCONOx™ is a zero ammonia technology for the control of CO and NOx emissions developed by Goal Line Environmental Technologies and distributed by Alstom Power for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which is within the operating range of the exhaust gas from heat recovery steam generators. SCONOx™ can achieve control efficiencies in the range of 90% to 98%. If the differential installed cost between SCONOx™ and SCR is less than $8 million, TEC must install a SCONOx™ system on at least one of the Bayside combined cycle gas turbine units.

The Department worked closely with TEC on developing appropriate cost estimates in accordance with the Consent Final Judgement. The cost differential between the two control technologies was determined to be greater than $8 million. Therefore, TEC is not required to install a SCONOx™ system. SCR systems shall be installed on all seven combined cycle units at the Bayside Power Station and designed to minimize ammonia emissions.

NOx Controls and Standards

For the Bayside project, an SCR system will be installed on each combined cycle unit in combination with the dry low-NOx combustion design when firing the primary fuel of natural gas and water injection when firing distillate oil as a backup fuel. At the time of this project, this level of control is generally accepted as BACT for attainment areas. The applicant requests the following NOx emissions standards.

- NOx Standard: 3.5/16.4 ppmvd corrected to 15% oxygen for gas/oil firing

The DEP/TEC Consent Final Judgment requires the installation of SCR for each combined cycle unit with a NOx emission standard of 3.5 ppmvd corrected to 15% oxygen when firing natural gas. However, it is silent on the issue of firing distillate oil as a backup fuel as well as ammonia emissions resulting from SCR. As discussed previously, EPA/TEC Consent Decree conditionally allows the firing of low sulfur distillate oil provided that all air pollution control equipment is utilized to the "maximum extent possible".

For two recent similar projects (Tenaska Alabama II Partners, L.P. and Hines Power Block No. 2), BACT for NOx emissions was determined to be 3.5/12.0 ppmvd corrected to 15% oxygen for gas/oil firing. These projects were based on the installation of an SCR system for combined cycle gas turbines of a similar size. The Hines Power Block No. 2 project also established an ammonia slip rate of 5/9 ppmvd corrected to 15% oxygen for gas/oil firing. The Department accepts 12.0 ppmvd corrected to 15% oxygen with an ammonia slip of 9 ppmvd corrected to 15% oxygen as utilization of the SCR system to the "maximum extent possible" when firing distillate oil as a backup fuel. Therefore, the Department establishes the following draft NOx emissions standards.

- NOx Standard: 3.5/12.0 ppmvd corrected to 15% oxygen for gas/oil firing (24-hour block avg.)

These limits are much more stringent than the NOx standards of NSPS, Subpart GG.

4.5 Draft SAM/SO_2 Standards

Due to the emissions decreases resulting from the shutdown of the existing coal-fired Gannon Units 5 and 6, a BACT determination was not required for emissions of sulfur dioxide. However, the state and federal settlement agreements require re-powering with natural gas as the primary fuel. The EPA/TEC Consent Decree allows firing low sulfur distillate oil as a backup fuel. Emissions of sulfur dioxide are generated from sulfur in natural gas and distillate oil when these fuels are combusted. Small amounts of SO_2 may be converted to sulfuric acid mist emissions. Natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants. At the uncontrolled emission rates estimated when firing pipeline-quality natural gas and very low sulfur distillate oil, the installation of add-on controls such as flue gas desulfurization equipment would be cost prohibitive. The applicant requests the specifications and restrictions of the authorized fuels as acceptable work practice standards in lieu of emissions standards.

The Department agrees that further control of sulfur dioxide and sulfuric acid mist emissions with add-on control technologies would be cost prohibitive due to the relatively low uncontrolled emissions of this pollutant. The specification of clean fuels (pipeline-quality natural gas and very low sulfur distillate oil) constitutes a pollution prevention technique and is given favorable consideration for this project. These specifications have previously been established as the draft PM/PM_{10} BACT standards for this project. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The above fuel specifications effectively limit the potential emissions of these pollutants and are typically considered BACT for gas turbine projects Therefore, the

- The primary fuel for each combined cycle gas turbine shall be pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 SCF of natural gas.
- The backup fuel shall be No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight and subject to the restrictions listed under "authorized fuels".

4.6 Ammonia Emissions

Ammonia is injected into the exhaust gas stream as part of the Selective Catalytic Reduction system that is used to control NOx emissions. Some of the ammonia will escape past the catalyst without reaction, which is known as "ammonia slip". Ammonia emissions can be exhausted as ammonia or combine with sulfur to form fine particulate matter such as ammonium sulfates and bisulfates. Ammonia has been designated as an Extremely Hazardous Substance under federal SARA Title III regulations. It also adds to the nitrogen loading of the waters and soils. As part of the NOx control system, higher levels of ammonia slip can indicate reduced catalyst effectiveness. Limiting ammonia emissions also minimizes the formation of fine particulate matter. Therefore, the Department establishes the following standards for ammonia slip.

- Ammonia Slip: 5/9 ppmvd corrected to 15% oxygen for gas/oil firing

4.7 VOC Emissions from the Fuel Oil Storage Tanks: Prior to submittal of the Bayside re-powering application, the applicant requested approval to construct a 5.85 million gallon oil storage tank. The oil storage tank is subject to NSPS Subpart Kb and currently serves the existing Gannon plant. In the future, the tank will serve as backup fuel storage for the Bayside Station combined cycle gas turbines. The Department approved construction and operation of the tank contingent on considering any potential VOC emissions from the tank in the Bayside re-powering application. The Bayside re-powering project already requires a BACT determination for VOC emissions from the gas turbines. The distillate oil tank is subject only to the NSPS Subpart Kb record keeping requirements.

4.8 Excess Emissions: Based on Rules 62-210.700 and 62-4.130, F.A.C. and the design of the gas turbines and control systems, the following conditions will be included in the permit to address periods of excess emissions.

Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the calculation of the 24-hour block averages to demonstrate compliance with the continuous CO and NOx emissions standards. [Rule 62-210.700(4), F.A.C.]

Excess Emissions Defined: During startup, shutdown, and unavoidable malfunction, the following permit conditions allow excess emissions or the exclusion of monitoring data. The conditions only apply if operators employ best operational practices to minimize the amount and duration of excess emissions.

- During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.
- Except for startup and shutdown, operation below 50% base load is prohibited.
- A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. To minimize emissions during such startup, no more than one gas turbine shall be operated during a steam turbine cold startup for each Bayside Unit.
- For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of the procedures, and the methods used to minimize emissions during these periods. Within 90 days of completing the eighth steam turbine cold startup of a Bayside Unit, the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether the period of data exclusion for a steam turbine cold startup defined under the CEMS requirements shall be *decreased* to represent good operational practices.

CEMS Data Exclusion: The Draft Permit does not allow periods of emissions in excess of the CO and NOx standards, but does allow for the exclusion of specific CO and NOx CEMS data.

- Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented unavoidable malfunction shall not exceed two hours in any 24-hour block period . Periods of data excluded for such episodes shall not exceed a total of four hours in any 24-hour block period.
- Periods of data excluded for a steam turbine cold startup shall not exceed sixteen hours in any block 24-hour block period. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. Based on actual operating experience and data, the Department may *decrease* this period of data exclusion in the Title V air operating permit without modifying this PSD permit. {Note: TEC states their design engineers believe that 16 hours may be necessary to warm up nearly 2000 feet of steam piping and to gradually bring the existing steam turbine up to temperature to prevent thermal fatigue of the materials. The Department has no information available to refute this claim. It is noted that the recent FPL Ft. Myers re-powering project allowed up to 12 hours of data exclusion for a steam turbine cold startup.}
- If the permittee provides at least five days advance notice prior to a tuning session, data may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards. Periods of data excluded for such episodes shall not exceed a total of three hours in any 24-hour block period.

5. MACT 112(g) APPLICABILITY

The application states that potential formaldehyde emissions are 7.25 tons per year and total HAP emissions are 27.87 tons per year. Total HAP emissions are above the threshold of 25 tons per year, which requires a case-by-case MACT determination in accordance with Section 112(g). Because Bayside Units 1 and 2 are attached to individual stream turbines, TEC believes that Section 112(g) allows evaluation as separate "process units". Based on this interpretation, neither unit would trigger the MACT thresholds. The Department believes that TEC's interpretation is flawed because projects could be contrived simply to avoid MACT applicability regardless of the actual HAP emissions.

The Department believes that the HAP emissions from all of the Bayside gas turbines must be aggregated for comparison to the HAP major source thresholds. Jim Little of EPA Region 4 confirmed the Department's interpretation with Sims Roy, the author of EPA's interpretative rule for MACT determinations regarding gas turbines. In addition, Mr. Little confirmed the Department's interpretation with Kathy Kaufman, the EPA 112(g) MACT coordinator. TEC's interpretation is not in accordance with MACT program as interpreted by the Department and EPA. Absent a proposed MACT determination from TEC, the Department reviewed the following available information.

- EPA may propose MACT to be an oxidation catalyst for new gas turbine projects (2001).
- Formaldehyde emissions are the single greatest HAP emission. The highest levels of formaldehyde emissions occur when firing natural gas.
- The application estimates formaldehyde emissions to be 7.25 tons per year and total HAP emissions to be 27.87 tons per year. The total "organic" HAP emissions constitute approximately 22 tons per year of HAP emissions. An oxidation catalyst would only control organic HAP emissions.
- EPA updated Section 3.1 of AP-42 in April of 2000 to include emission factors for HAP emissions. TEC selected only the HAP emission rates for gas turbines larger than 100 MW for use in this project. This seems appropriate because many of the remaining test results were for smaller units (< 30 MW), which typically have lower exhaust temperatures and combustion efficiencies (CO emissions of 25 ppmvd or higher). The HAP emission rates used for the larger gas turbines were based on tests for older model units.
- The General Electric Model PG7241(FA) has an exhaust temperature of 1100° F to 1200° F. The maximum CO and VOC emissions when firing natural gas are approximately 8 and 2 ppmvd corrected to 15% oxygen,

respectively. Recent test reports for this model gas turbine indicate actual CO emissions are less than 1 ppmvd when firing natural gas. General Electric has not yet released HAP emissions data specific to the Model PG7241(FA) gas turbine.

- The Bayside combined cycle units include the necessary equipment that would simplify after-the-fact installation of an oxidation catalyst, should it later be required.

Because estimated potential emissions are just above the major source HAP thresholds and there is little HAP emissions data available for this specific model, the Department defers 112(g) MACT applicability at this time. Therefore, the Department will specify the following testing requirements to resolve this issue:

1. TEC will test at least one installed Bayside Unit 1 combined cycle gas turbine for emissions of acetaldehyde, formaldehyde, toluene, and xylene as determined by EPA Method 18.
2. The tests will be conducted between 65-75% and 90-100% base load. For each load condition, the tests shall consist of at least three 1-hour runs.
3. Emissions will be reported in terms of ppmvd @ 15% oxygen, lb/mmBTU, lb/MW-hr, and lb/hr.
4. The test report shall include a revised MACT applicability analysis and propose a MACT, if necessary.

The Department will review the test results and determine whether or not the Bayside project triggers a MACT determination. If so, the Department will modify the PSD permit to include MACT controls.

6. SUMMARY OF EMISSIONS STANDARDS AND COMPLIANCE METHODS

Table 6.1 Summary of Emissions Standards

Pollutant	Gas Firing	Oil Firing
Standards Based on Emissions Performance Tests (Based on permitted capacity and an inlet temperature of 59° F)		
Ammonia	5 ppmvd @ 15% O_2	9 ppmvd @ 15% O_2
CO (BACT)	7.8 ppmvd @ 15% O_2 28.7 lb/hr	15.0 ppmvd @ 15% O_2 64.5 lb/hr @ 59° F
Fuel Specification (BACT)	Natural Gas: 2 grains sulfur per 100 SCF	Distillate Oil: 0.05% sulfur by weight
NOx	3.5 ppmvd @ 15% O_2 23.1 lb/hr	12.0 ppmvd @ 15% O_2 79.2 lb/hr @ 59° F
PM/PM_{10} (BACT)	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {12 lb/hr, estimated maximum}	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {30 lb/hr, estimated maximum}
SAM/SO_2	Fuel Specifications	Fuel Specifications Oil use limited to equivalent of 875 hr/yr.
VOC (BACT)	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 3.0 lb/hr, equivalent to 1.3 ppmvd @ 15% O_2.}	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 7.5 lb/hr, equivalent to 3.0 ppmvd @ 15% O_2.}
Standards Based on CEMS Data		
CO (BACT)	9.0 ppmvd @ 15% O_2, 24-hr block avg.	20.0 ppmvd @ 15% O_2, 24-hr block avg.
NOx	3.5 ppmvd @ 15% O_2, 24-hr block avg.	12.0 ppmvd @ 15% O_2, 24-hr block avg.

Notes:

a. Compliance shall be determined based on a 3-run test average conducted between 90% and 100% of the permitted capacity.

b. Measured mass emission rates (pounds per hour) shall be corrected to a compressor inlet temperature of 59° F based on General Electric emissions performance curves or equations specific to the Model PG7241(FA).

c. NOx emissions are defined as oxides of nitrogen measured as NO_2.

d. The 24-hour block CEMS average is the average emissions for the number of valid operating hours during a 24-hour period. "Valid" operating hours do not include hours that had no operation or hours that were excluded in accordance with the permit conditions regarding startups, shutdowns, and documented unavoidable malfunctions.

Table 6.2 Compliance Methods

EPA Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
5	Determination of Particulate Matter Emissions from Stationary Sources • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 dscf per run.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography • EPA Method 18 may be used concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane from the measured VOC emissions.
20	Determination of Oxides of Nitrogen, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Notes:

a. Initial performance tests shall be conducted for emissions of ammonia, CO, NOx, and opacity when firing each fuel. Thereafter, compliance with the CO and NOx emissions standards shall be determined by valid, certified continuous monitoring data. Compliance with the CO standards shall serve as a surrogate for emissions of PM and VOC.

b. For one unit (Bayside Unit 1A, 1B, or 1C), initial performance tests shall be conducted for emissions of total volatile organic compounds and acetaldehyde, formaldehyde, toluene, and xylene. The test shall be performed at 75% and 100% of base load. For each load condition, the tests shall consist of at least three 1-hour runs.

c. To determine regulated VOC emissions, EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane.

d. The NSPS requirements for testing NOx emissions (EPA Method 20) may be satisfied with EPA Method 7E and valid, certified continuous monitoring data.

e. EPA Method 20 for SO_2 emissions is not required. Compliance shall be demonstrated in accordance with the specified fuel sulfur sampling and analysis as well as the acid rain requirements.

f. A unit firing more than 200 hours of oil per year shall be tested when firing oil for visible emissions and ammonia slip.

g. Annual performance tests shall be conducted each federal fiscal year (October 1st to September 30th) for ammonia and visible emissions when firing gas and when firing oil. Compliance with the CO and NOx emissions standards shall be determined from data collected by the CEM systems during the required annual RATA. Compliance with the CO standards shall serve as a surrogate for emissions of PM and VOC.

7. OTHER PROJECT CONSIDERATIONS

7.1 Shutdown of Gannon Units

The DEP/TEC Consent Final Judgment indicates that Gannon Units 2, 4, and 5 shall be re-powered and Gannon Units 1, 3, and 6 shall be shutdown. The EPA/TEC Consent Decree requires the re-powering of a combination of units totaling at least 550 MW. The Bayside application requests the re-powering of Gannon Units 5 and 6. Correspondence between the Department and TEC (April 19, 20, and 26, 2000) indicates that re-powering Gannon Units 5 and 6 meets the intent of the DEP/TEC Consent Final Judgment.

The applicant used emissions decreases generated from the shutdown of existing Gannon Units 5 and 6 to "net out" of PSD applicability for several pollutants. Therefore, the Draft Permit will require the applicable Gannon Unit to be shut down prior to commencing operation of each corresponding Bayside Unit. This will not impose any hardship on TEC because the existing Gannon Units must be disconnected from the steam-electrical turbines during construction. The Draft Permit will also require the shutdown of the remaining Gannon Units 1-4 before January 1, 2005.

7.2 Interim Coal Firing

The applicant did not predict any emissions increases for existing coal-fired Gannon Units 1-4 after the shut down of Gannon Units 5 or 6. To ensure that large increases in actual emissions do not occur from these units, the Draft Permit will reduce the limit on the total heat input through the coal yard when Gannon Units 5 and 6 are shut down. Based on the representative 2-year "past actual" average coal firing rates for each unit and the average coal heat content, the reduced heat inputs are:

Table 7.2, Coal Yard Heat Input Limits

Unit	Tons Coal per Year	BTU per lb coal	mmBTU per year
Title V Permit Limit, All Gannon Units			$69.9 \times 10^{+06}$
Gannon Unit 5	549,023	12,000	$13.2 \times 10^{+06}$
Gannon Units 1, 2, 3, 4 and 6; Remaining After Shutdown of Unit 5			$56.7 \times 10^{+06}$
Gannon Unit 6	890,562	12,000	$21.4 \times 10^{+06}$
Gannon Units 1, 2, 3, and 4; Remaining After Shutdown of Units 5 and 6			$35.3 \times 10^{+06}$
Gannon Units 1-6, After 12/31/2004			0

Therefore, when Gannon Unit 5 is shutdown, the coal yard heat input will be reduced from 69.9 to 56.7 x 10^{+06} mmBTU per year. When Gannon Unit 6 is shutdown, the coal yard heat input will be reduced from 56.7 to 35.3 x 10^{+06} mmBTU per year. In accordance with the EPA/TEC Consent Decree, all six coal-fired boilers must be shutdown and cease operation before January 1, 2005. Shutdown means the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including "wood-derived" fuels) nor produce any steam for electricity production, other than through re-powering. The Draft Permit will require the dispatch of any operational Bayside Unit before operating any existing Gannon Unit.

7.3 Re-Powering Other Units

The EPA/TEC Consent Decree requires TEC to shutdown and cease any and all operation of all six Gannon coal-fired boilers before January 1, 2005. It allows TEC to retain any shutdown unit on reserve/standby, unless such unit is to be (or has been) re-powered. If TEC later decides to restart any shutdown unit retained on reserve/standby, then TEC must timely apply for a PSD permit for the unit to be re-powered and abide by such permit (including installation of BACT and its corresponding emission rate as determined at the time of the restart). TEC must operate the re-powered unit to meet the NOx emission rate established in the PSD permit or an emission rate for NOx of 3.5 ppmvd corrected to 15% oxygen, whichever is more stringent. TEC must provide a copy of any permit applications, proposed permits, and permits to the EPA. For any unit shutdown and placed on reserve/standby, TEC also may elect to fuel such a unit with a gaseous fuel other than (or in addition to) natural gas, if and only if TEC: applies for and obtains a PSD permit before using such fuel in any such unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to re-powering.

Both the state and federal settlement agreements require the shutdown of Gannon Units 1-4 before January 1, 2005. The shutdowns may potentially result in emissions decreases. However, the emissions decreases must be based on actual emissions during the two years immediately preceding any proposed future project. Because the settlement agreements require the shutdowns and re-powering the Gannon plant with natural gas, "normal operations" for Gannon Units 1-4 are expected to be greatly reduced in 2003 with little or no operation in 2004.

7.4 Permanent Bar on Combustion of Coal

The EPA/TEC Consent Decree prohibits TEC from combusting coal in the operation of any unit at Gannon plant commencing on January 1, 2005.

8. AIR QUALITY IMPACTS

8.1 Executive Summary

In accordance with Rule 62-212.400(5)(d), F.A.C., an ambient impact analysis is required for projects subject to the PSD preconstruction review requirements. For each emission increase exceeding a PSD significant emissions rate defined in Table 62-212.400-2, F.A.C., the applicant must demonstrate that the project will not cause or contribute to a violation of any ambient air quality standard or maximum allowable ambient increase. Nitrogen dioxide (NO_2), particulate matter (PM_{10}), and sulfur dioxide (SO_2) are criteria pollutants with defined ambient air quality standards (AAQS), PSD increments, Class I significant impact levels, and Class II significant impact levels. Carbon monoxide (CO) is a criteria pollutant with defined AAQS and PSD Class II significant impact levels. VOC is a precursor to the criteria pollutant ozone with a defined threshold of 100 tons per year, above which could trigger an ambient impact analysis.

As previously described, the proposed project will increase net emissions of CO and VOC in excess of PSD significant emission rates. Although the evaluation of Best Available Control Technology included PM_{10}, this was based on the revised netting analysis, which assumed "present day" BACT controls were installed on existing Gannon Units 5 and 6. In reality, no such controls are in place and the Bayside project will result in a net emissions decrease for PM_{10} as well as NO_2 and SO_2. Therefore, an evaluation of the ambient impacts from the significant emissions of CO and VOC is required for the Bayside project. In addition, an analysis must be performed for the project impacts on soils, vegetation, and visibility as well as impacts to air quality related to growth resulting from the project.

The net VOC emissions increase from the Bayside project is 71 tons per year (99.6 potential tons per year). This emission rate is greater than the PSD significant emission rate of 40 tons per year, but is less than the de minimis level of 100 tons per year listed in Table 212.400-3, F.A.C. Therefore, no ambient impact analysis was required for VOC emissions. Even if the project did result in a VOC emissions increase above the de minimis level, the Department typically determines that it is not feasible to use regional models that incorporate the complex chemical mechanisms for predicting ozone formation resulting from specific projects.

The applicant's preliminary ambient impact analysis for CO revealed no significant impacts in the PSD Class II areas surrounding the proposed facility. Therefore, a full analysis evaluating the project impacts related to the Class II areas, the AAQS, and the PSD Class II increments was not required. No analysis for the project impacts to Class I areas were required because CO has no defined PSD Class I significant impact levels.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

8.2 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempt or satisfied. If available, representative existing monitoring data may be used to satisfy this monitoring requirement. For each pollutant, an exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the air quality modeling predicts that the maximum ambient impact resulting from the emissions increase is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentration is less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, a determination of the background concentration for each PSD significant pollutant with an established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year. The following table shows the maximum predicted air quality impacts from the project compared to the de minimis levels listed in Table 212.400-3, F.A.C.

8.2 Maximum Air Quality Impacts Compared to the De Minimis Levels

Pollutant	Averaging Time	Maximum Predicted Impact	De Minimis Level	Greater Than De Minimis Impact?
CO	8-hour	163 $\mu g/m^3$	575 $\mu g/m^3$	No
VOC	Annual Emission Rate	71	100 TPY	No

As shown in the table, CO and VOC emissions are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. Also, because VOC is below the specified de minimis level, no ambient impact analysis is required for VOC emissions.

8.3 Models and Meteorological Data Used in Significant Impact and AAQS Analyses

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. The stack height proposed for each Bayside gas turbine is 150 feet, which is less than the de minimis GEP stack height of 65 meters (213 feet). Therefore, the stacks will not exceed the good engineering practice (GEP) stack height criteria. Direction-specific downwash parameters were used for all sources for which downwash was considered.

Meteorological data used in the ISCST3 model was obtained from the National Climatic Data Center (NCDC) and consisted of the concurrent 5-year period from 1992 through 1996. This NCDC station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. Surface data was from the St. Petersburg/Clearwater International Airport (SPG), Station ID 72211. Upper air data was from Ruskin (RUS), Station 12842. The surface and mixing height data for each of the five 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.

Because five years of data are used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted annual average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

8.4 Significant Impact Analysis

A PSD Class II significant impact analysis was performed for CO emissions impacts. Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 500 receptors were placed along the facility's restricted property line and out to 12 km from the facility, which is located in a PSD Class II area. Receptors were placed at 10-degree increments beginning at 10 degrees on rings at 250 and 500 meters, if the specific polar receptor was an ambient air location. Complete rings with receptors located at 10-degree increments beginning at 10 degrees were located at 250-meter increments from 750 to 7000 meters and at 8000, 9000, 10,000, and 12,000 meters. These receptor grids are consistent with prior dispersion modeling studies submitted to the Department for this site.

For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, the modeling analysis compares maximum predicted impacts due to the project with PSD significant impact levels. This will reveal whether the project will cause or contribute to significant impacts in the vicinity of the facility (Class II areas) or in a Class I area based on the model's predictions. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. In addition to the impact from the project, a full impact analysis also considers impacts from other major sources located within the vicinity of the project as well as background concentrations to determine whether the project will cause or contribute to an exceedance of an applicable AAQS or PSD increment. Consequently, a preliminary modeling analysis showing an insignificant impact is accepted as the required air quality analysis and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant.

Because distillate oil firing resulted in the highest emissions rates, twelve scenarios were modeled for oil firing consisting of three load conditions and four compressor inlet temperatures. The following table shows the results of the significant impact analysis.

Table 8.4 Maximum Air Quality Impacts Compared to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact? (Yes/No)
CO	8-hour	163	500	No
	1-hour	411	2,000	No

As shown in the table, no significant CO emissions impacts are predicted in the vicinity of the facility (Class II areas). There are no PSD significant impact levels defined for CO emissions impacts to Class I areas. Therefore, no further modeling analysis was required for this project.

8.5 Requested Modeling Analysis

At the request of the Department, the applicant did perform an ambient impact analysis for CO, NO_2, PM/PM_{10}, and SO_2 based on the ISCST3 air dispersion model and the 12 scenarios for distillate oil, the worst-case fuel. The following table summarizes the results based on the November 17th revision:

Table 8.5 Maximum Predicted Ambient Impacts from Bayside Project

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)	Federal AAQS ($\mu g/m^3$)
CO	HSH, 1-hr	408	40,000	40,000
	HSH, 8-hr	134	10,000	10,000
NO_2	Annual	5	100	100
PM_{10}	HSH, 24-hr	54	150	150
	Annual	4	50	50
SO_2	HSH, 3-hr	320	1300	1300
	HSH, 24-hr	85	260	365
	Annual	5	60	80

The analysis indicates that the project, evaluated independently, will not cause a violation of the state or federal ambient air quality standards.

8.6 Analysis of Additional Impacts on Soils, Vegetation, Visibility, and Air Quality (from Growth)

The Bayside project is the re-powering of an existing coal-fired plant with modern combined cycle gas turbines fired primarily with natural gas. After shutdown of all coal-fired units, it is estimated that the project will reduce actual emissions of nitrogen oxides by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. The chart presented as Attachment B provides an estimate of the expected actual emissions reductions. The modeling predicted insignificant impacts from increased CO emissions. The maximum ambient impacts from the project alone are predicted to be less than the respective ambient air quality standard (AAQS). Because the AAQS are designed to protect both the public health and welfare, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant. Because the project involves the re-powering of an existing plant, it is believed there will be little growth associated with this project.

9. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the conditions specified in the Draft Permit. Chris Carlson and Cleve Holladay are the project meteorologists responsible for reviewing and validating the Air Quality Analysis for this project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determination, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(DRAFT PERMIT)

PERMITTEE:

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No.	0570040-013-AC
Air Permit No.	PSD-FL-301
Facility ID No.	0570040
SIC No.	4911
Expires:	December 31, 2004

PROJECT AND LOCATION

This permit authorizes construction of seven new combined cycle gas turbines to re-power the existing Gannon Station with a nominal electrical production capacity of approximately 1700 MW. The existing plant is renamed the "Bayside Power Station" and is located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. The UTM coordinates are Zone 17, 360.00 km E, 3087.50 km N.

STATEMENT OF BASIS

The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department. This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. Specifically, this permit is issued pursuant to the Chapter 62-212, F.A.C. requirements for Preconstruction Review of Stationary Sources and the Prevention of Significant Deterioration (PSD) of Air Quality. The conditions of this permit do not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A - Terminology
Appendix B - Summary of BACT and Emissions Standards
Appendix E - Summary of Mass Emissions for Given Inlet Temperatures
Appendix GC - General Conditions
Appendix GG - NSPS Subpart GG Requirements for Gas Turbines
Appendix XS - Semi-Annual Continuous Monitor Systems Report

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

When complete, the new Bayside Power Station will have a nominal electrical production capacity of approximately 1742 MW. The following table summarizes the emission units and current status upon issuance of this air construction permit.

EU No.	Status [a]	Emission Unit Description
001	A [d]	Gannon Unit 1 – 125 MW coal fired boiler with steam electrical generator
002	A [d]	Gannon Unit 2 – 125 MW coal fired boiler with steam electrical generator
003	A [d]	Gannon Unit 3 – 180 MW coal fired boiler with steam electrical generator
004	A [d]	Gannon Unit 4 – 188 MW coal fired boiler with steam electrical generator
005	A [b, d]	Gannon Unit 5 – 239 MW coal fired boiler with steam electrical generator
006	A [c, d]	Gannon Unit 6 – 414 MW coal fired boiler with steam electrical generator
007	A	Combustion Turbine No. 1 – 14 MW simple cycle gas turbine
008	A	Gannon Station Coal Yard - Serves Gannon Units 1 – 6
009	A	Economizer Ash Silo w/Baghouse – Serves Gannon Unit No. 4
010	A	Fly Ash Silo No. 1 w/Baghouse – Serves Gannon Units 5 and 6
011	A	Fly Ash Silo No. 2 w/Baghouse – Serves Gannon Units 1 – 4
012	A	Pug Mill and Truck Unloading – Serves Gannon Units 5 and 6
013	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 1
014	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 2
015	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 3
016	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 4
017	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 5
018	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 6
019	I	Inactive emission unit
020	C [b]	Bayside Unit 1A – 170 MW combined cycle gas turbine
021	C [b]	Bayside Unit 1B – 170 MW combined cycle gas turbine
022	C [b]	Bayside Unit 1C – 170 MW combined cycle gas turbine
023	C [c]	Bayside Unit 2A – 170 MW combined cycle gas turbine
024	C [c]	Bayside Unit 2B – 170 MW combined cycle gas turbine
025	C [c]	Bayside Unit 2C – 170 MW combined cycle gas turbine
026	C [c]	Bayside Unit 2D – 170 MW combined cycle gas turbine
027	A	Distillate Oil Storage Tank - 8 million gallon capacity serves Bayside Units

Notes:

a. Status: A (Active), I (Inactive), C (Under Construction)

b. EU 005 must be shutdown before operating EUs 020, 021, and 022.

c. EU 006 must be shutdown before operating EU 023, 024, 025, and 026.

d. EUs 001, 002, 003, 004, 005, and 006 must be shut down before January 1, 2005.

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). The MACT applicability determination for this project is deferred until one new combined cycle gas turbine is tested for HAP emissions.

Title IV: The facility has several emissions units, including the new combined cycle gas turbines, that are subject to the Acid Rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PPSC: The existing Gannon Station was constructed prior to the power plant site certification requirements of Chapter 62-17, F.A.C. The re-powering project is not subject to power plant site certification because there will be no expansion of the steam electrical generating capacity.

PSD: This facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the industries listed as one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

NESHAP: The permittee did not identify any emission unit as being subject to a National Emissions Standard for Hazardous Air Pollutants (NESHAP).

NSPS: The new combined cycle gas turbines are subject the New Source Performance Standards (NSPS) of 40 CFR 60, Subpart GG and the oil storage tank is subject to 40 CFR 60, Subpart Kb.

RELEVANT DOCUMENTS

- DEP/TEC Consent Final Judgment signed in December of 1999;
- EPA/TEC Consent Decree signed in February of 2000; and
- PSD permit application received on September 21, 2000 and all related correspondence.

ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authorities: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southwest District Office, Florida Department of Environmental Protection, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218. The phone number is 813/744-6100 and the fax number is 813/744-6084. Copies of all such documents shall be submitted to the Air Management Division of the Hillsborough County Environmental Protection Commission, 1410 North 21 Street, Tampa, FL 33605. The phone number is 813/272-5530 and the fax number is 813/272-5605.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.

4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. Such an extension does not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree. [40 CFR 52.21(r)(2)]

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. Such an extension does not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with an extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The

Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least ninety days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. [Rule 62-210.700(4), F.A.C.]

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

18. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. **Required Sampling Time**. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

b. **Minimum Sample Volume**. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. **Calibration of Sampling Equipment**. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

[Rule 62-297.310(4), F.A.C.]

19. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

20. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

21. Determination of Process Variables

a. **Required Equipment**. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

b. **Accuracy of Equipment**. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

22. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

23. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

24. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

25. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

A. COMBINED CYCLE GAS TURBINES

This section of the permit addresses the following new emissions units.

EU ID	Bayside ID	Common Emission Unit Description
020 021 022 023 024 025 026	1A 1B 1C 2A 2B 2C 2D	Combined Cycle Gas Turbine: Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the primary fuel with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas and with water injection when firing very low sulfur distillate oil as a backup fuel. At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F. At a compressor inlet air temperature of 59° F and firing 1995 mmBTU (HHV) per hour of very low sulfur distillate oil, each unit produces approximately 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,160,000 acfm at 275° F. Bayside Units 1A, 1B, and 1C supply steam to a single steam electrical generator (formerly serving Gannon Unit 5) with a nameplate rating of 239 MW. Bayside Units 2A, 2B, 2C, and 2D supply steam to a single steam electrical generator (formerly serving Gannon Unit 6) with a nameplate rating of 414 MW of electrical power.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), particulate matter, (PM/PM_{10}), and volatile organic compounds (VOC). [Rule 62-212.400(BACT), F.A.C.]

2. MACT Determination: The MACT applicability determination for this project is deferred until a combined cycle gas turbine is tested for HAP emissions in accordance with Condition No. 23 of this section. However, the permittee shall plan accordingly for the possibility of future applicable controls. If additional controls are later required, the Department shall allow the permittee a reasonable time to install equipment and conform to new or additional conditions. [Rules 62-4.080 and 62-204.800(10)(d), F.A.C.; Section 112(g), CAAA.]

3. NSPS Requirements: Each gas turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

    a. **Subpart A, General Provisions**, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

    b. **Subpart GG, Standards of Performance for Stationary Gas Turbines** as specified in *Appendix GG* of this permit.

EQUIPMENT

4. Schedule: Bayside Unit 1 is scheduled for completion in March 2003. Bayside Unit 2 is scheduled for completion in March 2004. The permittee shall inform the Department of any substantial changes to the construction schedule. [Application; Rule 62-212.400, F.A.C.]

5. Combined Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain seven new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 170 MW of *direct* electrical power. Each unit shall be designed as a combined cycle system to include an automated gas turbine control system, an inlet air filtration system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter, and associated support equipment. [Applicant Request; Design]

6. Heat Recovery Steam Generators (HRSG): The preliminary design of the HRSGs provides three levels of steam conditions when firing natural gas (high pressure, intermediate pressure, and low pressure) and two levels of steam conditions when firing very low sulfur distillate oil as a backup fuel (high pressure and intermediate pressure). The Bayside 1 Unit HRSGs will be identical and the Bayside 2 Unit HRSGs will be identical. The permittee shall submit the final design data upon completion. [Design]

7. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated gas turbine control system for each combined cycle unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. [Design; 62-212.400(BACT), F.A.C.]

8. DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each combined cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the dry low-NOx combustors and automated gas turbine control system shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. The permittee shall provide at least 5 days advance notice prior to any tuning session.[Design; Rule 62-212.400(BACT), F.A.C.]

9. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate and maintain an SCR system to control NOx emissions from each combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, anhydrous ammonia storage, monitoring and control system, electrical, piping and other support equipment. The SCR system shall be designed to control NOx emissions to the permitted levels with an ammonia slip no greater than 5 ppmvd corrected to 15% oxygen when firing natural gas and no greater than 9 ppmvd corrected to 15% oxygen when firing distillate oil. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]

10. Evaporative Inlet Air-Cooling System: Each combined cycle gas turbine may have an evaporative cooling system designed to reduce the temperature of the inlet air to the gas turbine compressor. The reduced temperature provides a greater mass flow rate and increase in power production with additional fuel combustion. The preliminary design is for a water distribution system with packed media blocks of corrugated layers of fibrous material. Air passing over the system wicks moisture away from the media to create the cooling effect. The permittee shall submit the final design data upon completion. [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

11. Permitted Capacity: The maximum heat input rates to each gas turbine shall not exceed the following:

a. **Natural Gas Firing**: 1842 mmBTU per hour with a compressor inlet air temperature of 59° F and producing approximately 170 MW.

b. **Distillate Oil Firing**: 1995 mmBTU per hour with a compressor inlet air temperature of 59° F and producing approximately 182 MW.

The heat input rates are based on the higher heating values (HHV) of each fuel and accommodate expected performance levels in addition to the manufacturer's guarantee. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

12. Allowable Fuels: As the primary fuel, each combined cycle gas turbine shall fire pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet of natural gas. As a backup fuel, each combined cycle gas turbine may be fired with very low sulfur No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight. No other fuels are allowed. [Design; Rules 62-210.200(PTE); DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree]

13. Operation: After completion of Bayside Unit 1, the permittee shall fully dispatch Bayside Unit 1 before operating any remaining Gannon unit. After completion of Bayside Units 1 and 2, the permittee shall fully dispatch Bayside Units 1 and 2 before operating any remaining Gannon unit. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree]

14. Restricted Operation: The hours of operation for each combined cycle gas turbine are not limited (8760 hours per year). However, very low sulfur distillate oil may only be fired as a backup fuel, provided:

a. The unit cannot fire natural gas;

b. The unit fires No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight as the backup fuel;

c. The unit fires no more than 11,775,000 gallons of very low sulfur distillate oil during any consecutive 12 months (equivalent to 875 hours per year of oil firing).

d. All air pollution controls are functional and used to the maximum extent possible for the unit; and

e. The unit is in compliance with the emissions standards of this permit.

[Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.; EPA/TEC Consent Decree]

15. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combined cycle gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix B of this permit.}

16. Emissions Standards Based on Performance Tests: The following standards apply to each combined cycle gas turbine as determined by emissions performance tests conducted at permitted capacity. The mass emission limits are based a compressor inlet temperature of 59° F. For comparison to the standard, actual

measured mass emissions shall be corrected to a compressor inlet temperature of 59° F with manufacturer's data on file with the Department.

a. **Ammonia Slip**: Each SCR system shall be designed and operated for a maximum ammonia slip of no more than 5 ppmvd corrected to 15% oxygen when firing natural gas and no more than 9 ppmvd corrected to 15% oxygen when firing distillate oil. [Rule 62-4.070(3), F.A.C.]

b. **Carbon Monoxide (CO)**: When firing natural gas, CO emissions shall not exceed 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen. When firing distillate oil, CO emissions shall not exceed 64.5 pounds per hour and 15.0 ppmvd corrected to 15% oxygen. Compliance shall be based on a 3-run test average as determined by EPA Method 10. Certified CEM system data may be used to demonstrate compliance with this standard. [Rule 62-212.400(BACT), F.A.C.]

c. **Nitrogen Oxides (NOx)**: When firing natural gas, NOx emissions shall not exceed 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen. When firing distillate oil, NOx emissions shall not exceed 79.2 pounds per hour and 12.0 ppmvd corrected to 15% oxygen. NOx emissions are defined as oxides of nitrogen measured as NO_2. Compliance shall be based on a 3-run test average as determined by EPA Methods 7E. Certified CEM system data may be used to demonstrate compliance with this standard. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree; 40 CFR 60.332]

d. **Particulate Matter (PM/PM_{10})**: The fuel specifications in Condition No. 12 of this section combined with the efficient combustion design and operation of each combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter. Compliance with the fuel specifications, CO standards, and visible emissions standards of this section shall serve as surrogate standards for particulate matter. {Permitting Note: Particulate matter emissions are expected to be less than 12 pounds per hour when firing natural gas and less than 30 pounds per hour when firing distillate oil, as determined by EPA Methods 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]

e. **Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)**: The limits on fuel sulfur specified in Condition No. 12 of this section effectively limit the potential emissions of SO_2 and SAM. Compliance with the fuel sulfur limits shall be demonstrated by the fuel sampling, analysis, record keeping and reporting requirements of Condition No. 29 this section. [Design; 40 CFR 60.333]

f. **Visible Emissions**: When firing either natural gas or distillate oil, visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition No. 19 of this section, this standard applies during all loads. [Rule 62-212.400(BACT), F.A.C.]

g. **Volatile Organic Compounds (VOC)**: The efficient combustion of clean fuels and good operating practices for each combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the CO standards shall serve as surrogate standards for VOC emissions. {Permitting Note: VOC emissions are expected to be less than 3 pounds per hour (1.3 ppmvd corrected to 15% oxygen) when firing natural gas and less than 7.5 pounds per hour (3.0 ppmvd corrected to 15% oxygen) when firing distillate oil, as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-212.400(BACT), F.A.C.]

17. <u>Emissions Standards Based on CEM System Data</u>: The following standards apply to each combined cycle gas turbine based on data collected from required Continuous Emissions Monitoring (CEM) systems.

a. **Carbon Monoxide (CO)**: When firing natural gas, CO emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, CO emissions shall not exceed 20.0 ppmvd corrected to 15% oxygen based on a 24-hour block average.

b. **Nitrogen Oxides (NOx)**: When firing natural gas, NOx emissions shall not exceed 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 24-hour block average.

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

18. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the CO and NOx CEM system compliance averages. [Rule 62-210.700(4), F.A.C.]

19. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of each combined cycle gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

    (a) During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

    (b) Except for startup and shutdown, operation below 50% base load is prohibited.

    (c) A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. To minimize emissions, no more than one gas turbine for each Bayside Unit shall be operated during such a startup. The permittee shall notify each Compliance Authority at least 24-hours in advance of a steam turbine cold startup.

    (d) In accordance with Condition No. 27 of this section, specific data collected by the CEM systems during startup, shutdown, malfunction, and tuning may be excluded from the CO and NOx compliance averaging periods. If a CEM system reports emissions in excess of a 24-hour block emissions standard, the permittee shall notify the Compliance Authority within (1) working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    (e) For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of the procedures, and the methods used to minimize emissions during these periods. Within 90 days of completing the eighth steam turbine cold startup of a Bayside Unit, the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether the period of data exclusion for a steam turbine cold startup defined in Condition 27 of this section shall be *decreased* to represent good operational practices.

[Design; Rule 62-210.700; Rule 62-4.130, F.A.C.; Rule 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

20. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

21. Test Methods: Required tests shall be performed in accordance with the following reference methods.

EPA Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
5	Determination of Particulate Matter Emissions from Stationary Sources • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 dscf per run.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography • EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CT-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Tests: Each combined cycle gas turbine shall be tested when firing each authorized fuel to demonstrate compliance the emission standards for CO, NOx, visible emissions and ammonia slip. The tests must be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. Tests for CO, NOx, and VOC shall be conducted concurrently. Certified CEM system data may be used to demonstrate compliance with the CO and NOx standards. The test results for ammonia slip shall also report the average NOx emissions during each test run. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

23. Initial HAP Performance Tests: At least one of the Bayside Unit 1 combined cycle gas turbines shall be tested when firing natural gas for total volatile organic compounds and the following hazardous air pollutant (HAP) emissions: acetaldehyde, formaldehyde, toluene, and xylene. EPA Method 25A shall be used to determine the emission rate of total volatile organic compounds and EPA Method 18 shall be used to determine the emission rate of each individual HAP. The tests must be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. Tests shall be conducted at two operating rates: between 65% and 75% of permitted capacity and between 90% to 100% of permitted capacity. For each operating rate, the tests shall consist of at least three 1-hour runs and emissions shall be reported in terms of ppmvd corrected to 15% oxygen, pounds per million BTU, pounds per hour, and pound per MW-hour. The test report shall include the gas turbine exhaust temperature (prior to the heat recovery steam generator) and the average CO and NOx emissions recorded by the CEM systems. In addition, the test report shall include the permittee's revised MACT applicability analysis (based on the test data and current EPA guidance) and propose a Maximum Available Control Technology, if necessary.

24. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each combined cycle gas turbine shall be tested when firing natural gas to demonstrate compliance with the emission standards for ammonia slip and visible emissions. Each combined cycle gas turbine that fires more than 200 hours of distillate oil during the federal fiscal year shall also be tested for visible emissions and ammonia slip when firing oil. Compliance with the CO and NOx emissions standards shall be determined from data collected by the CEM systems during the required annual RATA. NOx emissions recorded by the CEM system during the test for ammonia slip shall be reported for each test run. [Rules 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.]

25. Additional Ammonia Slip Testing: If the annual tested ammonia slip rate exceeds 4.5 ppmvd corrected to 15% oxygen when firing natural gas, the permittee shall begin testing and reporting the ammonia slip during each subsequent calendar quarter. If the ammonia slip exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas, the permittee shall take corrective action, test, and demonstrate compliance with the maximum ammonia slip rate within 180 days of first detection. When subsequent tests indicate the ammonia slip rate is less than 4 ppmvd corrected to 15% oxygen, testing shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

26. Tests After Substantial Modifications: The Department may require additional performance tests after any substantial modification and appropriate shakedown period of the gas turbines, including the replacement of dry low-NOx combustors, or modification of the air pollution control equipment. Shakedown periods shall not exceed 100 days after re-starting each combined cycle gas turbine. This does not apply to routine maintenance. [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

27. Continuous Emission Monitoring System: The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring (CEM) system in the exhaust stack of each emissions unit to measure and record the emissions of NOx and CO from these emissions units in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit. The oxygen content or the carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where NOx and CO are monitored to correct the measured CO and NOx emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel fired. The CEM system shall be used to demonstrate compliance with the CEM emission standards for NOx and CO specified in this permit.

a. *Data Collection.* Compliance with the CEM emission standards for NOx and CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. Each hourly value shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

b. *NOx Certification.* The NOx monitor shall be certified and operated in accordance with the following requirements. The NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the CEM emission standards of this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

c. *CO, CO_2, and Oxygen Certification.* The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. The oxygen monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to each Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 60 ppm, as corrected to 15% oxygen. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60. The RATA tests required for the oxygen monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *Data Exclusion.* Emissions data for NOx, CO and CO_2 (or oxygen content) shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NOx and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards as provided in this paragraph.

(1) Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented unavoidable malfunction shall not exceed two hours in any 24-hour block period . Periods of data excluded for such episodes shall not exceed a total of four hours in any 24-hour block period. Gas turbine startup is the commencement of operation of a gas turbine which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion. A documented unavoidable malfunction is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

(2) Periods of data excluded for a steam turbine cold startup shall not exceed sixteen hours in any block 24-hour block period. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. Based on actual operating experience and data, the Department may *decrease* this period of data exclusion in the Title V air operating permit without modifying this PSD permit.

(3) If the permittee provides at least five days advance notice prior to a tuning session, data may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards. Periods of data excluded for such episodes shall not exceed a total of three hours in any 24-hour block period. Tuning sessions must be performed in accordance with the manufacturer's recommendations. No more than two tuning sessions are expected during any year.

All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported semi-annually to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.

f. *Data Conversion.* Upon request from the Department, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

g. *Availability.* NOx and CO monitor availability shall not be less than 95% in any calendar quarter.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

28. Ammonia Monitoring Requirements: The permittee shall install, calibrate, maintain and operate, in accordance with the manufacturer's specifications, an ammonia flow meter to measure and record the ammonia injection rate to each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of combustion turbine load conditions allowed by this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS

29. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

30. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of consumption of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of each combined cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

31. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption and hours of operation for each gas turbine. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

B. STORAGE TANK

This section of the permit addresses the following emissions unit.

EU ID	Emission Unit Description
027	Oil Storage Tank: Existing eight million gallon storage tank supplies low sulfur distillate oil as a backup fuel to the combined cycle gas turbines (EUs 020 through 026).

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE REQUIREMENTS

3. Equipment: The existing 8 million gallon tank shall provide storage for the very low sulfur distillate oil used as backup fuel for the combined cycle gas turbines. [Applicant Request]

4. Hours of Operation: Operation for the distillate oil storage tank is not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

RECORDS

5. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual throughput of distillate oil through the storage tank. [Rule 62-210.370(3), F.A.C.]

6. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

C. EXISTING EMISSIONS UNITS

The following conditions supplement all other valid air construction and operation permits for these units.

EU No.	Emission Unit Description
001	Gannon Unit 1 – 125 MW coal fired boiler with steam electrical generator
002	Gannon Unit 2 – 125 MW coal fired boiler with steam electrical generator
003	Gannon Unit 3 – 180 MW coal fired boiler with steam electrical generator
004	Gannon Unit 4 – 188 MW coal fired boiler with steam electrical generator
005	Gannon Unit 5 – 239 MW coal fired boiler with steam electrical generator
006	Gannon Unit 6 – 414 MW coal fired boiler with steam electrical generator
008	Gannon Station Coal Yard - Serves Gannon Units 1 – 6

SHUTDOWN REQUIREMENTS

1. Shutdown of Gannon Unit 5: Gannon Unit 5 (EU-005) shall be shut down and rendered incapable of operation prior to first fire in any combined cycle gas turbine for Bayside Unit 1 (EU 020 – EU 022). Upon first fire in any combined cycle gas turbine for Bayside Unit 1, the heat input limit on the coal yard (EU-008) is reduced to $56.7 \times 10^{+06}$ mmBTU per consecutive 12 months. [Rule 62-212.400(BACT), F.A.C.]

2. Shutdown of Gannon Unit 6: Gannon Unit 6 (EU-006) shall be shut down and rendered incapable of operation prior to first fire in any combined cycle gas turbine for Bayside Unit 2 (EU 023 – EU 026). Upon first fire in any combined cycle gas turbine for Bayside Unit 2, the heat input limit on the coal yard (EU-008) is reduced to $35.3 \times 10^{+06}$ mmBTU per consecutive 12 months. [Rule 62-212.400(BACT), F.A.C.]

3. Shutdown of Gannon Units 1 - 6: The permittee shall shutdown and cease any and all operation of coal-fired Gannon Units 1 - 6 (EU 001 - 006) no later than December 31, 2004. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including wood-derived fuel) nor produce any steam for electricity production, other than through re-powering as specified in this permit. [EPA/TEC Consent Decree]

4. Permanent Bar on Combustion of Coal: Commencing on January 1, 2005, the permittee shall not combust coal in the operation of any unit at this plant. [EPA/TEC Consent Decree]

5. Notification: Before January 1, 2005, the permittee shall notify the Department of plans for the coal storage and handling facilities. Additional permits may be required. [Rule 62-210.300, F.A.C.]

6. Revisions or Extensions: The provisions of this section shall not be extended or revised the without prior written approval of the U.S. EPA. [EPA/TEC Consent Decree]

SECTION IV. APPENDIX A

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

CCGT	-	Combined Cycle Gas Turbine
CEM	-	Continuous Emissions Monitor
DARM	-	Division of Air Resource Management
DEP	-	State of Florida, Department of Environmental Protection
DLN	-	Dry Low-NOx Combustion Technology
EPA	-	United States Environmental Protection Agency
°F	-	Degrees Fahrenheit
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
HRSG	-	Heat Recovery Steam Generator
UTM	-	Universal Transverse Mercator
SCR	-	Selective Catalytic Reduction

FORMATS FOR PERMIT REFERENCES AND RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example: [Rule 62-213.205, F.A.C.]

Where: 62 - identifies the specific Title of the F.A.C.

62-213 - identifies the specific Chapter of the F.A.C.

62-213.205 - identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001

Where: 099 - identifies the specific county location

0221 - identifies the specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV

Where: AC - identifies the permit as an Air Construction Permit

AV - identifies the permit as a Title V Major Source Air Operation Permit

099 - identifies the specific county that project is located in

2222 - identifies the specific facility

001 - identifies the specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456

Where: AC - identifies the permit as an Air Construction Permit

AO - identifies the permit as an Air Operation Permit

123456 - identifies the specific permit project

SUMMARY OF BACT AND EMISSIONS STANDARDS

For informational purposes, the following table summarizes the standards specified in this permit.

Table B-1. Summary of Emissions Standards for Bayside Units 1 and 2

Pollutant	Gas Firing	Oil Firing
Standards Based on Emissions Performance Tests (Based on permitted capacity and an inlet temperature of 59° F)		
Ammonia	5 ppmvd @ 15% O_2	9 ppmvd @ 15% O_2
CO (BACT)	7.8 ppmvd @ 15% O_2 28.7 lb/hr	15.0 ppmvd @ 15% O_2 64.5 lb/hr @ 59° F
Fuel Specification (BACT)	Natural Gas: 2 grains sulfur per 100 SCF	Distillate Oil: 0.05% sulfur by weight
NOx	3.5 ppmvd @ 15% O_2 23.1 lb/hr	12.0 ppmvd @ 15% O_2 79.2 lb/hr @ 59° F
PM/PM_{10} (BACT)	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {Estimated maximum is 12 lb/hr.}	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {Estimated maximum is 30 lb/hr.}
SAM/SO_2	Fuel Specifications	Fuel Specifications Oil use limited to equivalent of 875 hr/yr.
VOC (BACT)	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 3.0 lb/hr, equivalent to 1.3 ppmvd @ 15% O_2.}	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 7.5 lb/hr, equivalent to 3.0 ppmvd @ 15% O_2.}
Standards Based on CEMS Data		
CO (BACT)	9.0 ppmvd @ 15% O_2, 24-hr block avg.	20.0 ppmvd @ 15% O_2, 24-hr block avg.
NOx	3.5 ppmvd @ 15% O_2, 24-hr block avg.	12.0 ppmvd @ 15% O_2, 24-hr block avg.

Notes:

- NOx emissions are controlled by and SCR system combined with dry low-NOx combustion when firing gas and combined with water injection when firing oil.
- A detailed description of the BACT evaluation is presented in the Technical Evaluation and Preliminary Determination.
- Construction is scheduled to begin in April of 2001. First firing is scheduled for March of 2003 for Bayside Units 1A, 1B, and 1C. First firing is scheduled for March of 2004 for Bayside Units 2A, 2B, 2C, and 2D.

BACT DETERMINATIONS

The project resulted in significant net increases of actual emissions of carbon monoxide (CO) and volatile organic compounds (VOC). Based on an interpretation by EPA Region 4, emissions of particulate matter (PM/PM_{10}) would also be significant if BACT controls had previously been installed on existing Gannon Units 5 and 6. For CO, PM, and VOC emissions, the Department determined that the efficient combustion of clean fuels and good operating practices represent BACT for the combined cycle units. A continuous monitoring system is required for CO emissions to demonstrate continuous compliance with the corresponding CO standard and as surrogate standards for PM and VOC emissions.

SUMMARY OF BACT AND EMISSIONS STANDARDS

The Department's technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued on (DRAFT) with the Draft Permit.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

H. L. Rhodes, Director (Date)
Division of Air Resources Management

Table E. Summary of Mass Emissions for Given Compressor Inlet Temperatures

Pollutant	Inlet Temp.	Mass Emission Rate, lb/hour	
		Gas Firing	Oil Firing
CO	18° F	31.1	70.0
	35° F	30.0	68.0
	59° F	28.7	64.5
	72° F	27.8	62.5
	93° F	26.9	60.4
NOx	18° F	24.7	96.8
	35° F	23.8	94.3
	59° F	23.1	90.9
	72° F	22.6	89.0
	93° F	21.9	86.0
PM/PM10	18° F	11.5	29.0
	35° F	11.4	28.6
	59° F	11.3	28.0
	72° F	11.3	27.6
	93° F	11.2	27.1
VOC	18° F	3.0	7.8
	35° F	3.0	7.5
	59° F	2.8	7.3
	72° F	2.7	7.1
	93° F	2.7	6.9

Notes:

- NOx emissions standards for emissions controlled by an SCR system.
- PM are based on EPA Method 5 (front-half catch only).

GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections

403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (Yes, for CO, PM/PM_{10}, and VOC);

(b) Determination of Prevention of Significant Deterioration (Yes); and

(c) Compliance with New Source Performance Standards (Yes with Subparts GG and Kb).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
N≤0.015	0
0.015<N≤0.1	0.04(N)
0.1<N≤0.25	0.004+0.0067(N–0.1)
N>0.25	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides*. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.
Noxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SECTION IV. APPENDIX XS

SEMI-ANNUAL CONTINUOUS MONITOR SYSTEMS REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: SO_2 NOx TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [a]: ________________________

Emission data summary [a]		**CMS performance summary** [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) / [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months.

I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Title

______________________________________ ____________________
Signature *Date*

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief – Bureau of Air Regulation

THROUGH: Al Linero, Administrator - New Source Review Section aal 2/2

FROM: Jeff Koerner, Project Engineer - New Source Review Section JK

DATE: February 1, 2001

PROJECT: Tampa Electric Company
Bayside Power Station (Gannon Re-Powering Project)
Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301

Attached is the intent to issue permit and public notice package to re-power the existing Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and consists of seven new gas-fired combined cycle gas turbine units. The nominal electric generating capacity for this site will increase from approximately 1100 MW to approximately 1700 MW. My attached P.E. certification provides a brief summary of the required controls and emissions standards. The attached Technical Evaluation and Preliminary Determination provides a detailed analysis of the project.

Day #74 of the permitting time clock is March 9, 2001. I recommend your approval of the attached Draft Permit.

CHF/AAL/jfk
Attachments

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Project No.	0570040-013-AC
Draft Permit No.	PSD-FL-301
Facility ID No.	0570040
SIC No.	4911

PROJECT DESCRIPTION

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Tampa's Port Sutton Road in Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have an electrical production capacity of approximately 1700 MW.

The project will result in significant net increases in actual emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions PM/PM_{10}. The Best Available Control Technology (BACT) for each of these pollutants is determined to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (< 0.05% sulfur by weight) is the backup fuel. Each unit may fire may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired in the unit. The state and federal settlement agreements specified installation of the SCR systems. NOx emissions are controlled by an SCR system combined with dry low-NOx combustion technology when firing natural gas and combined with water injection when firing oil. Each combined cycle unit will have CO and NOx continuous emissions monitoring systems to demonstrate compliance. The CO emissions standards serve as surrogate standards for emissions of PM/PM_{10} and VOC.

After shutdown of the coal-fired units, it is estimated that the Bayside project will reduce *actual* emissions of nitrogen oxides by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required for each pollutant, the emissions standards specified in the Draft Permit for CO, NOx, PM/PM_{10}, SO_2, and VOC represent BACT-level controls. In addition, the CO and NOx emissions monitors will provide a continuous demonstration of compliance with the standards and efficient combustion of each unit.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery F. Koerner
02-01-01

Jeffery F. Koerner, P.E.
Registration Number: 49441

(Date)

DARM/BAR - New Source Review Section
Florida Department of Environmental Protection

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January 19, 2001

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. 7919 5024 5070

Re: Comments on Remaining Issues
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Thank you for providing Tampa Electric Company with the opportunity to review and discuss the remaining issues associated with the Bayside Power Station Air Construction Permit Application. Out of the meeting that took place on January 12, 2001 several issues arose that Tampa Electric Company would like to take this opportunity to comment on. For your convenience, TEC has stated each issue and provided associated comments.

Issue 1-Ammonia Slip

According to the Discussion Purposes document provided during the January 12, 2001 meeting, FDEP indicated that it would limit ammonia slip from each Bayside CT to 5 ppmvd @ 15% O_2 during natural gas-firing.. The Department stated that this limit is based on other similar projects that have undergone BACT evaluations for NOx and is intended to provide the Department with reasonable assurance that each SCR system is operating properly.

The main difference between the Bayside repowering project and other similar projects in terms of NOx emissions is that the Bayside repowering project did not undergo PSD review for NOx. Accordingly, BACT for NOx is not applicable to this situation; TEC is only required to meet a NOx emission limit of 3.5 ppm @ 15% O_2 when firing natural gas. Due to this, coupled with the fact that ammonia is not a regulated air pollutant, TEC believes that FDEP does not have the authority to limit the ammonia slip emissions to 5 ppm and that an ammonia slip limit of 10 ppm during natural gas-firing for this project is reasonable.

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

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

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

Issue 2 - Carbon Monoxide Emissions Monitoring

The Discussion Paper mentioned above indicated that CO continuous emissions monitoring systems (CEMS) would be required for each combustion turbine at Bayside Power Station. However, TEC does not believe that CO CEMS are warranted for the Bayside Power Station. A periodic demonstration of compliance with all applicable CO emission rates on an annual basis should provide the Department with reasonable assurance that all permit limits are complied with. Furthermore, based on modeling evaluations, CO emissions will not cause any health or safety concerns during the operation of Bayside Unit 1 and 2.

Issue 3 - Particulate Matter BACT Evaluation

Per FDEP request, an analysis of PM/PM_{10} BACT demonstrating that the use of clean fuels represents BACT for this project is enclosed.

Issue 4 - Revised NOx Emission Limits During Oil Firing

Emissions of NO_x during oil-firing were estimated based on the same SCR control efficiency for natural gas-firing; i.e., 61 percent. Because the Bayside project is not subject to NO_x BACT review, TEC requests that the oil-firing NO_x permit limitations be set consistent with those submitted to the FDEP in the Air Construction Permit Application.

Issue 5 - CT Maximum Permitted Heat Input When Firing Natural Gas or Distillate Oil

Although the Department is considering a maximum permitted heat input for each CT when firing natural gas of 1603 MMBtu/hr and when firing distillate oil of 1822 MMBtu/hr, TEC believes that CT vendors are typically conservative when guaranteeing heat input rates. In addition, over time, thermal efficiency degradation occurs as evidenced in the enclosed curves. As such, these limits may prove to be unnecessarily restrictive. Tampa Electric Company will demonstrate compliance with all applicable emissions limits regardless of the heat input limit. Therefore, TEC requests that the permit condition addressing heat input limits includes the following language:

> *"The maximum permitted heat inputs shall be revised upward if actual performance testing indicates that the guaranteed heat input rates provided by the vendor are conservative.*
>
> *To account for age related thermal efficiency degradation, the maximum permitted heat inputs shall be revised upward by 3.5%."*

Issue 6 - CT MACT Evaluation

Although TEC continues to support the position that Bayside Units 1 and 2 are separate processes or production units as defined in 40 CFR 63.41, TEC will agree to defer the MACT determination for Bayside Units 1 and 2 until actual testing is performed.

Issue 7 - Excess Emissions During Startup

During the January 12, 2001 meeting, the Department provided a handout identified as 'Handout A' with suggested language that would apply to the startup of a cold steam turbine. TEC suggests using the language from Option 2 below. However, since the Department is authorized to allow excess emissions without establishing additional limits during startup, TEC does not feel that emissions of CO and NOx should be subject to a cold steam startup limit. This is consistent with the language found in Specific Condition 24 of FDEP Air Construction Permit number 071002-004-AC which provides for excess emissions allowances during a cold combined cycle steam turbine startup without establishing additional emissions limits.

> *" A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more, or the first stage turbine metal temperature is 250° F or less. During any steam turbine cold startup, no more than one gas turbine shall be operated. Steam turbine cold startups shall be complete within 16 hours. The SCR system shall be operated to the maximum extent possible. CEMS data collected during a steam turbine cold startup shall be excluded from the 24-hour block CEMS compliance average. The 24-hour block CEMS compliance averages shall be based on the remaining available CEMS data and must include at least three valid 1-hour CEMS averages."*

Issue 8 - Future SO_2 Air Quality Analyses

The Department has indicated that it would like to see an air quality analysis of the SO_2 impacts of any future projects that may occur at Gannon Station. Since this requirement pertains to future projects, it should be addressed during the permitting of any future projects that trigger PSD review for SO_2 emissions, not during the permitting of Bayside Units 1 and 2.

Issue 9 - Continuous Emission Monitoring System Requirements

During the January 12, 2001 meeting, the Department provided TEC with suggested language outlining the requirements of the Bayside Power Station CEM systems. After a detailed review of the suggested language, TEC has determined that much of the language is not applicable to this project. Instead, TEC suggests the language specified in Conditions 39. through 44. of Final Permit Number PSD-FL-263 issued for the new TEC Polk Power Station CTs.

TEC appreciates the opportunity to provide the Department with comments on the remaining issues associated with the permitting of Bayside Units 1 and 2.

If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Gregory M. Nelson

Gregory M. Nelson, P.E.
Director
Environmental Affairs

EP\gm\SKT224

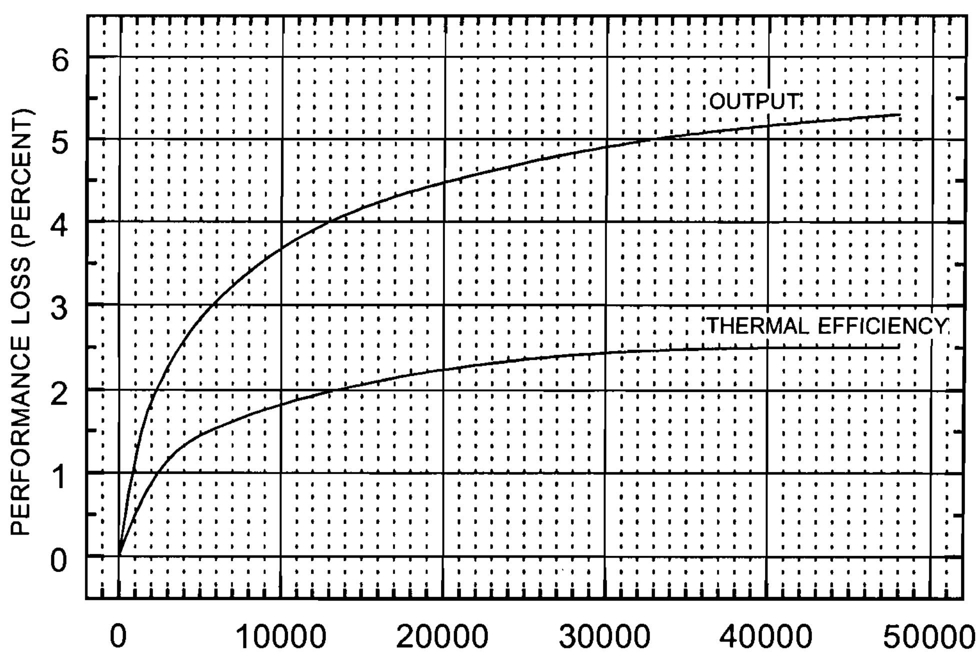
Enclosure

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

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

- PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
- ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
- ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
- A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
- GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
- THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
- DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



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4.0B BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR PARTICULATE MATTER

4.1B METHODOLOGY

The BACT analysis for particulate matter and particulate matter less than ten microns in size (PM/PM_{10}) was performed as previously described in the September 2000 permit application.

4.2B FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR Part 60), NESHAPs (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

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

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

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The Bayside Units 1 and 2 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 PM/PM_{10} emission limitations.

FDEP emission standards for stationary sources are contained in Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards.* Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through -.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart GG.

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 1 and 2 CTs. However, Subpart GG does not contain any PM/PM_{10} emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state PM/PM_{10} emission limitations applicable to Bayside Units 1 and 2.

4.3B BACT ANALYSIS FOR PM/PM_{10}

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

4.3.1B 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 and distillate fuel oil 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 ($cfm\text{-}ft^2$). 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 CTs will be fired with natural gas as the primary fuel and distillate fuel oil as the back-up fuel source. Combustion of natural gas and distillate fuel oil will generate low PM/PM_{10} emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentration for the Bayside CTs during oil-firing at base load and 59°F is approximately 0.005 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.

4.3.2B PROPOSED BACT EMISSION LIMITATIONS

Recent Florida BACT determinations for natural gas- and distillate fuel oil-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 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 primarily with pipeline quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up fuel source. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 4-1B summarizes the PM/PM_{10} BACT emission limits proposed for the Bayside CTs.

Table 4-1B. Proposed PM/PM_{10} BACT Emission Limits

Emission Source	Proposed PM/PM_{10} BACT Emission Limits opacity (%)
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)	
PM/PM_{10} (Natural Gas)	10.0
PM/PM_{10} (Distillate Fuel Oil)	10.0

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

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oxidized mercury can be removed (7). Additional tests showed that the oxidized mercury removal efficiency was limited only by gas-film mass transfer. Elemental mercury vapor does not appear to be removed by an FGD system. This is not surprising since elemental mercury has a very low solubility in water. Other tests of mercury removal by FGD systems have shown similar results, with little or no removal of elemental mercury (1,8).

The testing at the ECTC determined that all of the mercury removed by the FGD system was incorporated into the byproduct solids, although the exact chemical form was not reported (7). No elevated levels of mercury were found in the process liquor or system blowdown stream.

3.6 Lime- and Limestone-Based FGD Process Material Balance

Figure 3-6 illustrates an overall material balance for a lime- or limestone-based FGD process. The primary inlet stream (in terms of mass flow rate) is the flue gas. In most cases, prior to entering the FGD system, the flue gas is treated by a particulate control device such as a high-efficiency electrostatic precipitator (ESP) or fabric filter. These devices are capable of removing over 99.5% of the fly ash in the flue gas. Although some lime- and limestone-based wet FGD systems are designed to remove fly ash from the flue gas or to use alkaline fly ash as a reagent, fly ash can have several detrimental effects on the process and is normally removed upstream of the FGD system. In any case, however, some fly ash passes through the particulate control device and enters the FGD process. Major components of the inlet flue gas include nitrogen, carbon dioxide, water vapor, and oxygen. Minor components include sulfur dioxide, nitrogen oxides, hydrogen chloride, hydrogen fluoride, and sulfuric acid vapor. Some additional soluble trace elements may be present in the flue gas or fly ash.

In the FGD system, SO_2 and some oxygen are removed from the flue gas. In the limestone-based process, about one mole of CO_2 is added to the flue gas per mole of SO_2 absorbed. In the lime-based process, a small amount of CO_2 may be removed from the flue gas (typically, < 0.1 mole CO_2/mole SO_2). An FGD process that removes 95% of the SO_2

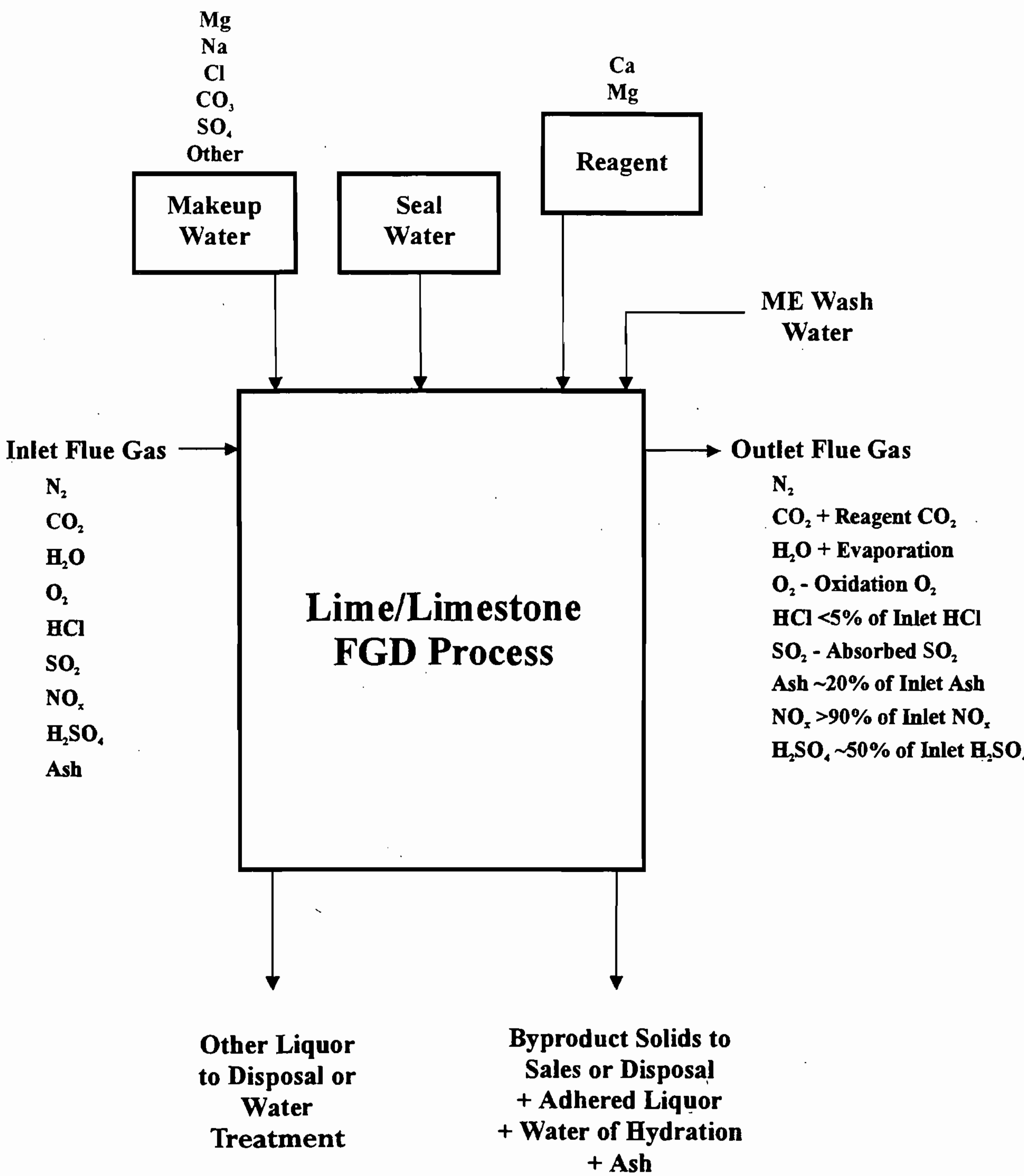

Figure 3-6. Overall System Material Balance

will also remove essentially all of the hydrogen chloride (HCl) from the flue gas because HCl is more readily absorbed than SO_2. Chloride introduced to the FGD system by the flue gas plays an important role in process chemistry. Nitric oxide (NO) that is present in the inlet flue gas typically passes through the FGD system. Although nitrogen dioxide (NO_2) may be absorbed, it is typically only a small fraction of the total nitrogen oxides in the flue gas.

Some vapor-phase sulfuric acid is typically present in the inlet flue gas. Although the H_2SO_4 (g) concentration is only about 1% of the SO_2 concentration, the presence of H_2SO_4 can have significant consequences. When the flue gas is first cooled at the absorber inlet, vapor-phase H_2SO_4 rapidly condenses to form a submicrometer-sized acid mist. Typically, less than about 50% of this mist is removed in the absorber. The remaining mist that penetrates the absorber module may cause a visible stack plume as a result of light scattering by the submicrometer-sized particles.

If the FGD system is downstream of a high-efficiency ESP, up to 80% of the residual fly ash that escapes the particulate control device may be removed in the FGD system. This fly ash typically accounts for only a small fraction of the total FGD byproduct solids, but trace chemical species introduced with the ash can affect process chemistry, especially if wastewater is to be discharged. Trace chemical species, such as iron and manganese, introduced with the ash can also act as oxidation catalysts, providing a benefit to forced-oxidation systems or a detriment to inhibited-oxidation processes.

In the absorber, the flue gas becomes saturated with water. Water evaporation in the absorber is an extremely important material balance term. The amount of water evaporated depends on coal composition, the inlet gas temperature, and inlet gas moisture content, but is usually about 0.06 to 0.07 L/s (1 to 1.2 gpm) for each megawatt of electrical power produced if all of the flue gas is treated.

Water also leaves the process as liquor that is lost with the dewatered byproduct solids. The amount of water that leaves with the solids is small compared to the

Table 1. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

	Unit 5 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	98,99 Avg
Coal Usage (tons)	519,780.0	574,584	450,802	556,487	541,559	528,642	549,023
Wt % Ash	6.98	7.47	8.26	8.15	7.58	7.69	7.87
Wt % S	1.11	1.19	1.16	1.21	1.17	1.17	1.19
Oil Usage (10^3 gal)	332.6	311.0	600.9	599.0	397.0	448.1	498.0
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.35
NO_x [(a)] AOR (CEMS Data)	883.6	1,063.0	451.5	470.6	478.7	669.5	474.7
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data → 157.0	173.0	← Stack Test Data → 1,687.7	2,083.4	2,027.5	1,225.7	2,055.5
SO_2 [(a)] AOR (CEMS Data)	1,037.4	1,296.8	1,075.3	1,370.1	1,260.1	1,207.9	1,315.1
H_2SO_4 [(b)] AP-42 (1998)	32.2	38.2	29.2	37.7	35.4	34.5	36.6
PM_{10} [(c)] AP-42	47.2	55.8	48.4	59.0	53.4	52.7	53.7
PM [(c)] AP-42	127.0	150.2	130.3	158.7	143.7	142.0	144.5
Pb AOR	3.5	3.8	3.0	3.7	3.6	3.5	3.7
VOC AP-42 (1998)	10.4	11.5	9.1	11.2	10.9	10.6	11.0

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 2. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

	Unit 6 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	97,98 Avg
Coal Usage (tons)	897,070.0	892,742	920,526	860,597	693,039	852,795	890,562
Wt % Ash	7.22	7.48	8.79	8.41	7.28	7.84	8.60
Wt % S	1.10	1.19	1.18	1.22	1.13	1.16	1.20
Oil Usage (10^3 gal)	378.9	311.0	639.9	599.0	362.0	458.1	619.4
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.22
NO_x [a] AOR (CEMS Data)	1,525.5	1,652.0	1,092.9	1,093.4	958.8	1,264.5	1,093.2
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data → 270.0	269.0	← Stack Test Data → 3,446.3	3,221.9	2,594.6	1,960.4	3,334.1
SO_2 [a] AOR (CEMS Data)	1,880.1	2,030.8	2,282.9	2,370.4	1,602.9	2,033.4	2,326.7
H_2SO_4 [b] AP-42 (1998)	55.0	59.3	60.6	58.7	43.8	55.5	59.6
PM_{10} [c] AOR	84.2	86.8	105.2	94.1	65.6	87.2	99.6
PM [c] AOR	226.7	233.7	283.2	253.3	176.6	234.7	268.3
Pb AOR	6.0	5.9	6.1	5.7	4.6	5.7	5.9
VOC AP-42 (1998)	18.0	17.9	18.5	17.3	13.9	17.1	17.9

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 3. Bayside Station
Bayside Units 1 & 2/F.J. Gannon Units 5 & 6 Emissions Netting Analysis

	Units 5 & 6 (tpy)					Unit 5	Unit 6	Total		Net	PSD	PSD
	1995	1996	1997	1998	1999	2 Yr [a] Avg	2 Yr [b] Avg	2 Yr [a], [b] Avg	CT 1A-2D (tpy)	Change (tpy)	Threshold (tpy)	Review (Y/N)
Coal Usage (tons)	1,416,850	1,467,326	1,371,328	1,417,084	1,234,598	549,023	890,562	1,439,585	N/A	N/A	N/A	N/A
Wt % Ash	7.10	7.48	8.53	8.28	7.43	7.87	8.60	8.23	N/A	N/A	N/A	N/A
Wt % S	1.11	1.19	1.17	1.22	1.15	1.19	1.20	1.20	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	711.5	622.0	1,240.8	1,198.0	759.0	498.0	619.4	1,117.4	N/A	N/A	N/A	N/A
Wt % S	0.16	0.30	0.15	0.28	0.41	0.35	0.22	0.28	N/A	N/A	N/A	N/A
NO_x [c] AOR (CEMS Data)	2,409.1	2,715.0	1,544.4	1,564.0	1,437.5	474.7	1,093.2	1,567.8	1,018.2	-549.6	40.0	N
CO AOR & Stack Test	427.0	442.0	5,134.0	5,305.3	4,622.1	2,055.5	3,334.1	5,389.6	989.7	-4,399.9	100.0	N
SO_2 [c] AOR (CEMS Data)	2,917.5	3,327.6	3,358.2	3,740.5	2,863.0	1,315.1	2,326.7	3,641.8	576.3	-3,065.4	40.0	N
H_2SO_4 [d] AP-42 (1998)	87.2	97.5	89.8	96.3	79.2	36.6	59.6	96.2	96.7	0.5	7.0	N
PM_{10} [e] AOR	131.4	142.6	153.6	153.1	119.0	53.7	99.6	153.3	721.4	568.1	15.0	Y
PM [e] AOR	353.7	384.0	413.5	412.1	320.3	144.5	268.3	412.8	721.4	308.6	25.0	Y
Pb AOR	9.4	9.8	9.1	9.4	8.2	3.7	5.9	9.6	1.1	-8.5	0.6	N
VOC AP-42 (1998)	28.4	29.4	27.6	28.5	24.8	11.0	17.9	28.9	99.6	70.7	40.0	Y

(a) Fuel data represents 1998, 1999 average for Unit 5.
(b) Fuel data represents 1997, 1998 average for Unit 6.
(c) Actual emissions reduced by 90% to reflect retroactive BACT.
(d) Actual emissions reduced by 35% to reflect retroactive BACT.
(e) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Unit 5	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.39	24.65	23.96	24.00	24.00	21.80	24.65
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/hr)	6,486,102	14,208,885	10,884,135	13,438,679	13,052,202	11,614,000	14,208,885
PM/PM_{10} - AOR (tpy)	193.0	212.3	392.3	273.0	196.7	253.5	392.3
PM/PM_{10} - AOR (lb/MMBtu)	0.0595	0.0299	0.0721	0.0406	0.0301	0.0465	0.0721
H_2SO_4 - AOR (tpy)	49.54	58.75	44.95	57.95	54.53	53.14	58.75
H_2SO_4 - AOR (lb/MMBtu)	0.0153	0.0083	0.0083	0.0086	0.0084	0.0098	0.0153

Unit 6	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.47	24.85	24.28	24.01	24.00	21.92	24.85
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/hr)	11,238,901	22,229,515	22,438,664	20,745,925	16,682,892	18,667,179	22,438,664
PM/PM_{10} - AOR (tpy)	1,116.0	1,109.3	818.6	911.0	765.1	944.0	1,116.0
PM/PM_{10} - AOR (lb/MMBtu)	0.1986	0.0998	0.0730	0.0878	0.0917	0.1102	0.1986
H_2SO_4 - AOR (tpy)	84.69	91.21	93.26	90.24	67.34	85.35	93.26
H_2SO_4 - AOR (lb/MMBtu)	0.0151	0.0082	0.0083	0.0087	0.0081	0.0097	0.0151

Table 1. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

	Unit 5 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	98,99 Avg
Coal Usage (tons)	519,780.0	574,584	450,802	556,487	541,559	528,642	549,023
Wt % Ash	6.98	7.47	8.26	8.15	7.58	7.69	7.87
Wt % S	1.11	1.19	1.16	1.21	1.17	1.17	1.19
Oil Usage (10^3 gal)	332.6	311.0	600.9	599.0	397.0	448.1	498.0
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.35
NO_x[(a)] AOR (CEMS Data)	883.6	1,063.0	451.5	470.6	478.7	669.5	474.7
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data → 157.0	173.0	← Stack Test Data → 1,687.7	2,083.4	2,027.5	1,225.7	2,055.5
SO_2[(a)] AOR (CEMS Data)	1,037.4	1,296.8	1,075.3	1,370.1	1,260.1	1,207.9	1,315.1
H_2SO_4[(b)] AP-42 (1998)	32.2	38.2	29.2	37.7	35.4	34.5	36.6
PM_{10}[(c)] AP-42	47.2	55.8	48.4	59.0	53.4	52.7	53.7
PM[(c)] AP-42	127.0	150.2	130.3	158.7	143.7	142.0	144.5
Pb AOR	3.5	3.8	3.0	3.7	3.6	3.5	3.7
VOC AP-42 (1998)	10.4	11.5	9.1	11.2	10.9	10.6	11.0

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 2. Bayside Station Units 1 and 2
Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

	Unit 6 (tpy)						
	1995	1996	1997	1998	1999	95-99, 5 Yr Avg	97,98 Avg
Coal Usage (tons)	897,070.0	892,742	920,526	860,597	693,039	852,795	890,562
Wt % Ash	7.22	7.48	8.79	8.41	7.28	7.84	8.60
Wt % S	1.10	1.19	1.18	1.22	1.13	1.16	1.20
Oil Usage (10^3 gal)	378.9	311.0	639.9	599.0	362.0	458.1	619.4
Wt % S	0.16	0.30	0.15	0.28	0.41	0.26	0.22
NO_x [(a)] AOR (CEMS Data)	1,525.5	1,652.0	1,092.9	1,093.4	958.8	1,264.5	1,093.2
CO Gannon Unit 5 4/7,8/00 Stack Test Avg. = 0.295 lb/MMBtu E.F. = 7.488 lb/ton	← AOR Data → 270.0	269.0	← Stack Test Data → 3,446.3	3,221.9	2,594.6	1,960.4	3,334.1
SO_2 [(a)] AOR (CEMS Data)	1,880.1	2,030.8	2,282.9	2,370.4	1,602.9	2,033.4	2,326.7
H_2SO_4 [(b)] AP-42 (1998)	55.0	59.3	60.6	58.7	43.8	55.5	59.6
PM_{10} [(c)] AOR	84.2	86.8	105.2	94.1	65.6	87.2	99.6
PM [(c)] AOR	226.7	233.7	283.2	253.3	176.6	234.7	268.3
Pb AOR	6.0	5.9	6.1	5.7	4.6	5.7	5.9
VOC AP-42 (1998)	18.0	17.9	18.5	17.3	13.9	17.1	17.9

(a) Actual emissions reduced by 90% to reflect retroactive BACT.
(b) Actual emissions reduced by 35% to reflect retroactive BACT.
(c) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Table 3. Bayside Station
Bayside Units 1 & 2/F.J. Gannon Units 5 & 6 Emissions Netting Analysis

	Units 5 & 6 (tpy)					Unit 5 2 Yr [a] Avg	Unit 6 2 Yr [b] Avg	Total 2 Yr [a, b] Avg	CT 1A-2D (tpy)	Net Change (tpy)	PSD Threshold (tpy)	PSD Review (Y/N)
	1995	1996	1997	1998	1999							
Coal Usage (tons)	1,416,850	1,467,326	1,371,328	1,417,084	1,234,598	549,023	890,562	1,439,585	N/A	N/A	N/A	N/A
Wt % Ash	7.10	7.48	8.53	8.28	7.43	7.87	8.60	8.23	N/A	N/A	N/A	N/A
Wt % S	1.11	1.19	1.17	1.22	1.15	1.19	1.20	1.20	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	711.5	622.0	1,240.8	1,198.0	759.0	498.0	619.4	1,117.4	N/A	N/A	N/A	N/A
Wt % S	0.16	0.30	0.15	0.28	0.41	0.35	0.22	0.28	N/A	N/A	N/A	N/A
NO_x [c] AOR (CEMS Data)	2,409.1	2,715.0	1,544.4	1,564.0	1,437.5	474.7	1,093.2	1,567.8	1,018.2	-549.6	40.0	N
CO AOR & Stack Test	427.0	442.0	5,134.0	5,305.3	4,622.1	2,055.5	3,334.1	5,389.6	989.7	-4,399.9	100.0	N
SO_2 [c] AOR (CEMS Data)	2,917.5	3,327.6	3,358.2	3,740.5	2,863.0	1,315.1	2,326.7	3,641.8	576.3	-3,065.4	40.0	N
H_2SO_4 [d] AP-42 (1998)	87.2	97.5	89.8	96.3	79.2	36.6	59.6	96.2	96.7	0.5	7.0	N
PM_{10} [e] AOR	131.4	142.6	153.6	153.1	119.0	53.7	99.6	153.3	721.4	568.1	15.0	Y
PM [e] AOR	353.7	384.0	413.5	412.1	320.3	144.5	268.3	412.8	721.4	308.6	25.0	Y
Pb AOR	9.4	9.8	9.1	9.4	8.2	3.7	5.9	9.6	1.1	-8.5	0.6	N
VOC AP-42 (1998)	28.4	29.4	27.6	28.5	24.8	11.0	17.9	28.9	99.6	70.7	40.0	Y

(a) Fuel data represents 1998, 1999 average for Unit 5.
(b) Fuel data represents 1997, 1998 average for Unit 6.
(c) Actual emissions reduced by 90% to reflect retroactive BACT.
(d) Actual emissions reduced by 35% to reflect retroactive BACT.
(e) AP-42 uncontrolled emissions reduced by 99% to reflect retroactive BACT.

Sources: ECT, 2000.
TEC, 2000.

Unit 5	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.39	24.65	23.96	24.00	24.00	21.80	24.65
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/yr)	6,486,102	14,208,885	10,884,135	13,438,679	13,052,202	11,614,000	14,208,885
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PM/PM_{10} - AOR (lb/MMBtu)	0.0595	0.0299	0.0721	0.0406	0.0301	0.0465	0.0721
H_2SO_4 - AOR (tpy)	49.54	58.75	44.95	57.95	54.53	53.14	58.75
H_2SO_4 - AOR (lb/MMBtu)	0.0153	0.0083	0.0083	0.0086	0.0084	0.0098	0.0153

Unit 6	1995	1996	1997	1998	1999	Average	Maximum
Fuel Heat Content - Coal (MMBtu/ton)	12.47	24.85	24.28	24.01	24.00	21.92	24.85
Fuel Heat Content - Oil (MMBtu/10^3 gal)	138.40	138.56	137.99	138.55	138.00	138.30	138.56
Heat Input (MMBtu/yr)	11,238,901	22,229,515	22,438,664	20,745,925	16,682,892	18,667,179	22,438,664
PM/PM_{10} - AOR (tpy)	1,116.0	1,109.3	818.6	911.0	765.1	944.0	1,116.0
PM/PM_{10} - AOR (lb/MMBtu)	0.1986	0.0998	0.0730	0.0878	0.0917	0.1102	0.1986
H_2SO_4 - AOR (tpy)	84.69	91.21	93.26	90.24	67.34	85.35	93.26
H_2SO_4 - AOR (lb/MMBtu)	0.0151	0.0082	0.0083	0.0087	0.0081	0.0097	0.0151

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January 10, 2001

Ms. Diana Lee, P.E
Mr. Rob Kalch.
Environmental Protection Commission
of Hillsborough County
1900 9th Avenue
Tampa, Florida 33605

Via Fed Ex
Airbill No. 7919 4206 1967

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

Dear Ms. Lee and Mr. Kalch:

Tampa Electric Company (TEC) submits this letter as a follow up to the meeting between our parties on December 13, 2000 regarding the Gannon repowering project. TEC has restated each EPC comment below followed by a response from TEC.

EPC Comment No. 1:
In a letter addressed to Mr. Jamie Hunter, Tampa Electric Company, dated August 22, 2000, a determination was made that a new fuel oil tank did not need a construction permit due to the low emissions from the tank. The letter further stated that the emissions from the tank did need to be included in the pre-construction review of the planned Bayside re-powering. The construction application states that a 5.85 million gallon fuel oil storage tank will be added as part of the construction project, but the tank that was evaluated in the letter dated August 22, 2000 was an 8 million gallon tank. Are the two tanks the same or has the 8 million gallon tank been omitted?

TEC Response:
The two tanks are the same. The 8 million-gallon tank will also be used in existing Gannon Station operations.

EPC Comment No. 2:
It was noted that the combined MW to be produced by Bayside Units 1 and 2 do not add up correctly. Please provide clarification on this. As an example Bayside Units 1 and 2 are evaluated:

Bayside Unit No.1		
	3 CTs at	**166 MW**
	1 ST (unit no.5)	**239 MW**
	EPC calculated total MW produced	**737 MW**
	TEC projected total MW produced	**753 MW**
Bayside Unit No. 2		
	4 CTs at	**166 MW**

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

1 ST (unit no.6)	**414 MW**
EPC calculated total MW produced	**1078 MW**
TEC projected total MW produced	**975 MW**

TEC Response:
Under current operating conditions, steam is removed from the strategic locations in turbine serving Gannon Units 5 and 6 and used in other locations in the process. When the Bayside power station comes online, it is anticipated that this steam will no longer need to be removed and will thus provide additional capacity to each steam turbine. This is the reason that the capacity of Bayside Unit 1 is higher than the sum of the permitted capacity of the steam turbine serving Gannon Unit 5 and the design capacities of the combustion turbines serving Bayside Unit 1. Bayside Unit 2 should be higher in capacity for the same reason that Bayside Unit 1 will be, however, it is anticipated that the steam turbine serving Gannon Unit 6 will operate at a much lower capacity than it is currently permitted due to the fact that the HRSGs serving the unit will not produce enough steam for the turbine to achieve full load. Therefore, the overall output of Bayside Unit 2 is less than the sum of the permitted capacity of Gannon Unit 6 and the design capacities of the combustion turbines serving Bayside Unit 2. It is also worth noting that the capacities contained in the permit application reflect maximum output design data, and the actual output of each combustion turbine and steam turbine may vary depending on ambient conditions, operation of the inlet fogging systems, age related degradation and other operational factors.

EPC Comment No. 3:
EPC staff noted on Page 1-2 in the project description that Units 5 and 6 will permanently cease coal fired operations. What about wood derived fuels (WDF) and tire derived fuels (TDF)?

TEC Response:
When combusting WDF or TDF, TEC actually combusts a weight percent blend of each fuel with coal. Typically, these blends are less than 10% by weight of WDF or less than 20% by weight of TDF. It would be very difficult, if not impossible to combust 100% WDF or 100% TDF due to operational issues that arise from handling and firing each fuel. Therefore, TEC does not anticipate operating the existing coal fired boilers at Gannon Station with WDF or TDF. If TEC does, however, decide to fire a fuel other than coal in any existing Gannon boiler, it will submit a permit application before doing so as mandated by both the Consent Decree and Consent Final Judgement.

EPC Comment No. 4:
EPC staff noted on Page 1-2 in the project description that it is proposed that one "Bayside Unit" be equipped with "SCONO$_x$" technology. Has this technology been approved by EPA as required by Consent Agreement 99-2524, CIV-T-23F? Does the term "unit" mean one individual CT or a group of CTs? If the term "unit" is to be a group of CTs which group is to be controlled with the SCONO$_x$ technology, and if the term "unit" is to be a single CT, which one will be equipped with the SCONO$_x$ technology?

TEC Response:
At this time, both TEC and FDEP agree that the SCONOx technology is not economically feasible as defined by Condition V.B. of the Consent Final Judgement. In this particular case, the term 'unit' is intended to mean an individual CT. However, in most other cases, the term 'unit' is taken to mean the collection of combustion turbines that provide steam to an existing steam turbine.

EPC Comment No. 5:
What percentage of the total cost of re-powering Bayside does the installation of the oxidation catalyst system represent? What percentage of the present annual operating and maintenance costs does the projected annual operating cost associated with the oxidation catalyst system represent?

TEC Response:
Although no final costs for the Bayside project are available yet, the repowering is expected to cost about $740 million, and the total capital investment of an oxidation catalyst system is $9,586,600. The resulting ratio of cost of oxidation catalyst system to total cost of the Bayside project is 0.013. The average Annual Operating and Maintenance Costs for Gannon Station between the years 1996-1999 was approximately $32.7 million and TEC projects that it will cost approximately $2,599,199 to operate and maintain the oxidation catalyst system. Therefore, the annual operating cost associated with the oxidation catalyst system represents about 7.9% of the current Gannon operating and maintenance costs.

EPC Comment No. 6:
Has TEC performed modeling using the SCONO$_x$ technology? If so, what are the results?

TEC Response:
No, TEC has not performed modeling using the SCONOx technology. Since SCONOx has never been installed on a GE 7F combustion turbine, most of the emissions are unknown. However, it is not anticipated that modeling would reveal greater ambient impacts as a result of installing the SCONOx technology when compared to SCR systems.

EPC Comment No. 7:
EPC staff noted on Page 2-8 (third paragraph), of the project description, that both of the heat inputs do not agree with the requested heat input listed on Page 14, Section B, Item no.1 of the construction application. The values listed on page 2-8 are 1779.4 and 1928.0 MMBtu/hr and the construction application requests 1940 MMBtu/hr.

TEC Response
The paragraph referenced above on Page 2-8 goes on to read in part, "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. TEC therefore requests a permit condition that would allow for a higher maximum heat input rate based on actual performance tests." This is the reason for the difference in heat inputs.

EPC Comment No. 8:
EPC staff noted that on Page 2-9 of the project description TEC requested 18 hours per cold start for the steam turbines. What is the time frame is being set for the 18 hour request (i.e. 18 hours per 24 hours)? Please note, since the steam turbine(s) are connected to the CT exhausts, allowing excess emissions from the steam turbines for a period of 18 hours would effectively allow excess emissions for a period of 18 hours for the CTs as well. What excess emissions does TEC expect to be emitted from an unfired steam turbine?

TEC Response:
Based on further discussions with the Bayside engineering team, only one CT will generate excess emissions during a cold steam turbine startup. This period of excess emissions is expected to last for 16 hours during which the CT will operate at less than 50% load.

EPC Comment No. 9:
Please note, EPC staff noted on Page 3-1 of the project description that TEC has stated that Hillsborough County is attainment for ozone, but Hillsborough County is a maintenance area for ozone.

TEC Response:
TEC does not object to this issue.

EPC Comment No. 10:
EPC staff noted that TEC has requested the option of firing fuel oil in the CTs for 876 hr equivalents at 100 % base load. The Consent Agreement limits the hour equivalents to 875 hrs per year at 100 % of the base load. All of the potential emissions calculations contained in the construction permit application are also based on 876 hr/yr and need to be updated to reflect 875 hrs/yr as required by the consent order.

TEC Response:
TEC requests a permit limit of 875 full load equivalent hours of operation per year on oil. Since the calculations based on 876 hours of full load equivalent operation represent a worst case scenario, TEC suggests that the potential calculations are conservative and do not need to be revised.

EPC Comment No. 11:
EPC staff noted on Page 22 of the construction application that the CO Potential Emissions are based on 876 hrs per year firing fuel oil at 100 % load and 59°F. EPC staff believes that the potential emissions

should be based on firing fuel oil at 50 % load and 93°F for 1750 hours per year since the hourly emissions are greater at the reduced load and TEC has requested the option of operating at less than 100% of the base load.

TEC Response:
The emission rate at 93°F and 50% load represents a short-term worst case emission rate. The annual emission rate calculated at 100% load and 59°F represents a reasonable annual average and is used for annual modeling. TEC feels that the modeling performed was done so correctly; as the emission rate calculated at 59°F and 100% load is an industry accepted standard.

EPC Comment No. 12:
Will TEC be removing or permanently disabling the coal fired boilers at Gannon (Bayside) after construction is complete? If the coal fired units are to remain on-site and functional, EPC staff feels that the potential emissions from these units should be included evaluated as well.

TEC Response:
TEC is not permitted by law to fire coal in any of those boilers after December 31, 2004 and, as such, will disable each coal fired boiler. Therefore, the boilers will not have any emissions to evaluate.

EPC Comment No. 13:
EPC staff noted that on Pages 24 and 26 of the construction permit application that PM and PM_{10} emissions are based on modeling performed at 59°F but the application states the modeling was performed at 18°F, which is the worst case for PM and PM_{10}. Please clarify which is correct.

TEC Response
The hourly emission rates of PM and PM_{10} are based on an ambient temperature of 18°F. This represents a short-term worst case emission rate of each species. The annual emission rates of PM and PM_{10} are based on an ambient temperature of 59°F, which is an industry standard that represents a reasonable annual average temperature.

EPC Comment No. 14
EPC staff noted that on Page 30 of the construction permit application that the annual H_2SO_4 emissions were based on modeling performed for 59°F, but the modeling predicts the worst case at 18°F. What is the basis for basing annual emissions at 59°F instead of the worst case?

TEC Response
See the response to Comment 13.

EPC Comment No. 15:
EPC staff noted that on Page 32 of the construction permit application that the annual VOC emissions were based on modeling performed for 59°F, but the modeling predicts the worst case at 18°F. What is the basis for basing annual emissions at 59°F instead of the worst case?

TEC Response
See the response to Comment 13.

TEC appreciates the opportunity to work with EPC to resolve these issues in an expedited manner. This will help to ensure that construction will commence on the Bayside Power Station under a schedule that will allow TEC to comply with the dates outlined in the FDEP Consent Final Judgement and the EPA Consent Decree. If you have any questions, please feel free to telephone me at (813) 641-5125.

Sincerely,

Shannon K. Todd
Environmental Engineer
Environmental Affairs

EP\gm\SKT209

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

TAMPA ELECTRIC

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DEC 26 2000

BUREAU OF AIR REGULATION

December 22, 2000

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. 7904 3137 2873

Re: Second Request for Additional Information
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter of incompleteness dated December 15, 2000 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. For your convenience, TEC has restated each point and provided a response below each specific issue.

1. **<u>Netting Analysis</u>: Please verify that *all* emissions increases and decreases for *all* emissions units have been included in the netting analysis for the contemporaneous period. Describe any outstanding air permitting projects that TEC has for the Gannon Plant, including any projects submitted to either the Department's Tallahassee Office as well as the Southwest District Office. For example, please describe the addition of wood-derived fuels (WDF) as authorized fuels for Gannon Units 1 – 4. What is the purpose of adding new fuels for these boilers? Will this result in an increase in actual annual emissions? Is this request related to the shutdown of Units 5 and 6 or the re-powering project in any way?**

TEC Response

Most emissions increases and decreases for all emissions units have been included in the netting analysis for the contemporaneous period. One outstanding project, the combustion of Wood Derived Fuel blends, however, was not included in the netting analysis. This project involves the combustion of paper pellets and /or yard trash as part of Tampa Electric Company's Smart Source Program. The Smart Source Program provides the opportunity for TEC customers to purchase electricity generated from alternative and renewable sources such as Wood Derived Fuel. During calendar year 2001, Tampa Electric expects to fire up to 1,250 tons of Wood Derived Fuel at Gannon Station which will result in emissions decreases of SO_2 and NO_x, while PM emissions will remain unchanged. Based on the stack tests performed and submitted to the Department, TEC intends to fire yard trash composed of wood chips up to 4% by weight.

Finally, TEC is not required by this permit to fire Wood Derived Fuel, so considering any emissions decreases in the netting analysis would be inappropriate. This project is in no way related to the repowering of Gannon Station to Bayside Station.

2. **Gas Turbines / HRSGs: Please provide the "preliminary design" data for the Heat Recovery Steam Generators (HRSGs), including the maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG. Will each HRSG be identical?**

TEC Response

The requested information is provided below. TEC has provided this information with the understanding that it will be used for descriptive purposes, only and will not be used to limit the operation of either Bayside Unit 1 or 2. Furthermore, this is preliminary design data and, as such, is subject to change as the design changes. The HRSG's serving Bayside Unit 1 are identical and the HRSG's serving Bayside Unit 2 are also identical.

	Natural Gas Fired Operation (per HRSG)	*Fuel Oil Fired Operation (per HRSG)*
Bayside Unit 1		
HP Steam flow [lbm/hr]	455,450	478,250
IP Steam flow [lbm/hr]	508,540	525,120
LP steam flow [lbm/hr]	44,860	0
Total steam flow [lbm/hr]	1,008,850	1,003,370
Max. Steam Temperature [°F]	1,011	1,012
Max. Steam Pressure [psia]	1,597	1629
Bayside Unit 2		
HP Steam flow [lbm/hr]	447,100	449,400
IP Steam flow [lbm/hr]	518,100	515,200
LP steam flow [lbm/hr]	18,300	0
Total steam flow [lbm/hr]	983,500	964,600
Max. Steam Temperature [°F]	1,010	1,010
Max. Steam Pressure [psia]	1,796	1,837

3. **Proposed Control Equipment: The Department is working with TEC to resolve the evaluation of zero ammonia technologies. Please note that this issue must be resolved before the Department will deem the Bayside PSD permit application complete.**

TEC Response

TEC understands that the evaluation of zero ammonia technologies has been completed and that the SCONOx system will not be applied to any combustion turbine at the Bayside Power Station. Since the issue is now resolved, TEC understands that the Department is free to deem the application complete relative to this item.

4. **<u>BACT Determination for CO</u>: The Department does not believe a one-time emissions performance test conducted on Gannon Unit 5 in April of 2000 to be representative of actual CO emissions from Gannon Units 5 and 6 for the base years of 1997, 1998, and 1999. Again, please submit a top-down BACT analysis for the control of carbon monoxide. When evaluating the oxidation catalyst, please include the items previously addressed for the revised cost analysis for the VOC oxidation catalyst. Note that a CO control efficiency of at least 90% would be expected. If no CO BACT is proposed, the Department will establish a CO BACT standard without input from TEC.**

TEC Response

Recent conversations between Sheila McDevitt, General Counsel of TECO Energy and USEPA have resulted in the determination that NSR was not intended to apply to the Bayside repowering project. In addition, Condition M. of the Consent Final Judgement states that:

> *"Tampa Electric Company shall also be protected from triggering NSR requirements with respect to repairs, maintenance, and physical or operation changes during the term of the Consent Final Judgement which term shall remain effective until the actions required hereunder have been implemented."*

Although TEC believes that the performance test on Gannon Unit 5 does, in fact, represent actual CO emissions from Units 5 and 6 for the base years of 1997, 1998, and 1999, and that the Bayside repowering was never intended to be subject to PSD review, a BACT analysis is enclosed. The total cost of CO control is $2,918 per ton of CO removed, which has historically been considered economically infeasible by the Department.

5. **<u>MACT Determination for Hazardous Air Pollutants (HAPs)</u>: As previously discussed, the EPA and the Department disagree with TEC's interpretation regarding the applicability of a case-by-case MACT determination. TEC has stated that Bayside Units 1 and 2 are attached to separate stream turbines and should therefore be evaluated as individual process units. The Department believes that TEC's interpretation is flawed because it would lead to a conclusion that *each* combined cycle gas turbine could be evaluated as a separate "process unit" and evaluated for MACT applicability based on the individual emissions. Further, each gas turbine is connected to an individual HRSG, after which any additional controls would be added.**

   The Department believes that the HAP emissions from all of the Bayside gas turbines must be aggregated for comparison to the HAP major source thresholds. Jim Little of EPA Region 4 confirmed the Department's interpretation with Sims Roy, the author of EPA's interpretative rule for MACT determinations regarding gas turbines. In addition, Mr. Little confirmed the Department's interpretation with Kathy Kaufman, the EPA 112(g) MACT coordinator. TEC's interpretation is not in accordance with MACT program as interpreted by the Department and EPA. Please submit a case-by-

case MACT analysis for the Bayside. If no MACT is proposed, the Department will establish case-by-case MACT standards without input from TEC.

TEC Response

TEC maintains the position that Bayside Units 1 and 2 should be considered separately when considering MACT applicability. This would not, however, lead to the conclusion that each CT should be considered separately. According to 40 CFR 63.41, the term 'Construct a Major Source' means, in part:

"(2) To fabricate, erect, or install at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP...."

According to the same rule, the definition of 'Process or Production Unit' mentioned above is:

"...any collection of structures and/or equipment, that processes assembles, applies, or otherwise uses material inputs to produce or store an intermediate or final product. A single facility may contain more than one process or production unit." (Emphasis added)

Bayside Power Station clearly represents the construction and operation of two separate production units as evidenced by the facts below:

- *Each production unit will be constructed and begin operation independently.*
- *Each production unit will operate independently of the other.*
- *Each production unit will produce steam to supply a separate steam turbine.*

Furthermore, the definition of 'Process or Production Unit' allows for the siting of more than one unit per facility. TEC does not claim that the individual combustion turbines that provide heat and power to serve Bayside Units 1 and 2 should be considered individually for MACT applicability. These individual combustion turbines do not fit the definition of Processes or Production Units anymore than the individual burners that provide energy in operating a coal fired unit.

Based on this definition and the fact that Bayside Units 1 and 2 each produce steam for separate, individual steam turbines, it is clear that they must be defined as separate production units when considering MACT applicability.

6. **Excess Emissions: Will the gas turbines be operated below 50% load during a steam turbine cold startup? If so, for how long? From the response provided, TEC is unsure of the emission rates from the gas turbines during a steam turbine cold startup. The Department understands that the steam turbine cold startup may last for 14 to 16 hours, but that emissions may not be elevated during the entire period. Please provide data regarding the emission levels during this type of startup and/or the duration of gas turbine operation below 50% load.**

TEC Response

Based on continued discussions with the Bayside engineering team, TEC has determined that it is only necessary to operate one combustion turbine per production unit below 50% load per *cold steam turbine startup. Consequently, TEC requests an allowance for excess emissions for 16 hours for only one CT per production unit during a cold steam turbine startup.*

7. **Requirements of the EPA/TEC Consent Decree: EPA Region 4 is reviewing the Bayside application and the Department expects comments shortly. When received, the Department will forward any EPA Region 4 questions TEC for a response.**

TEC Response

TEC appreciates the opportunity to comment on any EPA Region 4 questions raised regarding the Bayside Power Station permit application.

TEC appreciates the opportunity to work with the Department to resolve these issues in an expedited fashion, as the receipt of the final Air Construction Permit is critical to maintain a construction schedule that will support the commencement of operation of the Bayside Power Station as outlined in the Consent Final Judgement and the Consent Decree. 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\

Enclosure

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

4.0A BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR CARBON MONOXIDE

4.1A METHODOLOGY

The CO BACT analysis was performed as previously described in the September 2000 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), NESHAPs (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

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

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

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The Bayside Units 1 and 2 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 CO emission limitations.

FDEP emission standards for stationary sources are contained in Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards.* Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through -.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart GG.

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 1 and 2 CTs. However, Subpart GG does not contain any CO emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state CO emission limitations applicable to Bayside Units 1 and 2.

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

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 consider the competing factors involved in NO_x and CO 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 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) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO 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 1 and 2. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO 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 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 1 and 2 (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 1 and 2 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 primary fuel for the Bayside Power Station) 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 1 and 2 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 3,199,152 kilowatt-hours (kwh) (10,163 MMBtu) per year at baseload (166-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 72.8 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3) for all seven CTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $671,822 per year for all seven CTs.

4.3.3A ECONOMIC IMPACTS

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

Table 4-1A. 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 request.

Sources: ECT, 2000.
TEC, 2000.

Table 4-2A. Capital Costs for Oxidation Catalyst System, Seven CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	4,921,000	A
Sales tax	295,260	0.06 x A
Instrumentation	492,100	0.10 x A
Freight	246,050	0.05 x A
Subtotal Purchased Equipment	**5,954,410**	**B**
Installation		
Foundations and supports	476,353	0.08 x B
Handling and erection	833,617	0.14 x B
Electrical	238,176	0.04 x B
Piping	119,088	0.02 x B
Insulation for ductwork	59,544	0.01 x B
Painting	59,544	0.01 x B
Subtotal Installation Cost	**1,786,323**	
Total Direct Costs (TDC)	**7,740,733**	
Indirect Costs		
Engineering	595,441	0.10 x B
Construction and field expenses	297,721	0.05 x B
Contractor fees	595,441	0.10 x B
Startup	119,088	0.02 x B
Performance test	59,544	0.01 x B
Contingency	178,632	0.03 x B
Total Indirect Costs (TIC)	**1,845,867**	
TOTAL CAPITAL INVESTMENT (TCI)	**9,586,600**	TDC + TIC

Source: ECT, 2000.

Table 4-3A. Annual Operating Costs for Oxidation Catalyst System, Seven CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	4,855,872	
Credit for used catalyst	(655,200)	15% credit
Annualized Catalyst Costs	**1,024,505**	
Energy Penalties		
Turbine backpressure	671,822	0.2% penalty
Total Direct Costs (TDC)	**1,696,327**	
Indirect Costs		
Administrative charges	191,732	0.02 x TCI
Property taxes	95,866	0.01 x TCI
Insurance	95,866	0.01 x TCI
Capital recovery	519,409	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**902,873**	
TOTAL ANNUAL COST (TAC)	**2,599,199**	TDC + TIC

Sources: ECT, 2000.
TEC, 2000.

The base case Bayside Units 1 and 2 annual CO emission rate (i.e., for all seven CT /HRSG units) is 989.7 tpy based on CT baseload operation at 59°F for 7,884 and 876 hr/yr for natural gas and distillate fuel oil firing, respectively. The controlled annual CO emission rate, based on 90 percent control efficiency, is 99.0 tpy. Base case and controlled CO emission rates are summarized in Table 4-4A.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $2,918 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 4-4A.

4.3.4A 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- and distillate fuel oil-fired combustion turbines is provided in Tables 4-5A and 4-6A, respectively.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from 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 4-4A. Summary of CO BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	(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	22.6	99.0	890.7	9,586,600	2,599,199	2,918	76,412	N	Y
Baseline	226.0	989.7	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Seven GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 7,884 hr/yr, and fuel oil-firing for 876 hr/yr.

Sources: ECT, 2000.
GE, 2000.
TEC, 2000

Table 4-5A 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
Draft	CPV Gulfcoast, Ltd. (Power Augmentation Off)	170	9	Good combustion
Draft	CPV Gulfcoast, Ltd. (Power Augmentation On)	170	15	Good combustion

Source: FDEP, 2000.

Table 4-6A Florida BACT CO Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
5/98	City of Tallahassee Purdom Unit 8	160	90	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	90	Good combustion
9/28/98	Florida Power Corp. Hines Energy Complex	165	30	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	25	Good combustion
10/8/99	Tampa Electric Company – Polk Power Station	165	20	Good combustion
10/8/99	TECO Power Services – Hardee Power Station	75	20	Good combustion
10/18/99	Vandolah Power Project	170	12	Good combustion
12/28/99	Reliant Energy Osceola	170	20	Good combustion
1/13/00	Shady Hills Generating Station	170	20	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB Off)	167	20	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB On)	167	30	Good combustion
2/24/00	Gainesville Regional Utilities	83	20	Good combustion
Draft	CPV Gulfcoast, Ltd. (90 – 100 % Load)	170	20	Good combustion
Draft	CPV Gulfcoast, Ltd. (75 – 89 % Load)	170	22	Good combustion
Draft	CPV Gulfcoast, Ltd. (50 – 74 % Load)	170	29	Good combustion

Source: FDEP, 2000.

Maximum natural gas and distillate fuel oil firing CO exhaust concentrations from the CT/HRSG units will be less than or equal to 9.0 and 39.0 ppmvd, respectively. These CO exhaust concentrations are consistent with recent FDEP CO BACT determinations for CT/HRSG units. CO BACT emission limits proposed for Bayside Units 1 and 2 are provided in Table 4-7A.

Table 4-7A. 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)	9.0	31.1
CO (Distillate Fuel Oil)	39.0	81.3

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

FLORIDA

Jeb Bush
Governor

Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

December 15, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Karen Sheffield, General Manager
Bayside Power Station, Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

Re: Request for Additional Information No. 2
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Ms. Sheffield:

On November 17, 2000, the Department received the additional information with attachments for the Bayside Power Station, a project intended to re-power the Gannon Plant. The Department has reviewed this information and the application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Netting Analysis: Please verify that *all* emissions increases and decreases for *all* emissions units have been included in the netting analysis for the contemporaneous period. Describe any outstanding air permitting projects that TEC has for the Gannon Plant, including any projects submitted to either the Department's Tallahassee Office as well as the Southwest District Office. For example, please describe the addition of wood-derived fuels (WDF) as authorized fuels for Gannon Units 1 – 4. What is the purpose of adding new fuels for these boilers? Will this result in an increase in actual annual emissions? Is this request related to the shutdown of Units 5 and 6 or the re-powering project in any way?

2. Gas Turbines / HRSGs: Please provide the "preliminary design" data for the Heat Recovery Steam Generators (HRSGs), including the maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG. Will each HRSG be identical?

3. Proposed Control Equipment: The Department is working with TEC to resolve the evaluation of zero ammonia technologies. Please note that this issue must be resolved before the Department will deem the Bayside PSD permit application complete.

4. BACT Determination for CO: The Department does not believe a one-time emissions performance test conducted on Gannon Unit 5 in April of 2000 to be representative of actual CO emissions from Gannon Units 5 and 6 for the base years of 1997, 1998, and 1999. Again, please submit a top-down BACT analysis for the control of carbon monoxide. When evaluating the oxidation catalyst, please include the items previously addressed for the revised cost analysis for the VOC oxidation catalyst. Note that a CO control efficiency of at least 90% would be expected. If no CO BACT is proposed, the Department will establish a CO BACT standard without input from TEC.

5. MACT Determination for Hazardous Air Pollutants (HAPs): As previously discussed, the EPA and the Department disagree with TEC's interpretation regarding the applicability of a case-by-case MACT determination. TEC has stated that Bayside Units 1 and 2 are attached to separate stream turbines and should therefore be evaluated as individual process units. The Department believes that TEC's interpretation is flawed because it would lead to a conclusion that *each* combined cycle gas turbine could be evaluated as a separate "process unit" and evaluated for MACT applicability based on the individual emissions. Further, each gas turbine is connected to an individual HRSG, after which any additional controls would be added.

The Department believes that the HAP emissions from all of the Bayside gas turbines must be aggregated for comparison to the HAP major source thresholds. Jim Little of EPA Region 4 confirmed the Department's interpretation with Sims Roy, the author of EPA's interpretative rule for MACT determinations regarding gas turbines. In addition, Mr. Little confirmed the Department's interpretation with Kathy Kaufman, the EPA 112(g) MACT coordinator. TEC's interpretation is not in accordance with MACT program as interpreted by the Department and EPA. Please submit a case-by-case MACT analysis for the Bayside. If no MACT is proposed, the Department will establish case-by-case MACT standards without input from TEC.

6. Excess Emissions: Will the gas turbines be operated below 50% load during a steam turbine cold startup? If so, for how long? From the response provided, TEC is unsure of the emission rates from the gas turbines during a steam turbine cold startup. The Department understands that the steam turbine cold startup may last for 14 to 16 hours, but that emissions may not be elevated during the entire period. Please provide data regarding the emission levels during this type of startup and/or the duration of gas turbine operation below 50% load.

7. Requirements of the EPA/TEC Consent Decree: EPA Region 4 is reviewing the Bayside application and the Department expects comments shortly. When received, the Department will forward any EPA Region 4 questions TEC for a response.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Mr. Patrick Shell, TEC
Mr. Shannon Todd, TEC
Mr. Thomas Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

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Name (Please Print Clearly) (to be completed by mailer)
Karen Sheffield, TECO
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Karen Sheffield
General Manager
Bayside Power Station
Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

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REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

DEC 15 2000

4 APT-ARB

RECEIVED
DEC 21 2000
BUREAU OF AIR REGULATION

A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: PSD Permit Application for TECO Gannon/Bayside Power Station (PSD-FL-301) located in Hillsborough County, Florida

Dear Mr. Linero:

Thank you for sending the draft prevention of significant deterioration (PSD) permit application for the Tampa Electric Company (TECO) Gannon/Bayside Power Station dated September 27, 2000. The PSD permit application is for a repowering project involving the shutdown of TECO Gannon's coal-fired units 5 and 6 and the addition of seven combined cycle combustion turbines (CTs) with a total nominal generating capacity of 1728 MW. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CTs would fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 876 hours per year.

Based on our review of the PSD permit application, we have the following comments:

Netting Analysis

TECO's estimates of the net emission changes from the proposed project are a decrease of 14,659.8 tons per year (TPY) of nitrogen oxides, a decrease of 4,399.9 TPY of carbon monoxide, a decrease of 35,841.2 TPY of sulfur dioxide, a decrease of 51.3 TPY of sulfuric acid mist, a decrease of 378.2 TPY of particulate matter, a decrease of 8.5 TPY of lead and an increase of 70.7 TPY of volatile organic compounds. These net emission changes are based on the potential emission increases from the seven new CTs and the actual emission decreases resulting from the shutdown of boiler units 5 and 6. In reference to this subject, the Consent Decree signed by TECO and the U.S. Environmental Protection Agency (EPA) on February 28, 2000, is being interpreted as described below. It is EPA's opinion that emission reductions can be used in part to avoid PSD review for this project; however, a more appropriate method of calculating the net emission changes from this repowering project is to include the emission reductions resulting from the shutdown of boiler units 5 and 6 as if best available control technology (BACT) had been applied to the boilers. In other words, the emission reductions which are available for use in avoiding PSD review for this project would be the actual emission levels for the coal-fired boilers if present-day BACT methods were in use. Additionally, any remaining emission reductions not needed at this time to avoid PSD review may potentially be used by TECO in future netting analyses. Consequently, EPA recommends that TECO revise the netting analysis for this project and re-evaluate which pollutants are subject to PSD review. For clarity, the Consent Decree will be modified in the near future to reflect the above described interpretation.

112(g) Applicability

Consistent with previous discussions between EPA Region 4 and the Florida Department of Environmental Protection, our opinion is that total hazardous air pollutant emissions combined from all CTs being added to a facility should be used to determine if 112(g) case-by-case maximum achievable control technology requirements apply.

Thank you for the opportunity to comment on the TECO Gannon/Bayside Power Station PSD permit application. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Paul Wagner

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Koerner
C. Carlson
S. Todd, TECO
G. Kissel, SWD
J. Campbell, EPC
NPS

FAX Cover Sheet

USEPA - Region 4
61 Forsyth St., SW
Atlanta, Georgia 30303

RECEIVED
DEC 18 2000
BUREAU OF AIR REGULATION

TO: Jeff Koerner
FDEP

FAX #: 850-922-6979

RE: TECO

FROM: Katy Forney
Air Permits Section, Region 4 USEPA

Phone #: 404-562-9130

Date: 12-15-00

# of Pages (including cover): 3

COMMENTS:

If this FAX is poorly received, please call
Katy Forney: 404-562-913

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

DEC 1 5 2000

4 APT-ARB

A. A. Linero, P.E.
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

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(PSD-FL-301) located in Hillsborough County, Florida

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Sincerely,

Paul Wagner

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

TECO

TAMPA ELECTRIC

RECEIVEI

NOV 17 2000

BUREAU OF AIR REGULATI

November 14, 2000

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. 7923 8230 3267

Re: Request for Additional Information
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter of incompleteness dated October 16, 2000 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. For your convenience, TEC has restated each point and provided a response below each specific issue. TEC intends to complete this project in accordance with the deadlines outlined in the Consent Final Judgement and the Consent Decree and looks forward to the resolution of these issues by working closely with the Department in all phases of the process. Below, the Company has provided comprehensive responses to each specific incompleteness issue and, with this submission, TEC understands that the Department will continue processing the application.

1. **Netting Analysis: Attachment D of the PSD permit application provides a netting analysis that summarizes the actual emissions decreases from the shut down of Gannon Units 5 and 6 and the potential emissions increases from operation of the new Bayside Units. Previous EPA guidance suggests that emissions decreases needed to meet regulatory requirements should not be included in calculating net emissions increases for a project. Please explain TEC's understanding of the DEP/TEC Consent Final Judgement related to the issue of netting. Note that the remaining questions presume netting.**

TEC Response

The Consent Final Judgement (CFJ) and the Consent Decree (CD) represent agreements between the DEP and the EPA respectively. These agreements and any subsequent modifications that may be made to the CFJ or CD, provide the conditions under which the parties are required to operate in order to satisfy the terms of the agreement and to be deemed in compliance with law. The terms of the CFJ and the CD were negotiated resolutions to disputed claims and address discrete subject matters. There is nothing contained in either the CFJ or the CD that requires a reduction in emissions to meet regulatory requirements. Therefore, the guidance referenced by DEP is not applicable for the reasons cited. It is clear that the emission reductions resulting from the implementation of the any component of the CFJ or the CD may be used in the calculation of net emissions for this and other projects.

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

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

Tampa Electric agrees that the CFJ and the CD are designed to achieve significant emission reductions from the repowering of the Gannon Station and other projects identified in the CFJ and CD. To meet this requirement, it is appropriate for the Department to expect significant and reasonable emission reductions from the implementation of the requirements of the CFJ or the CD that can be expected to produce emission reductions.

2. <u>Gas Turbines / HRSGs</u>

a. **Please identify the model of dry low NOx combustor that will be installed on each General Electric Model PG 7241(FA) gas turbine. Is this the latest version?**

TEC Response

A General Electric Co. (GE) Model PG 7241 (FA) gas turbine will be provided with GE's standard Dry Low NO_x (DLN) 2.6 combustion system.

b. **Please identify the automated gas turbine control system that will be installed with each unit. Describe how this system will interact with the SCR and SCONOx™ control systems to reduce NOx emissions.**

TEC Response

Each gas turbine will be provided with GE's standard Mark VI controls. The system may or may not interact with the SCR and/or $SCONO_x$ depending on the control configuration established by Alstom Power. If an exhaust gas flow meter and uncontrolled NO_x monitor is installed (see response to Item 3a), then Mark VI interaction or feedback of unit operation, such as load, anticipated uncontrolled NO_x, exhaust gas flow, etc., may not be required.

c. **Is the evaporative cooler a high-pressure direct spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.**

TEC Response

The evaporative cooler is not a high-pressure spray or fogging type of system. The evaporative cooler consists of a water distribution system and media packed blocks made of corrugated layers of fibrous material. Water is distributed over the top of the blocks and flows down through a set of channels. The air passes over alternate channels, which are wetted by the wicking action of the media. It is supplied as part of the GE package. The manufacturer has not been selected at this time. TEC will supply this information when it is available.

d. **Will this project include natural gas fuel heaters or cooling towers? If so, please provide the information required on the permit application form for these emissions units.**

TEC Response

The Bayside project does not include a natural gas "fired" fuel heater. Fuel gas heating, to attain superheat requirements imposed by GE DLN 2.6 combustors during startup, is provided by an electric heater. During base load operation, fuel heating is performed by hot water extracted from the Heat Recovery Steam Generator (HRSG). The Bayside Plant design includes two small cooling towers, which will provide cooling water to various equipment associated with the new gas turbines and HRSGs. Note that the cooling towers are currently being bid and the configuration, performance and design is dependent on the vendor selected.

Required cooling tower information (per tower):	*Unit 1**	*Unit 2**

1.	*Recirculation water flow rate; gpm*	*5,100*	*6,800*
2.	*Recirculation water total dissolved solids (TDS); ppmw*	*1,000 to 1,855*	*1,000 to 1,855*
3.	*Recirculation water total suspended solids (TSS); ppmw*	*<5*	*<5*
4.	*Tower drift loss rate; % of recirculation water*	*0.08*	*0.08*
5.	*If available, PM_{10} fraction of PM drift; weight %*	*N/A*	*N/A*
6.	*Number of cells per tower*	*3*	*3*
7.	*Tower dimensions – length, width, and height (from grade to deck); ft*	*90 X 35 X 41*	*90 X 35 X 41*
8.	*Height of exhaust stack outlet above deck; ft*	*8*	*8*
9.	*Exhaust stack outlet inner diameter; ft*	*21*	*21*
10.	*Design exhaust flow rate per cell; acfm*	*150,000 to 190,000*	*150,000 to 190,000*
11.	*Location of tower on facility plot plan*	*See Item 37 on G/A*	*See Item 37 on G/A*

**These are approximate values only. Since the units are currently in the bidding process, exact values are unknown at this time.*

e. **Is each Heat Recovery Steam Generator (HRSG) identical? What is the designed maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG? What are the current existing maximum and design capacities of the steam turbines for Gannon Units 5 and 6?**

TEC Response

The HRSG designs have not yet been finalized, and as such, the maximum steam production rate, steam temperature, and steam pressure for each HRSG are not yet available. Currently, the steam turbine serving Gannon Unit 5 is permitted for 239.4 MW and the steam turbine serving Gannon Unit 6 is permitted for 414 MW. These capacities may change depending on the final HRSG design. TEC will provide the requested information when it is available.

f. **The application established maximum mass emission rates at an ambient temperature of 17° F. Based 48 years of data from the www.weatherbase.com Internet web site, the lowest "average daily" temperatures in Tampa occurred during the months of January (61° F), February (62° F), and December (62° F). The average "low temperatures" for these months are January (50° F), February (52° F), and December (52° F). The "lowest recorded temperatures below 32° F" occur in January (21° F), February (24° F), March (29° F), November (23° F), and December (18° F). The "average number of days below 32° F" is one each for the months of January, February, and December. Please revise the mass emission rates for the Model PG7241(FA) to reflect a more reasonable "low temperature" of 32° F for the Tampa area. Permit conditions for gas turbines typically allow adjustment of the mass emission rate for compressor inlet temperature, if necessary. Otherwise, the Department is considering mass emission rates based on a compressor inlet temperature of 59° F or other available information.**

TEC Response

Mass emission rates from combustion turbines (CTs) will vary with ambient temperatures. Due to increased air density at lower temperatures, CT fuel flows and emission rates will increase with decreasing ambient temperatures and vice versa.

To provide the Department with reasonable estimates of maximum hourly emission rates as required by the Department's Application for Air Permit – Title V Source form, a minimum ambient temperature of 18°F was selected. TEC understands that CT mass emission rates will fluctuate with ambient temperature and will accept a permit condition limiting mass emission rates consistent with the emission rates submitted by TEC to the Department and that also allows Bayside Units 1 and 2 to operate in compliance under all ambient conditions. Accordingly, submittal of additional (and lower) mass emission rate data for a 32°F operating scenario is not considered necessary.

g. Please provide the "Emissions Performance Estimates" from General Electric for the proposed Model PG 7241(FA) gas turbine. This specification sheet identifies the emission rates for CO, NOx, PM/PM10, SO2, and VOC in terms of ppmvd and lb/hour as estimated by the manufacturer. In addition to the emission rates, these performance specification sheets should also include the unit performance, load conditions, power generation, heat input, fuel consumption, stack conditions, compressor inlet temperature, and fuel type. Specifically, the Department requests "Emissions Performance Estimate" data sheets from General Electric for:

- **Gas firing at 100% base load with an inlet compressor temperature of 59° F;**
- **Gas firing at 100% base load with an inlet compressor temperature of 32° F;**
- **Oil firing at 100% base load with an inlet compressor temperature of 59° F; and**
- **Oil firing at 100% base load with an inlet compressor temperature of 32° F.**
- **Oil firing at 50% base load with an inlet compressor temperature of 93° F.**

If necessary, the Department will provide an example from a similar project.

TEC Response

As discussed, GE data for the 32 °F case is not available at this time. The raw data obtained from GE, which was used in the emission calculations for the cases requested, is attached. This transmittal includes:

- *Gas firing at 100% base load with inlet compressor temperature of 59 °F*
- *Oil firing at 100% base load with inlet compressor temperature of 59 °F*
- *Oil firing at 50% base load with an inlet compressor temperature of 93 °F*

3. <u>Proposed Control Equipment</u>

a. Does the proposed Selective Catalytic Reduction (SCR) system include a NOx emissions monitor prior to the ammonia injection grid to measure uncontrolled NOx emissions? Please identify and describe the automated control system that will be used to adjust the ammonia injection rates based on uncontrolled NOx emissions. What are the input parameters to this system? How will the ammonia slip concentration be determined? What is the proposed test method and frequency for the determination of ammonia slip? For similar combined cycle projects, maximum ammonia slip has been limited to 5 ppm. Please comment.

TEC Response

There is still very little information on the Selective Catalytic Reduction (SCR) system design. The system design has just recently been awarded by Alstom Power (AP) to a subcontractor. AP is responsible for providing a working system and as such the system configuration and control philosophy *are currently being finalized. Part of the design does include an uncontrolled NO_X monitor upstream of the ammonia injection grid (AIG). Similarly, an NO_X and a NH_3 monitor are included downstream of the AIG.*

To calculate ammonia slip, TEC intends to use the following formula:

$$Ammonia\ slip\ @\ 15\%O_2 = (A - (\frac{B * C}{1000000})) * \frac{1000000}{B} * D$$

Where: A =ammonia injection rate (lb/hr) / 17 lb/lb-mol

B = dry gas exhaust flow rate (lb/hr) / 29 lb/lb-mol

C = change in measured NO_x (ppmv@15% O_2) across catalyst

D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

TEC proposes stack testing for ammonia slip annually after three years of operation using either EPA Conditional Method 027 or Method ST-1B. TEC is aware of other projects requesting an ammonia slip of 5 ppm. However, ammonia is not a regulated air pollutant, and as such, is not subject to a formal limit in the manner that NO_x, SO_2, PM and others are. TEC has selected an ammonia slip limit of 10 ppm based on anticipated best operational practices and feels that considering the overall reduction of all regulated air pollutants that will take place upon the repowering of Gannon Station, this is a reasonable limit.

b. The DEP/TEC Consent Final Judgement requires an evaluation of zero ammonia NOx control technologies. (Question No. 11 summarizes these issues.) The PSD permit application identifies SCONOx™ as such a technology. Please indicate which Emission Unit the SCONOx™ system would be installed on, provide a process flow diagram, and identify emission levels for all pollutants from the combined cycle unit controlled with a SCONOx™ system.

Please note that the issue concerning the evaluation of zero ammonia technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

TEC Response

The $SCONO_X$ system has never before been applied to a GE 7 FA combustion turbine. In addition, TEC proposes to evaluate the SCONOx system on Unit 2D if the system meets the cost, guarantee and remedy requirements of the CFJ. TEC has attached the available process flow diagrams for the SCONOx system. The $SCONO_X$ system is currently out for bid by Alstom Power. As such, the expected emission levels of pollutants are not available.

Please see TEC's response in question 11.e. for a response to the issue concerning the Bayside PSD permit and resolution of the zero ammonia technology evaluation required under the CFJ.

c. For each NOx control system, describe any unique performance or operating conditions related to startups, shutdowns, or maintenance requirements.

TEC Response

The response to this issue is largely dependent on the interpretation of what is 'unique'. The SCR performance during startup is described in the response to Question 9. SCR systems have been installed on several other combined cycle installations, and the operation of the TEC units during shutdown and *maintenance is not expected to deviate significantly from those applications. The performance of the SCONOx system during startup, shutdown or maintenance is unknown at this time because (1) TEC has not yet received the SCONOx bid package from Alstom Power and (2) the SCONOx system has never been operated on a GE 7F combustion turbine. As such, many of the operational characteristics of the system will not be known without operational experience.*

4. <u>Operation</u>

   a. **The application requests continuous operation (8760) for each gas turbine unit with up to 876 hours of operation per unit when firing low sulfur distillate oil. No other methods of operation are requested. Is this correct?**

TEC Response

TEC has based this request on 876 equivalent full load hours of operation. This translates into approximately 1,797,552 MMBtu/yr (HHV) or 12,720 x 10^3 gallons of fuel oil combusted per year. TEC understands the meaning of "method of operation" in this question to mean type of fuel firing. TEC is not requesting any other method of operation other than natural gas and low sulfur fuel oil firing.

5. <u>**BACT Determination for CO**</u>

A review of the Annual Operation Reports filed by TEC with the Department indicates the following inconsistency with information submitted as part of the application (Attachment D, Tables 1 – 3):

Gannon Unit	1997		1998		1999		2-Year Average	
	AOR	App.	AOR	App.	AOR	App.	AOR	App.
5	---	---	140.00	2083.40	136.38	2027.50	138.19	2055.5
6	278.00	3446.30	216.00	3221.90	---	---	247.00	3334.1
						Totals	385.19	5389.60

Note: An equipment explosion affected operation of Unit No. 6 in 1999. Therefore, 1997 and 1998 data was used to establish actual emissions representative of "normal operation".

   a. **The application briefly notes that CO emissions were based on tests conducted in April of 2000. Neither the Department's Southwest District Office nor the Air Quality Division of the Hillsborough County Environmental Protection Commission have any records related to these emission performance tests. There is no information on record of the test methods, duration, number of tests, performance conditions, levels of other pollutants during these tests, or submittal of a test report. The Department is interested in TEC's rationale for, and the support of, the submitted values. However, TEC is required to submit a top-down BACT analysis for the control of carbon monoxide based upon the Department's records and ensuing conclusion regarding the applicability of BACT. When evaluating the oxidation catalyst, please include the items listed below under "Proposed VOC BACT". Note that a CO control efficiency of at least 90% would be expected.**

TEC Response

TEC feels that the CO emissions based on the test results are reasonable and applicable to this analysis. As documented in numerous EPA and industry reports and publications increased CO emission rates are commonly associated with operational changes made to reduce emissions of oxides of nitrogen (NO_x). In *response to recent Title IV regulations requiring NO_x emission reductions and previous reductions achieved to meet the Memorandum of Understanding between the Environmental Protection Commission of Hillsborough County and TEC, TEC implemented starting in 1996 several NO_x control strategies at the Gannon Station. These strategies included the combustion of low heat content, high moisture fuels, combustion optimization/air flow modifications and the use of lower excess air (LEA) operations. These operations have resulted in the common impacts such as increased Loss of Ignition (LOI), increased tube metal wear and other effects. These are all side effects of the reduction in the available oxygen, higher moisture coal and the resulting lower flame temperature intended to reduce the formation of NO_x. TEC has implemented operational measures to optimize the reduction of NO_x emissions while at the same time ensuring that LOI formation is maintained at the lowest possible levels. Unfortunately, the reductions have been demonstrated to be mutually exclusive for the Gannon Units, like many other units in the United States.*

Historically TEC has relied on AP-42 emission factors for the calculation of annual CO emissions. TEC accepted these emission factors as representative of the CO emissions for the specific classification of boiler combusting its design coal. After the implementation of the NO_x control measures discussed above and the resulting increase in LOI (a common indicator of increased LOI), it became apparent that these AP-42 emission factors may not longer be valid, therefore TEC tested the emission rates in early 2000 to establish the actual emission rates. Unit 5 was tested to provide a representation of the CO emissions from the Gannon turbo-fired wet-bottom units and Unit 1 was tested to represent emissions from the cyclone units. The testing was conducted in accordance with EPA methodology and copies of the above referenced test reports have been attached for review by FDEP and EPCHC. The results of the test indicate the Gannon 5 CO concentration was 117 ppm. This is a reasonable concentration for a unit with the combustion modifications and LEA operation optimized for low NOx operation. This conclusion is supported by various EPA documents such as Alternative Control Techniques Document—NO_x Emissions from Utility Boilers and Electric Power Research Institute (EPRI) documentation. Copies of portions of the EPA documentation are provided in Attachment 1.

Based on this information and the enclosed test reports, TEC believes that the Department will understand and accept the rationale and documentation for the use of the revised CO emission rates and will utilize the reasonable and proven emission factors for CO in the Bayside Air Construction application.

Please identify the controlled CO emission levels from a combined cycle unit controlled by a SCONOx™ system.

TEC Response

The SCONOx system has never been applied to a GE 7 FA combustion turbine and is currently in the bidding process. Therefore, the CO emission levels from the system are unknown at this time. TEC will provide the requested information when it is available from AP.

6. **Proposed VOC BACT**

   a. **With regard to the oxidation catalyst cost analysis, please provide:**

      - **Vendor quotes for the oxidation catalyst system, replacement catalyst, and instrumentation.**
      - **Supporting documentation for a VOC control efficiency of only 33% or revise the cost analysis based on a VOC control efficiency of at least 50%.**

- **Supporting documentation showing a cost of $0.04/kwh for TEC to generate electricity, otherwise revise the energy penalty accordingly. (The Department believes the actual cost for TEC to be lower than the stated cost.)**
- **A revised cost analysis using a 7% interest rate or provide substantial detail for the assumed interest rate of 9.55%. (TEC's parent company, TECO Energy, Inc., states in its annual report issuance of fixed rate bonds with interest rates of 6% to 8% for terms of over 20 years. It appears that Tampa Electric can issue tax-exempt bonds, which usually carry a lower interest rate than comparable corporate bonds. It is also noted that the federal 30-year bond rate is less than 5.9%.)**
- **A revised cost analysis if the contracted package for the HRSG that will be supplied by Alstom Power already includes the spool piece for an oxidation catalyst. (Costs estimated for foundations, supports, handling, erection, engineering, construction field expenses, and contractor fees appear excessive and/or unnecessary.)**

TEC Response

Alstom Power information to substantiate the oxidation catalyst estimate is attached. Please note that the email from AP dated July 10, 2000, discusses the capital costs of the CO/VOC catalyst, including the sunk cost of the spool piece.

Furthermore, TEC feels that the values used in the original analysis are reasonable and provide a comprehensive BACT evaluation. However, per the request of the Department, the interest rate, removal efficiency, and energy costs have been revised for demonstration purposes and the resulting analysis is enclosed. Based on the revised analysis, the cost of VOC removal remains excessive at $47,251 per ton of VOC removed.

b. The application (Table 4-5) indicates that TEC rejects the oxidation catalyst based on high costs and the adverse environmental impacts related to collateral increases of sulfuric acid mist emissions (SAM). The Department will review the revised cost analysis, but notes that natural gas and low sulfur distillate oil contain minimal amounts of sulfur. The application does not discuss the amount and consequences of additional SAM emissions. In addition, the Department would expect an oxidation catalyst to result in a significant reduction of hazardous air pollutants for which this project appears to be major. Therefore, the Department disagrees that the addition of an oxidation catalyst would result in net adverse environmental impacts. Please comment.

TEC Response

An assessment of collateral environmental impacts associated with the application of VOC oxidation catalyst controls is provided in Section 4.3.2 of the submitted PSD permit application. The Bayside PSD permit application did not indicate that there would be a "net adverse environmental impact" due to the use of oxidation catalyst. As stated on Page B.46 of EPA's Draft October 1990 New Source Review Workshop Manual, "the environmental impacts portion of the BACT analysis concentrates on impacts other than impacts on air quality standards due to emissions of the regulated pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of unregulated pollutants". The submitted PSD permit application simply noted that there will be an increase in emissions of sulfuric acid mist resulting from the use of oxidation catalyst.

TEC also notes that the use of an oxidation catalyst system for Bayside Units 1 and 2 will have an insignificant impact on CO and VOC ambient air quality (including HAPs). As previously noted, the VOC stack exhaust concentrations proposed for Bayside Units 1 and 2, without the application of oxidation catalyst controls, are only 1.3 and 3.0 ppmvd at 15% O_2 for natural gas and distillate fuel oil firing, respectively. Organic HAP exhaust concentrations, being a subset of VOCs, will be much lower. The highest, second highest 1- and 8-hour average CO impacts during natural gas-firing (the primary fuel for the Bayside Power Station) are projected to be only 0.3 and 0.5 percent of the Florida and Federal CO ambient air quality standards.

c. **Please complete the appropriate emissions unit pages of the permit application form for the distillate oil tank. The Department previously allowed construction of this tank contingent on TEC including it as part of the BACT analysis in the application to repower the Gannon Station. Also, please propose a VOC BACT for this emissions unit.**

TEC Response

TEC intends to use this tank to support existing operations at Gannon Station. As such, TEC did not feel that it was appropriate to include the tank in the Bayside air construction permit application. Enclosed is the exemption letter from permitting issued by FDEP. The letter states in part "...emissions associated with the construction of this new fuel oil tank will need to be evaluated during preconstruction review of the planned Bayside repowering project." Since the emissions from the tank represent a contemporaneous increase in VOC emissions, its contribution to the netting will be evaluated. Since the Bayside project represents a significant increase in VOC emissions, this evaluation will not make a difference when considering whether or not the project in total results in a significant increase in VOC emissions.

Since (1) the tank is considered by FDEP to be a minor source that is exempt from permitting and (2) the tank will be used for existing operations at Gannon Station, TEC believes that a BACT analysis is not applicable to this unit. Furthermore, the tank will be light in exterior color and will be equipped with pressure/vacuum conservation vent.

7. <u>MACT Determination for Hazardous Air Pollutants (HAPs)</u>

a. **The application (Page 1-5) indicates that this project will NOT be a major source of hazardous air pollutants (HAPs) because potential emissions are less than 10 TPY of any individual HAP and 25 TPY for all HAPs. However, the supporting documentation (Attachment C, Table 7) shows total potential HAP emissions for Bayside Units 1 and 2 combined will be 27.87 TPY, which is greater than the 25 TPY threshold for total HAPs. Projects that are major for HAP emissions are required to obtain case-by-case MACT determinations until EPA promulgates a final NESHAP for gas turbines. Please submit a technical review and proposal for MACT.**

TEC Response

EPA Rule 40 CFR 63, Subpart B directs any owner or operator who constructs or reconstructs a major source of HAP's to undergo a case by case MACT evaluation. Specifically, the source, whether constructed or reconstructed is considered to be subject to a MACT evaluation if it ***in and of itself*** *emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAPs. Since Bayside Units 1 and 2 can operate independently of one another, they are considered separate processes or production units for the purpose of HAP MACT analysis per the preamble to 40*

CFR 63 Subpart B. Hence, HAP emissions were not aggregated for this analysis and each unit in and of itself is not subject to a MACT evaluation.

The Department notes that EPA issued a December 30, 1999 memorandum entitled, "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines". This guidance discusses the use of an oxidation catalyst for the control of HAP emissions.

b. **The HAP emission calculations (Attachment C) were based on selected test rates from data used to compile EPA's recent AP-42 update for gas turbines. TEC believes the selected rates are more representative of large frame-type gas turbines. Please provide specific HAP emission rates for the Model PG7241(FA) from General Electric and revise the potential emissions calculations accordingly.**

TEC Response

To TEC's knowledge, HAP emission rates are not currently available from GE for the Model PG7241(FA). This is the reason that TEC based the HAP emission calculations on the selected test results from the data used to compile EPA's AP-42 database.

8. Emissions Standards Proposed in the Application

a. **Please comment on the following items:**

- **CEMS have been required to demonstrate compliance with CO emission standards for similar combined cycle projects currently under review by the Department (e.g. Calpine, FPC).**

TEC Response

CO is not regulated under the Acid Rain program, the Bayside Units are not subject to BACT for CO and the installation and operation of the Bayside Station will result in significant reductions of CO emissions. In addition, ISCST3 modeling results demonstrate that the maximum highest, second highest 1- and 8-hour CO impacts are 1% and 1.3% of the Federal and Florida AAQS, respectively. Therefore, TEC believes that an annual stack test will be sufficient to provide the Department with reasonable assurance that all CO emission standards are complied with.

- **For similar combined cycle projects, compliance with a NOx emission standard for gas firing of 3.5 ppmvd corrected to 15% oxygen has been based on CEMS data for both a 3-hour rolling average as well as a 24-hour block average of actual operating hours.**

TEC Response

For the purposes of demonstrating compliance, TEC believes that a 24-hour block average is the appropriate to provide the Department with reasonable assurance that the NOx emission standard is being complied with. Like most industrial processes, this process may be variable in nature from time to time, therefore a 3-hour rolling average may not allow for intermittent fluctuations in operation.

- **For recent gas turbine projects, annual tests for volatile organic compounds and particulate matter have been required to demonstrate compliance with the applicable emission standards.**

TEC Response

Emissions from natural gas fired combined cycle units do not vary significantly over time with proper maintenance and operation. Therefore, TEC feels that initial compliance tests for PM and VOC coupled with an annual opacity limit as a surrogate measure of PM emissions and the use of the annual CO stack test as a surrogate for VOC emissions will be sufficient to provide the Department with reasonable assurance that Bayside Power Station will operate in compliance with the respective standards.

- **EPA Region 4 has recently recommended testing for selected emissions of hazardous air pollutants, such as formaldehyde.**

TEC Response

Although typically emitted at extremely low rates (in the PPB range) formaldehyde is the HAP emitted in the greatest quantity when compared to others. Other HAP's are typically emitted at rates 2 to 100 times lower than formaldehyde in combustion turbines. There are no existing emission limitations for formaldehyde nor are there any health-related concerns resulting from formaldehyde exposure in the Tampa Bay area. Since Bayside Units 1 and 2 are minor sources of HAP's, TEC feels that testing each unit for formaldehyde emissions is not necessary. In addition, due to low emission rates, the current methods for formaldehyde testing are often not capable of consistently detecting this compound at the levels emitted from gas turbines. Finally, other similar projects have recently been permitted without a requirement for formaldehyde testing. Based on the above discussion, TEC feels that formaldehyde testing is not necessary for this project.

b. **The application states that maximum CO emissions (30.3 ppmvd @ 15% oxygen) occur at 50% base load when firing oil with a compressor inlet temperature of 93° F. Please provide supporting documentation from General Electric.**

TEC Response

CO emissions for 50% load case at 93 ^{O}F ambient condition appear correct. As indicated on the GE data sheets (see Item 2g), CO production at this ambient/load condition is 82 lbs/hr, which is very close to the calculated value of 81.3 lbs/hr shown on Table 3 of the air permit.

c. **Is TEC proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO2?**

TEC Response

TEC requests that the alternative monitoring included in recent FDEP permits for similar projects be included in the Bayside Power Project permit. The following permit language is proposed:

"<u>Alternate Monitoring Plan</u>: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

(a) NO_x CEM data may be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG. Subject to EPA approval, the calibration of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS.

(b) NO_x CEM data shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG.

(c) *When requested by the Department, the CEMS emission rates for NO_x shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.*

(d) *A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following conditions are met.*

(1) *The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.*

(2) *The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 2 grains of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);*

(3) *Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.*

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d)."

9. Excess Emissions

The application (Page 2-8) requests the following periods of permitted excess emissions:

- ***Typical Operation*: Up to 2 hours in any 24-hour period due to startup, shutdown, or unavoidable malfunction.**
- ***CT Warm Startup*: Up to 3 hours in any 24-hour period when the CT/HRSG has been down for more than 2 hours and less than or equal to 24 hours.**
- ***CT Cold Startup*: Up to 4 hours in any 24-hour period when the CT/HRSG has been down for more than 24 hours.**
- ***Steam Turbine Cold Startup*: Up to 18 hours of excess emissions resulting from the cold startup of the repowered steam turbines due to metal temperature limitations.**

a. Please describe the warm and cold startups of the CT/HRSG units and the associated excess emissions. Please provide supporting documentation to include the duration of each startup and the quantity and duration of excess emissions. How many warm and cold CT/HRSG startups are predicted for each year?

TEC Response

Based on further design development of the Bayside Unit's steam systems, TEC believes that the combustion turbine warm and cold startups will be conducted within the allowable 2 hour of excess emissions for startup.

b. Please describe the process of bringing the repowered steam turbines back on-line during a cold startup and define "cold startup" for this equipment. Please provide data that indicates the exhaust gas emissions from the gas turbines will be in excess of the proposed standards for the entire 18-hour cold startup of a steam turbine. Please identify any startup methods that could be used to minimize damage to the steam turbine while allowing the gas turbines to

achieve steady-state operation and avoid excess emissions. For example, is it possible to operate a single gas turbine at 75% load to gradually heat up the repowered steam turbine? Is it possible to use steam from the other Bayside Unit to gradually heat up the repowered steam turbine? How many cold startups of each steam turbine are predicted for each year?

TEC Response

A cold startup occurs either (1) when the first stage turbine metal temperature is 250°F or colder or (2) when the steam turbine has been offline for 24 hours or longer. During a cold startup, great care must be taken to ensure that steam turbine is heated gradually to prevent the premature fatiguing of metal parts due to thermal expansion. As such, TEC intends to perform a cold startup as follows:

1. *The combustion turbine will be fired and brought online at a minimum load to generate steam that will not damage the steam turbine through rapid thermal expansion. This initial combustion turbine startup lasts approximately one hour.*

2. *As the main steam pressure piping warms, the condenser will be brought online. Due to the length of the piping, this typically takes approximately three hours. During this three hours, the main steam temperature should reach the required 100°F superheat to begin the steam turbine roll to 2,250 rpm.*

3. *After thirty minutes, the steam turbine will reach 2,250 rpm. To prevent thermal stress and degradation of the 2,000 feet of hot reheat, cold reheat and low pressure steam lines, four hours will be necessary to gradually increase the temperature of this equipment. During this four hour period at 2,250 rpm, the intermediate pressure inlet steam temperature (IPT) will reach 500°F*

4. *Once the turbine IPT has reached 500°F, it must be maintained at 2,250 rpm for approximately three hours to allow for the rotating elements and fixed parts to heat and expand at an acceptable rate. Once all rotating elements and fixed parts have been heated to an acceptable temperature, the unit can be brought online at 3,600 rpm within thirty minutes.*

5. *Finally, the steam turbine rotor and casing as well as the steam piping and HRSG must thermally stabilize. This process takes approximately two hours to complete.*

The process as described above takes approximately 14 hours to complete. However, considering the lack of experience in the industry with operating a plant with a configuration similar to the Bayside project, TEC requests that an additional two hours be added to the startup allowance for operational contingencies. This would bring the total allowance for excess emissions to 16 hours during startup. TEC is estimating that the total number of cold starts could be as many as 26 per steam turbine per year. This number of cold steam turbine startups may vary. This estimate is subject to change based on system demand, fuel availability, and other unit specific process parameters.

c. **For each requested period of excess emissions, what is the duration (hours), amount (ppmvd and lb/hour), frequency (incidents per year), and resulting annual emissions (tons per year).**

TEC Response

The amount and duration of warm and cold starts have been described in bullets a and b. Because this is a unique project with no operational experience, the resulting emissions due to startup are unknown at this time.

d. **Note that the permit can only allow excess emissions for pollutants for which the compliance status would be known. For this project, compliance should be readily identifiable for CO (CEMS), NOx (CEMS), and visible emissions (EPA Method 9 observation). Please comment.**

TEC Response

Per Rule 62-210.700(2), TEC will limit periods of excess emissions during startup, shutdown or malfunction by utilizing best operational practices. This rule covers excess emissions of all pollutants regardless of monitoring methodology. TEC feels that annual stack testing for CO will provide the Department with reasonable assurance that all CO limits are complied with.

10. <u>Repowering - Bayside Startup and Gannon Shutdown</u>

a. **As stated in the application (Attachment D), the actual emissions decreases from the Gannon Units must take place on or before the date that emissions from the modification project (new Bayside Units) first occur and must be federally enforceable on and after the date the Department issues a permit for the modification project. However, the Project Summary indicates that each Gannon Unit will be shut down after installation and "commercial startup" of the corresponding Bayside Unit. Please define "commercial startup" in specific terms.**

b. **For each new combined cycle unit, please provide an estimated schedule for the start of construction, the completion of construction, the shakedown period, the initial performance testing, "commercial startup", and initial power generation. Also, please indicate when each of the six coal-fired Gannon Units will be shut down.**

TEC Response

Because TEC must shutdown Gannon Unit 5 in order to tie in the steam piping to the Gannon Unit 5 steam turbine the Gannon unit will be shutdown prior to the "commercial startup" date, TEC is planning on February 11, 2003 as the late schedule date for this event. See attachment for specific dates.

c. **Gannon Units that are not being repowered are required to be shutdown between January 1, 2003 and December 31, 2004. It is expected that any permit issued for this project would be conditioned to require:**

- **Permanent shutdown of the Gannon Units within this time frame.**
- **A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 5 when shutdown.**
- **A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 6 when shutdown.**
- **Permanent shutdown of all coal-fired Gannon units when both Bayside Units are operational.**

Otherwise, allowing the remaining Gannon Units 1 – 4 to fire additional coal could cause actual emissions increases and trigger additional PSD requirements. Please comment.

TEC Response

TEC is obligated by both the Consent Final Judgement and Consent Decree to permanently cease coal fired operations at Gannon Station by January 1, 2005, and TEC intends to comply with these *conditions. Therefore, if the text from the Consent Decree and/or Consent Final Judgement addressing this situation is included in the Bayside Air Construction Permit, TEC will not object. TEC is not obliged to shut down operations of any type, but to shut down "coal-fired" operations by January 1, 2005. If other fuel and/or technologies are employed in the future, such activities would be subject to all required permitting.*

The start up of Bayside Units 1 and 2 will coincide with the shutdown of Gannon Units 5 and 6, respectively. However, TEC does not feel that a reduction of the heat input limit on the fuel yard would be appropriate when Gannon Units 5 and 6 are shut down. The installation and operation of Bayside Units 1 and 2 may cause temporary significant emissions increases, but the Department has reasonable assurance that TEC will minimize these increases through the use of natural gas as a primary fuel for PM and SO_2 control and the application of SCR (and possibly SCONOx) for NO_x control. It is conceivable that TEC could find it necessary to operate Gannon Units 1-4 more frequently than expected to meet increasing customer demand or to compensate for lost generation due to potential process upsets in the new Bayside Units. Finally, PSD rules allow for an emissions source to increase utilization to accommodate load growth. Further limiting the heat input on the fuel yard may not allow TEC to serve demand resulting from load growth and will not allow TEC to compensate for process upsets during the 'shakedown' of the Bayside Units.

11. **Requirements of the DEP/TEC Consent Final Judgement**
   Paraphrasing Section V of the DEP/TEC Consent Final Judgement (CFJ), this agreement requires the following for the Gannon Station:

   ***CFJ Section V, A*: TEC shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, and 5 to be phased-in between January 1, 2003 and December 31, 2004. The repowered units shall fire gas and meet a NOx emission rate of 3.5 ppm.**

   a. **The application indicates that the steam boilers for Gannon Units 5 and 6 will be shutdown and the steam turbines for Gannon Units 5 and 6 will be repowered with steam from Bayside Units 1 and 2. How does this comply with the requirements of the CFJ to repower Gannon Units 3, 4, and 5?**

TEC Response

Based on correspondence between Sheila McDevitt, General Counsel of TEC and Teri Donaldson, General Counsel of FDEP, the parties agreed to modify the requirements of Section V. A. of the CFJ such that the repowering of specific units was not required, but rather a minimum number of megawatts of generation as described in the Consent Decree was to be repowered. The referenced correspondence is enclosed.

   b. **The CFJ requires the shutdown of Gannon Units 1, 2, and 6. The application does not appear to discuss the future status of any Gannon units that are not being repowered. The Department understands that the steam boilers for any repowered Gannon units must be permanently shut down prior to operation of any corresponding Bayside Unit. The steam boilers for the remaining Gannon units must be shut down between January 1, 2003 and December 31, 2004. In addition, all coal-fired Gannon Units must be permanently shutdown when both Bayside Units are operational. These emissions decreases will not be available for any future projects at the Bayside Station. Please comment.**

TEC Response

TEC has submitted an application for the repowering of Gannon Units 5 & 6. This application is not intended to address the status of the other coal-fired units as their emission reductions were not considered in the netting analysis. The future status of these units are described in the Title V permit for the Gannon Station and the CFJ and CD which are incorporated into the Title V permit. The requirements for cessation of coal-firing for the Gannon Station units are the repowering of no less than 200 MW by May 1, 2003 and the cessation of operation of all six Gannon coal fired units on or before December 31, 2004. It is not intended or anticipated that the repowering component will involve the continued operation of the furnace for the repowered units for any length of time after shutdown to disconnect the turbine from the unit. Because Tampa Electric is repowering Gannon Unit 5 to meet the requirement to repower 200 MW by May 1, 2003, it is appropriate for the Department to assume the air emission from that Gannon Unit will permanently cease by May 1, 2003.

Neither the CFJ nor the CD require that, "all coal fired Gannon Units must be permanently shutdown when both Bayside Units are operational". Both the CFJ and the CD require that, all coal fired units at the Gannon Station will cease operation by December 31, 2004 and that emission reductions resulting from this activity may be considered in future permitting as allowed by Florida and federal laws and regulations.

c. **In several places, the application indicates that Gannon Units 5 and 6 will "... permanently cease coal-fired operation." The Department understands this to mean that the steam boilers for Gannon Units 5 and 6 will be permanently shutdown and rendered incapable of operation prior to beginning operations of the corresponding Bayside Unit. Please comment.**

TEC Response

The Department is correct in the understanding that the repowered Gannon Units 5 & 6 steam boilers will be rendered incapable of operation as their associated steam turbines and other non air emission components will be utilized by Bayside Units 1 & 2 respectively.

d. **The application requests 876 hours per year of very low sulfur distillate oil firing as a backup fuel with an emission standard of 16.4 ppmvd corrected to 15% oxygen. How does this meet the requirements of the CFJ to repower with *gas-fired* units meeting a NOx emissions standard of *3.5 ppm*?**

TEC Response

Tampa Electric is proposing the use of oil firing only as a backup fuel as described in the specific and restricting requirements of the Consent Decree (see condition below). The ability to fire the Bayside Units with oil is requested only to ensure that Tampa Electric can meet it's legal requirement to provide power to it's customers in the event the Bayside units cannot be fired with natural gas.

Condition 26. 3. (Consent Decree)

> *A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulfur content of less than 0.05 percent (by weight); (4)*

> *Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.*

Because the CFJ does not prohibit oil firing and the requirements of the CD allow for the combustion of oil only when natural gas can not be fired, Tampa Electric believes that these requirements are consistent with the CFJ. In addition, by limiting the potential hours of operation on oil, the Bayside Units meet the definition of natural gas fired units as defined under state and federal regulations.

It is clear that the intended NO_x limit on natural gas is 3.5 ppmvd, but it is further clarified in Condition 26. 2 that the NO_x emission rate limit is required only for the primary fuel. Further the intent of the CD was not to hold the oil firing NO_x limit to a limit of 3.5 ppmvd, but rather to a rate equivalent to the level of NO_x removal efficiency achieved to meet 3.5 ppmvd on natural gas. It is Tampa Electric's understanding that this interpretation agrees with the intent of the CFJ because oil firing will only occur if natural gas can not be fired and Best Available Control Technology (BACT) is utilized to control NO_x.

***CFJ Section V, B*: TEC must evaluate "zero ammonia" NOx control technologies for the Gannon facility. If the capital cost differential above Selective Catalytic Reduction (SCR) does not exceed $8 million and TEC obtains acceptable performance guarantees and remedies from the manufacturer, TEC shall install such technology on one repowered unit no later than December 31, 2004. Otherwise, TEC shall spend up to $8 million to demonstrate alternative commercially viable NOx control technologies for natural gas or coal-fired generating units.**

e. SCONOx™ is identified as a commercially viable "zero ammonia" NOx control technology and is available for large frame-type units from Alstom Power. Please describe the progress to date on obtaining capital cost estimates, manufacturer performance guarantees and remedies (in accordance with generally recognized industry standards), and all other information necessary for the Department to conclude the required evaluation.

Please note that the issue of evaluating "zero ammonia" NOx control technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

TEC Response

Tampa Electric has been working diligently with the DEP to develop an appropriate Request for Proposal (RFP) for submittal to Alstom Power (AP). The RFP has been reviewed by the DEP and it is Tampa Electric's understanding from verbal conversations with DEP staff, that the RFP is acceptable and requests the necessary information to evaluate the capital cost of the components of the $SCONO_x$ system. Tampa Electric has requested from AP, information on the assembly and construction of the $SCONO_x$ system in order to develop a RFP for the construction of the $SCONO_x$ system. Tampa Electric will work with DEP on the development of this RFP as we did for the previous RFP. The RFP for the components of the $SCONO_x$ was submitted to AP on October 23, 2000. Tampa Electric is currently awaiting a response from AP on the RFP. AP has indicated that they will provide a response the week of November 13th.

It is Tampa Electric's position that the evaluation of the non-ammonia nitrogen oxide control technology is a separate issue from the air construction permit for the Bayside Units 1 & 2 and therefore does not have to be resolved for the Department to deem the PSD permit application complete and resume it's processing. Tampa Electric believes that it is not only reasonable but also necessary for the Department *to proceed with the permitting process in order for TEC to meet the deadlines for compliance with the CFJ and the CD. The Department can certainly impose reasonable conditions if necessary to address the installation of the SCONO$_x$ system if required prior to issuing the final permit.*

f. **The Department expects that any permit issued for the proposed Bayside project will comport with the Consent Final Judgement. Please comment.**

TEC Response

Tampa Electric's will comply with all provisions of the CFJ. In furtherance Tampa Electric has submitted the application for construction of Bayside Units 1 & 2. Tampa Electric expects to work with the Department to implement all provisions of the CFJ.

12. <u>Requirements of the EPA/TEC Consent Decree</u>

a. **The Department notes that TEC has signed a separate Consent Decree with the U.S. Environmental Protection Agency. The conditions of the order vary from the requirements of the Department's Consent Final Judgement. EPA Region 4 is currently reviewing the permit application for purposes of PSD as well as compliance with the federal order. When received, the Department will forward any questions from EPA to TEC for comment.**

TEC Response

TEC appreciates the opportunity to review and comment on EPA's review of the application. TEC believes that the CFJ and the CD are consistent in all material respects.

13. <u>Air Quality Analysis</u>

a. **Please review Table 6-1 on pages 6-2, 6-3, and 6-4. The data presented in these tables does not appear consistent with the data provided in the electronic modeling files. Also, please revise the AAQS modeling analysis to include impacts from nearby major sources.**

TEC Response

The files have been corrected and sent to FDEP for review.

b. **Please provide an additional modeling analysis for SO2 that demonstrates compliance with the AAQS for the following case: Bayside Unit 1 is on-line, repowered Gannon Unit 5 is permanently shut down, and the remaining Gannon Units are on-line. This new analysis should also include impacts from nearby major sources.**

TEC Response

The analysis of ambient air quality was revised in response to the questions raised in the Department's October 16, 2000 correspondence and October 19, 2000 e-mail from Mr. Jeff Koerner.

A revised Section 6.0 and Table 6-1 are attached. In addition to the ambient air quality impacts shown on Table 6-1 (reflecting impacts due to distillate fuel oil-firing), Table 6-2 attached also provides the air quality impacts due to combustion of the primary fuel – natural gas. As noted in the submitted application, use of backup low sulfur distillate fuel oil will be limited to an annual capacity factor of no more than 10 percent.

With reference to the Department's October 19, 2000 e-mail, evaluation of ambient air quality impacts for the Existing Case (Gannon Units 1-6 in operation) was previously conducted by the Department as part of the Title V operation permit review process. Due to the potential for the Gannon Station to *contribute to exceedances of Florida's SO_2 ambient air quality standards (AAQS), TEC initially proposed to increase the stack heights of Gannon Units 5 and 6 and implement an additional 24-hour average SO_2 emission limit for Gannon Units 1-6; reference the F.J. Gannon Station Title V SO_2 Air Dispersion Modeling Report dated October 1998. As a result of Bayside repowering project, modifications to physical stack heights and fuel contracts are no longer appropriate due to the short life remaining for the Gannon Station coal-fired units. In accordance with the CFJ, all Gannon coal-fired units will be removed from service by December 31, 2004. Instead, TEC has proposed a SO_2 "glidepath" to address the issue of SO_2 air quality impacts during the period prior to December 31, 2004.*

In response to the Department's October 19, 2000 e-mail, an assessment of SO_2 ambient air quality impacts resulting from Interim Case 1 (Bayside Unit 1 and Gannon Units 1, 2, 3, 4, and 6 in operation) was also conducted. This analysis evaluated the SO_2 air quality impacts resulting from the operation of Bayside Unit 1 (during back-up low sulfur distillate fuel oil-firing, Case 4) and Gannon Units 1-4 and 6 (at a station-wide SO_2 emission rate of 8.3 tons per hour [24-hour average] - equivalent to 1.7 lb SO_2/MMBtu). The results of this assessment are provided on Table 6-3.

The dispersion model results shown on Tables 6-1 through 6-3 provide reasonable assurance that operation of the Bayside Units 1 and 2 will not contribute to any exceedances of an AAQS. Following installation of Bayside Units 1 and 2 and cessation of Gannon coal-fired operations, the highest, second highest (HSH) 24-hour average SO_2 impact will be only 4.2 percent of the Florida AAQS during natural gas-firing (the primary fuel for Bayside Power Station) and only 32.7 percent of the Florida AAQS during back-up distillate fuel oil-firing.

14. <u>Miscellaneous</u>

a. The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new Bayside Units will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

TEC Response

The Acid Rain permit application is currently under development and will be submitted 24 months prior to the commencement of operation.

b. Please be aware that the anhydrous ammonia storage tanks will require an update of the current Risk Management Plan for this site.

TEC Response

A Risk Management Plan for the anhydrous ammonia storage tanks is currently under development.

TEC appreciates the opportunity to work with the Department to resolve these issues in an expedited fashion, as the receipt of the final Air Construction Permit is critical to maintain a construction schedule that will support the commencement of operation of the Bayside Power Station as outlined in the Consent Final Judgement and the Consent Decree. 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\SKT209

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

Question 2.g. Attachment

RECEIVED
NOV 17 2000
BUREAU OF AIR REGULATION

GENERAL ELECTRIC PROPRIETARY INFORMATION

TECO Bayside

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	59.
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,886
Fuel Temperature	Deg F	60
Output	kW	169,400.
Heat Rate (LHV)	Btu/kWh	9,465.
Heat Cons. (LHV) X 10^6	Btu/h	1,603.4
Exhaust Flow X 10^3	lb/h	3535.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	966.9

EMISSIONS

NOx	ppmvd @ 15% O2	9.
NOx AS NO2	lb/h	59.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90
Nitrogen	74.36
Oxygen	12.33
Carbon Dioxide	3.89
Water	8.53

SITE CONDITIONS

Elevation	ft.	9.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	14.0
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90510 version code- 2 . 0 . 1 Opt: N 72411298
HENRYCO 02/02/2000 17:22 TECO Bayside gas60 59pp 14 020200.dat

GENERAL ELECTRIC PROPRIETARY INFORMATION

TECO Bayside

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	59.
Fuel Type		Liquid
Fuel LHV	Btu/lb	18,550
Fuel Temperature	Deg F	60
Liquid Fuel H/C Ratio		1.78
Output	kW	181,500.
Heat Rate (LHV)	Btu/kWh	10,040.
Heat Cons. (LHV) X 10^6	Btu/h	1,822.3
Exhaust Flow X 10^3	lb/h	3677.
Exhaust Temp.	Deg F.	1100.
Exhaust Heat (LHV) X 10^6	Btu/h	1013.8
Water Flow	lb/h	119,680.

EMISSIONS

NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	319.
CO	ppmvd	20.
CO	lb/h	65.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	3.5
VOC	lb/h	7.5
SO2	ppmvw	11.0
SO2	lb/h	93.0
SO3	ppmvw	1.0
SO3	lb/h	7.0
Sulfur Mist	lb/h	10.0
Particulates	lb/h	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85
Nitrogen	71.29
Oxygen	11.05
Carbon Dioxide	5.51
Water	11.30

SITE CONDITIONS

Elevation	ft.	9.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	14.0
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.05% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.05% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- 90510 version code- 2 . 0 . 1 Opt: N 72411298
HENRYCO 02/02/2000 17:33 TECO Bayside dis59pp 14 020200.dat

GENERAL ELECTRIC PROPRIETARY INFORMATION

TECO Bayside

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		50%
Ambient Temp.	Deg F.	93.
Fuel Type		Liquid
Fuel LHV	Btu/lb	18,550
Fuel Temperature	Deg F	60
Liquid Fuel H/C Ratio		1.78
Output	kW	80,600.
Heat Rate (LHV)	Btu/kWh	13,420.
Heat Cons. (LHV) X 10^6	Btu/h	1,081.7
Exhaust Flow X 10^3	lb/h	2357.
Exhaust Temp.	Deg F.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	713.3
Water Flow	lb/h	50,030.

EMISSIONS

NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	185.
CO	ppmvd	39.
CO	lb/h	82.
UHC	ppmvw	7.
UHC	lb/h	10.
VOC	ppmvw	3.5
VOC	lb/h	5.
SO2	ppmvw	11.0
SO2	lb/h	55.0
SO3	ppmvw	0.0
SO3	lb/h	4.0
Sulfur Mist	lb/h	6.0
Particulates	lb/h	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86
Nitrogen	71.69
Oxygen	11.90
Carbon Dioxide	5.00
Water	10.56

SITE CONDITIONS

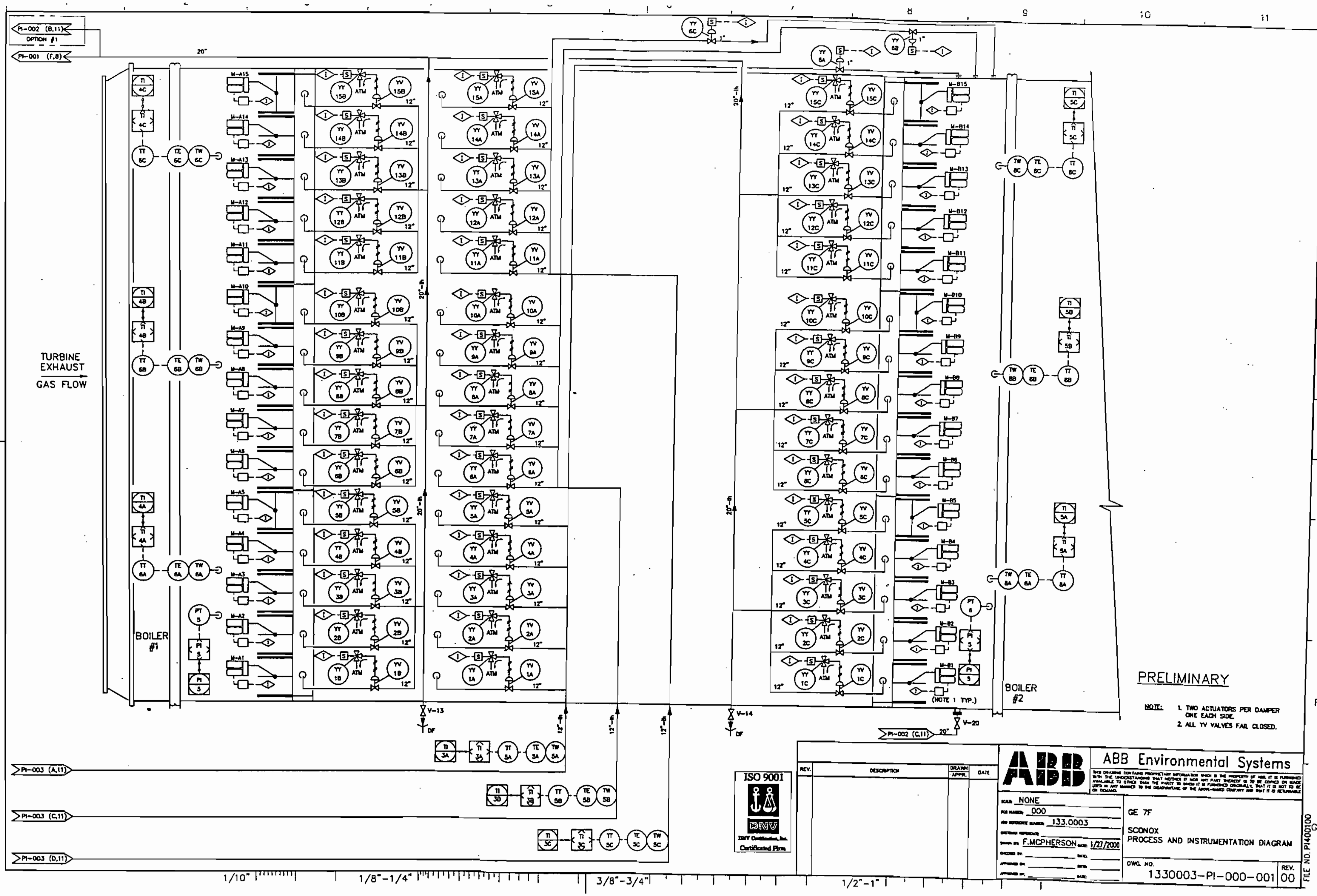
Elevation	ft.	9.0
Site Pressure	psia	14.7
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	14.0
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.05% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.05% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- 90510 version code- 2 . 0 . 1 Opt: N 72411298
HENRYCO 02/02/2000 17:09 TECO Bayside dis93pp 14 020200.dat

Question 3.b. Attachment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EXHAUST
GAS FLOW
BOILER #1
BOILER #2
PI-002 (B,11)
OPTION #1
PI-001 (F,8)
PI-002 (C,11)
PI-003 (A,11)
PI-003 (C,11)
PI-003 (D,11)
PRELIMINARY
NOTE: 1. TWO ACTUATORS PER DAMPER ONE EACH SIDE.
2. ALL TV VALVES FAIL CLOSED.
(NOTE 1 TYP.)
ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm
ABB Environmental Systems
SCALE NONE
000
133.0003
F.MCPHERSON
1/27/2000
GE 7F
SCONOX
PROCESS AND INSTRUMENTATION DIAGRAM
DWG. NO. 1330003-PI-000-001
REV. 00
FILE NO. PI400100
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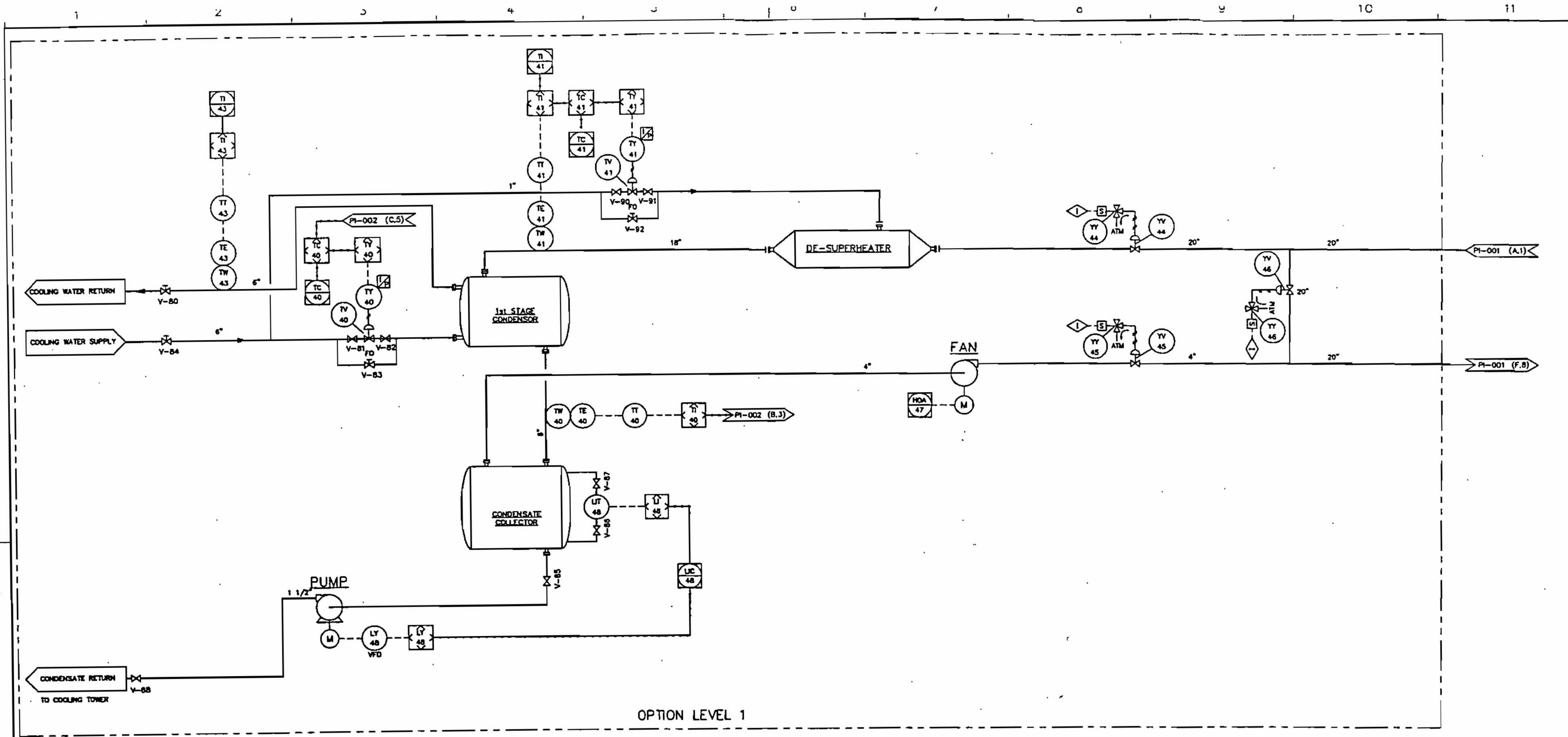
1/8"-1/4"
3/8"-3/4"
1/2"-1"



PRELIMINARY

REV.	DESCRIPTION	DRAWN / APPR.	DATE

ISO 9001
DNV
DNV Certification, Inc.
Certificated Firm

ABB ABB Environmental Systems

SCALE NONE
000
133.0003
DRAWN BY F.MCPHERSON DATE 1/27/2000

GE 7F

PROCESS AND INSTRUMENTATION DIAGRAM

DWG. NO. 1330003-PI-000-002
REV. 00

FILE NO. PI400202

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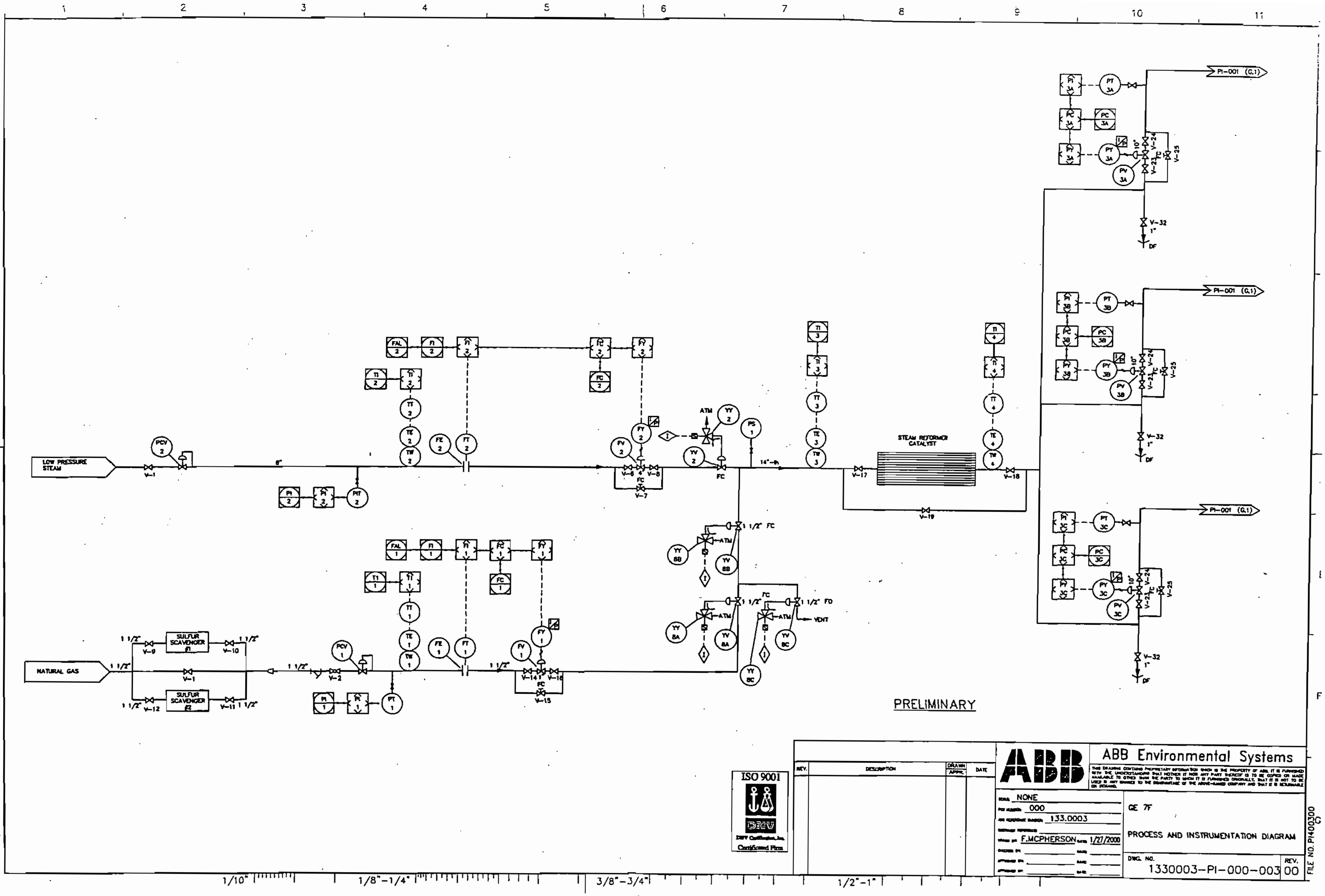
LOW PRESSURE STEAM
NATURAL GAS
SULFUR SCAVENGER #1
SULFUR SCAVENGER #2
STEAM REFORMER CATALYST
PI-001 (G,1)
ATM
VENT
PRELIMINARY
ISO 9001
DNV
ABB Environmental Systems
NONE
000
133.0003
F.MCPHERSON
1/27/2000
GE 7F
PROCESS AND INSTRUMENTATION DIAGRAM
1330003-PI-000-003
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FILE NO. PI400300
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1/8"-1/4"
3/8"-3/4"
1/2"-1"

Question 5.a. Attachments

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-453/R-94-023
March 1994

Air

EPA

Alternative Control Techniques Document -- NOx Emissions from Utility Boilers

ESD

TABLE 5-1. NO_x EMISSION CONTROL TECHNOLOGIES FOR FOSSIL FUEL UTILITY BOILERS

NO_x control options	Fuel applicability
Combustion Modifications	
Operational Modifications	Coal, natural gas, oil
- Low excess air - Burners-out-of-service - Biased burner firing	
Overfire Air	Coal, natural gas, oil
Low NO_x Burners (except cyclone furnaces)	Coal, natural gas, oil
Low NO_x burners and overfire air	Coal, natural gas, oil
Reburn	Coal, natural gas, oil
Flue gas recirculation	Natural gas, oil
Postcombustion Flue Gas Treatment Controls	
Selective noncatalytic reduction	Coal, natural gas, oil
Selective catalytic reduction	Coal, natural gas, oil

5.1 COMBUSTION CONTROLS FOR COAL-FIRED UTILITY BOILERS

There are several combustion control techniques for reducing NO_x emissions from coal-fired boilers:

- Operational Modifications
  - Low excess air (LEA);
  - Burners-out-of-service (BOOS); and
  - Biased burner firing (BF);
- Overfire air (OFA);
- Low NO_x burners (LNB); and
- Reburn.

Operational modifications such as LEA, BOOS, and BF are all relatively simple and inexpensive techniques to achieve some NO_x reduction because they only require changing certain boiler operation parameters rather than making hardware modifications. These controls are discussed in more detail in section 5.1.1.

Overfire air and LNB are combustion controls that are gaining more acceptance in the utility industry due to increased experience with these controls. There are numerous ongoing LNB demonstrations and retrofit projects on large coal-fired boilers; however, there are only a couple of projects in which LNB and OFA are used as a retrofit combination control. Both OFA and LNB require hardware changes which may be as simple as replacing burners or may be more complex such as modifying boiler pressure parts. These techniques are applicable to most coal-fired boilers except for cyclone furnaces. Overfire air and LNB will be discussed in sections 5.1.2 and 5.1.3, respectively.

Reburn is another combustion hardware modification for controlling NO_x emissions. There are four full-scale retrofit demonstrations on U. S. coal-fired utility boilers. Reburn will be discussed in section 5.1.5.

5.1.1 Operational Modifications

5.1.1.1 Process Description. Several changes can be made to the operation of some boilers which can reduce NO_x emissions. These include LEA, BOOS, and BF. While these changes may be rather easily implemented, their applicability and effectiveness in reducing NO_x may be very unit-specific. For example, some boilers may already be operating at the lowest excess air level possible or may not have excess pulverizer capacity to bias fuel or take burners out of service. Also, implementing these changes may reduce the operating flexibility of the boiler, particularly during load fluctuations.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. With less oxygen (O_2) available in the combustion zone, both thermal and fuel NO_x formation are inhibited. A range of optimum O_2 levels exist for each boiler and is inversely proportional to the unit load. Even at stable loads, there are small variations in the O_2 percentages which depend upon overall equipment condition, flame stability, and carbon monoxide (CO) levels. If the O_2 level is reduced too low, upsets can occur such as smoking or high CO levels.[1]

Burners-out-of-service involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This is accomplished by removing the pulverizer (or mill) that provides fuel to the upper row of burners from service and keeping the air registers open. The balance of the fuel is redirected to the lower burners, creating fuel-rich conditions in those burners. The remaining air required to complete combustion is introduced through the upper burners. This method simulates air staging, or overfire air conditions, and limits NO_x formation by lowering the O_2 level in the burner area.

Burners-out-of-service can reduce the operating flexibility of the boiler and can largely reduce the options available to a coal-fired utility during load fluctuations. Also, if BOOS is improperly implemented, stack opacity and CO levels may increase. The success of BOOS depends on the initial NO_x level; therefore, higher initial NO_x levels promote higher NO_x reduction.[2]

Biased burner firing consists of firing the lower rows of burners more fuel-rich than the upper row of burners. This may be accomplished by maintaining normal air distribution in all the burners and injecting more fuel through the lower burners than through the upper burners. This can only be accomplished for units that have excess mill capacity; otherwise, a unit derate (i.e., reduction in unit load) would occur. This method provides a form of air staging and limits fuel and thermal NO_x formation by limiting the O_2 available in the firing zone.

5.1.1.2 Factors Affecting Performance. Implementation of LEA, BOOS, and BF technologies involve changes to the normal operation of the boiler. Operation of the boiler outside the "normal range" may result in undesirable conditions in the furnace (i.e., slagging in the upper furnace), reduced boiler efficiency (i.e., high levels of CO and unburned carbon [UBC]), or reductions in unit load.

The appropriate level of LEA is unit-specific. Usually at a given load, NO_x emissions decrease as excess air is decreased. Lower than normal excess air levels may be achievable for short periods of time; however, slagging in the upper furnace or high CO levels may result with longer periods of LEA. Therefore, the minimum excess air level is generally defined by the acceptable upper limit of CO emissions and high emissions of UBC, which signal a decrease in boiler efficiency. Flame instability and slag deposits in the upper furnace may also define the minimum excess air level.[3]

The applicability and appropriate configuration of BOOS are unit-specific and load dependent. The mills must have excess capacity to process more fuel to the lower burners. Some boilers do not have excess mill capacity; therefore, full load may not be achievable with a mill out of service. Also, the upper mill and corresponding burners would be required to operate at full capacity during maintenance periods for mills that serve the lower burners. The BOOS pattern may not be constant. For example, a BOOS pattern at low load may be very different than that at high load.[1]

The same factors affecting BOOS also applies to BF, but to a lesser degree. Because all mills and burners remain in service for BF, it is not necessary to have as much excess mill capacity as with BOOS. Local reducing conditions in the lower burner region caused by the fuel-rich environment associated with BOOS and BF may cause increased tube wastage. Additionally, increased upper furnace slagging may occur because of the lower ash fusion temperature associated with reducing conditions.

5.1.1.3 Performance of Operational Modifications. Table 5-2 presents data from four utility boilers that use operational modifications to reduce NO_X emissions. Three of the boilers, (Crist 7, Potomac River 4, and Johnsonville) are not subject to new source performance standards (NSPS) and do not have any NO_X controls; Mill Creek 3 and Conesville 5 are subject to subpart D standards; and Hunter 2 is subject to subpart Da standards. Mill Creek 3 has dual-register burners (early LNB), Conesville 5 has OFA ports, and Hunter 2 has OFA and LNB in order to meet the NSPS NO_X limits. The data presented show only the effect of reducing the excess air level on three of these units. On one unit (Crist 7), the fuel was biased in addition to lowering the excess air.

As shown in table 5-2, LEA reduced NO_X emissions by as much as 21 percent from baseline levels for the subpart D and subpart Da units. These three units had uncontrolled NO_X levels of 0.63 to 0.69 pound per million British thermal unit (lb/MMBtu) and were reduced to 0.53 to 0.56 lb/MMBtu with LEA. For several units at the Johnsonville plant, LEA reduced the NO_X levels to 0.4-0.5 lb/MMBtu, or 10-15 percent while BOOS reduced the NO_X to 0.3-0.4 lb/MMBtu or 20-35 percent. A boiler tuning program at Potomac River 4 reduced NO_X by

TABLE 5-2. PERFORMANCE OF OPERATIONAL MODIFICATIONS ON U. S. COAL-FIRED UTILITY BOILERS

Utility	Unit (standard)[a]	Rated capacity (MW)	OEM[b]	Control type[c]	Length of test[d]	Capacity tested (%)	Uncontrolled NO_x emissions (lb/MMBtu)	Controlled NO_x emissions (lb/MMBtu)	Reduction in NO_x emissions (%)	Reference
TANGENTIALLY-FIRED BOILERS, BITUMINOUS COAL										
Potomac Electric Power Co.	Potomac River 4 (Pre)	108	ABB-CE	Tuned	Short	100 60	0.62 0.59	0.39 0.34	37 42	4
Tenn. Valley Authority	Johnsonville (1-6) (Pre)	120	ABB-CE	LEA BOOS	Short Short	UNK[e] 83	0.5-0.55 0.5-0.55	0.43-0.5 0.34-0.4	10-15 20-35	5
Columbus Southern Power Co.	Conesville 5 (D)	420	ABB-CE	LEA	Short	80-100	0.69	0.53	21[f]	6
Utah Power and Light Co.	Hunter 2 (Da)	446	ABB-CE	LEA	Short	100	0.64	0.55	14[g]	7
Tenn Valley Authority	Johnsonville (1-6)	120	ABB-CE	BOOS	Short	83	0.50-0.55	0.34-0.40	20-35	5
WALL-FIRED BOILERS, BITUMINOUS COAL										
Louisville Gas and Electric Co.	Mill Creek 3 (D)	420	B&W.	LEA	Short	80-100	0.63	0.56	10	6
Gulf Power Co.	Crist 7 (Pre)	500	FW	BF + LEA	Short	80-100	1.27	1.00	21	6

[a]Standard: Da = Subpart Da; D = Subpart D; and Pre = Pre-NSPS

[b]OEM = Original equipment manufacturer; ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; and FW = Foster Wheeler

[c]Type Control: LEA = Low Excess Air; BOOS = Burners-Out-Of-Service; BF = Biased Burner Firing; and Tuned = Boiler tuning.

[d]Short = Short-term test data, i.e., hours.

[e]UNK = Unknown.

[f]NO_x reductions are from lowering boiler oxygen levels from 5.0 percent to 3.5 percent.

[g]NO_x reductions are from lowering boiler oxygen levels from 4.5 percent to 3.5 percent.

approximately 40 percent and consisted of a combination of lowering the excess air, improving mill performance, optimizing burner tilt, and biasing the fuel and air.

A combination of BF and LEA on Crist 7 shows approximately 21 percent reduction in NO_x emissions. This unit had high uncontrolled NO_x emissions of 1.27 lb/MMBtu; therefore, the NO_x level was only reduced to 1.0 lb/MMBtu with BF and LEA. The baseline or uncontrolled NO_x level did not seem to influence the percent NO_x reduction; however, all these units are less than 20 years old and may be more amenable to changing operating conditions than older boilers that have smaller furnace volumes and outdated control systems and equipment.

5.1.2 Overfire Air

5.1.2.1 Process Description. Overfire air is a combustion control technique whereby a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the furnace remains unchanged. In the typical boiler shown in figure 5-1a, all the air and fuel are introduced into the furnace through the burners, which form the main combustion zone. For an OFA system such as in figure 5-1b, approximately 5 to 20 percent of the combustion air is injected above the main combustion zone to form the combustion completion zone.[8] Since OFA introduces combustion air at two different locations in the furnace, this combustion hardware modification is also called air staging.

Overfire air limits NO_x emissions by two mechanisms: (1) suppressing thermal NO_x formation by partially delaying and extending the combustion process, resulting in less intense combustion and cooler flame temperatures, and (2) suppressing fuel NO_x formation by lowering the concentration of air in the burner combustion zone where volatile fuel nitrogen is evolved.[8]

7.0 ENVIRONMENTAL AND ENERGY IMPACTS OF NO_x CONTROLS

This chapter presents the reported effects of combustion modifications and flue gas treatment controls on boiler performance and secondary emissions from new and retrofit fossil fuel-fired utility boilers. Since most of these effects are not routinely measured by utilities, there are limited data available to correlate boiler performance and secondary emissions with nitrogen oxides (NO_x) emissions or NO_x reduction. These effects are combustion-related and depend upon unit-specific factors such as furnace type and design, fuel type, and operating practices and restraints. As a result, the data in this chapter should be viewed as general information on the potential effects of NO_x controls, rather than a prediction of effects for specific boiler types.

The effects of combustion controls on coal-fired boilers, both new and retrofit applications, are given in section 7.1. The effects of combustion controls on natural gas- and oil-fired boilers are presented in section 7.2. The effects of flue gas treatment controls on conventional and fluidized bed combustion (FBC) boilers are given in section 7.3.

7.1 EFFECTS FROM COMBUSTION CONTROLS ON COAL-FIRED UTILITY BOILERS

Combustion NO_x controls suppress both thermal and fuel NO_x formation by reducing the peak flame temperature and by delaying mixing of fuel with the combustion air. This can result in a decrease of boiler efficiency and must be considered during the design of a NO_x control system for any new or retrofit application.

In coal-fired boilers, an increase in unburned carbon (UBC) indicates incomplete combustion and results in a reduction of boiler efficiency. The UBC can also change the properties of the fly ash and may affect the performance of the electrostatic precipitator. Higher UBC levels may make the flyash unsalable, thus increasing ash disposal costs for plants that currently sell the flyash to cement producers.

Other combustion efficiency indicators are carbon monoxide (CO) and total hydrocarbon (THC) emissions. An increase in CO emissions also signals incomplete combustion and can reduce boiler efficiency. Emissions of THC from coal-fired boilers are usually low and are rarely measured.

7.1.1 Retrofit Applications

7.1.1.1 Carbon Monoxide Emissions. The results from combustion modifications on coal-fired boilers are presented in table 7-1. Carbon monoxide emissions are presented for burners-out-of-service (BOOS), advanced overfire air (AOFA), low NO_x burners (LNB), LNB + AOFA, and reburn. For several of these applications, the data show increased CO emissions with retrofit combustion controls. For other units, however, the CO levels after application of controls were equal to or less than the initial levels.

For the only reported BOOS application, the CO emissions increased from 357 parts per million (ppm) to 392-608 ppm. The corresponding NO_x reduction was 30 to 33 percent.

While there were four units mentioned in section 5.1.2.3 that have NO_x emission data from retrofit AOFA, only one unit (Hammond 4) had corresponding CO emissions data. This unit is an opposed-wall unit firing bituminous coal. Data are presented for different loads prior to and after the retrofit of an AOFA system. The CO levels prior to the retrofit of AOFA range from 20 to 100 ppm over the load range. With the AOFA system, the CO levels decreased to an average of 15 ppm across the load range. The NO_x reduction was 10 to 25 percent across the load range. These data indicate a large decrease in CO; however, the CO levels were not routinely monitored

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
OPERATIONAL MODIFICATIONS, BITUMINOUS COAL									
Gulf Power Co.	Crist 7 (Pre)	Wall	500	BOOS	85	357	392-608	30-33	1
OVERFIRE AIR, BITUMINOUS COAL									
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	AOFA (FW)	100 80 60	100 30 20	15 15 15	25 -- 10	2,3
LOW NO_x BURNERS, BITUMINOUS COAL									
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS I (ABB-CE)	95 71 60	12 15 15	15 10 20	42 39 34	4,5
Ohio Edison Co.	Edgewater 4 (Pre)	Wall	105	XCL + SI (B&W)	100 78 63	16 16 16	100 130 170	39 43 42	6
Tennessee Valley Authority	Johnsonville 8 (Pre)	Wall	125	IFS (FW)	100	50	--	55	7,8
Board of Public Utilities	Quindaro 2 (Pre)	Wall	137	RO-II (ABB-CE)	90 70 55	-- -- --	50 50 95	-- -- --	9
Alabama Power Co.	Gaston 2 (Pre)	Wall	272	XCL (B&W)	100 68 50	60 -- --	60 50 --	50 46 43	10,11
Georgia Power Co.	Hammond 4 (Pre)	Wall	500	CF/SF (FW)	100 80 60	100 30 20	8 8 8	45 -- 50	2,3,12
Dayton Power & Light Co.	JM Stuart 4 (Pre)	Cell	610	LNCB (B&W)	100 75 56	26 17 20	35 28 10	55 54 47	13

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONTINUED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
LOW NO_x BURNERS, SUBBITUMINOUS COAL									
Board of Public Utilities	Quindaro 2 (Pre)	Wall	137	RO-II (ABB-CE)	80 70 55	-- -- --	70 70 50	-- -- --	9
Arizona Public Service Co.	Four Corners 4 (Pre)	Wall	818	CF/SF (FW)	105 69 49	53 35 30	86 33 41	57 29 6	14
Arizona Public Service. Co.	Four Corners 5 (Pre)	Wall	818	CF/SF (FW)	93	--	<50	50	14
LOW NO_x BURNERS + OVERFIRE AIR, BITUMINOUS COAL									
Public Service Co. of CO	Valmont 5 (Pre)	Tan	165	LNCFS II (ABB-CE)	91 75 50	<30 -- --	<30 -- --	52 26 27	15
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS II (ABB-CE)	95 71 60	12 15 15	28 22 20	39 35 30	4,5,10
Public Service Co. of CO	Cherokee 4 (Pre)	Tan	350	LNCFS II (ABB-CE)	100 71 45	<30 -- --	<30 -- --	46 31 35	16
Gulf Power Co.	Lansing Smith 2 (Pre)	Tan	190	LNCFS III (ABB-CE)	95 71 60	12 15 15	45 25 22	48 47 39	4,5,10
Ohio Edison Co.	Sammis 6 (Pre)	Wall	630	DRB-XCL (B&W)	100 55	17.4-25.8 31.8	225-670 55		17
Public Service Co. of CO	Arapahoe 4 (Pre)	Roof	100	DRB-XCL + OFA (B&W)	100 80 60	48 42 39	38 21 12	66 71 63	18

TABLE 7-1. SUMMARY OF CARBON MONOXIDE EMISSIONS FROM COAL-FIRED BOILERS WITH COMBUSTION NO_x CONTROLS (CONCLUDED)

Utility	Unit (standard)[a]	Unit type[b]	Rated capacity (MW)	Control type[c] (vendor)[d]	Capacity tested	Carbon monoxide (ppm)		NO_x reduction (%)	Reference
						Uncontrolled	Control		
REBURN, BITUMINOUS COAL									
Illinois Power Co.	Hennepin 1 (Pre)	Tan	75	NGR (EERC)	100	2	2	63	19,20
Wisconsin Power and Light Co.	Nelson Dewey 2 (Pre)	Cyc	114	Coal Reburn (B&W)	100 75 50	60-70 40-70 80-94	90-110 80-100 80-100	53 50 36	21
Ohio Edison Co.	Niles 1 (Pre)	Cyc	125	NGR (EERC)	100 85 79 75	25-50 -- -- --	312 214 50 103	47 43 34 36	22

[a]Standard: Pre = Pre-NSPS

[b]Unit Type: Cell = Cell Burner; Cyc = Cyclone; Roof = Roof-fired; Tan = Tangentially-fired; and Wall = Wall-fired.

[c]Control Type: AOFA = Advanced Overfire Air; BOOS = Burners-out-of-service; CF/SF = Controlled Flow/Split Flame LNB; DRB-XCL = Dual Register Axial Control LNB; IFS = Internal Fuel Staged LNB; LNCB = Low NO_x Cell Burner; LNCFS, I, II, II = Low NO_x Concentric Firing System, Level I, II, III; NGR = Natural Gas Reburn; OFA = Overfire Air; RO-II = RO-II LNB; SI = Sorbent Injection for Sulfur Dioxide Control; and XCL = Axial Controlled LNB.

[d]Vendors: ABB-CE = Asea Brown Boveri-Combustion Engineering; B&W = Babcock & Wilcox; EERC = Energy and Environmental Research Corporation; and FW = Foster Wheeler.

-- = data not available.

prior to the retrofit and the decrease may be attributable to plant operating personnel taking action to reduce CO emissions after the retrofit.[2]

For the one tangential boiler with retrofit LNB (Lansing Smith 2), the uncontrolled CO emissions were 12 to 15 ppm while the CO emissions were 10 to 20 ppm with the Low NO_x Concentric Firing System (LNCFS) Level I which incorporates close-coupled OFA (CCOFA). The corresponding NO_x reduction was 34 to 42 percent across the load range.

For all but two of the wall-fired boilers firing bituminous coal with LNB, the reported uncontrolled CO emissions were 100 ppm or less and the controlled CO emissions were 60 ppm or less. However, for Edgewater 4, the CO increased from 16 ppm up to 100 to 170 ppm following retrofit of LNB. At reduced load, Quindaro 2 reported a CO level of 95 ppm with LNB. The CO level without LNB was not reported. The largest decrease in CO emissions was at the Hammond 4 unit. However, as previously discussed, the CO level was not routinely measured prior to the retrofit and the decrease may be attributable to plant operating personnel taking action to reduce the CO emissions after the retrofit. For the one cell-fired unit, J.M. Stuart 4, the CO emissions with LNB were slightly higher than uncontrolled levels at full-load and intermediate load. The CO emissions were less with LNB at low load. The corresponding NO_x reductions ranged from 47 to 55 percent.

The Four Corners 4 unit, which converted from cell firing to an opposed-wall circular firing configuration, showed a small increase in CO emissions with LNB when firing subbituminous coal. The corresponding NO_x reduction for Four Corners 4 ranged from 6 to 57 percent across the load range. Quindaro 2 was also tested on subbituminous coal and the CO ranged from 50-70 ppm across the load range.

There are four applications of LNB and AOFA on tangential boilers shown in table 7-1. The LNB represented are the LNCFS Levels II and III which incorporates separated OFA (SOFA) and a combination of SOFA and CCOFA, respectively. Three of these units (Valmont 5, Lansing Smith 2, and Cherokee 4) have the LNCFS II technology. For these units, the CO emissions for both uncontrolled and controlled conditions were less than 30 ppm. For the one unit employing LNCFS III technology (Lansing Smith 2), the CO emissions increased from uncontrolled levels of 12 to 15 ppm up to controlled levels of 22 to 45 ppm.

One wall-fired boiler, Sammis 6, was originally a cell-fired boiler and was retrofitted with LNB + OFA. At full-load, the CO increased to more than 225 ppm from baseline levels of 17-25 ppm. At reduced load, the CO also increased almost two-fold to 55 ppm. The reason for the large in CO at full-load was not reported. The NO_x reduction was approximately 65 percent. The one roof-fired boiler, Arapahoe 4, reported decreases in CO and ranged from 12-38 ppm with LNB + OFA. The NO_x reduction ranged from 63-71 percent across the load range.

For the tangentially-fired unit (Hennepin 1) with retrofit reburn, the CO emissions for both uncontrolled and controlled conditions were 2 ppm. Carbon monoxide data from two cyclone units with reburn are also given in table 7-1. One unit (Nelson Dewey 2), uses pulverized coal as the reburn fuel while the other unit (Niles 1), uses natural gas as the reburn fuel. The CO emissions for the cyclone boilers increased with the reburn system. For Nelson Dewey 2, the CO emissions were 60 to 94 ppm without reburn and 80 to 110 ppm with reburn. The corresponding NO_x reduction was 36 to 53 percent across the load range. For Niles 1, the CO emissions increased greatly from 25 to 50 to 312 ppm at full load. At lower loads, the CO emissions were still at elevated levels of 50 to 214 ppm. The corresponding NO_x reduction was 36 to 47 percent.

To summarize, the CO emissions may increase with retrofit combustion modifications. However, as shown in table 7-1, with few exceptions, the CO emissions were usually less than 100 ppm with retrofit combustion controls.

7.1.1.2 Unburned Carbon Emissions and Boiler Efficiency. Table 7-2 presents UBC and boiler efficiency data from 18 applications of retrofit combustion NO_x controls on coal-fired boilers. For Hammond 4, the AOFA resulted in an increase of UBC two or three times the uncontrolled level. Uncontrolled levels of UBC at Hammond 4 ranged from 2.3 percent at low load to 5.2 percent at full load. With the AOFA, the UBC levels increased to 7.1 percent at low load and 9.6 percent at full load. The boiler efficiency at low load decreased by 0.7 percentage points and by 0.4 percentage points at full load. The corresponding NO_x reduction with AOFA was 10 percent at low load and 25 percent at full load.

For the tangential unit with LNCFS I technology, Lansing Smith 2, the UBC levels range from 4.0 to 5.0 percent without LNB and 4.0 to 5.3 percent with LNB. The boiler efficiency with LNB decreased slightly to 89.6 percent.

The UBC from all of the wall-fired boilers increased with the retrofit of LNB and LNB with OFA. For Edgewater 4, the uncontrolled UBC levels increased from 2.7 to 3.2 percent to 6.6 to 9.0 percent with the LNB. The corresponding NO_x reduction was 39 to 43 percent across the load range. The boiler efficiency decreased by 1.3 percentages points at full load with the LNB.

For Gaston 2, the UBC increased from 5.3 to 6.3 percent at low load and 7.4 to 10.3 percent at full load. The corresponding NO_x reduction at Gaston 2 ranged from 43 to 50 percent across the load range. Boiler efficiency data were not available for this unit. For Hammond 4, the UBC increased from 2.3 to 5.8 percent at low load and 5.2 to 8.0 percent at full load with LNB. Increased UBC levels such as these could limit the sale of fly ash to cement producers that typically require UBC levels of 5 percent or less. The corresponding

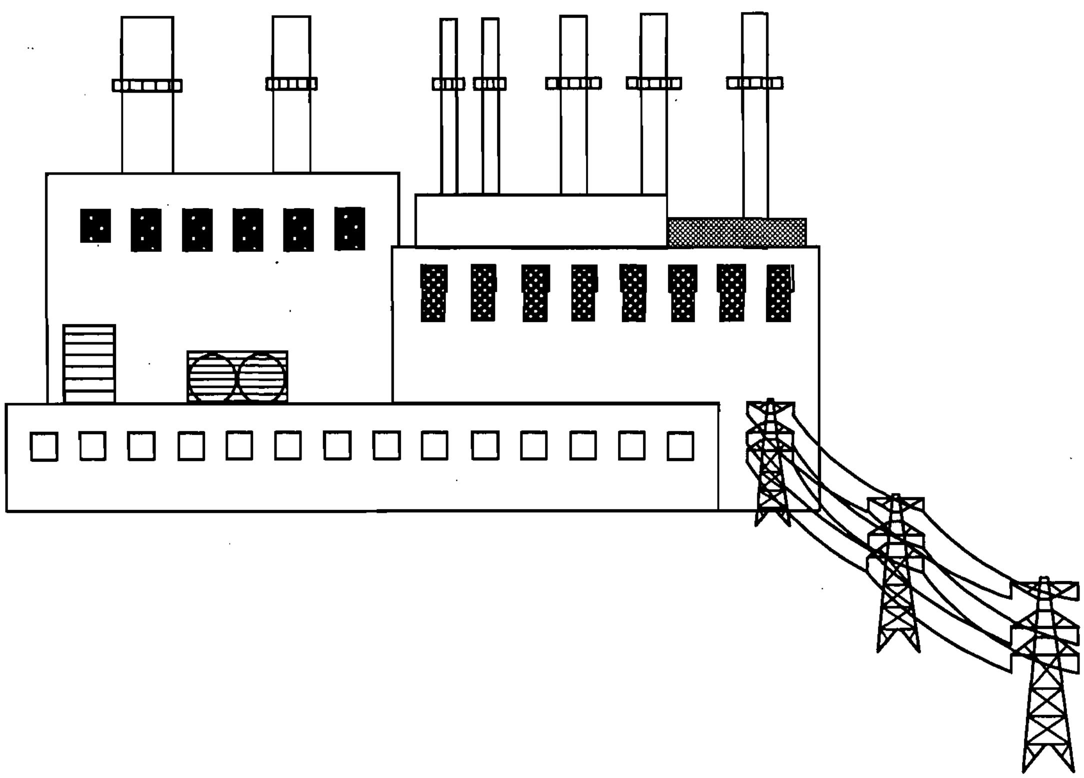
TECO
TAMPA ELECTRIC

CORPORATE ENVIRONMENTAL SERVICES

AIR PROGRAMS REPORT

SOURCE EMISSION TEST
F. J. GANNON GENERATING STATION
BOILER NO. 5
AIRS #0570040
APRIL 7 and 8, 2000

CARBON MONOXIDE



REPORT CERTIFICATION

I have reviewed all data in this report, and hereby certify that the test report is authentic and accurate to the best of my knowledge.

Date 5/1/2000 Signature ______________________

Quality Control/Quality Assurance Coordinator
Senior Environmental Technician
Air Services and Auditing
Corporate Environmental Services
Tampa Electric Company

The sampling and analysis performed for this report were carried out under my direction and, and I hereby certify that this test report is authentic and accurate.

Date 5/1/00 Signature ______________________

Test Team Leader
Senior Environmental Technician
Air Services and Auditing
Corporate Environmental Services
Tampa Electric Company

I have reviewed the testing details and results in this report, and hereby certify that the test report is authentic and accurate to the best of my knowledge.

Date 5-2-00 Signature ______________________

Administrator
Air Services and Auditing
Corporate Environmental Services
Tampa Electric Company

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1.0 SUMMARY OF RESULTS

On April 7 and 8, 2000, Corporate Environmental Services, Air Services and Auditing group of Tampa Electric Company, performed source emission tests at the F.J. Gannon Station, Boiler number 5, Airs # 0570040. Testing was conducted according to procedures stipulated by the Florida Department of Environmental Protection (FDEP) for fossil fuel steam generators, 40CFR60.

The Carbon Monoxide emission rate was derived from three test runs. The calculated average of CO was 0.295 lbs/MMBtu (lb/10^6 Btu) based on Oxygen content of the flue gas (O_2 F-factor).

During the tests on April 7 and 8, 2000, the boiler was operated at an average heat input rate of 2082 x 10^6 Btu/hr and an average load of 220 megawatts. The average quantity of fuel burned was 82 tons per hour. Details of boiler operations are included in Appendix C.

2.0 SOURCE DESCRIPTION/TEST PROCEDURES

F.J. Gannon Generating Station is located on Port Sutton Road, Tampa, Florida at UTM coordinates East 360.1 North 3087.5. Unit No. 1 source sampling location consists of a circular stack 12 feet in diameter with four sample ports located 90E apart on the stack circumference. A diagram of the stack sampling location is included in Figure 1 along with other pertinent information on the test site.

An electrostatic precipitator for the control of flyash emissions services boiler No. 1. Appendix C details the operational parameters of the electrostatic precipitator during the test period.

Carbon Monoxide sampling was performed according to U.S. EPA Method 10 - "Determination of Carbon Monoxide Emissions from Stationary Sources". Sampling was performed using the equipment depicted in Figure 2. Oxygen gas sampling was performed according to U.S. EPA Method 3A - "Determination of Oxygen and Carbon Monoxide Concentrations in Emissions from Stationary Sources "(Instrumental Analyzer Procedures)". Sampling was performed using the equipment depicted in Figure 2.

3.0 TCEMS Description

The following discussion briefly outlines the operation principles of Tampa Electric Company's Continuous Emissions Monitoring System (TCEMS). Additional information on instrument operation may be found in the individual instrument manuals provided by the manufacturers. A schematic of the TCEMS set-up is presented in Figure 2.

Servomex Model 1400 B O_2 Analyzer

The Servomex 1400B oxygen analyzer measures the paramagnetic susceptibility of the sample gas by means of a magneto-dynamic type measuring cell.

Thermo Environmental Instruments Model 48-H Gas Filter Correlation CO Analyzer High Range

Gas Filter Correlation (GFC) spectroscopy is based upon comparison of the detailed structure of the infrared absorption spectrum of the measured gas to that of other gases also present in the sample being analyzed. The technique is implemented by using a high concentration sample of the measured gas, i.e., CO, as a filter for the infrared radiation transmitted through the analyzer, hence the term GFC.

Radiation from an IR source is chopped and then passed through a gas filter alternating between CO and N_2 due to rotation of the filter wheel. The radiation then passes through a narrow bandpass interference filter and enters a multiple optical pass cell where absorption by the sample gas occurs. The IR radiation then exits the sample cell and falls on an IR detector.

The CO gas filter acts to produce a reference beam which cannot be further attenuated by CO in the sample cell. The N_2 side of the filter wheel is transparent to the IR radiation and therefore produces a measurement beam which can be absorbed by CO in the cell. The chopped detector signal is modulated by the alternation between the two gas filters with an amplitude related to the concentration of CO in the sample cell. Other gases do not cause modulation of the detector signal since they absorb the reference and measure beams equally. Thus the GFC system responds specifically to CO.

Data Acquisition System

The data acquisition system (DAS) developed by Entropy Environmentalists Inc., uses a portable personal computer with an internal 32 bit analog-to-digital converter with an external 16 channel multiplexer. In addition to providing an instantaneous display of analyzer responses, the DAS can average data, calculate emission rates, and document analyzer calibrations. The test results and calibrations are stored on the hard disk and printed on a dot matrix printer.

TCEMS Sample Handling System

The extractive monitors utilized in the TCEMS require that the effluent stream be conditioned to eliminate any possible interference (i.e., water vapor and particulate matter), before being transported and injected into each analyzer. Figure 2 depicts a schematic of the entire sample handling system. The major components of this system are listed below:

- Gas transport tubing
- Moisture removal system
- Sampling pump

Gas Transport Tubing

Two separate 1/4 inch O.D. Teflon tubes were used for the sample gas transport.

Moisture Removal System

The moisture removal system was comprised of an ice bath condenser, constructed of a 30-foot section of 3/8 inch O.D. Teflon tubing, wrapped in a 12-inch coil. Effluent travels through this coil and then passes, in series, through two stainless steel moisture traps where the condensate drops out and is removed via a condensate discharge pump. With the exception of the discharge pump, the entire assembly is chilled in an ice bath.

Sampling Pump

The Thomas Model 2107CE20-TFE pump is used to transport the effluent sample through the conditioning system to the analyzers. All internal parts of the pump that come into contact with the gas sample are constructed of 316 stainless steel or Teflon.

3.0 TEST RESULTS

TEST SUMMARY
CARBON MONOXIDE TEST RESULTS

PLANT:	F. J. GANNON STATION
SAMPLING LOCATION:	BOILER NO. 5
DATE:	April 7 and 8, 2000

USEPA Method 10

RUN NO.	**ppm CO**	**Oxygen %**	**lbs. CO /MM Btu**
1	117.3	13.52	0.222
2	158.9	12.36	0.259
3	243.4	12.49	0.404
Averages	173.2	12.79	0.295

SOURCE SAMPLING NOMENCLATURE

A	=	Absorbance of sample.
A_n	=	Cross-sectional area of nozzle, m5 (ft5).
A_s	=	Cross-sectional area of stack, m5 (ft5).
B_{ws}	=	Water vapor in the gas steam, proportion by volume.
C	=	Concentration of particulate matter, (lbs/dscf), Method 5,17.
C	=	Concentration of NO_x, as NO_2, basis, corrected to standard conditions, mg/dscm (lbs/dscf), Method 7.
C_a	=	Concentration of acetone blank residue, mg/g.
CH_2SO_4	=	Sulfuric acid (including SO_3) concentration, g/dscm (lbs/dscf).
C_p	=	Pitot tube coefficient, dimensionless.
c_s	=	Concentration of stack gas particulates, dry basis corrected to standard conditions, g/dscm (lbs/dscf).
CSO_2	=	Sulfur dioxide concentration, mg/dscm (lbs/dscf).
E	=	Pollutant emissions, lbs/10^6 Btu.
EM	=	Particulate emission rate, lbs/hr.
F	=	Factor ratio of generated flue gases to calorific value of fuel, Method 5,17.
F	=	Dilution factor (i.e., 25/5, 25/10, etc.) required only if sample dilution was needed to reduce the absorbance to the range of calibration, Method 7.
FDA	=	Fraction of dry air.
I	=	Percent of isokinetic sampling, %.
K_c	=	Spectrophotometer calibration factor.
K_p	=	Pitot tube constant,

$$34.97 m/\text{sec}\left[\frac{(g/g\text{-}mole)(mmHg)}{(°K)(mmH20)}\right]1/2$$

Metric

$$85.49ft/\sec\left[\frac{(lb/lb\text{-}mole)('' Hg)}{(°K)(mmH2O)}\right]1/2$$

English

L_a	=	Maximum acceptable leakage rate for either a pretest leak check or a leak check following a component change; equal to 0.00057 m^3/min (0.02 ft^3/min) or 4% of the average sampling rate, whichever is less.
L_i	=	Individual leakage rate observed during the leak check conducted prior to the "ith" component change (i = 1, 2, 3,...n), m^3/min (ft/min).
L_p	=	Leakage rate observed during the post test leak check, m^3/min (ft^3/min).
m	=	Mass of NO_x as NO_2 in gas sample, :g.
m_a	=	Mass of acetone residue after evaporation, mg.
M_d	=	Molecular weight of stack gas, dry basis, g/g-mole (lb/lb-mole).
m_f	=	Filter weight gain, mg.
m_n	=	Total amount of particulates collected, mg.
M_s	=	Molecular weight of stack gas, wet basis, g/g-mole (lb/lb-mole), or $M_d(1 - B_{ws}) = 18.0\ B_{ws}$.
M_w	=	Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
N	=	Normality of $Ba(ClO_4)_2 \cong 3H_2O$ titrant, g-eq/l.
N	=	Normality of barium perchlorate titrant, meq/ml.
P_a	=	Density of acetone, mg/ml (see bottle label).
P_{bar}	=	Barometric pressure at sampling site, mm Hg (in. Hg).
P_f	=	Final absolute pressure of flask, mm Hg (in. Hg).
P_g	=	Stack static pressure, mm Hg (in. Hg).
P_i	=	Initial absolute pressure of flask, mm Hg (in. Hg).
P_s	=	Absolute stack pressure, 760 mm Hg (29.92 in. Hg).
P_w	=	Density of water, 0.9982 g/ml (0.0022 lb/ml).
Q_s	=	Volumetric flow rate, actual cubic feet per min, acf/min.
Q_{std}	=	Dry volumetric stack gas flow rate corrected to standard conditions dsm^3/hr (dscf/hr).
R	=	Ideal gas constant, 0.06236 (mm Hg - m^3)/(EK - g - mole) for metric units and 21.85 (in. Hg - ft^3)(ER - 1b - mole) for English units.
S.V.P.	=	Saturated vapor pressure of water at average stack temperature mm Hg

(in. Hg).

T_f = Final absolute temperature of flask, K (ER).
T_i = Initial absolute temperature of flask, K (ER).
T_m = Absolute average dry gas meter temperature, K (ER).
t_s = Stack temperature, EC (EF).
T_s = Absolute stack temperature, K (ER), or 273 + t_s for metric system or 460 + t_s for English system.
T_{std} = Standard absolute temperature, 293K (528ER).
V_a = Volume of acetone blank, ml, (Method 5,17).
V_a = Volume of sample aliquot titrated, ml, (Method 6).
V_a = Volume of absorbing solution, 25 ml, (Method 7).
V_a = Volume of sample aliquot titrated, 100 ml for H_2SO_4 and 10ml for SO_2 (Method 8).
V_{aw} = Volume of acetone used in wash, ml.
V_f = Final volume of condenser water, ml.
V_f = Volume of flask and valve, ml.
V_i = Initial volume of condenser water, ml.
V_{ic} = Total volumes of liquid and silica gel collected in impingers, ml.
V_m = Dry gas volume measured by dry gas meter, scm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter and corrected to standard condition, dscm (dscf).
v_s = Average stack gas velocity calculated by Method 2, m/sec (ft/sec).
V_{sc} = Sample volume at standard conditions (dry basis), ml.
V_{soln} = Total volume of solution in which the sulfur dioxide sample is contained, 100 ml, (method 6).
V_{soln} = Total volume of solution in which the H_2SO_4 or SO_2 sample is contained, 250 ml or 1000 ml, respectively, (Method 8).
V_t = Volume of $Ba(ClO_4)_2 \cong 3H_2O$ titrant used for the sample, ml, (Method 8).
V_t = Volume of barium perchlorate titrant used for the sample (average of replicate titrations), ml, (Method 6).
V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.
$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).
$V_{wc(std)}$ = Volume of condensed water vapor, corrected to standard conditions,

sm^3(scf).

$V_{wsg(std)}$	=	Volume of water vapor collected in silica gel, corrected to standard conditions, sm^3 (scf).
W_a	=	Weight of acetone wash residue, mg.
W_f	=	Final weight of silica gel or silica gel plus impinger, g.
W_i	=	Initial weight of silica gel or silica gel plus impinger, g.
Y	=	Dry gas meter calibration factor.
)H	=	Average pressure differential across the orifice meter, mm (in) H_2O.
)H@	=	Measurement of pressure differential across the orifice meter, mm (in.) H_2O.
)p	=	Average velocity head of stack gas, mm (in.) H_2O.
)V_m	=	Incremental volume measured by dry gas meter at each traverse point, dm^3 (dcf).
%CO	=	Percent CO by volume (dry basis), average of three CO values.
%CO_2	=	Percent CO_2 by volume (dry basis), average of three analyses.
%EA	=	Percent excess air, %.
%N_2	=	Percent N_2 by volume (dry basis), average of three N_2 values.
%O_2	=	Percent O_2 by volume (dry basis), average of three O_2 values.
0.262	=	Ratio of O_2 to N_2 in air, v/v.
2	=	50/25, the aliquot factor, (Method 7).
13.6	=	Specific gravity of mercury (Hg).
18.0	=	Molecular weight of water, g/g-mole (lb/lb-mole).
32.03	=	Equivalent weight of sulfur dioxide.
60	=	Seconds per minute (sec/min).
100	=	Conversion to percent, %.
3600	=	Conversion factor, (sec/hr).
2	=	Total sampling time, min.
2_I	=	Interval of sampling time from beginning of a run until first component change, min.
2_i	=	Interval of sampling time between two successive component changes, beginning with first and second changes, min.
2_p	=	Interval of sampling time from final (nth) component change until the end of the sampling run, min.

4.0 FIGURES

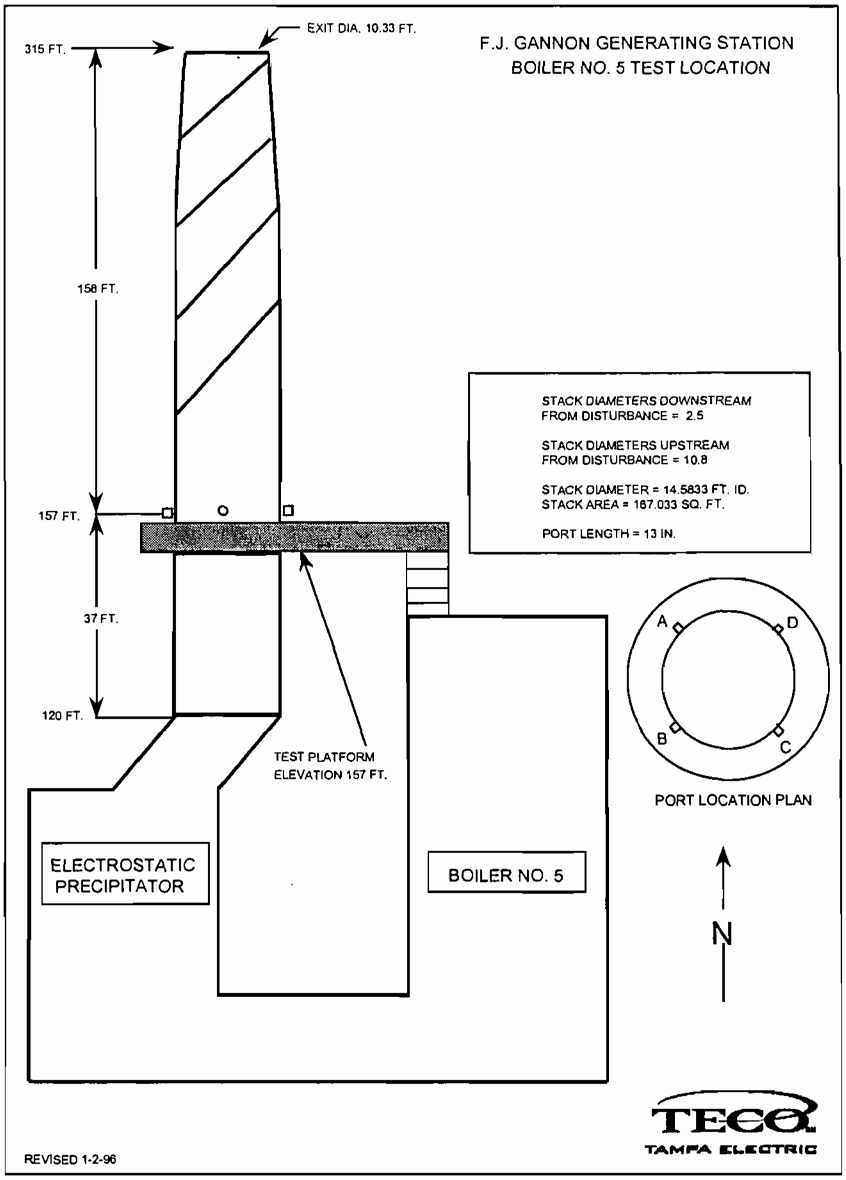
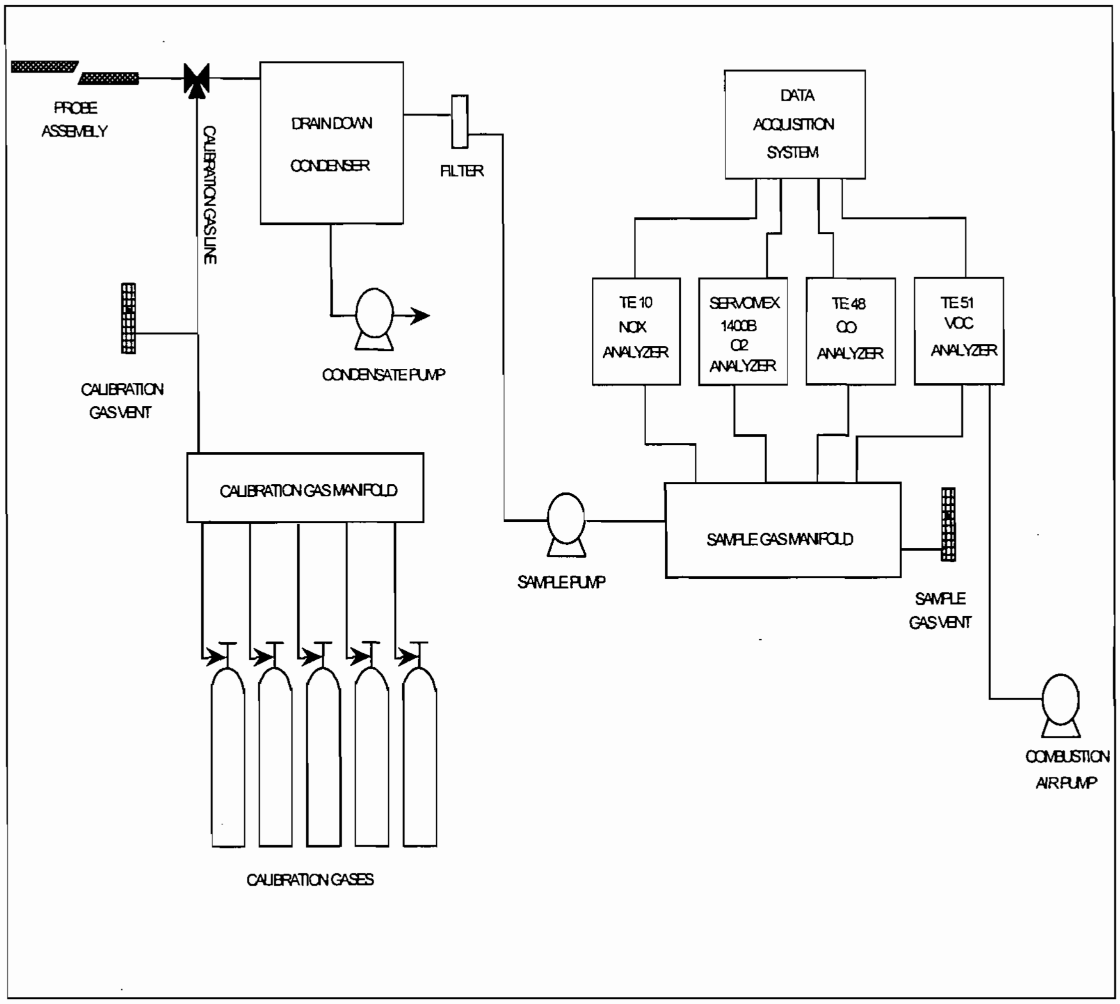

F.J. GANNON GENERATING STATION
BOILER NO. 5 TEST LOCATION
EXIT DIA. 10.33 FT.
315 FT.
158 FT.
157 FT.
37 FT.
120 FT.
STACK DIAMETERS DOWNSTREAM FROM DISTURBANCE = 2.5
STACK DIAMETERS UPSTREAM FROM DISTURBANCE = 10.8
STACK DIAMETER = 14.5833 FT. ID.
STACK AREA = 167.033 SQ. FT.
PORT LENGTH = 13 IN.
A
D
B
C
PORT LOCATION PLAN
TEST PLATFORM ELEVATION 157 FT.
ELECTROSTATIC PRECIPITATOR
BOILER NO. 5
N
TECO
TAMPA ELECTRIC
REVISED 1-2-96

FIGURE 1



TECO
TAMPA ELECTRIC

FIGURE 2
Carbon Monoxide and Nitrogen Oxide Sampling Trains

USEPA METHODS 3A, 10, 20, 25 CEM SYSTEM LAYOUT

A. GAS CALCULATIONS

A-1 CARBON MONOXIDE CALCULATIONS
A-2 OXYGEN CALCULATIONS

A-1 CARBON MONOXIDE CALCULATIONS

CALCULATION OF AVERAGE CARBON MONOXIDE CONCENTRATION

RUN: 1

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 ppm CO	3.30	2.20	2.75
150.00 ppm CO	146.00	142.20	144.10

$\bar{C}$ = 113.3 ppm CO

02= 13.52

EMISSION RATE = (ppm CO) (9190) (0.7263E-07) [20.9/(20.9 - %02)]

CORRECTED RESULTS

117.3 ppm CO

0.222 lb/MMBtu

Corrected Conc. = Cma(C - $\bar{C}$o)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE CARBON MONOXIDE CONCENTRATION

RUN: 2

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 ppm CO	2.20	1.80	2.00
150.00 ppm CO	142.20	150.20	146.20

$\bar{C}$ = 154.8 ppm CO

02= 12.36

EMISSION RATE = (ppm CO) (9190) (0.7263E-07) [20.9/(20.9 - %02)]

CORRECTED RESULTS

158.9 ppm CO

0.259 lb/MMBtu

Corrected Conc. = Cma($\bar{C}$ - Co)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE CARBON MONOXIDE CONCENTRATION

RUN: 3

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 ppm CO	1.80	2.20	2.00
150.00 ppm CO	150.20	143.10	146.65

$\bar{C}$ = 236.7 ppm CO

02= 12.49

EMISSION RATE = (ppm CO) (9190) (0.7263E-07) [20.9/(20.9 - %02)]

CORRECTED RESULTS

243.4 ppm CO

0.404 lb/MMBtu

Corrected Conc. = Cma(C - $\bar{Co}$)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

A-2 OXYGEN CALCULATIONS

CALCULATION OF AVERAGE OXYGEN CONCENTRATION

RUN: 1

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 % Oxygen	0.06	0.23	0.15
11.96 % Oxygen	12.13	12.13	12.13

$\bar{C}$ = 13.52

CORRECTED RESULTS

13.3 % Oxygen

Corrected Conc. = $Cma(\bar{C} - Co)/(Cm - Co)$

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE OXYGEN CONCENTRATION

RUN: 2

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 % Oxygen	0.23	-1.35	-0.56
11.96 % Oxygen	12.13	11.93	12.03

$\bar{C}$ = 12.36

CORRECTED RESULTS

12.3 % Oxygen

Corrected Conc. = Cma(C - $\bar{C}$o)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

CALCULATION OF AVERAGE OXYGEN CONCENTRATION

RUN: 3

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

GAS VALUE	INITIAL CAL	FINAL CAL	MEAN CAL
0.00 % Oxygen	-1.35	-0.11	-0.73
11.96 % Oxygen	11.93	12.05	11.99

$\bar{C}$ = 14.42

CORRECTED RESULTS

14.2 % Oxygen

Corrected Conc. = Cma($\bar{C}$ - Co)/(Cm - Co)

Where: $\bar{C}$ = mean reference measurement
Co = mean zero calibration response
Cm = mean mid or upscale calibration gas response
Cma = actual mid or upscale calibration gas concentration

B. UNCORRECTED REFERENCE METHOD DATA

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
09:24	14.28	889.3	198.3	13.08	1.861	0.378
09:25	14.31	891.9	169.3	13.11	1.862	0.322
09:26	14.33	890.4	114.5	13.18	1.857	0.220
09:27	14.27	883.1	125.3	13.18	1.849	0.241
09:28	14.33	885.6	171.6	13.11	1.847	0.327
09:29	14.52	896.3	177.5	13.25	1.845	0.346
09:30	14.55	897.5	287.2	13.17	1.843	0.552
09:31	14.58	901.3	151.4	13.42	1.848	0.301
09:32	14.44	895.2	181.2	13.35	1.852	0.357
09:33	14.46	899.0	134.3	13.46	1.858	0.268
09:34	14.45	897.9	88.7	13.47	1.857	0.177
09:35	14.31	886.3	134.0	13.58	1.850	0.272
09:36	14.19	879.2	192.1	13.52	1.851	0.389
09:37	14.25	881.8	160.5	13.52	1.849	0.324
09:38	14.14	875.1	112.8	13.47	1.850	0.225
09:39	14.17	873.6	88.1	13.51	1.842	0.177
09:40	14.27	877.8	69.7	13.51	1.838	0.140
09:41	14.22	870.2	64.8	13.48	1.829	0.129
09:42	14.17	871.6	95.5	13.53	1.839	0.192
09:43	14.23	879.2	67.2	13.41	1.846	0.133
09:44	14.12	870.8	62.2	13.48	1.843	0.124
09:45	14.16	872.1	72.6	13.44	1.841	0.145
09:46	14.12	868.0	116.5	13.45	1.836	0.232
09:47	14.21	873.8	94.6	13.33	1.838	0.185
09:48	14.11	869.6	94.9	13.41	1.841	0.188
09:49	14.22	875.1	87.7	13.33	1.839	0.172
09:50	14.26	877.4	91.7	13.56	1.838	0.186
09:51	14.24	877.1	114.5	13.40	1.840	0.227
09:52	14.16	870.7	74.0	13.52	1.838	0.149
09:53	14.17	870.2	104.7	13.45	1.835	0.208
09:54	14.15	868.4	87.1	13.56	1.834	0.176
09:55	14.25	877.1	66.8	13.56	1.839	0.135
09:56	14.20	872.9	58.0	13.63	1.837	0.119
09:57	14.05	865.8	55.1	13.56	1.841	0.112
09:58	14.06	864.3	64.9	13.69	1.837	0.134
09:59	14.15	870.2	90.5	13.62	1.837	0.185
10:00	14.18	870.6	84.8	13.62	1.834	0.174
10:01	14.21	872.7	63.0	13.72	1.836	0.130
10:02	14.18	871.0	65.5	13.64	1.835	0.134
10:03	14.15	869.0	76.6	13.67	1.835	0.157
10:04	14.27	876.7	96.6	13.63	1.836	0.197
10:05	14.27	876.2	87.7	13.73	1.835	0.182
10:06	14.32	880.3	133.6	13.76	1.837	0.278
10:07	14.36	881.4	154.6	13.64	1.834	0.316
10:08	14.33	880.9	132.1	13.70	1.836	0.273
10:09	14.46	891.4	84.5	13.74	1.842	0.175
10:10	14.33	881.3	103.8	13.71	1.837	0.214
10:11	14.44	889.8	71.1	13.79	1.841	0.148
10:12	14.40	884.9	127.5	13.51	1.836	0.256
10:13	14.45	892.6	109.8	13.53	1.846	0.221
10:14	14.44	894.6	107.6	13.51	1.851	0.216
10:15	14.28	885.5	129.0	13.52	1.853	0.259
10:16	14.42	894.3	81.9	13.49	1.853	0.164
10:17	14.43	895.1	110.8	13.64	1.853	0.226
10:18	14.53	901.8	115.7	13.54	1.855	0.233

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
10:19	14.48	900.7	117.0	13.87	1.858	0.248
10:20	14.46	897.0	199.4	13.79	1.854	0.418
10:21	14.44	894.2	91.6	13.80	1.850	0.192
10:22	14.49	896.3	163.4	13.77	1.848	0.339
10:23	14.48	893.9	172.0	13.66	1.845	0.354

AVERAGE VALUES FOR THE LAST HOUR: 60 MINUTES OF VALID DATA

10:23	14.30	882.3	113.3	13.52	1.844	0.228

COMMENTS: END RUN ONE

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
10:57	14.67	913.2	227.1	11.73	1.860	0.368
10:58	14.65	907.9	344.9	11.68	1.852	0.556
10:59	14.75	915.0	376.9	11.88	1.854	0.619
11:00	14.73	915.9	211.1	11.82	1.858	0.345
11:01	14.61	906.5	267.7	11.94	1.854	0.444
11:02	14.63	910.2	471.5	11.85	1.859	0.774
11:03	14.68	917.2	314.3	11.93	1.866	0.521
11:04	14.71	918.3	201.6	12.26	1.865	0.345
11:05	14.61	907.4	100.6	12.24	1.855	0.173
11:06	14.35	885.9	111.0	12.35	1.844	0.193
11:07	14.29	881.8	206.2	12.20	1.844	0.352
11:08	14.24	881.1	149.7	12.55	1.849	0.266
11:09	14.24	882.2	229.2	12.28	1.851	0.394
11:10	14.30	888.9	327.7	12.11	1.857	0.553
11:11	14.33	895.2	431.5	12.09	1.866	0.727
11:12	14.49	911.6	483.7	12.10	1.880	0.816
11:13	14.53	919.4	324.3	12.05	1.891	0.544
11:14	14.59	920.2	187.8	12.14	1.885	0.318
11:15	14.62	916.8	118.7	12.18	1.874	0.202
11:16	14.47	902.9	146.6	12.09	1.864	0.247
11:17	14.42	899.0	183.7	11.83	1.863	0.301
11:18	14.40	900.4	145.1	12.01	1.868	0.242
11:19	14.38	897.0	97.5	12.13	1.864	0.165
11:20	14.31	891.8	102.4	12.25	1.862	0.176
11:21	14.31	891.8	119.0	12.16	1.862	0.202
11:22	14.30	893.5	98.2	11.93	1.867	0.162
11:23	14.32	889.5	120.6	12.06	1.856	0.203
11:24	14.36	888.5	98.1	12.19	1.849	0.167
11:25	14.27	884.0	133.3	12.25	1.851	0.229
11:26	14.25	883.2	123.0	12.24	1.852	0.211
11:27	14.21	882.5	84.7	12.41	1.856	0.148
11:28	14.14	876.0	126.2	12.36	1.851	0.220
11:29	14.14	874.5	173.2	12.37	1.848	0.302
11:30	14.22	879.9	96.3	12.46	1.849	0.169
11:31	14.30	879.2	106.9	12.39	1.837	0.187
11:32	14.26	875.4	90.4	12.43	1.834	0.159
11:33	14.25	875.0	120.0	12.45	1.835	0.211
11:34	14.20	871.5	96.5	12.63	1.834	0.173
11:35	14.23	873.0	75.2	12.56	1.833	0.134
11:36	14.20	868.6	78.9	12.63	1.828	0.142
11:37	14.27	872.8	109.9	12.71	1.828	0.200
11:38	14.26	873.2	94.9	12.85	1.830	0.175
11:39	14.30	876.0	94.1	12.56	1.830	0.168
11:40	14.33	876.1	72.6	12.69	1.827	0.131
11:41	14.31	875.6	162.7	12.75	1.828	0.296
11:42	14.28	875.5	95.4	12.67	1.833	0.172
11:43	14.26	873.2	95.1	12.85	1.830	0.177
11:44	14.22	872.3	106.1	12.80	1.833	0.195
11:45	14.18	868.0	118.2	12.78	1.829	0.216
11:46	14.21	869.1	80.6	12.85	1.828	0.149
11:47	14.27	872.7	81.7	12.60	1.828	0.146
11:48	14.32	875.8	76.8	12.57	1.827	0.137
11:49	14.32	874.8	96.9	12.57	1.825	0.173
11:50	14.29	874.1	72.5	12.63	1.828	0.130
11:51	14.20	870.0	64.4	12.90	1.830	0.119

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
11:52	14.22	870.3	86.4	12.60	1.829	0.155
11:53	14.22	870.8	62.0	12.74	1.830	0.113
11:54	14.29	877.3	75.8	12.82	1.835	0.139
11:55	14.22	871.6	69.4	12.86	1.832	0.128
11:56	14.18	865.5	70.8	12.80	1.824	0.130

AVERAGE VALUES FOR THE LAST HOUR: 60 MINUTES OF VALID DATA

11:56	14.35	887.1	154.8	12.36	1.847	0.265

COMMENTS: END RUN TWO

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
12:26	14.20	872.2	92.5	12.34	1.835	0.160
12:27	14.41	885.2	281.1	12.39	1.836	0.489
12:28	14.55	897.5	146.4	12.48	1.843	0.259
12:29	14.43	890.0	125.1	12.40	1.843	0.218
12:30	14.34	884.6	177.6	12.62	1.843	0.319
12:31	14.43	890.9	85.9	12.57	1.845	0.153
12:32	14.29	880.0	180.4	12.51	1.840	0.319
12:33	14.40	888.4	183.4	12.56	1.844	0.327
12:34	14.42	892.2	159.5	12.69	1.848	0.289
12:35	14.45	891.5	181.1	12.67	1.844	0.327
12:36	14.46	891.3	128.2	12.72	1.841	0.233
12:37	14.43	889.8	105.8	12.69	1.843	0.191
12:38	14.33	884.7	134.4	12.65	1.844	0.242
12:39	14.34	884.8	174.1	12.74	1.844	0.316
12:40	14.46	894.7	206.8	12.61	1.849	0.373
12:41	14.40	891.7	270.8	12.57	1.850	0.478
12:42	14.25	884.5	331.0	12.76	1.855	0.600
12:43	14.45	898.6	362.8	12.54	1.858	0.646
12:44	14.37	890.8	257.5	12.56	1.852	0.460
12:45	14.45	900.1	236.1	12.74	1.861	0.428
12:46	14.51	899.0	285.1	12.55	1.851	0.507
12:47	14.37	890.4	175.3	12.75	1.852	0.320
12:48	14.40	892.1	363.9	12.57	1.851	0.650
12:49	14.44	894.1	274.2	12.63	1.851	0.491
12:50	14.40	894.3	368.4	12.61	1.856	0.659
12:51	14.50	902.4	263.7	12.62	1.860	0.473
12:52	14.53	901.7	172.3	12.68	1.854	0.311
12:53	14.57	902.3	117.2	12.59	1.850	0.210
12:54	14.56	898.8	320.3	12.30	1.844	0.555
12:55	14.48	898.5	302.2	12.40	1.854	0.529
12:56	14.50	903.0	273.6	12.42	1.860	0.479
12:57	14.55	902.7	330.8	12.52	1.853	0.585
12:58	14.52	900.7	187.6	12.60	1.853	0.335
12:59	14.41	891.4	254.5	12.52	1.848	0.451
13:00	14.41	891.2	224.8	12.64	1.848	0.405
13:01	14.45	896.7	239.3	12.30	1.854	0.415
13:02	14.47	895.7	412.2	12.24	1.850	0.709
13:03	14.59	903.4	141.0	12.39	1.850	0.245
13:04	14.47	897.1	113.2	12.30	1.852	0.195
13:05	14.35	885.9	106.0	12.51	1.845	0.188
13:06	14.35	886.5	101.8	12.34	1.846	0.176
13:07	14.33	883.7	100.5	12.50	1.843	0.178
13:08	14.32	884.5	326.8	12.34	1.846	0.570
13:09	14.42	894.4	285.7	12.42	1.853	0.504
13:10	14.45	899.0	348.4	12.18	1.859	0.594
13:11	14.47	901.2	328.6	12.29	1.861	0.567
13:12	14.58	908.7	186.5	12.32	1.862	0.323
13:13	14.53	901.7	302.1	12.25	1.854	0.518
13:14	14.45	897.2	174.3	12.30	1.855	0.301
13:15	14.42	895.8	375.7	12.42	1.856	0.656
13:16	14.41	895.3	332.2	12.26	1.856	0.570
13:17	14.29	890.0	354.6	12.41	1.861	0.620
13:18	14.50	905.6	233.9	12.46	1.867	0.409
13:19	14.52	901.7	271.7	12.39	1.855	0.478
13:20	14.37	889.9	208.5	12.39	1.851	0.363

F.J. GANNON BOILER 5 COMPLIANCE TEST 04-07-2000

TIME	CHAN 2 STACK %CO2	CHAN 1 STACK ppmSO2	CHAN 4 STACK ppmCO	CHAN 3 STACK %O2	STACK lb SO2 MM-BTU	STACK lb CO MM-BTU
13:21	14.27	884.5	368.4	12.52	1.851	0.651
13:22	14.28	889.0	419.0	12.40	1.861	0.734
13:23	14.23	888.6	252.7	12.58	1.865	0.449
13:24	14.37	898.8	290.1	12.54	1.869	0.517
13:25	14.31	891.7	191.6	12.41	1.862	0.335

AVERAGE VALUES FOR THE LAST HOUR: 60 MINUTES OF VALID DATA

13:25	14.42	893.5	236.7	12.49	1.851	0.417

COMMENTS: END RUN THREE

C. BOILER OPERATIONAL DATA

F. J. GANNON GENERATING STATION HEAT INPUT CALCULATIONS

F. J. GANNON STATION BOILER NO. 5 ANNUAL COMPLIANCE TEST April 7 & 8, 2000	
March Gross Heat Rate =	9.478 $X10^6$ Btu/MWH
BOILER NO. 5 SOURCE TEST HEAT INPUT CALCULATIONS	
Final MWH (781099) - Initial MWH(780183) =	916 MWH
Time =	4.17 Hours
Average MW = 916MWH) 4.17 H =	219.7 MW
9.478X 10^6 Btu/MWH X 916 MWH)4.17 H =	2082 X 10^6 MMBtu/H

COMPLIANCE TEST DATA

F. J. GANNON STATION

BOILER NO. 5 TEST DATE April 7, 2000

UNIT LOAD (MN) 215 MW

BASE LOADED (TIME) 1900

TEST DATA

MEGAWATTS INTEGRATOR		INITIALS
BEGIN MWH 780183	BEGIN SAMPLING 2058	CB
END MWH 781099	END SAMPLING 0108	CB

SOOTBLOWING

RUN	BEGIN TIME	END TIME	INITIALS
1SB	2058	2206	CB/ [illegible]
2SB	2234	2339	CB/ [illegible]
3SB	0004		CB/ [illegible]

FLYASH REINJECTION

RUN	REINJECTION (Y/N)	% REINJECTION	INITIALS
1SB	yes	100%	CB/ WK
2SB	yes	100%	CB/ WK
3SB	yes	100%	CB/ WK

MCD\COMPFORM.WP

D. FUEL ANALYSIS

TECO
TAMPA ELECTRIC

Corporate Environmental Laboratory Services

5012 Causeway Blvd * Tampa Fl. 33619 * Ph (813)630-7378 * Fax (813)630-7360 * CompQAP #910140G * DOH #E54272

Tuesday, April 25, 2000

Report For: David Smith, Air Programs, CES

Sample Information

Sample ID: **AA54325**
Location Code: GN-STK-5
Location Description: Gannon, Stack Test - Unit 5

Lab Submittal Date: 04/10/2000
Sample Collection Date: 04/08/2000
Sample Collector: R.DECECIO

Laboratory Results

Coal Analysis - As Received	Result	Units	Lower Limit	Upper Limit	Violation
Ash, as Received	8.63	%			
BTU, as Received	12691	BTU/Lb			
Sulfur, as Received	1.15	%			

Coal Analysis - Dry Basis	Result	Units	Lower Limit	Upper Limit	Violation
Ash, Dry Basis	9.24	%			
BTU, Dry Basis	13583	BTU/Lb.			
Sulfur, Dry Basis	1.23	%			

Coal Analysis - Miscellaneous	Result	Units	Lower Limit	Upper Limit	Violation
BTU, Moisture-Ash Free	14966	BTU/Lb.			
Pounds SO2 / Million BTU	1.72	Lbs. SO2/MMBTU		2.4	
Total Moisture	6.57	%			

Comments:

Gannon ID# S-6488
Quality Control Values of Knowns
Sulfur
ID:NIST 2683 b True Value: 1.88 % CES Value: 1.86%
BTU
ID:AR 1722 True Value: 14667BTU/ Lb+/-70 CES Value: 14616 Lbs./BTU

TAMPA ELECTRIC
A TECO ENERGY COMPANY

CORPORATE ENVIRONMENTAL SERVICES
ANALYSIS REQUEST & CHAIN OF CUSTODY

5012 CAUSEWAY BLVD.
TAMPA, FLORIDA 33619
PHONE: 813/228-4111

- [ ] AIR LAB
- [x] FUEL LAB
- [ ] WATER LAB

CLIENT NAME: CINDY BARRINGER
TELEPHONE: 35-397
SAMPLER(S) NAME(S): Ron DiCecio

PAGE ___ OF ___

- [ ] STANDARD TAT
- [ ] RUSH TAT

SAMPLING DATE	SAMPLING TIME	SAMPLING IDENTIFICATION	MATRIX TYPE	COAL SAMPLE	MATRIX TYPE	MATRIX TYPE	60 Mesh Residual Moisture ASTM D 3173	Total Moisture ASTM D 3302	Percent Sulfur ASTM D 4239	BTU ASTM 240	COMMENTS
4-8-00	1100	#5 UNIT STACK TEST S-6488 (GANNON)		✓							

(NUMBER OF CONTAINERS SUBMITTED)

RELINQUISHED BY: (SIGNATURE)	DATE	TIME	RECEIVED BY: (SIGNATURE)	DATE	TIME
Larry Kauleisan	4/10/00	8:07	Elena Beitia	4/10/00	8:07
Elena Beitia	4/10/00	1:15	David A Smith	4/10/00	1:15
Brian [illegible]	4/10/00	1520	Cristina Stefanovic	04/10/00	15:20

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E. TCEMS CALIBRATION DATA

E-1 INITIAL/FINAL TCEMS CALIBRATIONS

E-2 SYSTEM BIAS TESTS

E-3 SYSTEM BIAS AND DRIFT CALCULATIONS

E-1 INITIAL/FINAL TCEMS CALIBRATIONS

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: INITIAL DAILY CAL

DATE : 04-07-2000 TIME: 20:50 - 21:18

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.14
2	STACK	%CO2	9.97	10.04
2	STACK	%CO2	17.95	17.93
1	STACK	ppmSO2	0.0	5.9
1	STACK	ppmSO2	693.4	668.2
1	STACK	ppmSO2	1239.0	1234.3
4	STACK	ppmCO	0.0	3.3
4	STACK	ppmCO	150.0	146.0
4	STACK	ppmCO	301.2	304.3
3	STACK	%O2	0.00	0.06
3	STACK	%O2	11.96	12.13
3	STACK	%O2	20.90	20.93

CONTINUOUS EMISSIONS MONITORING SET-UP

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

DATE: 04-07-2000 TIME: 21:22

A/D CHAN	DESCRIP	UNITS	SPAN	INPUT VOLTAGE	ZERO OFFSET
2	STACK	%CO2	20	5.00 V	20%
1	STACK	ppmSO2	1350	10.00 V	0%
4	STACK	ppmCO	500	1.00 V	0%
3	STACK	%O2	25	1.00 V	0%

AVERAGING PERIODS: ONE HOUR,

EMISSION RATE 1: lb SO2/MMBTU STACK

E = (ppm SO2) (1800) (0.1660E-06) (100/%CO2)

ppm SO2 from A/D Channel 1
%CO2 from A/D Channel 2

EMISSION RATE 2: lb CO /MMBTU STACK

E = (ppm CO) (9780) (0.7263E-07) [20.9/(20.9 - %O2)]

ppm CO from A/D Channel 4
%O2 from A/D Channel 3

E-2 SYSTEM BIAS TESTS

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: RUN ONE BIAS CAL

DATE : 04-07-2000 TIME: 10:27 - 10:37

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.20
2	STACK	%CO2	9.97	9.85
1	STACK	ppmSO2	0.0	7.2
1	STACK	ppmSO2	693.4	680.4
4	STACK	ppmCO	0.0	2.2
4	STACK	ppmCO	150.0	142.2
3	STACK	%O2	0.00	0.23
3	STACK	%O2	11.96	12.13

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: RUN TWO BIAS CAL

DATE : 04-07-2000 TIME: 11:56 - 12:07

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.12
2	STACK	%CO2	9.97	9.76
1	STACK	ppmSO2	0.0	5.9
1	STACK	ppmSO2	693.4	686.5
4	STACK	ppmCO	0.0	1.8
4	STACK	ppmCO	150.0	150.2
3	STACK	%O2	0.00	-1.35
3	STACK	%O2	11.96	11.93

CALIBRATION SUMMARY

SOURCE: F.J. GANNON BOILER 5 COMPLIANCE TEST

REASON: RUN THREE BIAS CAL

DATE : 04-07-2000 TIME: 13:27 - 13:38

A/D CHAN	MONITOR DESCRIPTION	UNITS	GAS VALUE	MONITOR RESPONSE
2	STACK	%CO2	0.00	0.15
2	STACK	%CO2	9.97	9.79
1	STACK	ppmSO2	0.0	7.3
1	STACK	ppmSO2	693.4	692.9
4	STACK	ppmCO	0.0	2.2
4	STACK	ppmCO	150.0	143.1
3	STACK	%O2	0.00	-0.11
3	STACK	%O2	11.96	12.05

E-3 SYSTEM BIAS AND DRIFT CALCULATIONS

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 1

SPAN VALUE: 500 ppm CO

	INITIAL VALUES			FINAL VALUES		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
CO ZERO GAS	3.30	3.30	0.00	2.20	-0.22	-0.22
CO UP-SCALE	146.00	146.00	0.00	142.20	-0.76	-0.76

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 1

SPAN VALUE: 25 % Oxygen

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
O2 ZERO GAS	0.06	0.06	0.00	0.23	0.68	0.68
O2 UP-SCALE	12.13	12.13	0.00	12.13	0.00	0.00

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \text{ X 100}$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \text{ X 100}$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 2

SPAN VALUE: 500 ppm CO

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
CO ZERO GAS	3.30	2.20	-0.22	1.80	-0.30	-0.08
CO UP-SCALE	146.00	142.20	-0.76	150.20	0.84	1.60

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE} - \text{ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE} - \text{INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 2

SPAN VALUE: 25 % Oxygen

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
O2 ZERO GAS	0.06	0.23	0.68	-1.35	-5.64	-6.32
O2 UP-SCALE	12.13	12.13	0.00	11.93	-0.80	-0.80

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 3

SPAN VALUE: 500 ppm CO

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
CO ZERO GAS	3.30	1.80	-0.30	2.20	-0.22	0.08
CO UP-SCALE	146.00	150.20	0.84	143.10	-0.58	-1.42

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

SYSTEM CALIBRATION BIAS AND DRIFT CALCULATIONS

SOURCE: F.J. GANNON STATION BOILER 5

TEST DATE: 4/7/00

RUN NUMBER: 3

SPAN VALUE: 25 % Oxygen

	------INITIAL VALUES------			------FINAL VALUES------		
	ANALYZER CAL. RESPONSE	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	SYSTEM CAL. RESPONSE	SYSTEM CAL. BIAS (% OF SPAN)	DRIFT (% OF SPAN)
O2 ZERO GAS	0.06	-1.35	-5.64	-0.11	-0.68	4.96
O2 UP-SCALE	12.13	11.93	-0.80	12.05	-0.32	0.48

$$\text{SYSTEM CAL. BIAS} = \frac{\text{SYSTEM CAL. RESPONSE - ANALYZER CAL. RESPONSE}}{\text{SPAN}} \times 100$$

$$\text{DRIFT} = \frac{\text{FINAL SYSTEM CAL. RESPONSE - INITIAL CAL. RESPONSE}}{\text{SPAN}} \times 100$$

F. CALIBRATION GAS CERTIFICATES OF ANALYSIS

Scott Specialty Gases

RATA CLASS

Dual-Analyzed Calibration Standard

1750 EAST CLUB BLVD,DURHAM,NC 27704

Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ACCURACY: EPA Protocol Gas

Assay Laboratory

SCOTT SPECIALTY GASES
1750 EAST CLUB BLVD
DURHAM,NC 27704

P.O. No.: N31923
Project No.: 12-33126-001

Customer

TAMPA ELECTRIC CO
RAY MCDARBY
5010 CAUSEWAY BLVD
TAMPA FL 33619

ANALYTICAL INFORMATION

This certification was performed according to EPA Traceability Protocol For Assay & Certification of Gaseous Calibration Standards; Procedure #G1; September, 1997.

Cylinder Number: ALM020393 **Certification Date:** 3/11/99 **Exp. Date:** 3/11/2002

Cylinder Pressure*:** 2015 PSIG

COMPONENT	CERTIFIED CONCENTRATION	ANALYTICAL ACCURACY**	TRACEABILITY
OXYGEN	11.96 %	+/- 1%	NIST
NITROGEN	BALANCE		

*** Do not use when cylinder pressure is below 150 psig.

** Analytical accuracy is inclusive of usual known error sources which at least include precision of the measurement processes.
Product certified as +/- 1% analytical accuracy is directly traceable to NIST standards.

REFERENCE STANDARD

TYPE/SRM NO.	EXPIRATION DATE	CYLINDER NUMBER	CONCENTRATION	COMPONENT
NTRM 2658	1/02/01	ALM031884	9.680 %	OXYGEN

INSTRUMENTATION

INSTRUMENT/MODEL/SERIAL#	DATE LAST CALIBRATED	ANALYTICAL PRINCIPLE
VARIAN/3400/16804-O2	02/22/99	GC / TCD

ANALYZER READINGS

(Z=Zero Gas R=Reference Gas T=Test Gas r=Correlation Coefficient)

First Triad Analysis **Second Triad Analysis** **Calibration Curve**

OXYGEN

First Triad Analysis		
Date: 03/11/99	Response Unit: AREA	
Z1=0.0000	R1=247696	T1=306452
R2=248148	Z2=0.0000	T2=306564
Z3=0.0000	T3=306567	R3=248251
Avg. Concentration:	11.96	%

Calibration Curve	
Concentration=A+Bx+Cx2+Dx3+Ex4	
r=0.99999	
Constants:	A=0.00
B=1.00	C=0.00
D=0.00	E=0.00

Special Notes:

APPROVED BY: B. M. Becton
B.M. BECTON

Scott Specialty Gases

Shipped From: 1750 EAST CLUB BLVD
DURHAM NC 27704
Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ANALYSIS

TAMPA ELECTRIC CO
RAY MCDARBY
5010 CAUSEWAY BLVD

TAMPA FL 33619

PROJECT #: 12-32332-003
PO#: E-N31293
ITEM #: 1202RCOC AL
DATE: 1/29/99

CYLINDER #: ALM007103
FILL PRESSURE: 1046 PSIG

ANALYTICAL ACCURACY: +/- 1%
PRODUCT EXPIRATION: 1/29/2002

RECERTIFICATION

COMPONENT	ANALYSIS
CARBON MONOXIDE	150.0 PPM
NITROGEN	BALANCE

ANALYST: B.M. Becton
B.M. BECTON

CES MMC Y

Scott Specialty Gases

1750 EAST CLUB BLVD,DURHAM,NC 27704 Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ANALYSIS: Interference-Free™ EPA Protocol Gas

Customer
TAMPA ELECTRIC CO

5010 CAUSEWAY BLVD

TAMPA,FL 33619

Assay Laboratory

SCOTT SPECIALTY GASES
1750 EAST CLUB BLVD
DURHAM,NC 27704

Project No.: 12-29539-001
P.O. No.: E-N31293

ANALYTICAL INFORMATION

This certification was performed according to EPA Traceability Protocol For Assay & Certification of Gaseous Calibration Standards; Procedure #G1; September, 1993.

Cylinder Number: ALM065138 **Certification Date:** 7/17/98 **Exp. Date:** 7/17/2001
Cylinder Pressure*:** 1818 PSIG

COMPONENT	CERTIFIED CONCENTRATION	ANALYTICAL ACCURACY**
CARBON MONOXIDE	301.2 PPM	+/- 1% NIST Traceable
NITROGEN	BALANCE	

*** Do not use when cylinder pressure is below 150 psig.
** Analytical accuracy is inclusive of usual known error sources which at least include precision of the measurement processes.
Product certified as +/- 1% analytical accuracy is directly traceable to NIST standards.

REFERENCE STANDARD

TYPE/SRM NO.	EXPIRATION DATE	CYLINDER NUMBER	CONCENTRATION	COMPONENT
NTRM2636	1/08/01	ALM034285	244.2 PPM	CO/N2

INSTRUMENTATION

INSTRUMENT/MODEL/SERIAL#	LAST DATE CALIBRATED	ANALYTICAL PRINCIPLE
FTIR System/8220/AAB9400252	06/18/98	Scott Enhanced FTIR

ANALYZER READINGS

(Z=Zero Gas R=Reference Gas T=Test Gas r=Correlation Coefficient)

CARBON MONOXIDE

First Triad Analysis

Date: 07/10/98	Response Unit: PPM	
Z1=0.0495	R1=243.81	T1=300.89
R2=244.34	Z2=0.0524	T2=301.39
Z3=0.0735	T3=301.15	R3=244.44
Avg. Concentration:	301.1	PPM

Second Triad Analysis

Date: 07/17/98	Response Unit: PPM	
Z1=0.0187	R1=244.11	T1=301.40
R2=244.09	Z2=0.0229	T2=301.12
Z3=-0.014	T3=301.46	R3=244.40
Avg. Concentration:	301.3	PPM

Calibration Curve

Concentration = A + Bx + Cx2 + Dx3 + Ex4
r = 0.999990

Constants:	A = 0.000000
B = 1.000000	C = 0.000000
D = 0.000000	E = 0.000000

Special Notes:

ANALYST: B. M. Becton
B.M. Becton

G. TEST PARTICIPANTS

TEST PARTICIPANTS

Corporate Environmental Services

Robert Barthelette, Jr	Environmental Technician
Craig Coronado	Environmental Technician
David Smith	Sr. Environmental Technician
Tom Toombs	Environmental Technician

F. J. Gannon Generating Station

Elena Beitia	Operations Engineer

Question 6.a. Attachments

Date: 7/28/00 5:25 PM
Sender: ALAN THELEN
To: DEBRA A LUKASIEWICZ
Priority: Normal
Subject: Re: Bayside - CO/VOC Catalyst Info Needs for Air Permit

---

Pls file under HRSG

Al

Forward Header

Subject: Re: Bayside - CO/VOC Catalyst Info Needs for Air Permit
Author: philip.a.stepczyk@us.abb.com at nxmime
Date: 7/10/00 10:35 AM

Alan,

I apologize for the delay in responding.

The total estimated cost for the six (6) CO/VOC catalysts is Three Million Three Hundred Thirty Five Thousand Dollars, ($3,335,000).

The total estimated cost for the six spool pieces to accommodate the future installation of the CO/VOC catalysts is Five Hundred Thousand Dollars, ($ 500,000).

With regards to the additional support steel to support future expansion of the SCR catalysts by two (2) rows, the estimated cost for six (6) units is One Hundred Thirty Eight Thousand Dollars, ($ 138,000)

We are continuing to work to obtain the balance of information requested.

Regards,

Phil

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Table 4-2. 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, 2000.
TEC, 2000.

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

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	4,474,120	A
Sales tax	268,447	0.06 x A
Freight	223,706	0.05 x A
Instrumentation	447,412	0.10 x A
Subtotal Purchased Equipment Cost	**5,413,685**	**B**
Installation		
Foundations and supports	433,095	0.08 x B
Handling and erection	757,916	0.14 x B
Electrical	216,547	0.04 x B
Piping	108,274	0.02 x B
Insulation for ductwork	54,137	0.01 x B
Painting	54,137	0.01 x B
Subtotal Installation Cost	**1,624,106**	
Subtotal Direct Costs	**7,037,791**	
Indirect Costs		
Engineering	541,369	0.10 x B
Construction and field expenses	270,684	0.05 x B
Contractor fees	541,369	0.10 x B
Startup	108,274	0.02 x B
Performance test	54,137	0.01 x B
Contingency	162,411	0.03 x B
Subtotal Indirect Costs	**1,678,242**	
TOTAL CAPITAL INVESTMENT	**8,716,033** (TCI)	

Source: Alstom Power Inc., 2000.
ECT, 2000.
S&L, 2000.

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

Item	Dollars		Basis
<u>Direct Costs</u>			
Catalyst costs			
Replacement (materials and labor)	4,326,191		
Credit for used catalyst	(583,622)		15% credit
Subtotal Catalyst Costs	3,742,570		
Annualized Catalyst Costs	**912,778**		5 yr @ 7.0%
Energy Penalties			
Turbine backpressure	610,747		0.2% penalty
Subtotal Direct Costs	**1,523,525**	(TDC)	
<u>Indirect Costs</u>			
Administrative charges	174,321		0.02 x TCI
Property taxes	87,160		0.01 x TCI
Insurance	87,160		0.01 x TCI
Capital recovery	481,981		15 yr @ 7.0%
Subtotal Indirect Costs	**830,622**		
TOTAL ANNUAL COST	**2,354,147**		

Sources: Alstom Power Inc., 2000.
ECT, 2000.
S&L, 2000.
TEC, 2000.

Table 4-5. Summary of VOC BACT Analysis **Rev. 1 – 11/10/00**

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	11.4	49.8	49.8	8,716,033	2,354,147	47,251	69,465	N	Y
Baseline	22.7	99.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Seven GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 7,884 hr/yr, and fuel oil-firing for 876 hr/yr.

Sources: ECT, 2000.
GE, 2000.
TEC, 2000

Question 6.c. Attachment

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

August 22, 2000

RECEIVED
AUG 28 2000
ENVIRONMENTAL AFFAIRS

Mr. Jamie Hunter
Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Re: Gannon/Bayside Station
New Fuel Oil Storage Tank

Dear Mr. Hunter:

We have reviewed your letters of July 27 and August 15 regarding installation of a new fuel oil storage tank at the Gannon Station. You requested concurrence that the installation did not require an air construction permit pursuant to the exemption criteria of Rule 62-210.300(3)(b)1, F.A.C. Pursuant to your description, the tank will have a nominal capacity of 8 million gallons and will be used to store new number 2 fuel oil to serve the existing requirements of the Gannon Station and the requirements of the future Bayside Station as the Gannon steam units are phased out of service. It will replace the existing 300,000 gallon fuel tank.

Given the facts presented in your letters, and evaluating this project as an isolated project, the Department agrees that no air construction permit is required for Tampa Electric Company to proceed with construction of this new fuel oil storage tank. As mentioned previously, emissions associated with the new tank will need to be evaluated during preconstruction review of the planned Bayside re-powering project. The change will also need to be reflected in the facility's Title V permit.

Please contact me at 850-921-9519 if you have any questions about the above.

Sincerely,

Joseph Kahn, P.E.
New Source Review Section

/jk

cc: Bill Thomas, P.E., DEP SWD
Jerry Campbell, Hillsborough County EPC

Question 10.b. Attachment

Attachment for Question 10.b.

TEC's draft startup schedule does not have a specific time period designated "shakedown", "commercial startup", or "initial power generation". TEC has listed below estimated dates that should provide the Department with the information requested.

Activity	**Bayside Unit 1**	**Bayside Unit 2**
Start of Construction	April 1, 2000	April 1, 2000
First Firing of a Unit's CT	March 16, 2003	March 14, 2004
Initial Performance Testing	With in 60 days of attainment of maximum production rate	Within 60 days of attainment of maximum production rate

Question 11.a. Attachment

Gail S. Dreggors
P. O. Box 111, Tampa, Florida 33601
(813) 228-4293
(813) 228-4811 (fax)

TECO Energy, Inc.

Fax

To:	Greg Nelson	From:	Gail S. Dreggors
Fax:	46881	Pages:	6
Phone:		Date:	10/18/00
Re:		CC:	

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● Comments:

letters you requested

SHEILA M. MCDEVITT
VICE PRESIDENT-
GENERAL COUNSEL

April 26, 2000

Ms. Teri L. Donaldson, General Counsel
Florida Dept. of Environmental Protection
3900 Commonwealth Blvd.
MS #35
Tallahassee, Florida 32399-3000

Dear Ms. Donaldson:

I am in receipt of your letter dated April 20, 2000, and I appreciate your agreeing to allow us the flexibility requested with respect to the repowering of units at Gannon station. We will proceed as described in my communications to you.

I note that you have agreed to extend the date of determination of commercial viability of the zero ammonia NOx control technology through July, 2000. However, since Tampa Electric proceeded in the belief that May 1, 2000 was the deadline (not hearing to the contrary from you) we have provided the information that was available to us. I'm not sure what more information we can provide or what is expected of us. Therefore, I would hope someone from the Department would contact Greg Nelson or Patrick Shell in order to communicate any further expectations. In any event, performance by Tampa Electric is totally predicated upon the regulatory approval, and I attempted to communicate to you that it is unlikely that there will be such approval.

Accordingly, I would appreciate some rational discussion with respect to the other issues raised in the letter. I guess I must have been in a different meeting than you; but I believed that you had agreed to the $6 million dollar figure. As I am sure you are aware, Tampa Electric will have to install the SCR anyway in order to meet schedule and achieve environmental compliance.

Sincerely yours,
Sheila McDevitt

SMMcD/mle
Cc: Spence Autry
Greg Nelson
Patrick Shell

TECO ENERGY, INC.
702 N. FRANKLIN ST. TAMPA, FL 33602
P.O. BOX 111 TAMPA, FL 33601-0111
813-228-1804 FAX 813-228-1328/228-4811
SMMCDEVITT@TECOENERGY.COM

Department of Environmental Protection

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Jeb Bush
Governor

David B. Struhs
Secretary

copy to:
Spence Autry
Chuck Black
Greg Nelson
4/20/00

April 20, 2000

Sheila M. McDeVitt — NO Title
702 N. Franklin Street
Tampa, Florida 33602

RE: TECO

Dear Mr. McDeVitt,

I write in reply to your letter of April 19, 2000. With regard to the repowering of Gannon, we are prepared to accept the approach described in paragraph 1 of your letter. Thank you for keeping us advised.

With regard to the zero ammonia control technology issue, we will extend determination of commercial viability through and including July, 2000. We cannot agree, however, to lower the potential expenditure from $8 million to $ 6 million. Thank you for providing to the Air Division the information referenced in paragraph 2 of your letter. As you may know, the Air Division received this information only two days ago. We will review it and contact you to discuss our concerns.

I hope this letter addresses your most immediate questions. We will contact you regarding the remaining issues at the earliest possible opportunity. Thank you for your patience.

Sincerely,

Teri L. Donaldson
General Counsel

TLD/yw

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

Printed on recycled paper

SHEILA M. MCDEVITT
VICE PRESIDENT-
GENERAL COUNSEL

April 19, 2000

Ms. Teri Donaldson, General Counsel
Florida Dept. of Environmental Protection
3900 Commonwealth Blvd.
MS #35
Tallahassee, Florida 32399-3000

Re: Tampa Electric Company
Consent Final Judgment

Dear Teri:

This letter again follows up on the letter and enclosures I forwarded to you on March 21, 2000 suggesting some conforming changes to the Consent Final Judgment relative to the Consent Decree entered into with the United States. Among those suggestions were two of significant to which I wish you would direct your attention.

1. As you know, we are attempting to meet the deadlines required by both the Consent Final Judgment and the Consent Decree with respect to the repowering of Gannon Station by 2003 and 2004. As I indicated in my letter to you of March 21, 2000, between the entry of the Consent Final Judgment and lodging the Consent Decree, the engineers have developed a more optimum scenario for repowering Gannon Station. In other words, Units 3, 4 & 5 at Gannon which are called out in the Consent Final Judgment are not the units which will be repowered. Now the intention is to repower a different configuration which would also include 6; however, the number of megawatts would be substantially the same and the reductions would occur in approximately the same increments. Because we are well into the engineering and the expenditure of significant dollars, I would hope that the DEP could at least provide a waiver of the requirement to

TECO ENERGY, INC.
702 N. FRANKLIN ST. TAMPA, FL 33602
P.O. BOX 111 TAMPA, FL 33601-0111
813-228-1604 FAX 813-228-1328/228-4811
SMMCDEVITT@TECOENERGY.COM

specifically repower those units identified and let us proceed since I have not had any response to my communication of March 21st.

2. As we discussed several times, the Consent Final Judgment requires that the commercial viability of the "zero ammonia" control technology be determined by the DEP no later than May, 2000. Since it is now April 19, 2000, and the DEP has still not responded to the request that that date be adjusted along with a reduction in the capital cost differential from $8 million to $6 million dollars. Tampa Electric has provided to your Air Division the information we were able to assimilate with respect to the availability of the technologies and the respective capital costs. We have also provided the additional O&M costs as we understand them. Regardless of whether the dollar value was reduced to $6 million the incremental capital cost seems to exceed the requirements of the Consent Final Judgment by 3 times. Accordingly, I would hope that we could move forward by May 1 to dispose of this particular requirement.

There are several other suggested changes which were provided in the March 21 communication, but the two I mentioned are those most important. It seems that some of the suggestions would be to the benefit of DEP and if you are so inclined to agree to them that would suit me fine.

I am leaving for Chicago where the Gannon repowering team is currently located and actively engaged in the engineering and procurement phase of this project. We are proceeding under the assumption that DEP will be reasonable in connection with the change in the designated units required to be repowered and with respect to the use of the "zero ammonia" NOx technology. It is important for us to be able to proceed with the development of this project since we are on a very tight time frame in order to meet the in service dates called out by both the Consent Final Judgment and the Consent Decree. I have attempted to contact you by telephone, fax, and mail and have been unsuccessful with those efforts. I would appreciate the courtesy of a response at least letting me know when I can expect to have a discussion regarding these issues.

Sincerely yours,

SMMcD/gsd
Cc: Spence Autry
bcc: Virginia Wetherell

Question 13.a. Attachment

6.0 AMBIENT IMPACT ANALYSIS RESULTS

The refined ISCST3 model was used to model each of the 12 Bayside Units 1 and 2 operating scenarios during fuel oil-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 during distillate fuel oil-firing are summarized on Table 6-1.

Maximum highest, second highest (HSH) 3- and 24-hour SO_2 impacts are projected to be 320.2 and 85.1 $\mu g/m^3$, respectively. The 3-hour HSH SO_2 impact is 24.6 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 23.3 and 32.7 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 5.2 $\mu g/m^3$. This impact is 6.5 and 8.7 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 4.8 $\mu g/m^3$. This impact is 4.8 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 53.6 $\mu g/m^3$. This impact is 35.7 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 3.9 $\mu g/m^3$. This impact is 7.7 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 408.4 and 134.0 $\mu g/m^3$, respectively. These impacts are 1.0 and 1.3 percent of the Federal and Florida 1- and 8-hour average AAQS of 40,000 and 10,000 $\mu g/m^3$, respectively.

The air quality impacts described above reflect the operation of Bayside Units 1 and 2 assuming all units are fired with back-up distillate fuel oil. Air quality impacts during use of the primary fuel, natural gas, are considerably lower. For example, the maximum highest, second highest (HSH) 3- and 24-hour SO_2 impacts during natural gas-firing are projected to be 40.3 and 10.8 $\mu g/m^3$, respectively. The 3-hour HSH SO_2 impact is 3.1 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 3.0 and 4.2 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 0.8 $\mu g/m^3$. This impact is 1.0 and 1.4 percent of the Federal and Florida annual average AAQS of 80 and 60 $\mu g/m^3$, respectively. ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts during natural gas-firing are summarized on Table 6-2.

In response to the Department's October 19, 2000 e-mail, an assessment of SO_2 ambient air quality impacts resulting from Interim Case 1 (Bayside Unit 1 and Gannon Units 1, 2, 3, 4, and 6 in operation) was also conducted. This analysis evaluated the SO_2 air quality impacts resulting from the operation of Bayside Unit 1 (during back-up low sulfur distillate fuel oil-firing, Case 4) and Gannon Units 1-4 and 6 at a station-wide SO_2 emission rate of 8.3 tons per hour, 24-hour average. Gannon Units 1-4 and Unit 6 were modeled at SO_2 emission rates of 1.64 and 1.80 lb SO_2/MMBtu, respectively. The results of this assessment are provided on Table 6-3.

The dispersion model results shown on Tables 6-1 through 6-3 provide reasonable assurance that operation of the Bayside Units 1 and 2 will not contribute to any exceedances of an AAQS. Following installation of Bayside Units 1 and 2 and cessation of Gannon coal-fired operations, the HSH 24-hour average SO_2 impact will be only 4.2 per cent of the Florida AAQS during natural gas-firing (the primary fuel for Bayside Power Station) and only 32.7 percent of the Florida AAQS during back-up distillate fuel oil-firing.

Table 6-3. Bayside/ F.J. Gannon Stations SO_2 Air Quality Impact Analysis Summary
Interim Case 1 (Bayside Unit 1 and Gannon Units 1-4 and 6)

SO_2 Impacts	1992	1993	1994	1995	1996
Annual Average SO_2 Impacts					
ISCST3 Impact ($\mu g/m^3$)	15.2	14.8	11.5	11.6	13.7
Florida AAQS ($\mu g/m^3$)	60	60	60	60	60
Exceed Florida AAQS (Y/N)	N	N	N	N	N
Percent of Florida AAQS (%)	25.3	24.7	19.1	19.4	22.8
Receptor UTM Easting (m)	360,306.0	360,306.0	359,601.6	360,244.4	360,244.4
Receptor UTM Northing (m)	3,087,197.5	3,087,197.5	3,087,136.0	3,087,136.0	3,087,136.0
HSH 24-Hour SO_2 Impacts					
ISCST3 Impact ($\mu g/m^3$)	222.3	218.8	216.0	175.3	257.8
Florida AAQS ($\mu g/m^3$)	260	260	260	260	260
Exceed Florida AAQS (Y/N)	N	N	N	N	N
Percent of Florida AAQS (%)	85.5	84.2	83.1	67.4	99.1
Receptor UTM Easting (m)	360,356.0	360,244.4	360,306.0	360,244.4	359,601.6
Receptor UTM Northing (m)	3,087,269.0	3,087,136.0	3,087,197.5	3,087,136.0	3,087,136.0
HSH 3-Hour SO_2 Impacts					
ISCST3 Impact ($\mu g/m^3$)	590.0	543.9	543.2	510.9	583.8
Florida AAQS ($\mu g/m^3$)	1,300	1,300	1,300	1,300	1,300
Exceed Florida AAQS (Y/N)	N	N	N	N	N
Percent of Florida AAQS (%)	45.4	41.8	41.8	39.3	44.9
Receptor UTM Easting (m)	359,601.6	360,306.0	359,601.6	359,601.6	359,540.0
Receptor UTM Northing (m)	3,087,136.0	3,087,197.5	3,087,136.0	3,087,136.0	3,087,197.5

Source: ECT, 2000.

Table 6-1. Air Quality Impact Analysis Summary
Distillate Fuel Oil-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 ($\mu g/m^3$)	263.5	264.3	289.9	215.4	260.7	323.4	335.9	335.1	297.1	331.1	367.3	375.1	377.1	360.8	369.4	290.4	293.2	305.0	257.4	289.6
HSH, 3-Hour ($\mu g/m^3$)	123.2	114.1	122.3	117.2	130.1	161.4	171.3	157.8	128.1	168.6	207.9	193.0	192.4	141.3	176.4	134.6	134.3	134.0	122.4	149.4
HSH, 8-Hour ($\mu g/m^3$)	77.5	78.5	75.7	47.2	98.5	100.5	100.5	98.4	67.7	115.0	95.3	113.9	111.3	92.9	133.4	88.2	85.0	85.6	52.9	109.2
HSH, 24-Hour ($\mu g/m^3$)	43.8	30.6	43.1	19.1	60.6	63.0	49.6	51.5	30.4	78.4	68.6	57.1	55.4	42.9	88.1	51.7	39.8	46.8	22.2	68.8
Annual ($\mu g/m^3$)	2.0	1.4	1.4	0.8	1.2	3.9	3.2	2.6	1.8	2.3	5.7	4.8	3.6	2.6	3.4	2.6	2.0	1.7	1.1	1.5
SO_2																				
Emission Rate (g/s)	13.17	13.17	13.17	13.17	13.17	10.62	10.62	10.62	10.62	10.62	8.43	8.43	8.43	8.43	8.43	12.38	12.38	12.38	12.38	12.38
HSH, 3-Hour ($\mu g/m^3$)	162.3	150.3	161.0	154.3	171.3	171.4	182.0	167.5	315.5	179.0	175.2	162.7	162.2	304.2	148.7	166.7	166.3	165.9	151.5	184.9
HSH, 24-Hour ($\mu g/m^3$)	57.7	40.3	56.8	25.2	79.8	66.9	52.7	54.7	32.3	83.2	57.9	48.1	46.7	36.2	74.3	64.0	49.3	58.0	27.5	85.1
Annual ($\mu g/m^3$)	2.7	1.9	1.8	1.0	1.6	4.1	3.4	2.8	1.9	2.5	4.8	4.1	3.1	2.2	2.9	3.2	2.4	2.2	1.3	1.9
NO_2																				
Emission Rate (g/s)	16.67	16.67	16.67	16.67	16.67	13.31	13.31	13.31	13.31	13.31	10.47	10.47	10.47	10.47	10.47	15.65	15.65	15.65	15.65	15.65
Tier 2 Annual ($\mu g/m^3$)	2.5	1.8	1.7	1.0	1.5	3.9	3.2	2.6	1.8	2.3	4.5	3.8	2.9	2.1	2.7	3.0	2.3	2.1	1.3	1.8
PM/PM_{10}																				
Emission Rate (g/s)	6.78	6.78	6.78	6.78	6.78	6.30	6.30	6.30	6.30	6.30	5.88	5.88	5.88	5.88	5.88	6.63	6.63	6.63	6.63	6.63
HSH, 24-Hour ($\mu g/m^3$)	29.7	20.7	29.2	13.0	41.1	39.7	31.2	32.5	19.1	49.4	40.4	33.6	32.6	25.2	51.8	34.3	26.4	31.0	14.7	45.6
Annual ($\mu g/m^3$)	1.4	1.0	0.9	0.5	0.8	2.5	2.0	1.6	1.1	1.5	3.4	2.8	2.1	1.5	2.0	1.7	1.3	1.2	0.7	1.0
CO																				
Emission Rate (g/s)	8.82	8.82	8.82	8.82	8.82	8.14	8.14	8.14	8.14	8.14	9.34	9.34	9.34	9.34	9.34	8.13	8.13	8.13	8.13	8.13
HSH, 1-Hour ($\mu g/m^3$)	232.4	233.1	255.7	190.0	229.9	263.3	273.5	272.8	241.8	269.5	343.1	350.3	352.2	337.0	345.0	236.1	238.4	248.0	209.3	235.4
HSH, 8-Hour ($\mu g/m^3$)	68.3	69.3	66.7	41.7	86.9	81.8	81.8	80.1	55.1	93.6	89.0	106.4	104.0	86.8	124.6	71.7	69.1	69.6	43.0	88.8

	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 ($\mu g/m^3$)	336.3	350.6	351.8	317.3	344.3	384.6	388.2	392.4	382.1	382.2	294.2	298.1	307.9	264.6	294.5	338.6	352.9	354.5	322.0	346.7
HSH, 3-Hour ($\mu g/m^3$)	182.0	185.9	169.4	135.4	174.2	229.0	208.5	203.8	155.0	183.4	136.5	138.0	136.7	123.2	151.3	185.9	170.7	171.9	136.8	175.0
HSH, 8-Hour ($\mu g/m^3$)	105.2	114.3	102.8	75.9	120.8	101.3	120.2	116.2	102.5	139.6	89.6	85.8	87.1	53.8	110.9	106.0	116.9	103.6	77.7	121.8
HSH, 24-Hour ($\mu g/m^3$)	67.4	52.1	56.6	35.2	82.8	73.0	59.9	58.6	45.9	92.4	53.0	41.7	47.4	22.7	70.1	68.8	52.6	58.5	36.1	83.6
Annual ($\mu g/m^3$)	4.4	3.7	2.9	2.0	2.6	6.5	5.5	4.1	3.0	3.9	2.7	2.0	1.8	1.1	1.6	4.6	3.8	3.0	2.1	2.7
SO_2																				
Emission Rate (g/s)	10.00	10.00	10.00	10.00	10.00	7.97	7.97	7.97	7.97	7.97	12.10	12.10	12.10	12.10	12.10	9.75	9.75	9.75	9.75	9.75
HSH, 3-Hour ($\mu g/m^3$)	182.0	185.9	169.4	135.4	174.2	182.5	166.2	162.5	304.6	146.1	165.2	166.9	165.5	320.2	183.0	181.2	166.5	167.6	313.9	170.6
HSH, 24-Hour ($\mu g/m^3$)	67.4	52.1	56.6	35.2	82.8	58.2	47.7	46.7	36.6	73.6	64.1	50.5	57.3	27.5	84.8	67.1	51.3	57.1	35.2	81.5
Annual ($\mu g/m^3$)	4.4	3.7	2.9	2.0	2.6	5.2	4.4	3.3	2.4	3.1	3.2	2.5	2.2	1.3	1.9	4.4	3.7	2.9	2.0	2.6
NO_2																				
Emission Rate (g/s)	12.52	12.52	12.52	12.52	12.52	9.9	9.89	9.89	9.89	9.89	15.32	15.32	15.32	15.32	15.32	12.21	12.21	12.21	12.21	12.21
Tier 2 Annual ($\mu g/m^3$)	4.2	3.5	2.8	1.9	2.5	4.8	4.1	3.1	2.3	2.9	3.1	2.3	2.1	1.3	1.8	4.2	3.5	2.7	1.9	2.5
PM/PM_{10}																				
Emission Rate (g/s)	6.19	6.19	6.19	6.19	6.19	5.80	5.80	5.80	5.80	5.80	6.58	6.58	6.58	6.58	6.58	6.14	6.14	6.14	6.14	6.14
HSH, 24-Hour ($\mu g/m^3$)	41.7	32.3	35.1	21.8	51.3	42.3	34.7	34.0	26.6	53.6	34.8	27.5	31.2	15.0	46.1	42.3	32.3	35.9	22.2	51.3
Annual ($\mu g/m^3$)	2.7	2.3	1.8	1.2	1.6	3.8	3.2	2.4	1.8	2.2	1.8	1.3	1.2	0.7	1.0	2.8	2.3	1.8	1.3	1.7
CO																				
Emission Rate (g/s)	7.47	7.47	7.47	7.47	7.47	9.00	9.00	9.00	9.00	9.00	7.88	7.88	7.88	7.88	7.88	7.32	7.32	7.32	7.32	7.32
HSH, 1-Hour ($\mu g/m^3$)	251.3	261.9	262.8	237.0	257.2	346.2	349.4	353.1	343.9	344.0	231.8	234.9	242.6	208.5	232.1	247.9	258.3	259.5	235.7	253.8
HSH, 8-Hour ($\mu g/m^3$)	78.6	85.4	76.8	101.1	90.3	91.2	108.2	104.6	92.2	125.6	70.6	67.6	68.6	97.1	87.4	77.6	85.6	75.8	56.9	89.2

Table 6-1. Air Quality Impact Analysis Summary
Distillate Fuel Oil-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/m³)	386.1	389.7	394.0	384.3	383.6	300.4	306.0	312.3	272.5	302.5	345.6	358.6	360.2	333.5	352.6	391.3	394.2	398.9	390.7	387.9	398.9
HSH, 3-Hour (μg/m³)	230.1	211.7	205.0	156.8	184.1	139.6	146.0	141.4	124.6	154.5	195.6	177.3	178.0	140.2	176.9	233.4	215.0	208.4	161.8	186.5	233.4
HSH, 8-Hour (μg/m³)	102.0	120.9	116.8	103.5	128.9	92.0	87.3	89.5	56.4	113.8	108.0	121.9	105.5	82.1	124.4	100.8	122.9	118.5	107.7	130.8	139.6
HSH, 24-Hour (μg/m³)	73.4	60.2	58.9	46.2	89.1	55.1	46.3	48.3	24.0	72.6	70.8	53.9	59.4	38.6	85.6	68.5	61.1	60.5	48.1	86.6	92.4
Annual (μg/m³)	6.6	5.6	4.2	3.1	3.9	3.0	2.4	2.0	1.3	1.8	4.9	4.1	3.2	2.3	2.9	6.8	5.8	4.3	3.2	4.0	6.8
SO_2																					
Emission Rate (g/s)	7.75	7.75	7.75	7.75	7.75	11.70	11.70	11.70	11.70	11.70	9.25	9.25	9.25	9.25	9.25	7.35	7.35	7.35	7.35	7.35	13.2
HSH, 3-Hour (μg/m³)	178.3	164.1	158.9	297.8	142.7	163.4	170.8	165.4	145.8	180.8	180.9	164.0	164.6	308.5	163.7	171.6	158.0	153.2	287.2	137.1	320.2
HSH, 24-Hour (μg/m³)	56.9	46.7	45.6	35.8	69.0	64.5	54.2	56.5	28.1	84.9	65.5	49.8	55.0	35.7	79.1	50.3	44.9	44.5	35.4	63.7	85.1
Annual (μg/m³)	5.1	4.3	3.2	2.4	3.0	3.5	2.8	2.4	1.5	2.1	4.5	3.8	3.0	2.1	2.7	5.0	4.3	3.2	2.4	3.0	5.2
NO_2																					
Emission Rate (g/s)	9.61	9.61	9.61	9.61	9.61	14.82	14.82	14.82	14.82	14.82	11.58	11.58	11.58	11.58	11.58	9.10	9.10	9.10	9.10	9.10	16.7
Tier 2 Annual (μg/m³)	4.8	4.0	3.0	2.2	2.8	3.3	2.6	2.3	1.4	2.0	4.3	3.6	2.8	2.0	2.5	4.7	4.0	2.9	2.2	2.8	4.8
PM/PM_{10}																					
Emission Rate (g/s)	5.76	5.76	5.76	5.76	5.76	6.50	6.50	6.50	6.50	6.50	6.04	6.04	6.04	6.04	6.04	5.68	5.68	5.68	5.68	5.68	6.8
HSH, 24-Hour (μg/m³)	42.3	34.7	33.9	26.6	51.3	35.8	30.1	31.4	15.6	47.2	42.8	32.5	35.9	23.3	51.7	38.9	34.7	34.4	27.3	49.2	53.6
Annual (μg/m³)	3.8	3.2	2.4	1.8	2.2	1.9	1.5	1.3	0.8	1.2	3.0	2.5	1.9	1.4	1.8	3.9	3.3	2.4	1.8	2.3	3.9
CO																					
Emission Rate (g/s)	9.40	9.40	9.40	9.40	9.40	7.61	7.61	7.61	7.61	7.61	7.07	7.07	7.07	7.07	7.07	10.24	10.24	10.24	10.24	10.24	10.2
HSH, 1-Hour (μg/m³)	362.9	366.3	370.4	361.2	360.6	228.6	232.9	237.6	207.4	230.2	244.3	253.6	254.7	235.8	249.3	400.7	403.6	408.4	400.1	397.2	408.4
HSH, 8-Hour (μg/m³)	95.9	113.6	109.8	97.2	121.2	70.0	66.4	68.1	42.9	86.6	76.3	86.2	74.6	58.1	87.9	103.2	125.8	121.3	110.3	134.0	134.0

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (μg/m³)	320.2	7	1995	1,300	1,300	24.6	24.6
HSH, 24-Hour (μg/m³)	85.1	4	1996	260	365	32.7	23.3
Annual (μg/m³)	5.2	6	1992	60	80	8.7	6.5
NO_2							
Annual (μg/m³)	4.8	6	1992	100	100	4.8	4.8
PM_{10}							
HSH, 24-Hour (μg/m³)	53.6	6	1996	150	150	35.7	35.7
Annual (μg/m³)	3.9	12	1992	50	50	7.7	7.7
CO							
HSH, 1-Hour (μg/m³)	408.4	12	1994	40,000	40,000	1.0	1.0
HSH, 8-Hour (μg/m³)	134.0	12	1996	10,000	10,000	1.3	1.3

Source: ECT, 2000.

Table 6-2. 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 ($\mu g/m^3$)	307.0	313.6	317.9	280.5	309.2	373.3	378.0	384.1	369.7	370.1	448.6	462.3	447.6	440.0	440.7	335.0	349.1	350.8	311.2	340.2
HSH, 3-Hour ($\mu g/m^3$)	143.2	152.4	149.7	127.2	159.4	211.8	201.1	198.0	154.2	186.6	258.7	249.5	226.1	193.5	230.9	174.0	185.5	170.8	128.2	176.3
HSH, 8-Hour ($\mu g/m^3$)	96.3	89.1	92.2	58.8	118.5	116.8	133.5	112.3	98.7	134.6	146.4	139.5	128.9	144.7	147.3	107.3	112.1	102.4	75.4	131.8
HSH, 24-Hour ($\mu g/m^3$)	58.3	48.7	51.0	25.0	75.6	78.6	58.0	61.9	46.9	92.9	84.2	71.4	80.0	59.2	97.5	68.3	51.5	56.6	34.4	85.9
Annual ($\mu g/m^3$)	3.1	2.4	2.1	1.3	1.9	6.0	5.1	3.9	2.8	3.6	9.3	8.1	5.8	4.5	5.6	4.4	3.6	2.9	2.0	2.6
SO_2																				
Emission Rate (g/s)	1.35	1.35	1.35	1.35	1.35	1.09	1.09	1.09	1.09	1.09	0.88	0.88	0.88	0.88	0.88	1.26	1.26	1.26	1.26	1.26
HSH, 3-Hour ($\mu g/m^3$)	19.3	20.6	20.2	17.2	21.5	23.1	21.9	21.6	40.3	20.3	22.8	22.0	19.9	38.7	20.3	21.9	23.4	21.5	16.2	22.2
HSH, 24-Hour ($\mu g/m^3$)	7.9	6.6	6.9	3.4	10.2	8.6	6.3	6.7	5.1	10.1	7.4	6.3	7.0	5.2	8.6	8.6	6.5	7.1	4.3	10.8
Annual ($\mu g/m^3$)	0.4	0.3	0.3	0.2	0.3	0.7	0.6	0.4	0.3	0.4	0.8	0.7	0.5	0.4	0.5	0.5	0.5	0.4	0.2	0.3
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 ($\mu g/m^3$)	0.7	0.6	0.5	0.3	0.4	1.1	1.0	0.7	0.5	0.7	1.4	1.2	0.9	0.7	0.8	0.9	0.8	0.6	0.4	0.6
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 ($\mu g/m^3$)	15.1	12.6	13.2	6.4	19.5	19.8	14.6	15.6	11.8	23.4	20.8	17.6	19.8	14.6	24.1	17.5	13.2	14.5	8.8	22.0
Annual ($\mu g/m^3$)	0.8	0.6	0.5	0.3	0.5	1.5	1.3	1.0	0.7	0.9	2.3	2.0	1.4	1.1	1.4	1.1	0.9	0.7	0.5	0.7
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 ($\mu g/m^3$)	120.3	122.9	124.6	110.0	121.2	115.7	117.2	119.1	114.6	114.7	115.3	118.8	115.0	113.1	113.3	121.3	126.4	127.0	112.6	123.1
HSH, 8-Hour ($\mu g/m^3$)	37.8	34.9	36.1	23.0	46.5	36.2	41.4	34.8	30.6	41.7	37.6	35.9	33.1	37.2	37.9	38.8	40.6	37.1	27.3	47.7

Table 6-2. 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 ($\mu g/m^3$)	386.3	392.1	394.8	387.1	380.8	448.0	464.2	450.6	440.2	439.7	337.1	351.2	353.3	315.6	342.5	388.8	395.1	396.5	390.2	383.0
HSH, 3-Hour ($\mu g/m^3$)	218.6	212.2	216.9	162.4	187.8	259.1	248.8	226.1	192.1	232.3	177.9	187.6	171.7	129.1	177.2	219.7	214.1	220.6	163.4	188.4
HSH, 8-Hour ($\mu g/m^3$)	120.9	138.8	116.2	106.4	139.3	146.1	139.4	128.0	144.5	148.9	107.8	114.4	103.1	77.0	132.6	121.6	139.7	116.9	107.7	140.1
HSH, 24-Hour ($\mu g/m^3$)	82.2	60.2	64.1	50.4	96.3	84.3	71.3	79.8	59.2	98.0	68.8	52.0	56.9	35.2	86.6	82.8	60.7	64.4	50.8	96.9
Annual ($\mu g/m^3$)	6.7	5.7	4.3	3.2	4.0	9.3	8.0	5.8	4.5	5.6	4.4	3.7	2.9	2.0	2.6	6.8	5.8	4.4	3.2	4.0
SO_2																				
Emission Rate (g/s)	1.03	1.03	1.03	1.03	1.03	0.82	0.82	0.82	0.82	0.82	1.23	1.23	1.23	1.23	1.23	1.00	1.00	1.00	1.00	1.00
HSH, 3-Hour ($\mu g/m^3$)	22.5	21.9	22.3	16.7	19.3	21.2	20.4	18.5	36.1	19.0	21.9	23.1	21.1	38.8	21.8	22.0	21.4	22.1	39.0	18.8
HSH, 24-Hour ($\mu g/m^3$)	8.5	6.2	6.6	5.2	9.9	6.9	5.8	6.5	4.9	8.0	8.5	6.4	7.0	4.3	10.6	8.3	6.1	6.4	5.1	9.7
Annual ($\mu g/m^3$)	0.7	0.6	0.4	0.3	0.4	0.8	0.7	0.5	0.4	0.5	0.5	0.5	0.4	0.2	0.3	0.7	0.6	0.4	0.3	0.4
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 ($\mu g/m^3$)	1.2	1.0	0.8	0.6	0.7	1.3	1.1	0.8	0.6	0.8	0.9	0.8	0.6	0.4	0.6	1.2	1.0	0.7	0.6	0.7
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 ($\mu g/m^3$)	20.6	15.1	16.1	12.7	24.2	20.7	17.5	19.6	14.6	24.1	17.6	13.3	14.6	9.0	22.2	20.6	15.1	16.0	12.7	24.1
Annual ($\mu g/m^3$)	1.7	1.4	1.1	0.8	1.0	2.3	2.0	1.4	1.1	1.4	1.1	0.9	0.7	0.5	0.7	1.7	1.4	1.1	0.8	1.0
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 ($\mu g/m^3$)	114.3	116.1	116.8	114.6	112.7	110.2	114.2	110.8	108.3	108.2	118.0	122.9	123.7	110.5	119.9	111.6	113.4	113.8	112.0	109.9
HSH, 8-Hour ($\mu g/m^3$)	35.8	41.1	34.4	48.1	41.2	35.9	34.3	31.5	35.6	36.6	37.7	40.0	36.1	45.2	46.4	34.9	40.1	33.6	30.9	40.2

Table 6-2. 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 ($\mu g/m^3$)	449.2	467.6	454.2	441.4	442.1	341.6	355.8	358.1	324.8	347.3	396.2	404.2	403.4	399.5	389.4	453.7	479.5	466.1	445.9	453.0	479.5
HSH, 3-Hour ($\mu g/m^3$)	259.8	235.5	226.8	192.7	234.6	185.5	192.7	174.5	131.8	179.6	224.4	220.1	231.8	169.1	190.3	262.4	238.4	229.5	198.8	239.1	262.4
HSH, 8-Hour ($\mu g/m^3$)	146.4	139.8	128.4	143.3	149.3	109.3	119.5	104.6	80.5	134.6	124.0	142.6	119.4	112.6	145.4	147.7	141.2	135.3	145.0	150.9	150.9
HSH, 24-Hour ($\mu g/m^3$)	84.9	71.6	80.5	59.6	98.2	70.3	52.9	58.0	37.1	88.1	84.7	62.1	67.0	52.3	99.6	87.0	73.1	82.2	61.1	99.2	99.6
Annual ($\mu g/m^3$)	9.3	8.0	5.8	4.5	5.6	4.7	3.9	3.1	2.1	2.8	7.2	6.2	4.6	3.5	4.3	9.5	8.3	6.0	4.7	5.7	9.5
SO_2																					
Emission Rate (g/s)	0.80	0.80	0.80	0.80	0.80	1.19	1.19	1.19	1.19	1.19	0.95	0.95	0.95	0.95	0.95	0.76	0.76	0.76	0.76	0.76	1.4
HSH, 3-Hour ($\mu g/m^3$)	20.8	18.8	18.1	35.3	18.8	22.1	22.9	20.8	15.7	21.4	21.3	20.9	22.0	38.0	18.1	19.9	18.1	17.4	33.9	18.2	40.3
HSH, 24-Hour ($\mu g/m^3$)	6.8	5.7	6.4	4.8	7.9	8.4	6.3	6.9	4.4	10.5	8.0	5.9	6.4	5.0	9.5	6.6	5.6	6.2	4.6	7.5	10.8
Annual ($\mu g/m^3$)	0.7	0.6	0.5	0.4	0.4	0.6	0.5	0.4	0.3	0.3	0.7	0.6	0.4	0.3	0.4	0.7	0.6	0.5	0.4	0.4	0.8
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 ($\mu g/m^3$)	1.3	1.1	0.8	0.6	0.8	1.0	0.8	0.6	0.4	0.6	1.2	1.0	0.8	0.6	0.7	1.2	1.1	0.8	0.6	0.7	1.4
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 ($\mu g/m^3$)	20.9	17.6	19.8	14.7	24.2	17.9	13.5	14.8	9.5	22.5	21.0	15.4	16.6	13.0	24.7	21.2	17.8	20.1	14.9	24.2	24.7
Annual ($\mu g/m^3$)	2.3	2.0	1.4	1.1	1.4	1.2	1.0	0.8	0.5	0.7	1.8	1.5	1.1	0.9	1.1	2.3	2.0	1.5	1.1	1.4	2.3
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 ($\mu g/m^3$)	108.3	112.7	109.5	106.4	106.5	115.8	120.6	121.4	110.1	117.7	109.4	111.6	111.3	110.3	107.5	106.2	112.2	109.1	104.3	106.0	127.0
HSH, 8-Hour ($\mu g/m^3$)	35.3	33.7	31.0	34.5	36.0	37.0	40.5	35.5	27.3	45.6	34.2	39.4	33.0	31.1	40.1	34.6	33.0	31.7	33.9	35.3	48.1

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour ($\mu g/m^3$)	40.3	2	1995	1,300	1,300	3.1	3.1
HSH, 24-Hour ($\mu g/m^3$)	10.8	4	1996	260	365	4.2	3.0
Annual ($\mu g/m^3$)	0.8	3	1992	60	80	1.4	1.0
NO_2							
Annual ($\mu g/m^3$)	1.4	3	1992	100	100	1.4	1.4
PM_{10}							
HSH, 24-Hour ($\mu g/m^3$)	24.7	11	1996	150	150	16.5	16.5
Annual ($\mu g/m^3$)	2.3	12	1992	50	50	4.7	4.7
CO							
HSH, 1-Hour ($\mu g/m^3$)	127.0	4	1994	40,000	40,000	0.3	0.3
HSH, 8-Hour ($\mu g/m^3$)	48.1	5	1995	10,000	10,000	0.5	0.5

Source: ECT, 2000.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

October 16, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Karen Sheffield, General Manager
Bayside Power Station, Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

Re: Request for Additional Information
Project No. 0570040-013-AC (PSD-FL-301)
Bayside Power Station (Gannon Repowering Project)

Dear Ms. Sheffield:

On September 21, 2000, the Department received an application from the Tampa Electric Company (TEC) with sufficient fee for a PSD air permit to construct seven new combined cycle combustion turbine/electrical generator/HRSG sets. The stated purpose of the project is to repower the existing steam turbines for Units 5 and 6 at the Gannon Station located in Hillsborough County. The repowered electrical generating plant will be known as the Bayside Power Station. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Netting Analysis: Attachment D of the PSD permit application provides a netting analysis that summarizes the actual emissions decreases from the shut down of Gannon Units 5 and 6 and the potential emissions increases from operation of the new Bayside Units. Previous EPA guidance suggests that emissions decreases needed to meet regulatory requirements should not be included in calculating net emissions increases for a project. Please explain TEC's understanding of the DEP/TEC Consent Final Judgement related to the issue of netting. Note that the remaining questions presume netting.

2. Gas Turbines / HRSGs

   a. Please identify the model of dry low NOx combustor that will be installed on each General Electric Model PG 7241(FA) gas turbine. Is this the latest version?

   b. Please identify the automated gas turbine control system that will be installed with each unit. Describe how this system will interact with the SCR and SCONOx™ control systems to reduce NOx emissions.

   c. Is the evaporative cooler a high-pressure direct spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.

   d. Will this project include natural gas fuel heaters or cooling towers? If so, please provide the information required on the permit application form for these emissions units.

   e. Is each Heat Recovery Steam Generator (HRSG) identical? What is the designed maximum steam production rate (lb/hour), steam temperature (° F), and steam pressure (psig) for each HRSG? What are the current existing maximum and design capacities of the steam turbines for Gannon Units 5 and 6?

   f. The application established maximum mass emission rates at an ambient temperature of 17° F. Based 48 years of data from the www.weatherbase.com Internet web site, the lowest "average daily" temperatures in Tampa occurred during the months of January (61° F), February (62° F), and December (62° F). The average "low temperatures" for these months are January (50° F), February (52° F), and December (52° F). The "lowest recorded temperatures below 32° F" occur in January (21° F), February (24° F), March (29° F), November (23°

F), and December (18° F). The "average number of days below 32° F" is one each for the months of January, February, and December. Please revise the mass emission rates for the Model PG7241(FA) to reflect a more reasonable "low temperature" of 32° F for the Tampa area. Permit conditions for gas turbines typically allow adjustment of the mass emission rate for compressor inlet temperature, if necessary. Otherwise, the Department is considering mass emission rates based on a compressor inlet temperature of 59° F or other available information.

g. Please provide the "Emissions Performance Estimates" from General Electric for the proposed Model PG 7241(FA) gas turbine. This specification sheet identifies the emission rates for CO, NOx, PM/PM_{10}, SO_2, and VOC in terms of ppmvd and lb/hour as estimated by the manufacturer. In addition to the emission rates, these performance specification sheets should also include the unit performance, load conditions, power generation, heat input, fuel consumption, stack conditions, compressor inlet temperature, and fuel type. Specifically, the Department requests "Emissions Performance Estimate" data sheets from General Electric for:

- Gas firing at 100% base load with an inlet compressor temperature of 59° F;
- Gas firing at 100% base load with an inlet compressor temperature of 32° F;
- Oil firing at 100% base load with an inlet compressor temperature of 59° F; and
- Oil firing at 100% base load with an inlet compressor temperature of 32° F.
- Oil firing at 50% base load with an inlet compressor temperature of 93° F.

If necessary, the Department will provide an example from a similar project.

3. <u>Proposed Control Equipment</u>

a. Does the proposed Selective Catalytic Reduction (SCR) system include a NOx emissions monitor prior to the ammonia injection grid to measure uncontrolled NOx emissions? Please identify and describe the automated control system that will be used to adjust the ammonia injection rates based on uncontrolled NOx emissions. What are the input parameters to this system? How will the ammonia slip concentration be determined? What is the proposed test method and frequency for the determination of ammonia slip? For similar combined cycle projects, maximum ammonia slip has been limited to 5 ppm. Please comment.

b. The DEP/TEC Consent Final Judgement requires an evaluation of zero ammonia NOx control technologies. (Question No. 11 summarizes these issues.) The PSD permit application identifies SCONOx™ as such a technology. Please indicate which Emission Unit the SCONOx™ system would be installed on, provide a process flow diagram, and identify emission levels for all pollutants from the combined cycle unit controlled with a SCONOx™ system.

Please note that the issue concerning the evaluation of zero ammonia technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

c. For each NOx control system, describe any unique performance or operating conditions related to startups, shutdowns, or maintenance requirements.

4. <u>Operation</u>

a. The application requests continuous operation (8760) for each gas turbine unit with up to 876 hours f operation per unit when firing low sulfur distillate oil. No other methods of operation are requested. Is this correct?

5. <u>BACT Determination for CO</u>

A review of the Annual Operation Reports filed by TEC with the Department indicates the following inconsistency with information submitted as part of the application (Attachment D, Tables 1 – 3):

Gannon Unit	1997		1998		1999		2-Year Average	
	AOR	App.	AOR	App.	AOR	App.	AOR	App.
5	---	---	140.00	2083.40	136.38	2027.50	138.19	2055.5
6	278.00	3446.30	216.00	3221.90	---	---	247.00	3334.1
						Totals	385.19	5389.60

Note: An equipment explosion affected operation of Unit No. 6 in 1999. Therefore, 1997 and 1998 data was used to establish actual emissions representative of "normal operation".

a. The application briefly notes that CO emissions were based on tests conducted in April of 2000. Neither the Department's Southwest District Office nor the Air Quality Division of the Hillsborough County Environmental Protection Commission have any records related to these emission performance tests. There is no information on record of the test methods, duration, number of tests, performance conditions, levels of other pollutants during these tests, or submittal of a test report. The Department is interested in TEC's rationale for, and the support of, the submitted values. However, TEC is required to submit a top-down BACT analysis for the control of carbon monoxide based upon the Department's records and ensuing conclusion regarding the applicability of BACT. When evaluating the oxidation catalyst, please include the items listed below under "Proposed VOC BACT". Note that a CO control efficiency of at least 90% would be expected.

b. Please identify the controlled CO emission levels from a combined cycle unit controlled by a SCONOx™ system.

6. Proposed VOC BACT

a. With regard to the oxidation catalyst cost analysis, please provide:

- Vendor quotes for the oxidation catalyst system, replacement catalyst, and instrumentation.
- Supporting documentation for a VOC control efficiency of only 33% or revise the cost analysis based on a VOC control efficiency of at least 50%.
- Supporting documentation showing a cost of $0.04/kwh for TEC to generate electricity, otherwise revise the energy penalty accordingly. (The Department believes the actual cost for TEC to be lower than the stated cost.)
- A revised cost analysis using a 7% interest rate or provide substantial detail for the assumed interest rate of 9.55%. (TEC's parent company, TECO Energy, Inc., states in its annual report issuance of fixed rate bonds with interest rates of 6% to 8% for terms of over 20 years. It appears that Tampa Electric can issue tax-exempt bonds, which usually carry a lower interest rate than comparable corporate bonds. It is also noted that the federal 30-year bond rate is less than 5.9%.)
- A revised cost analysis if the contracted package for the HRSG that will be supplied by Alstom Power already includes the spool piece for an oxidation catalyst. (Costs estimated for foundations, supports, handling, erection, engineering, construction field expenses, and contractor fees appear excessive and/or unnecessary.)

b. The application (Table 4-5) indicates that TEC rejects the oxidation catalyst based on high costs and the adverse environmental impacts related to collateral increases of sulfuric acid mist emissions (SAM). The Department will review the revised cost analysis, but notes that natural gas and low sulfur distillate oil contain minimal amounts of sulfur. The application does not discuss the amount and consequences of additional SAM emissions. In addition, the Department would expect an oxidation catalyst to result in a significant reduction of hazardous air pollutants for which this project appears to be major. Therefore, the Department disagrees that the addition of an oxidation catalyst would result in net adverse environmental impacts. Please comment.

c. Please complete the appropriate emissions unit pages of the permit application form for the distillate oil tank. The Department previously allowed construction of this tank contingent on TEC including it as part of the BACT analysis in the application to repower the Gannon Station. Also, please propose a VOC BACT for this emissions unit.

7. MACT Determination for Hazardous Air Pollutants (HAPs)

a. The application (Page 1-5) indicates that this project will NOT be a major source of hazardous air pollutants (HAPs) because potential emissions are less than 10 TPY of any individual HAP and 25 TPY for all HAPs. However, the supporting documentation (Attachment C, Table 7) shows total potential HAP emissions for Bayside Units 1 and 2 combined will be 27.87 TPY, which is greater than the 25 TPY threshold for total HAPs. Projects that are major for HAP emissions are required to obtain case-by-case MACT determinations until EPA promulgates a final NESHAP for gas turbines. Please submit a technical review and proposal for MACT.

The Department notes that EPA issued a December 30, 1999 memorandum entitled, "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines". This guidance discusses the use of an oxidation catalyst for the control of HAP emissions.

b. The HAP emission calculations (Attachment C) were based on selected test rates from data used to compile EPA's recent AP-42 update for gas turbines. TEC believes the selected rates are more representative of large frame-type gas turbines. Please provide specific HAP emission rates for the Model PG7241(FA) from General Electric and revise the potential emissions calculations accordingly.

8. <u>Emissions Standards Proposed in the Application</u>

a. Please comment on the following items:

- CEMS have been required to demonstrate compliance with CO emission standards for similar combined cycle projects currently under review by the Department (e.g. Calpine, FPC).
- For similar combined cycle projects, compliance with a NOx emission standard for gas firing of 3.5 ppmvd corrected to 15% oxygen has been based on CEMS data for both a 3-hour rolling average as well as a 24-hour block average of actual operating hours.
- For recent gas turbine projects, annual tests for volatile organic compounds and particulate matter have been required to demonstrate compliance with the applicable emission standards.
- EPA Region 4 has recently recommended testing for selected emissions of hazardous air pollutants, such as formaldehyde.

b. The application states that maximum CO emissions (30.3 ppmvd @ 15% oxygen) occur at 50% base load when firing oil with a compressor inlet temperature of 93° F. Please provide supporting documentation from General Electric.

c. Is TEC proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO_2?

9. <u>Excess Emissions</u>

The application (Page 2-8) requests the following periods of permitted excess emissions:

- *Typical Operation*: Up to 2 hours in any 24-hour period due to startup, shutdown, or unavoidable malfunction.
- *CT Warm Startup*: Up to 3 hours in any 24-hour period when the CT/HRSG has been down for more than 2 hours and less than or equal to 24 hours.
- *CT Cold Startup*: Up to 4 hours in any 24-hour period when the CT/HRSG has been down for more than 24 hours.
- *Steam Turbine Cold Startup*: Up to 18 hours of excess emissions resulting from the cold startup of the repowered steam turbines due to metal temperature limitations.

a. Please describe the warm and cold startups of the CT/HRSG units and the associated excess emissions. Please provide supporting documentation to include the duration of each startup and the quantity and duration of excess emissions. How many warm and cold CT/HRSG startups are predicted for each year?

b. Please describe the process of bringing the repowered steam turbines back on-line during a cold startup and define "cold startup" for this equipment. Please provide data that indicates the exhaust gas emissions from the gas turbines will be in excess of the proposed standards for the entire 18-hour cold startup of a steam turbine. Please identify any startup methods that could be used to minimize damage to the steam turbine while allowing the gas turbines to achieve steady-state operation and avoid excess emissions. For example, is it possible to operate a single gas turbine at 75% load to gradually heat up the repowered steam turbine? Is it possible to use steam from the other Bayside Unit to gradually heat up the repowered steam turbine? How many cold startups of each steam turbine are predicted for each year?

c. For each requested period of excess emissions, what is the duration (hours), amount (ppmvd and lb/hour), frequency (incidents per year), and resulting annual emissions (tons per year).

d. Note that the permit can only allow excess emissions for pollutants for which the compliance status would be known. For this project, compliance should be readily identifiable for CO (CEMS), NOx (CEMS), and visible emissions (EPA Method 9 observation). Please comment.

10. Repowering - Bayside Startup and Gannon Shutdown

a. As stated in the application (Attachment D), the actual emissions decreases from the Gannon Units must take place on or before the date that emissions from the modification project (new Bayside Units) first occur and must be federally enforceable on and after the date the Department issues a permit for the modification project. However, the Project Summary indicates that each Gannon Unit will be shut down after installation and "commercial startup" of the corresponding Bayside Unit. Please define "commercial startup" in specific terms.

b. For each new combined cycle unit, please provide an estimated schedule for the start of construction, the completion of construction, the shakedown period, the initial performance testing, "commercial startup", and initial power generation. Also, please indicate when each of the six coal-fired Gannon Units will be shut down.

c. Gannon Units that are not being repowered are required to be shutdown between January 1, 2003 and December 31, 2004. It is expected that any permit issued for this project would be conditioned to require:

- Permanent shutdown of the Gannon Units within this time frame.
- A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 5 when shutdown.
- A reduction in the current annual "heat input" limit on the Gannon coal yard by an amount equivalent to that for Gannon Unit 6 when shutdown.
- Permanent shutdown of all coal-fired Gannon units when both Bayside Units are operational.

Otherwise, allowing the remaining Gannon Units 1 – 4 to fire additional coal could cause actual emissions increases and trigger additional PSD requirements. Please comment.

11. Requirements of the DEP/TEC Consent Final Judgement

Paraphrasing Section V of the DEP/TEC Consent Final Judgement (CFJ), this agreement requires the following for the Gannon Station:

CFJ Section V, A: TEC shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, and 5 to be phased-in between January 1, 2003 and December 31, 2004. The repowered units shall fire gas and meet a NOx emission rate of 3.5 ppm.

a. The application indicates that the steam boilers for Gannon Units 5 and 6 will be shutdown and the steam turbines for Gannon Units 5 and 6 will be repowered with steam from Bayside Units 1 and 2. How does this comply with the requirements of the CFJ to repower Gannon Units 3, 4, and 5?

b. The CFJ requires the shutdown of Gannon Units 1, 2, and 6. The application does not appear to discuss the future status of any Gannon units that are not being repowered. The Department understands that the steam boilers for any repowered Gannon units must be permanently shut down prior to operation of any corresponding Bayside Unit. The steam boilers for the remaining Gannon units must be shut down between January 1, 2003 and December 31, 2004. In addition, all coal-fired Gannon Units must be permanently shutdown when both Bayside Units are operational. These emissions decreases will not be available for any future projects at the Bayside Station. Please comment.

c. In several places, the application indicates that Gannon Units 5 and 6 will "... permanently cease coal-fired operation." The Department understands this to mean that the steam boilers for Gannon Units 5 and 6 will be permanently shutdown and rendered incapable of operation prior to beginning operations of the corresponding Bayside Unit. Please comment.

d. The application requests 876 hours per year of very low sulfur distillate oil firing as a backup fuel with an emission standard of 16.4 ppmvd corrected to 15% oxygen. How does this meet the requirements of the CFJ to repower with *gas-fired* units meeting a NOx emissions standard of *3.5 ppm*?

CFJ Section V, B: TEC must evaluate "zero ammonia" NOx control technologies for the Gannon facility. If the capital cost differential above Selective Catalytic Reduction (SCR) does not exceed $8 million and TEC obtains acceptable performance guarantees and remedies from the manufacturer, TEC shall install such technology on one repowered unit no later than December 31, 2004. Otherwise, TEC shall spend up to $8 million to demonstrate alternative commercially viable NOx control technologies for natural gas or coal-fired generating units.

e. SCONOx™ is identified as a commercially viable "zero ammonia" NOx control technology and is available for large frame-type units from Alstom Power. Please describe the progress to date on obtaining capital cost estimates, manufacturer performance guarantees and remedies (in accordance with generally recognized industry standards), and all other information necessary for the Department to conclude the required evaluation.

   Please note that the issue of evaluating "zero ammonia" NOx control technologies must be resolved before the Department will deem the Bayside PSD permit application complete.

f. The Department expects that any permit issued for the proposed Bayside project will comport with the Consent Final Judgement. Please comment.

12. Requirements of the EPA/TEC Consent Decree

   a. The Department notes that TEC has signed a separate Consent Decree with the U.S. Environmental Protection Agency. The conditions of the order vary from the requirements of the Department's Consent Final Judgement. EPA Region 4 is currently reviewing the permit application for purposes of PSD as well as compliance with the federal order. When received, the Department will forward any questions from EPA to TEC for comment.

13. Air Quality Analysis

   a. Please review Table 6-1 on pages 6-2, 6-3, and 6-4. The data presented in these tables does not appear consistent with the data provided in the electronic modeling files. Also, please revise the AAQS modeling analysis to include impacts from nearby major sources.

   b. Please provide an additional modeling analysis for SO_2 that demonstrates compliance with the AAQS for the following case: Bayside Unit 1 is on-line, repowered Gannon Unit 5 is permanently shut down, and the remaining Gannon Units are on-line. This new analysis should also include impacts from nearby major sources.

14. Miscellaneous

   a. The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new Bayside Units will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

   b. Please be aware that the anhydrous ammonia storage tanks will require an update of the current Risk Management Plan for this site.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268. Questions regarding the air quality analysis should be directed to the project meteorologist, Chris Carlson, at 850/921-9537.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Mr. Patrick Shell, TEC
Mr. Shannon Todd, TEC
Mr. Thomas Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3400 0000 1453 1613

Article Sent To:
Karen Sheffield, General Mgr.

Postage	$
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Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

TEC/Bayside
Power Stat.

Postmark
Here

Name (Please Print Clearly) (to be completed by mailer)
Karen Sheffield, Gen. Mgr.
Street, Apt. No.; or PO Box No.
Port Sutton Rd.
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Karen Sheffield, General Mgr.
Bayside Power Station
Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 10/20

C. Signature
X S/ Dominllu Vauw ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
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PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

ECT
Environmental Consulting & Technology, Inc.

RECEIVED
OCT 02 2000
BUREAU OF AIR REGULATION

September 29, 2000
ECT No. 991060-0100-1100

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

Re: Tampa Electric Company
Bayside Power Station

Dear Mr. Fancy:

On behalf of Tampa Electric Company (TEC), please find enclosed a revised Page 7 of the FDEP Construction Permit Application for the Bayside Power Station project. This revision updates the Facility Contact information. Elena Beitra

Please contact Shannon Todd of TEC at 813/641-5125 or the undersigned at 352/332-6230, Ext.351, if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Enclosure

cc: Mr. Shannon Todd, TEC

3701 Northwest 98TH Street
Gainesville, FL 32606

(352) 332-0444

FAX (352) 332-6722

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: **Elena Beitia, 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) 641-5595**	Fax: **(813) 641-5566**		

ECT

Environmental Consulting & Technology, Inc.

RECEIVED
OCT 02 2000
BUREAU OF AIR REGULATION

September 29, 2000
ECT No. 991060-0100-1100

Mr. C. H. Fancy, P.E.
Chief, Bureau of Air Regulation
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

Re: Tampa Electric Company
Bayside Power Station

Dear Mr. Fancy:

On behalf of Tampa Electric Company (TEC), please find enclosed six copies of a revised Page 7 of the FDEP Construction Permit Application for the Bayside Power Station project. This revision updates the Facility Contact information.

Please contact Shannon Todd of TEC at 813/641-5125 or the undersigned at 352/332-6230, Ext.351, if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Enclosures

cc: Mr. Shannon Todd, TEC

3701 Northwest
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Gainesville, FL
32606

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3. Facility Contact Telephone Numbers: Telephone: **(813) 641-5595** Fax: **(813) 641-5566**

FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

September 27, 2000

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Tampa Electric Company
F. J. Gannon/Bayside Power Station
PSD-FL-301
Facility ID No. 0570040-013-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Tampa Electric Company, proposes to repower its existing F. J. Gannon Station in Hillsborough County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner at 850/414-7268.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/jka

Enclosures

cc: J. Koerner

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

September 27, 2000

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Tampa Electric Company
F. J. Gannon/Bayside Power Station
PSD-FL-301
Facility ID No. 0570040-013-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Tampa Electric Company, proposes to repower its existing F. J. Gannon Station in Hillsborough County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner at 850/414-7268.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/jka

Enclosures

cc: J. Koerner

TAMPA ELECTRIC

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SEP 21 2000
BUREAU OF AIR REGULATION

September 20, 2000

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via Fed Ex
Airbill No. 7918 5340 7932

Re: Bayside Power Station Air Construction Permit Application

Dear Mr. Fancy:

Please find enclosed six signed, sealed copies of the Bayside Power Station Air Construction Permit Application. If you have questions, please contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen A. Sheffield

Karen A. Sheffield
General Manager
Gannon Station

EP\gm\SKT200

Enclosure

c/enc: Mr. Alvaro Linero -FDEP
Mr. Jerry Kissel - FDEP SW
Ms. Alice Harman - EPCHC
J. Kollner
C. Carlson
EPA
NPS

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

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

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