Memorandum

Florida Department of Environmental Protection

TO:	Clair Fancy, Chief – Bureau of Air Regulation	aaj for CHF
THROUGH:	Al Linero, Administrator - New Source Review Section	aaj
FROM:	Jeff Koerner, Project Engineer - New Source Review Section	JK
DATE:	November 16, 2001	
PROJECT:	Tampa Electric Company Bayside Power Station - Gannon Re-Powering Project Project No. 0570040-015-AC Draft Permit No. PSD-FL-301A	

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 consist of eleven new natural gas-fired combined cycle gas turbine that will re-power the existing steam-electrical generators for existing Gannon Units 3 through 6. The nominal electric generating capacity for this site will increase from approximately 1300 MW to 2800 MW. The 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 January 11, 2002. I recommend your approval of the attached Draft Permit package.

CHF/AAL/jfk
Attachments

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

P.E. CERTIFICATION STATEMENT

PERMITTEE

Tampa Electric Company
Bayside Power Station, Gannon Re-Powering Project
Port Sutton Road
Tampa, FL 33619

Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A
Facility ID No. 0570040
SIC No. 4911

PROJECT DESCRIPTION

The applicant, Tampa Electric Company, owns and operates the F.J. Gannon Station located on Tampa's Port Sutton Road in Hillsborough County, Florida. The applicant proposes to re-power the existing Gannon Station with eleven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment and with the EPA/TEC Consent Decree. Each combined cycle unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. The new combined cycle units will be grouped to re-power the steam-electric turbines for existing Gannon Units 3, 4, 5, and 6. The re-powering project will increase the nominal electrical generating capacity of this plant from 1285 MW to 2845 MW. All existing Gannon coal-fired boilers will be shut down prior to January 1, 2005.

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 of PM/PM_{10}. The Best Available Control Technology (BACT) for each of these pollutants is determined to be the efficient combustion design and operation combined with the exclusive firing of pipeline-quality natural gas. The CO BACT standard is specified as 9.0 ppmvd @15% oxygen based on a 24-hour block average as determined by CEMS data. Due to the very low uncontrolled emission rates, no emissions standards are specified for PM/PM_{10} and VOC. Instead, the CO CEMS will serve as a continuous indicator of efficient combustion to minimize emissions of these pollutants. The state and federal settlement agreements require the installation of SCR systems to reduce NOx emissions to 3.5 ppmvd @ 15% oxygen or less. A NOx CEMS is required for acid rain monitoring and will be used to demonstrate compliance with the emissions standard based on a 24-hour block average. The exclusive firing of pipeline-quality natural gas minimizes potential emissions of sulfuric acid mist (SAM) and SO_2. Based on the most recent HAP emissions data available, the project does not trigger a 112(g) case-by-case MACT determination.

After shutdown of all coal-fired units prior to 2005, 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 1400 tons per year; sulfur dioxide by more than 60,000 tons per year; sulfuric acid mist by more than 900 tons per year; and lead by more than 18 tons per year. The project will increase *potential* emissions of carbon monoxide and volatile organic compounds. However, based on recent stack test data for the General Electric Model PG7241(FA) gas turbine, actual CO and VOC emissions will likely be less than half of the allowable emissions, which would result in actual emission decreases for these pollutants as well. Although not specifically required for all pollutants, the emissions standards specified in the draft permit for CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC represent BACT-level controls consistent with other recent combined cycle gas turbine projects.

***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 J. Koerner

11-16-01

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

(Date)

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 16, 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. 0570040-015-AC
Draft Permit No. PSD-FL-301A
Draft PSD Permit for the Bayside Power Station
Revised 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 eleven new natural gas-fired combined cycle gas turbines. 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 850/921-9536.

Sincerely,

11/21

for C. H. Fancy, Chief
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

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. 0570040-015-AC
Draft Permit No. PSD-FL-301A
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 June 26, 2001 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 eleven 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.

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 the 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.

11/21

for 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 11/26/01 to the persons listed:

Ms. Karen Sheffield, Bayside*
Mr. Patrick Shell, Bayside
Mr. Adriano Alcoz, Bayside
Mr. Tom Davis, ECT
Chair, Hillsborough County BCC
Mr. Jerry Campbell, HEPC
Mr. Gerald Kissel, SWD
Mr. John Notar, NPS
Mr. Gregg Worley, 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.

Victoria Gibson 11/26/01
(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. 0570040-015-AC
Draft Permit PSD-FL-301A

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 a nominal electrical production capacity of 2845 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.

The applicant proposes to re-power the existing Gannon Station with eleven new combined cycle gas turbines. Each new unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. The new combined cycle units will be grouped to re-power the existing steam-electric turbines for existing Gannon Units 3, 4, 5, and 6. The re-powering project will increase the nominal electrical generating capacity of this plant to 2845 MW. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. All existing Gannon coal-fired boilers will be shut down prior to January 1, 2005.

Because the existing plant is a PSD-major source of air pollution, new projects are subject to the preconstruction review requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in Rule 62-212.400, F.A.C. The re-powering project will result in the following potential annual emissions: 1383 tons per year of carbon monoxide; 1113 tons per year of nitrogen oxides (NOx), 1.4 tons per year of lead, 368 tons per year of particulate matter (PM/PM_{10}), 89 tons per year of sulfuric acid mist (SAM), 487 tons per year sulfur dioxide (SO_2), and 135 tons per year of volatile organic compounds (VOC). The project is significant for emissions of CO, PM/PM_{10}, and VOC. Due to the large emissions reductions from the shutdown of the existing coal-fired boilers, the project nets out of PSD review for emissions of NOx, SAM, and SO_2. After the shutdown of all coal-fired units, the re-powering project will reduce emissions of: nitrogen oxides by more than 28,000 tons per year; particulate matter by more than 1600 tons per year; sulfur dioxide by more than 60,000 tons per year; sulfuric acid mist by more than 900 tons per year; and lead by more than 18 tons per year.

The Department is required to determine the Best Available Control Technology (BACT) for the significant emissions of CO, PM/PM_{10}, and VOC. For each of these pollutants, BACT is determined to be the efficient combustion design and exclusive firing of pipeline-quality natural gas. A continuous emissions monitoring system (CEMS) will be used to demonstrate compliance with the CO emissions standards and serve as an indicator of efficient combustion to minimize emissions of PM/PM_{10} and VOC.

The gas turbines incorporate dry low-NOx combustion technology and automated controls to minimize NOx emissions. The state and federal settlement agreements require the installation of a selective catalytic reduction (SCR) system to reduce NOx emissions. A continuous emissions monitoring system (CEMS) is required for acid rain monitoring and will be used to demonstrate compliance with the NOx emissions standard. The exclusive firing of pipeline-quality natural gas minimizes emissions of sulfuric acid mist (SAM) and SO_2. Based on the most recent HAP emissions data available, the project does not trigger a 112(g) case-by-case MACT determination.

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 indicates 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 alone.

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, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Bayside Power Station
Gannon Re-Powering Project

Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A

COUNTY

Hillsborough County

APPLICANT

Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

PERMITTING AUTHORITY

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

November 16, 2001

Filename: 301A TEPD.doc

TABLE OF CONTENTS

This document describes the overall project, identifies applicable air pollution regulations, provides the rationale for draft determinations of the Best Available Control Technology, establishes emissions standards, presents a review of the air quality impact analysis, and makes a preliminary determination to issue the air permit. It is organized by the following sections.

1. APPLICATION INFORMATION

Applicant Name and Address

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

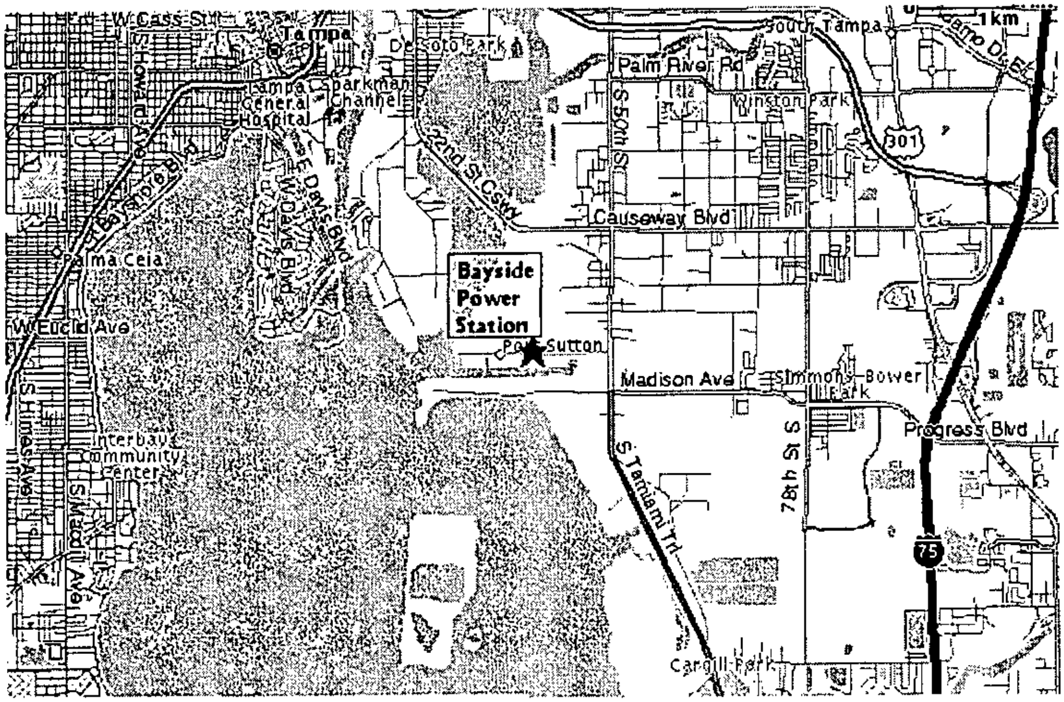
Authorized Representative:
Karen Sheffield, General Manager

Processing Schedule

- Issued Air Permit No. PSD-FL-301 on 03/30/01 for the Bayside Power Station (Units 1 and 2).
- Received application on 06/26/01 to add Units 3 and 4 to the Bayside Power Station.
- Received additional information on 07/17/01, 08/13/01, 09/11/01, 09/25/01, 10/01/01, and 10/30/01.

Facility Description and Location

The applicant, Tampa Electric Company, currently operates the F. J. Gannon Power Plant, which produces a nominal 1285 MW of electrical power primarily with coal-fired boilers. The applicant proposes to re-power the existing plant with eleven natural gas-fired combined cycle gas turbines, which will increase the nominal electrical generating capacity to 2845 MW. The primary Standard Industrial Classification (SIC) code for this facility is Industry No. 4911, Electric Services. The re-powered plant will be located within the existing plant boundaries on Port Sutton Road in Tampa, Florida. The UTM coordinates are: Zone 17, 360.00 km E, 3087.50 km N. The map coordinates are Latitude 27° 54' 18" and Longitude 82° 25' 21". The following map shows the approximate location of the plant.



Regulatory Categories

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a case-by-case 112(g) determination of the Maximum Available Control Technology (MACT).

Title IV: The new combined cycle gas turbines 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).

Siting: 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 existing 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 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: No activities are identified as 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 Subpart GG in 40 CFR 60.

2. PROPOSED PROJECT

Project Description

The applicant proposes to re-power the existing coal-fired F. J. Gannon Plant with eleven natural gas-fired combined cycle gas turbines. The re-powering project is required 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. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The following describes the equipment and controls for the new Bayside Power Station.

Unit Description: Each combined cycle 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 exclusive 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 a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Generating Capacity: Each gas turbine is paired with an individual HSRG. Individual combined cycle units are grouped to match the steam input capacity of the existing steam turbine electrical generators. The applicant identifies the groups of combined cycle gas turbines and steam turbines as "Bayside Units 1, 2, 3, and 4". The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

Table 2A. Summary of Generating Capacities

EU No.	Bayside Unit	MW, Shaft	Gannon ST	MW, ST	Total MW
020	1A	169 MW	No. 5	239	746
021	1B	169 MW			
022	1C	169 MW			
023	2A	169 MW	No. 6	414	1090
024	2B	169 MW			
025	2C	169 MW			
026	2D	169 MW			
027	3A	169 MW	No. 3	163	501
028	3B	169 MW			
029	4A	169 MW	No. 4	170	508
030	4B	169 MW			
Totals	11 units	1859 MW	4 units	986	2845

Note: The nameplate generating capacity is shown for each steam-electrical turbine (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). Firing natural gas as the exclusive fuel minimizes emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2) because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces emissions of nitrogen oxides (NOx).

Continuous Monitors: Each gas turbine is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas carbon dioxide content. The automated gas turbine control system also monitors fuel flow, heat input, power output, hours of operation, combustion reference temperatures, and other critical gas turbine control parameters.

Potential Emissions

The applicant estimates that the new gas turbines will result in the following potential annual emissions: 1383 tons per year of carbon monoxide; 1113 tons per year of nitrogen oxides, 1.4 tons per year of lead, 368 tons per year of particulate matter (front-half catch only), 89 tons per year of sulfuric acid mist, 487 tons per year sulfur dioxide, and 135 tons per year of volatile organic compounds. The shutdown of existing coal-fired units will result in large emissions decreases for many pollutants. PSD applicability is discussed later with the netting analysis.

3. RULE APPLICABILITY

State Regulations

The 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, and 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, 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 Siting Coordination Office dated 10/11/00).}

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 – PSD
40 CFR 52.21	Approval of Implementation Plans – PSD
40 CFR 60	New Source Performance Standards (NSPS)
40 CFR 60	NSPS - Subpart A, General Provisions for NSPS Sources
40 CFR 60	NSPS - Subpart GG, Stationary Gas Turbines
40 CFR 60	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.}

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 existing 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. Project emissions exceeding these rates are considered "significant". For each significant pollutant, the applicant must employ the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analyses. 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.

Description of PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of a PSD Significant Emission Rate. 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 specified in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). When reviewing control technologies for regulated pollutants, the Department will favorably consider the control or reduction of other "non-regulated" air pollutants in determining BACT. 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.

The second part of PSD review 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 not adversely impact Class I and Class II Areas.

Netting Analysis

The Bayside re-powering 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 categories 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).

As described in Rule 62-212.400(2)(e), F.A.C., the PSD regulations allow applicants to avoid PSD 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. As discussed previously, 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.

The revised application (09/11/01) identified the project as subject to PSD review for emissions of carbon monoxide, particulate matter, and volatile organic compounds. This was based on a netting analysis that considered the following:

- Emissions decreases from the shutdown of the coal-fired boilers for Gannon Units 3, 4, 5 and 6, and
- A netting analysis based on past actual emissions from the existing coal-fired Gannon Units as if "present-day BACT" were installed.

The Department and EPA entered into settlement agreements with the applicant intended to resolve alleged PSD violations. Therefore, it is appropriate that the past actual emissions from the existing coal-fired boilers reflect BACT-level controls that would otherwise have been required. This is consistent with the previous Bayside permitting action. The Department requested the applicant to base "present-day BACT" controls for a modified coal plant on the on the Department's most recent similar project, the Indiantown Cogeneration Limited Partnership coal-fired plant. The following table summarizes the controls and standards for this project.

Table 3A. Summary of "Present-Day" BACT Controls

Pollutant	Emission Rates			Control Efficiency	AP-42 (Range) Control Efficiency	Present-Day BACT Control Efficiency
	Past Actual [a]		Present Day BACT [b]			
	lb/ton coal	lb/mmBTU	lb/mmBTU	Percent (%)	Percent (%)	Percent (%)
CO	0.5	0.02	0.092, Good Combustion	NI	NA	NA
NOx	31.0	1.25	0.125, SCR	75 to 86%	90%	92%
Pb	4.2×10^{-04}	1.7×10^{-05}	1.6×10^{-05}, ESP/Baghouse	NI	6%	NA
PM/PM10	43.4	1.75	0.015, ESP/Baghouse	99 to 99.9%	99%	>99%
SAM [c]	2.85	0.11	0.0035, Lime Spray Dryer	NI	97%	95%
SO_2	57.0	2.30	0.142, Lime Spray Dryer	> 90%	94%	95%
VOC	0.04	0.002	0.003, Good Combustion	NI	NA	NA

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.

c. The applicant estimates a reduction of 35% in SAM emissions with a lime spray dryer. The Department estimates it would be at least 95%.

d. "NA" means not applicable. "NI" means no information.

Based on this information, the following table summarizes the revised netting analysis assuming that "present-day" BACT controls were installed on the re-powered Gannon Units during the representative two years of operation. It is primarily based on the applicant's submittal (09/11/01) with differences identified in the notes.

Table 3B. Summary of Netting Analysis

Pollutant	Gannon Units 3 - 6			Bayside Units 1 - 4	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]	**-609.3**	**0%**	**-609.3**	**1382.8**	**+773.5**	**100**	**Yes**
NOx	-33,921.3	92%	-2713.7	1113.0	-1600.7	40	No
Pb [b]	-12.2	84.5%	-1.9	1.4	-0.5	0.6	No
PM/PM10 [b]	**-1751.0**	**84.5%**	**-271.4**	**367.9**	**+96.5**	**25/15**	**Yes**
SAM [c]	-2461.7	95%	-123.1	89.4	-33.7	7	No
SO_2	-51,472.0	95%	-2573.6	486.5	-2087.1	40	No
VOC	**-78.1**	**0%**	**-78.1**	**134.9**	**+56.8**	**40**	**Yes**

Notes:

a. Past actual emissions are based on the annual operating reports for the representative two years and are shown as "negative" numbers to represent emissions decreases due to shutdown.

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

The Department also assumed that lead emissions would be reduced by a similar amount.

c. The applicant assumed a control efficiency of 35% from a lime spray dryer because of the low uncontrolled SAM emission levels. The Department assumed a control efficiency of 95% from a lime spray dryer similar to SO_2 control levels. Uncontrolled SAM emissions are based on actual SO_2 emissions and the ratio of SAM / SO_2 emission factors (AP-42).

According to the netting analysis, the Bayside re-powering project requires BACT determinations for emissions of CO, PM/PM_{10}, and VOC.

4. AVAILABLE INFORMATION

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

- Comments from EPA Region 4 and the Hillsborough EPC;
- 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 catalytic oxidation system to control CO and VOC emissions;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- U. S. Department of Energy Report (11/05/99) entitled, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" prepared by Onsite Sycom Energy Corporation;
- AP-42, Section 1.1 for coal-fired boilers (09/98);
- AP-42, Section 3.1 for gas turbines (04/00);
- EPA memorandums regarding gas turbines and MACT applicability dated 12/30/99 and 08/21/01;
- Annual Operating Reports for the Gannon Plant;
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;

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

Table 4A. Summary of Emissions Standards for 170 MW Combined Cycle Gas Turbines Firing Natural Gas

Project Location	Date	CT Model	Unit MW	Control Technologies	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	PM Limit	SO2/SAM Limit	VOC Limit ppm
Hinds Energy, MS	01/00	GE 7FA	170	DLN/SCR	20	3.5	NI	LSF	NI
Attala Energy, MS	02/00	GE 7FA	170	DLN/SCR	20	3.5	NI	LSF	NI
Calpine Delta, CA (LAER)	02/00	GE 7FA or S/W 501FD	170	LPM/SCR	10, w/DB, 3-hr	2.5, w/DB	Fuel Specification	LSF	2
Calpine Bullhead City, AZ	02/00?	S/W 501FD	170	LPM/SCR	10, w/DB, 3-hr	3.0, w/DB	18.3 lb/hr	LSF	1.5
Calpine Blue Heron, FL	02/00	S/W 501FD	170	LPM/SCR	10, 24-hr	3.5, 3-hr	10% opacity	LSF	1.2
Mobile Energy, AL	03/00	GE 7FA	170	DLN/SCR	18, gas w/DB	3.5, w/DB	10% opacity	LSF	5
GPC Boat Rock, AL	04/00	GE 7FA	170	DLN/SCR	30, gas w/DB	3.5, w/DB	NI	LSF	8, w/DB
Calpine Osprey, FL	05/00	S/W 501FD	170	LPM/SCR	10, 24-hr	4.0, w/DB, 3-hr	10% opacity	LSF	2.3
Hines PB II, FL	01/01	S/W 501FD	170	LPM/SCR	16, 24-hr	3.5, 24-hr	10% opacity	LSF	2
CPV Gulfcoast, FL	02/01	GE 7FA	170	DLN/SCR	9, 3-hr	3.5, 3-hr	10% opacity	LSF	1.4
CPV Atlantic, FL	05/01	GE 7FA	170	DLN/SCR	9, 24-hr	3.5, 24-hr	10% opacity	LSF	1.4
CPV Pierce, FL	07/01	GE 7FA	170	DLN/SCR	9, 24-hr	2.5, 24-hr	10% opacity	LSF	1.4
Enron Ft. Pierce, FL	08/01	MHI 501F	170	LPM/SCR	3.5, 3-hr	3.5, 24-hr	10% opacity	LSF	2.2
El Paso Deerfield, FL	08/01	GE 7FA	170	DLN/SCR	7.4, 3-hr	2..5, 24-hr	10% opacity	LSF	1.4
TEC Bayside, FL	*Draft*	*GE 7FA*	*170*	*DLN/SCR*	*8, 24-hr*	*3.5, 24-hr*	*10% opacity*	*LSF*	*None, GCP*

Abbreviations:

Manufacturer

GE – General Electric
S/W – Siemens/Westinghouse
MHI – Mitsubishi Heavy Industries

Controls

DLN – Dry Low-NOx Combustion
GCP – Good Combustion Practices
LPM – Lean Premix Combustion
SCR - Selective Catalytic Reduction
WI = Water or Steam Injection
LSF – Low Sulfur Fuel

Other

LAER – Lowest Achievable Emission Rate
BACT – Best Available Control Technology
CEMS – Continuous Emissions Monitoring System

Notes: All data presented is for combined cycle gas turbines with a nominal shaft-driven 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.

5. DRAFT BACT STANDARDS FOR CO AND VOC EMISSIONS

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 Frame 7FA gas turbine has also successfully reduced CO emissions concurrently with NOx emissions. Because the controls used to lower CO emissions would also lower VOC emissions, the control technologies for these pollutants are reviewed together.

Applicant's Proposal

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

A catalytic oxidation system 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 already low uncontrolled VOC emissions from the Model PG7241(FA) gas turbine, which are estimated to be less than 2.0 ppmvd corrected to 15% oxygen.

The applicant recognized a catalytic oxidation system as the top control for CO and VOC emissions, but identified the following additional adverse impacts.

<u>Energy Impacts</u>: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.2 inch of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit (approximately a 0.24 percent energy penalty). The applicant estimates the lost power generation to be approximately $107,223 per year per gas turbine.

<u>Environmental Impacts</u>: Although the project proposes natural gas as the exclusive fuel, the catalytic oxidation system would oxidize small amounts of fuel sulfur to sulfuric acid mist. Also, due to the inherently low CO and VOC emissions from the Model PG7241(FA) gas turbine, the applicant believes that the addition of a catalytic oxidation system 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.

<u>Economic Impacts</u>: The applicant estimates that the installation of a catalytic oxidation system would result in total capital investment of approximately $1,305,227 for one gas turbine with a total annualized cost of approximately $370,238 per year per gas turbine. Assuming 90% control efficiency, the catalytic oxidation system would remove in an additional 113.1 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $3300 per ton of CO removed. Assuming 50% control efficiency, the catalytic oxidation system would remove in an additional 6.1 tons of VOC per year per gas turbine resulting in a cost effectiveness of $60,400 per ton of VOC removed.

The applicant rejected the catalytic oxidation system as not cost effective for the project. In addition, the applicant did believe the additional controls would provide any measurable reductions in air quality impacts. The applicant proposed the following CO and VOC emissions standards for the combined cycle gas turbines based on the efficient combustion design of the Model PG7241(FA), the firing of natural gas as the exclusive fuel, and good operating practices.

- Requested CO Standard: 7.8 ppmvd corrected to 15% oxygen, 3-hour test average
- Requested VOC Standard: 1.3 ppmvd corrected to 15% oxygen, 3-hour test average

Draft BACT Determinations

The Department also recognizes the catalytic oxidation system as the top control alternative 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 a catalytic oxidation system would result in an energy penalty due to the pressure drop across the catalyst.

Environmental Impacts: Although a catalytic oxidation system could result in increased sulfuric acid mist emissions, the oxidation process would also result in lower sulfur dioxide emissions. However, such increases and decreases would be minimal due to the extremely low fuel sulfur content of pipeline-quality natural gas. A catalytic oxidation system would reduce emissions of hazardous air pollutants, such as formaldehyde. However, uncontrolled HAP emissions from the entire project are estimated to be less than 10 tons per year. 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 is specifically established for areas that are meeting the ambient air quality standards in order to prevent the deterioration of the current air quality. Actual ambient impacts from the project are evaluated in the modeling analysis and are not considered in making a determination of the Best Available Control Technology.

Economic Impacts: The Department does not endorse the applicant's estimate of the cost effectiveness for a catalytic oxidation system. However, it appears to be within the range of such estimates for other similar projects ($1500 to 4000 per ton). Even combining CO and VOC emission decreases results in a cost effectiveness of more than $3000 per ton of combined pollutants.

Due to the high combustion temperatures, efficient combustion design, and the firing of natural gas, emissions of CO, VOC, and even hazardous air pollutants (HAPs) such as formaldehyde are relatively low. Recent emissions performance tests at the Polk Power Station for the General Electric Model PG7241(FA) gas turbine indicate actual CO emission levels of less than 1 ppmvd when firing natural gas. Such low actual CO emissions would drive the cost effectiveness of a catalytic oxidation system even higher. The Department determines that add-on controls to further reduce CO and VOC emissions are unwarranted given the low emissions characteristics of this particular gas turbine and the exclusive firing of natural gas. Therefore, a catalytic oxidation system is rejected as not cost effective for this project. The Department recommends the following draft BACT standards.

- CO Draft BACT: 9.0 ppmvd corrected to 15% oxygen, based on a 24-hour block average of CEMS data
- VOC Draft BACT: Compliance with the CO standard represents a continuous indication of efficient combustion practices.

Compliance with the CO standard will be demonstrated by continuous emissions monitoring system (CEMS). Therefore, a slightly higher emission standard is specified. Uncontrolled VOC emissions are expected to be near detectable levels of the test method due to the efficient combustion design. Therefore, the compliance with the CO CEMS standard shall also serve as a continuous indication of efficient combustion practices to minimize emissions of volatile organic compounds.

6. DRAFT BACT STANDARDS FOR PM/PM_{10} EMISSIONS

Discussion

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

Requested Emissions Standards

At the estimated uncontrolled emission rates when firing pipeline-quality natural gas, the applicant states that installation of add-on controls such as baghouses or electrostatic precipitators would be cost prohibitive. In addition to firing natural gas as the exclusive fuel, the applicant proposed the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standard.

- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Draft BACT Determinations

The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive for a gas turbine firing only natural gas. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration for this project. Therefore, the following conditions are established as the draft BACT standards.

- Pipeline-quality natural gas shall be the exclusive fuel for each combined cycle gas turbine.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Compliance will be demonstrated by conducting at least annual opacity observations in accordance with EPA Method 9. Also, the CO CEMS standard will serve a continuous indication of efficient combustion practices to minimize emissions of particulate matter.

7. DRAFT STANDARDS FOR NOx EMISSIONS

Due to the high firing temperatures, nitrogen oxides (NOx) are the primary pollutant of concern from gas turbines. Although there are several available control alternatives, the DEP/TEC Consent Final Judgment requires the installation of a selective catalytic reduction (SCR) system 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. As previously discussed, the project nets out of PSD review for NOx emissions based on the emission rate specified in the DEP/TEC Consent Final Judgment.

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, the DEP/TEC Consent Final Judgment requires the installation of a SCONOx™ system on at least one of the Bayside combined cycle gas turbines.

During the original PSD permit application for the re-powering project, the Department worked closely with the applicant to develop appropriate cost estimates in accordance with the DEP/TEC Consent Final Judgment. The cost differential between the two control technologies was determined to be greater than $8 million and the installation of a SCONOx™ system was not required. Therefore, each combined cycle unit at the Bayside Power Station shall incorporate the dry low-NOx combustion design, the exclusive firing of natural gas, and an SCR system designed to minimize NOx and ammonia emissions. In accordance with the DEP/TEC Consent Final Judgment, the following is specified as the NOx emissions standard.

➤ NOx Standard: 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average

Compliance with the NOx standard will be demonstrated by continuous emissions monitoring system (CEMS). This level of control is generally within the range of recent BACT determinations for attainment areas. The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines.

8. DRAFT STANDARDS FOR SAM/SO_2 EMISSIONS

Emissions of sulfur dioxide (SO_2) are generated from fuel sulfur in the natural gas. Small amounts of SO_2 may be converted to sulfuric acid mist (SAM) emissions. Natural gas is a clean fuel containing little ash, sulfur, or other contaminants. At the estimated uncontrolled emission rate when firing pipeline-quality natural gas, the installation of add-on flue gas desulfurization equipment is not reasonable. Again, the state and federal settlement agreements require re-powering with natural gas as the primary fuel. As previously discussed, the project nets out of PSD review for SAM and SO_2 emissions. In accordance with the DEP/TEC Consent Final Judgment, the following is specified as the SAM/SO_2 emissions standard.

➤ Pipeline-quality natural gas shall be the primary fuel for each combined cycle gas turbine.

The above fuel specification also represents the draft BACT standard for particulate matter emissions. It is a work practice standard that effectively limits potential emissions of SAM and SO_2 emissions, is typically considered BACT for gas turbine projects, and is clearly more stringent than the NSPS Subpart GG standard of 0.8% sulfur by weight for gas turbines.

9. DRAFT STANDARDS FOR AMMONIA SLIP EMISSIONS

Ammonia is injected into the exhaust gas stream as part of the selective catalytic reduction (SCR) 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 and must be carefully managed to prevent accidental spills or nitrogen loading of the waters and soils. As part of the NOx control system, elevated levels of ammonia slip can indicate reduced catalyst effectiveness. Limiting ammonia slip can also minimize the formation of fine particulate matter, ammonium sulfates and ammonium bisulfates. Therefore, the following draft ammonia slip standards are specified.

➤ Each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs.

➤ If the tested ammonia slip rate exceeds 5 ppmvd corrected to 15% oxygen during the annual test, the permittee shall:

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

   b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering 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.

Compliance with the ammonia slip level shall be demonstrated at least annually in accordance with EPA's Conditional Test Method No. 27.

10. STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

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 CEMS compliance averages. [Rule 62-210.700(4), F.A.C.]

Alternate Standards and CEMS Data Exclusion

The following permit conditions establish alternate standards or allow the exclusion of monitoring data for specifically defined periods of startup, shutdown, and documented malfunction of a gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents. As provided by the authority in Rule 62-210.700(5), F.A.C., these requirements are established in lieu of the provisions of Rule 62-210.700(1), F.A.C.

Opacity During Startup and Shutdown: During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

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

- The gas turbine is firing natural gas;
- The CO and NOx CEMS are functioning properly during such periods and recording valid emissions data within the span range of each monitor; and
- The gas turbine remains in compliance with the 24-hour block CO and NOx emissions standards based on valid CEMS data.

CEMS Data Exclusion: CO and NOx emissions data shall be recorded by the CEMS during episodes of startup, shutdown, malfunction, and tuning. CO and NOx emissions data recorded during such episodes may be excluded from the 24-hour block compliance averages in accordance with the following requirements.

- Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented malfunction shall not exceed four 1-hour emission averages in any 24-hour block due to all such episodes. Gas turbine startup is the commencement of operation of a gas turbine that 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 malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.
- Periods of data excluded for a steam turbine cold startup shall not exceed sixteen 1-hour emission averages in any 24-hour block. 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 data and experience, the Department may modify this period of data exclusion in the Title V air

operation permit without modifying this PSD permit.

- If the permittee provides at least five days advance notice prior to a major tuning session performed by the manufacturer's representative, monitoring data during tuning may be excluded from the 24-hour block compliance average. Periods of data excluded for such episodes shall not exceed a total of three 1-hour averages in any 24-hour block. Tuning sessions must be performed in accordance with the manufacturer's recommendations. {Permitting Note: As an example, a major tuning session would occur after a combustor change-out. A tuning session may take a few hours each day over a few days. No more than two major tuning sessions would be expected during any year.}

If a CEMS reports emissions in excess of a CO or NOx 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. [Rule 62-4.130, F.A.C.]

Startup and Shutdown Plan: 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. 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 each procedure, 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 of completing 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 period of data exclusion allowed by this permit for a steam turbine cold startup 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.

11. MACT 112(g) APPLICABILITY

EPA is required to promulgate Maximum Available Control Technology (MACT) standards for hazardous air pollutant (HAP) emissions from gas turbines. Because EPA has not yet proposed these standards, states are required to review new projects for the applicability of 112(g), which requires case-by-case MACT determinations if emissions are 10 tons per year or more of any single HAP or 25 tons per year or more of all combined HAPs. Therefore, the Department estimated HAP emissions from the proposed Bayside project based on the following information:

Letter from General Electric dated August 1, 2001: GE conducted formaldehyde emission testing on several GE Model 7241FA gas turbines with dry low-NOx combustors. Due to several problems with the test procedure, GE suggests an emissions factor of 1.3×10^{-04} lb/MMBtu when firing natural gas, which represents the highest average value when blank corrected.

EPA Memorandum dated August 21, 2001: EPA states that the original HAP emissions information (EPA memorandum dated 12/30/99) was based primarily on existing diffusion flame combustor technology. This technology results in higher emissions of CO, NOx, and HAPs than lean pre-mix combustor designs, such as General Electric's dry low-NOx combustion technology. Based on additional emissions performance testing, EPA states that the average formaldehyde emissions factor is 6.49×10^{-05} lb/MMBtu for larger gas turbines (10 MW to 170 MW) utilizing lean premix combustion. One theory for the much lower HAP emission levels is that, although the premixing of fuel and air with staged entry limits flame temperature and residence time at peak flame temperatures, it also reduces "cold spots" throughout the combustion zone providing more uniform destruction. EPA also states that, "For purposes of monitoring HAP performance of lean premix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions."

The AP-42 formaldehyde emission factor for gas turbines is 7.1 x 10^{-04} lb/MMBtu. Based on the new formaldehyde emissions factor of 6.49 x 10^{-5} lb/MMBtu, lean premix combustion technology offers a 90% reduction in formaldehyde emissions. Assuming similar reductions in other organic HAP emissions, the following table summarizes the potential HAP emissions from the Bayside project.

11A. Summary of Potential HAP Emissions form the Bayside Re-Powering Project

Hazardous Air Pollutant	AP-42 [a] Emission Factor lb/MMBtu	LPM [b] Emission Factor lb/MMBtu	Potential Emissions [c] Tons Per Year
1,3-Butadiene	4.30 x 10^{-07}	4.30 x 10^{-08}	0.00
Acetaldehyde	4.00 x 10^{-05}	4.00 x 10^{-06}	0.35
Acrolein	6.40 x 10^{-06}	6.40 x 10^{-07}	0.06
Benzene	1.20 x 10^{-05}	1.20 x 10^{-06}	0.11
Ethylbenzene	3.20 x 10^{-05}	3.20 x 10^{-06}	0.28
Formaldehyde	7.1 x 10^{-04}	6.49 x 10^{-05}	5.76
Napthalene	1.30 x 10^{-06}	1.30 x 10^{-07}	0.01
PAH	2.20 x 10^{-06}	2.20 x 10^{-07}	0.02
Propylene Oxide	2.90 x 10^{-05}	2.90 x 10^{-06}	0.26
Toluene	1.30 x 10^{-04}	1.30 x 10^{-05}	1.15
Xylene	6.40 x 10^{-05}	6.40 x 10^{-06}	0.57
Total HAPs	NA	NA	8.57

Notes:

a. Published AP-42 HAP emission factors in Section 3.1 for gas turbines dated April 2000.

b. The HAP emission factors for lean premix (LPM) combustion technology are based on the AP-42 emission factors and 90% reduction due to efficient, uniform combustion. The LPM formaldehyde emission factor is based on the EPA memorandum.

c. Annual potential emissions are based on eleven gas turbines firing natural gas at 1842 MMBtu per hour for 8760 hours per year.

Potential emissions are less than 10 tons per year for all individual HAPs and less than 25 tons per year for all combined HAPs. Based on this estimate, case-by-case 112(g) MACT does not apply to this project. Each gas turbine will continuously monitor CO and NOx emissions, which will ensure proper lean premix combustor performance and thereby low HAP emissions.

12. EXISTING COAL-FIRED UNITS

Shutdown of Gannon Units

The DEP/TEC Consent Final Judgment requires the shutdown of Gannon Units 1, 2, and 6 and the re-powering of Gannon Units 3, 4, and 5 to meet a NOx BACT limit of 3.5 ppm for combined cycle gas turbines. The EPA/TEC Consent Decree requires the re-powering of a combination of units totaling at least 550 MW. The applicant proposes to re-power of Gannon Units 3 through 6 with eleven combined cycle gas turbines and shutdown Gannon Units 1 and 2.

PSD applicability for this project is based on a netting analysis that considers emission decreases resulting from the shutdown of the existing coal-fired boiler for each re-powered Gannon Unit. Therefore, the permit will require shutdown of the existing coal-fired boiler prior to commencing operation of each corresponding Bayside Unit. This will not impose any hardship on the applicant because the existing units must be disconnected from the steam-electrical turbines during construction. The permit will also require the shutdown of all existing coal-fired Gannon Units before January 1, 2005.

Interim Coal Firing and Permanent Bar on Coal Combustion

The applicant did not predict any emissions increases for the remaining coal-fired boilers after the shutdown of each re-powered Gannon Unit. To prevent large increases in actual emissions from the remaining coal-fired units, the permit will reduce the limit on the total heat input through the coal yard after each re-powered Gannon Unit is 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 13A. Reductions of Coal Yard Heat Input Limit

Shutdown Unit	Coal Usage Tons Per Year	Heating Value MMBtu per ton coal	Reduction of Limit mmBTU per year
Gannon Unit 3	453,054	20.0	$9.06 \times 10^{+06}$
Gannon Unit 4	435,187	20.0	$8.70 \times 10^{+06}$
Gannon Unit 5	549,023	24.0	$13.2 \times 10^{+06}$
Gannon Unit 6	890,562	24.0	$21.4 \times 10^{+06}$

The information presented above is based on the Annual Operating Reports submitted for the F. J. Gannon Power Plant. The current Title V operation permit limits the total heat input from the coal yard to $69.9 \times 10^{+06}$ MMBtu per year. After shutdown of the coal-fired boiler for each re-powered Gannon Unit, the limit on heat input from the coal yard shall be reduced by the actual annual heat input from the shutdown boiler as specified above. 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. In addition, the EPA/TEC Consent Decree prohibits TEC from combusting coal in the operation of any unit at Gannon plant commencing on January 1, 2005.

13. SUMMARY OF PROJECT EMISSIONS

The following table summarizes the actual annual emissions from the F. J. Gannon Power Plant and the potential annual emissions from the Bayside Power Station.

Table 13A. Comparison of Emissions After 2004

Pollutant	Gannon Units 1 – 6 Decreases Due to Shutdown Tons Per Year [a]	Bayside Units 1 – 4 Increases Due to New Units Tons Per Year [b]	Net Emissions Change Tons Per Year [c]
CO	- 748	+ 1383	+ 635
NOx	- 29,927	+ 1113	- 28,814
Pb	- 20	+ < 2	- 18
PM/PM10	- 1997	+ 578	- 1419
SAM	- 3056	+ 89	- 967
SO2	- 61,119	+ 487	- 60,632
VOC	- 114	+ 135	+ 21

Notes:

a. Actual annual emissions are based on the Annual Operating Reports for all emission units at the existing Gannon Plant.

b. Potential annual emissions are based on the permit limits and firing natural gas at the maximum permitted heat input rate for 8760 hours per year for each of the eleven gas turbines.

c. The net emissions change represents the difference between the current actual emission levels from the existing plant and the maximum permitted emissions from the proposed new plant after all coal-fired operations are shut down.

As shown, the project will result in large decreases in emissions of lead, nitrogen oxides, particulate matter, sulfuric acid mist, and sulfur dioxide. Based on potential emissions, the project results in increased emissions of carbon monoxide and volatile organic compounds. However, based on recent test data for the General Electric Model PG7241(FA) gas turbine, actual CO and VOC emissions will likely be less than half of the potential emissions, which would result in actual emission decreases for these pollutants as well.

14. AIR QUALITY IMPACT ANALYSIS

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 (NO2), particulate matter (PM10), and sulfur dioxide (SO2) 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 3 through 6. Actually, no such controls are in place and the Bayside project will result in net emissions decreases for PM_{10} as well as NO_2 and SO_2. Therefore, only an evaluation of the ambient impacts from the significant emissions of CO and VOC is required for this 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 57 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 the 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.

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.

Table 14A. 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	175 $\mu g/m^3$	575 $\mu g/m^3$	No
VOC	Annual Emission Rate	57 TPY	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.

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.

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 the 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.

Twelve scenarios were modeled for firing natural gas consisting of three load conditions and four compressor inlet temperatures. The following table shows the results of the significant impact analysis.

Table 14B. 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	175	500	No
	1-hour	262	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.

Requested Modeling Analysis

At the request of the Department, the applicant performed an ambient impact analysis for CO, NO_2, PM/PM_{10}, and SO_2 for comparison with the AAQS based on the ISCST3 air dispersion model and the 12 scenarios for firing natural gas. The following table summarizes the results based on the latest submittal.

Table 14C. Maximum Predicted Ambient Impacts from Bayside Project Alone

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	261	40,000	40,000
	HSH, 8-hr	175	10,000	10,000
NO_2	Annual	3	100	100
PM_{10}	HSH, 24-hr	59	150	150
	Annual	6	50	50
SO_2	HSH, 3-hr	91	1300	1300
	HSH, 24-hr	23	260	365
	Annual	2	60	80

The analysis indicates that the project, evaluated independently, will not cause a violation of the state or federal ambient air quality standards. The Department also required a PSD increment analysis for PM_{10}. The following table summarizes the results.

Table 14D. Summary of PM_{10} Class II Increment Analysis

Pollutant	Averaging Period	Maximum Project Impact ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
PM_{10}	HSH, 24-hr	19	30
	Annual	1	17

A similar analysis was not required for SO_2 due to the very large net emissions decreases resulting from the project (more than 50,000 tons per year), which would expand increment.

Analysis of Additional Impacts on Soils, Vegetation, and Wildlife from Growth

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas-fueled combustion turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The predicted maximum ground-level carbon monoxide concentrations from the proposed project will be considerably less than the respective significant impact levels. These values, in-turn, are less than the carnon monoxide 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. There will be little growth associated with this project because it involves the re-powering of an existing plant.

15. 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 impact analysis, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the air quality impact analysis. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, 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

PERMITTEE:

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

Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No. 0570040-015-AC
Air Permit No. PSD-FL-301A
Facility ID No. 0570040
SIC No. 4911
Expires: July 1, 2005

PROJECT AND LOCATION

This permit authorizes construction of eleven new combined cycle gas turbines with an approximate electrical production capacity of 2845 MW. The new units will be used to re-power the steam-electrical generators for Units 3, 4, 5, and 6 at the existing F. J. Gannon Station. The re-powered plant will be renamed the "Bayside Power Station". The project will be 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 Judgment 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 Rates
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
Division of Air Resources Management

(Date)

PROJECT DESCRIPTION

Upon completion of construction and shutdown of all coal-fired units, the new Bayside Power Station will have an approximate electrical production capacity of 2845 MW based on the nominal capacities for Bayside Unit 1 (746 MW), Bayside Unit 2 (1090 MW), Bayside Unit 3 (501 MW), and Bayside Unit 4 (508 MW). Note that the final design may not fully utilize the nameplate capacities of the existing steam-electrical turbines. The following table summarizes the emission units regulated by this air construction permit.

EU No.	Emission Unit Description
001	Gannon Unit 1 – existing coal fired boiler with 125 MW steam electrical generator
002	Gannon Unit 2 – existing coal fired boiler with 125 MW steam electrical generator
003	Gannon Unit 3 – existing coal fired boiler with 180 MW steam electrical generator
004	Gannon Unit 4 – existing coal fired boiler with 188 MW steam electrical generator
005	Gannon Unit 5 – existing coal fired boiler with 239 MW steam electrical generator
006	Gannon Unit 6 – existing coal fired boiler with 414 MW steam electrical generator
008	Gannon Station Coal Yard - Serves existing Gannon Units 1 – 6
020	Bayside Unit 1A – 169 MW combined cycle gas turbine fired with natural gas
021	Bayside Unit 1B – 169 MW combined cycle gas turbine fired with natural gas
022	Bayside Unit 1C – 169 MW combined cycle gas turbine fired with natural gas
023	Bayside Unit 2A – 169 MW combined cycle gas turbine fired with natural gas
024	Bayside Unit 2B – 169 MW combined cycle gas turbine fired with natural gas
025	Bayside Unit 2C – 169 MW combined cycle gas turbine fired with natural gas
026	Bayside Unit 2D – 169 MW combined cycle gas turbine fired with natural gas
027	Bayside Unit 3A - 169 MW combined cycle gas turbine fired with natural gas
028	Bayside Unit 3B - 169 MW combined cycle gas turbine fired with natural gas
029	Bayside Unit 4A – 169 MW combined cycle gas turbine fired with natural gas
030	Bayside Unit 4B – 169 MW combined cycle gas turbine fired with natural gas

Notes:

a. Gannon Unit 5 (EU 005) must be shutdown before operating Bayside Unit 1 (EUs 020, 021, and 022).
b. Gannon Unit 6 (EU 006) must be shutdown before operating Bayside Unit 2 (EU 023, 024, 025, and 026).
c. Gannon Unit 3 (EU 003) must be shutdown before operating Bayside Unit 3 (EU 027 and 028).
d. Gannon Unit 4 (EU 004) must be shutdown before operating Bayside Unit 4 (EU 029 and 030).
e. EUs 001, 002, 003, 004, 005, and 006 must be shut down before January 1, 2005. The Department expects that other coal-related activities will also cease operation shortly after the shutdown of the coal-fired boilers.

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a 112(g) case-by-case determination of the Maximum Available Control Technology (MACT).

Title IV: The existing facility has several emissions units, including the new combined cycle gas turbines, which 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: The existing 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 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.

RELEVANT DOCUMENTS

- DEP/TEC Consent Final Judgment signed on December 7, 1999.
- EPA/TEC Consent Decree entered on October 5, 2000.
- PSD permit application (Bayside Units 1 and 2) received on September 21, 2000 and all related correspondence.
- Original PSD air construction Permit No. PSD-FL-301 issued on March 30, 2001.
- PSD permit application (Bayside Units 3 and 4) received on June 26, 2001 and all related correspondence.

ADMINISTRATIVE REQUIREMENTS

1. Effective Date: The effective date of this permit is (DRAFT).

2. 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.

3. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should 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. Copies of all such documents shall 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.

4. 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.

5. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. [Rule 62-4.160, F.A.C.]

6. 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.]

7. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months of the effective date of this permit, 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 Judgment or the EPA/TEC Consent Decree. [40 CFR 52.21(r)(2)]

8. 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 Judgment or the EPA/TEC Consent Decree. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]

9. 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)]

10. 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.]

11. 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.]

12. 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]

13. 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; 40 CFR 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.

Emissions Units 020 – 030: Combined Cycle Gas Turbines

Description: Each emissions 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 exclusive 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 a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Generating Capacity: The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

EU No.	Bayside Unit	MW, Shaft	Existing Gannon ST	MW, ST	Total
020	1A	169 MW	No. 5	239	746
021	1B	169 MW			
022	1C	169 MW			
023	2A	169 MW	No. 6	414	1090
024	2B	169 MW			
025	2C	169 MW			
026	2D	169 MW			
027	3A	169 MW	No. 3	163	501
028	3B	169 MW			
029	4A	169 MW	No. 4	170	508
030	4B	169 MW			
Totals	11 GTs	1859 MW	4 STs	986	2845

Note: The nameplate generating capacity is shown for the steam-electrical turbines (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of CO, PM/PM_{10}, and VOC. Firing natural gas as the only authorized fuel minimizes emissions of SAM and SO_2 because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces NOx emissions.

Continuous Monitors: Each gas turbine is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. <u>BACT Determinations</u>: 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. 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

3. Schedule: Bayside Unit 1 is scheduled for completion in May of 2003 and Bayside Units 2, 3, and 4 are scheduled for completion in May of 2004. The permittee shall inform the Department of any substantial changes to the construction schedule. [Application; Rule 62-212.400(BACT), F.A.C.]
4. Combined Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain eleven new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 169 MW of shaft-driven 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]
5. 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). The permittee shall submit the final design data with the Title V application. [Design]
6. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated control system (or better) for each gas turbine. 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 and shutdown. [Design; 62-212.400(BACT), F.A.C.]
7. 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 provide efficient lean premix combustion. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]
8. SCR System: The permittee shall install, tune, operate and maintain a selective catalytic reduction (SCR) system to reduce NOx emissions from each combined cycle gas turbine. The SCR system shall consist of an ammonia injection grid, catalyst, ammonia storage, a monitoring and control system, electrical system, piping, and other ancillary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels. [DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]
9. Evaporative Inlet Air-Cooling System: Each 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 increases 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

10. Permitted Capacity: The maximum heat input rate to each gas turbine shall not exceed 1842 mmBTU per hour while producing approximately 169 MW. The maximum heat input rate is based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas and expected performance levels. 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.]

11. Allowable Fuels: Each gas turbine shall fire only pipeline-quality natural gas. No other fuels are allowed. [Design; Rules 62-210.200(PTE); DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree]

12. Restricted Operation: The hours of operation for each gas turbine are not limited (8760 hours per year).

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

13. 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 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 to minimize emissions during startup and shutdown. [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.}

14. 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 on a compressor inlet temperature of 59° F. 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 shall be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

    a. **Ammonia Slip**: Subject to the requirements of Condition No. 22 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 based on the average of three test runs. [Rule 62-4.070(3), F.A.C.]

    b. **Carbon Monoxide (CO)**: CO emissions shall not exceed 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen based on the average of three test runs as determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]

    c. **Nitrogen Oxides (NOx)**: NOx emissions shall not exceed 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen based on the average of three test runs as determined by EPA Method 7E. NOx emissions are defined as oxides of nitrogen reported as NO_2. [DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree; 40 CFR 60.332]

d. **Particulate Matter (PM/PM_{10})**: The exclusive firing of pipeline-quality natural gas combined with the efficient combustion design and operation of each gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with carbon monoxide and visible emissions standards shall serve as continuous indicators of efficient combustion to minimize particulate matter emissions. No performance tests are required. {Permitting Note: Particulate matter emissions are expected to be less than 12 pounds per hour when firing natural gas 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 exclusive firing of pipeline-quality natural gas effectively limits potential emissions of SO_2 and SAM. No performance tests are required. [Design; DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree; 40 CFR 60.333]

f. **Visible Emissions**: 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. 17 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

g. **Volatile Organic Compounds (VOC)**: The exclusive firing of pipeline-quality natural gas combined with the efficient combustion design and operation of each gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with carbon monoxide standards shall serve as a continuous indicator of efficient combustion to minimize VOC emissions. No performance tests are required. {Permitting Note: VOC emissions are expected to be less than 3 pounds per hour and 1.3 ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-212.400(BACT), F.A.C.]

15. Emissions Standards Based on CEMS Data: The following standards apply to each gas turbine based on data collected from each required Continuous Emissions Monitoring System (CEMS).

   a. **Carbon Monoxide (CO)**: CO emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average of CEMS data.

   b. **Nitrogen Oxides (NOx)**: NOx emissions shall not exceed 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average of CEMS data.

   Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive 1-hour averages. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of the available valid 1-hour averages. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

16. 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 compliance averages determined from the CO and NOx CEMS data. [Rule 62-210.700(4), F.A.C.]

17. Alternate Standards and CEMS Data Exclusion: The following permit conditions establish alternate standards or allow the exclusion of monitoring data for specifically defined periods of startup, shutdown, and documented malfunction of a gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of emissions during such incidents.

   a. **Opacity During Startup and Shutdown**: During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

b. **Low Load Operation**: Excluding startup, shutdown, and documented malfunction, each gas turbine is allowed up to three hours of operation below 50% base load in any 24-hour block, providing: the gas turbine is firing natural gas; the CO and NOx CEMS are functioning properly during such periods and recording valid emissions data within the span range of the monitors; and the gas turbine remains in compliance with the CO and NOx emissions standards based on 24-hour block averages of valid CEMS data.

c. **CEMS Data Exclusion**: For the following identified operational periods, CO and NOx emissions data may be excluded from the 24-hour block compliance averages in accordance with the corresponding requirements.

   (1) *Startup, Shutdown, and Malfunction*: Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented malfunction shall not exceed four 1-hour emission averages in any 24-hour block due to all such episodes. Gas turbine startup is the commencement of operation of a gas turbine that 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 malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

   (2) *Steam Turbine Cold Startup*: Periods of data excluded for a steam turbine cold startup shall not exceed sixteen 1-hour emission averages in any 24-hour block. 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 data and experience, the Department may modify this period of data exclusion in the Title V air operation permit without modifying this PSD permit.

   (3) *Tuning*: If the permittee provides at least five days advance notice prior to a major tuning session performed by the manufacturer's representative, monitoring data during tuning may be excluded from the 24-hour block compliance averages. Periods of data excluded for such episodes shall not exceed a total of three 1-hour averages in any 24-hour block. Tuning sessions must be performed in accordance with the manufacturer's recommendations. {Permitting Note: As an example, a major tuning session would occur after a combustor change-out. A tuning session may take a few hours each day over a few days. No more than two major tuning sessions would be expected during any year.}

   If a CEMS reports emissions in excess of a CO or NOx standard, the permittee shall notify the Compliance Authority within one 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.

d. **Startup and Shutdown Plan**: 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. 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 each procedure, 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 data exclusion allowed for a steam turbine cold startup defined in Condition 23 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.

As provided by the authority in Rule 62-210.700(5), F.A.C., the above requirements are established in lieu of the provisions of Rule 62-210.700(1), F.A.C. [Design; Rules 62-210.700(5), 62-4.130, and Rule 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

18. Operating Rate During Testing: Emissions performance testing 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.]

19. Test Methods: Any 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 • The minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 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 use a continuous sampling train.
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". Although no specific tests are required for emissions of particulate matter and volatile organic compounds, the test methods for are included for completeness. No other methods may be used for compliance testing unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

20. Initial Compliance Tests: Each gas turbine shall be tested to demonstrate compliance with 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 gas turbine. Tests for CO and NOx shall be conducted concurrently. Certified CEMS data may be used to demonstrate compliance with the initial CO and NOx standards. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.335]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for ammonia slip and visible emissions. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. {Permitting Note: Continuous compliance with the CO and NOx standards is demonstrated with certified CEMS data.} [Rules 62-212.400(BACT) and 62-297.310(7)(a)4, F.A.C.]

22. 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. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering 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

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

   a. **Emission Averages**. Compliance with the 24-hour standards for CO and NOx emissions shall be based on data collected by the required CEMS. The 24-hour block shall start at midnight of each operating day and consist of 24 consecutive 1-hour blocks. If a unit operates continuously throughout the day, the 24-hour block average shall be the average of 24 consecutive 1-hour emission averages. If a unit operates less than 24 hours during the day, the 24-hour block average shall be the average of available valid 1-hour emission averages collected during operation. If monitoring data is authorized for exclusion (due to startup, shutdown, malfunction, or tuning), the 24-hour block average shall be the average of the remaining available valid 1-hour emission averages collected during operation. Upon a request from the Department, the NOx emission rate shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

b. *Data Collection.* The CEMS shall be designed and operated to sample, analyze, and record CO, CO_2, and NOx data evenly spaced over the hour. Each 1-hour emission average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour emission average shall be computed from at least two data points separated by a minimum of 15 minutes. If the unit does not operate in more than one quadrant of a 1-hour block, the data is insufficient to determine a 1-hour emission average and shall be ignored. (Example: Unit begins startup with only ten minutes remaining in the 1-hour block.) All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. If the CEMS measures concentration on a wet basis, the CEMS 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, a curve of the flue gas moisture content versus load may be developed through manual stack test measurements and used in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). The CO and NOx CEMS shall express the 1-hour emission averages and the 24-hour block averages in terms of "ppmvd corrected to 15% oxygen".

c. *Data Exclusion.* CO, CO_2, and NOx emissions data shall be recorded by the CEMS at all times including episodes of startup, shutdown, malfunction, and tuning. CO and NOx emissions data recorded during such episodes may be excluded from the 24-hour block compliance averages in accordance with the requirements of Condition No. 17 of this section. All periods of data excluded due to startup, shutdown or malfunction 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 shall not be excluded if the 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 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. Excluded emissions shall be summarized in the required semiannual report.

d. *NOx Certification.* 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 CEMS emission standards of this permit, missing data shall not be substituted. Instead the 24-hour 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 7E or 20 as defined in Appendix A of 40 CFR 60. The span for the NOx monitor shall not be greater than 10 ppmvd corrected to 15% O_2. A dual span monitor may be used.

e. *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 use a continuous sampling train. The span for the CO monitor shall not be greater than 25 ppm corrected to 15% oxygen. A dual span CO monitor may be used. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

f. *Monitor Availability*. Monitor availability shall not be less than 95% in any calendar quarter. The report required in Condition 23e above shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEMS 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), 62-210.700(5), and 62-212.400(BACT), F.A.C.]

24. 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 through 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 in 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 AND REPORTS

25. Semiannual CEMS Report: In addition to the reports required pursuant to 40 CFR 60.7, the permittee shall submit semiannual reports for each gas turbine summarizing the CEMS data and equipment. For each calendar quarter, the report shall include: the 24-hour block compliance averages for each day of operation; the number of 1-hour emission averages excluded from each 24-hour compliance average; the emissions rate of the excluded monitoring data; the reason for excluding monitoring data; the hours of missing data due to monitor downtime; the reason for any monitor downtime; unusual maintenance or repair of the CEMS; and a summary of any RATA tests performed. A report covering operations from January through June shall be submitted by July 30th of each year. A report covering operations from July through December shall be submitted by January 30th of each year. The report due dates may be modified by the Title V permit. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Monitoring of Operations: To demonstrate compliance with the gas turbine capacity requirements, the permittee shall monitor and record the operating rate of each 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 CEMS required above, or by monitoring daily rates of consumption and heat content of natural gas in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B. EXISTING GANNON 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 – existing coal fired boiler with 125 MW steam electrical generator
002	Gannon Unit 2 – existing coal fired boiler with 125 MW steam electrical generator
003	Gannon Unit 3 – existing coal fired boiler with 180 MW steam electrical generator
004	Gannon Unit 4 – existing coal fired boiler with 188 MW steam electrical generator
005	Gannon Unit 5 – existing coal fired boiler with 239 MW steam electrical generator
006	Gannon Unit 6 – existing coal fired boiler with 414 MW steam electrical generator
008	Gannon Station Coal Yard - Serves existing Gannon Units 1 – 6

SHUTDOWN REQUIREMENTS

1. Shutdown of Coal-Fired Gannon Units
   a. *Shutdown of Gannon Unit 3*: The Gannon Unit 3 (EU 003) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 3 gas turbine (EU 027 and EU 028). Upon first fire in any Bayside Unit 3 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 9.06 x 10^{+06} mmBTU per calendar year.
   b. *Shutdown of Gannon Unit 4*: The Gannon Unit 4 (EU 004) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 4 gas turbine (EU 029 and EU 030). Upon first fire in any Bayside Unit 4 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 8.70 x 10^{+06} mmBTU per calendar year.
   c. *Shutdown of Gannon Unit 5*: The Gannon Unit 5 (EU 005) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 1 gas turbine (EU 020 - EU 022). Upon first fire in any Bayside Unit 1 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 13.2 x 10^{+06} mmBTU per calendar year.
   d. *Shutdown of Gannon Unit 6*: The Gannon Unit 6 (EU 006) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 2 gas turbine (EU 023 - EU 026). Upon first fire in any Bayside Unit 2 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 21.4 x 10^{+06} mmBTU per calendar year.
   e. *Shutdown of Gannon Units 1 - 6*: The permittee shall shutdown and cease any and all operation of coal-fired Gannon Units 1 through 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.

   [Rule 62-212.400(BACT), F.A.C.; EPA/TEC Consent Decree]
2. 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]
3. 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.]
4. 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]

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.

<u>Florida Administrative Code (F.A.C.) Rules</u>:

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.

<u>Facility Identification (ID) Number</u>:

Example: Facility ID No. 099-0001
Where: 099 - identifies the specific county location
0221 - identifies the specific facility

<u>New Permit Numbers</u>:

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

<u>Old Permit Numbers</u>:

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

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Table B-1. Emissions Standards for Bayside Units 1 - 4
Eleven General Electric Model PG7241(FA) Combined Cycle Gas Turbines Firing Natural Gas

Pollutant	Controls and Standards[a]
Standards based on emissions performance tests at permitted capacity and an inlet temperature of 59° F:	
Ammonia	*Standard*: 5 ppmvd @ 15% O_2 [b]
Fuel Specification (BACT)	*Standard*: Pipeline-quality natural gas
CO (BACT)	*Control*: DLN combustion technology and exclusive firing of natural gas *Standard*: 7.8 ppmvd @ 15% O_2 *Standard*: 28.7 lb/hour
NOx	*Controls*: SCR with DLN combustion technology and exclusive firing of natural gas *Standard*: 3.5 ppmvd @ 15% O_2 *Standard*: 23.1 lb/hour
PM/PM_{10} (BACT)	*Controls*: DLN combustion technology and exclusive firing of natural gas *Standard*: 10% opacity, 6-minute average *Comments*: The CO CEMS standard serves as a continuous indicator of efficient combustion. The estimated maximum emissions are 12 lb/hour (front-half catch only).
SAM/SO_2	*Standard*: Exclusive firing of natural gas
VOC (BACT)	*Controls*: DLN combustion technology and exclusive firing of natural gas *Comments*: The CO CEMS standard serves as a continuous indicator of efficient combustion. The estimated maximum emissions are 3 lb/hour (1.3 ppmvd @ 15% O_2).
Standards based on CEMS data:	
CO (BACT)	*Control*: DLN combustion technology and exclusive firing of natural gas *Standard*: 9.0 ppmvd @ 15% O_2, 24-hour block average
NOx	*Controls*: SCR with DLN combustion technology and exclusive firing of natural gas *Standard*: 3.5 ppmvd @ 15% O_2, 24-hour block average

Notes:

a. "BACT" means Best Available Control Technology. "SCR" means selective catalytic reduction system. "DLN" means dry low-NOx combustion technology.

b. If the tested ammonia slip rate exceeds 5 ppmvd corrected to 15% oxygen during the required annual test, the permittee shall begin testing and reporting the ammonia slip for each subsequent calendar quarter. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, the permittee shall take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen. The permittee shall test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

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 as a result of the DEP/TEC Consent Final Judgment and the EPA/TEC Consent Decree. The gas turbines are subject to the acid rain requirements, which require a continuous emissions monitoring system (CEMS) for NOx emissions. The NOx CEMS will also be used to demonstrate compliance with the specified permit standards.

The project did result in significant net actual emissions increases 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-level controls had previously been installed on the existing Gannon Units. For CO, PM/PM_{10}, and VOC emissions, the Department determines that the efficient combustion of pipeline-quality natural gas 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 the determination of Best Available Control Technology (BACT). A continuous monitoring system (CEMS) is required to demonstrate continuous compliance with the CO standards. The CO CEMS will also serve as a continuous indicator of efficient combustion to minimize PM and VOC emissions. The Department's detailed technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued with the draft permit package.

Determination By:

(DRAFT)

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

Recommended By:

(DRAFT)

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

Approved By:

(DRAFT)

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

SUMMARY OF MASS EMISSIONS RATES

Table E-1. Summary of Mass Emission Rates Vs. Compressor Inlet Temperatures

Pollutant	Compressor Inlet Temperature	Mass Emission Rate lb/hour
CO	18° F	31.1
	35° F	30.0
	59° F	28.7
	72° F	27.8
	93° F	26.9
NOx	18° F	24.7
	35° F	23.8
	59° F	23.1
	72° F	22.6
	93° F	21.9
PM/PM_{10}	18° F	11.5
	35° F	11.4
	59° F	11.3
	72° F	11.3
	93° F	11.2
VOC	18° F	3.0
	35° F	3.0
	59° F	2.8
	72° F	2.7
	93° F	2.7

Notes:

- Table represents the mass emission rates for the General Electric Model PG7241(FA) gas turbine (combined cycle) firing natural gas with a selective catalytic reduction system to reduce NOx emissions.
- NOx emission rates are reported as NO_2 and are based on control with DLN combustion and an SCR system.
- PM emission rates 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 extent 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).

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.]

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: For natural 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" value provided by the applicant is approximately 10.0 for natural gas. The equivalent emission standard is 108 ppmvd at 15% oxygen. The emissions standards of this permit are much 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.

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 that contains sulfur in excess of 0.8 percent by weight.

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:

(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.

<u>Department requirement</u>: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. 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).

<u>Department requirement</u>: 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.

<u>Pursuant to 40 CFR 60.335, Test Methods and Procedures</u>:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent 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.

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.

{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 CEMS data, provided that compliance is 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 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 monitoring methods.

(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.}

SEMIANNUAL CONTINUOUS MONITOR SYSTEMS REPORT

{Note: This form is based on 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 Units 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*

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 11/28/01

C. Signature

X Ron [illegible]

☐ Agent
☐ Addressee

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

Ron J [illegible]

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)*
7000 2870 0000 7028 2935

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

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Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+ 4
Tampa, FL 33619

PS Form 3800, May 2000 See Reverse for Instructions